REVENUE REQUIREMENT, DETERMINATION OF NET UTILITY INCOME

1. SUMMARY OF REVENUE REQUIREMENT

Hydro One Distribution follows standard regulatory practice and has calculated its revenue requirement consistent with the principles of the 2006 Electricity Distribution Rate Handbook as follows:

Table 1: Revenue Requirement ($ Millions)

Components	2017[1]	2018	Reference
OM&A	593.0	584.8	Exhibit C1, Tab 1, Schedule1
Depreciation and Amortization	390.2	392.6	Exhibit C1, Tab 6, Schedule 1
Income Taxes	48.7	61.5	Exhibit C1, Tab 7, Schedule 1
Return on Capital	435.8	461.1	Exhibit D1, Tab 2, Schedule 1
Total Revenue Requirement	**1,467.6**	**1,499.9**	Exhibit E2, Tab 1, Schedule 1
Deduct External Revenues and Other	(52.7)	(53.6)	Exhibit E1, Tab 1, Schedule 2
Rates Revenue Requirement	**1,414.9**	**1,446.3**	
Regulatory Deferral and Variance Accounts Disposition	11.1	6.2	Exhibit F1, Tab 2, Schedule 1, Attachment 1
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,452.4**	

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 above Revenue Requirement is the amount required by Hydro One Distribution to achieve its business objectives and aligns customer needs and preferences, responsible stewardship of a safe and reliable system, and impact on rates. The proposed Revenue Requirement is a reflection Hydro One's commitment to pursuing efficiencies and improved productivity before requesting its customers pay more.

Witness: Joel Jodoin

2. CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

2.1 OM&A EXPENSE

Table 2: OM&A Expense ($ Millions)

	2018
Sustaining	346.7
Development	11.0
Operations	36.7
Customer Service	131.6
Common Corporate Costs and Other Costs	53.9
Property Taxes & Rights Payments	4.9
Total OM&A	**584.8**

2.2 DEPRECIATION AND AMORTIZATION EXPENSE

Table 3: Depreciation and Amortization Expense ($ Millions)

	2018
Depreciation	379.3
Amortization (Excluding Other Reg. Amortization)	13.3
Total Expense	**392.6**

2.3 CORPORATE INCOME TAXES

Table 4: Corporate Income Taxes ($ Millions)

	2018
Regulatory Taxable Income	236.6
Tax Rate	26.5%
Subtotal	**62.7**
Less: Credits	(1.2)
Total Income Taxes	**61.5**

2.4 RETURN ON CAPITAL

Table 5: Return on Capital ($ Millions)

	2018
Return on Debt	191.6
Return on Equity	269.5
Return on Capital	**461.1**

3. REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

Table 6 below compares, by component, the Year 2017 approved Revenue Requirement (as per EB-2013-0416) with the Year 2018 proposed Revenue Requirement.

Table 6: Comparison of Revenue Requirement: 2018 vs. 2017 ($ Millions)

Description	**2018 vs. 2017**
OM&A	(8.2)
Depreciation and Amortization	2.4
Income Taxes	12.8
Return on Capital	25.3
Total Revenue Requirement	**32.3**
Less External Revenues	(0.9)
Rates Revenue Requirement	**31.4**
Regulatory Deferral and Variance Accounts Disposition	(4.9)
Rates Revenue Requirement (with Deferral and Variance Accounts)	**26.5**

Comparison of Proposed (2018) vs. Previously OEB-Approved (2017)

The increase in revenue requirement is largely attributable to the impact of rate base growth, as reflected in the increase in depreciation, return on capital, income tax expenses and lower external revenue forecast. These are partially offset by a lower cost of debt and lower OM&A costs.

Table 7 provides a summary of the value of the key impacts on the Rate Revenue Requirement.

Table 7: Impact of the Individual Component on Revenue Requirement
($ Millions)

Description	2018 vs. 2017	2018 vs. 2017
Decrease in OM&A	(8.2)	(0.5%)
Rate Base Growth	31.4	2.2%
Lower cost of debt	(3.7)	(0.3%)
Tax	12.8	0.9%
Impact on Revenue Requirement	**32.3**	**2.3%**
External Revenue	(0.9)	(0.1%)
Regulatory Deferral and Variance Accounts Disposition	(4.9)	(0.3%)
Total Change	**26.5**	**1.9%**

4. REVENUE REQUIREMENT WORKFORM

Exhibit E2, Tab 1, Schedule 2 includes the OEB's "Revenue Requirement Workform" for 2018 Test Year. At current approved rates there is a revenue deficiency of $74 million. The proposed rates in this Application eliminate this deficiency, as indicated in Tab 8 of the workform. Working Capital Rate in the workform is reflective of total working capital which includes cash working capital and materials and supply inventory.

Tabs 10 through 13 of the workform have not been completed as the template does not allow for the necessary flexibility required for Hydro One's cost allocation and rate design requirements. Exhibits G and H in this Application cover Rate Design and Cost Allocation in detail and provide information equivalent to that requested in the workform.

EXTERNAL REVENUES

1. INTRODUCTION

This Exhibit details Hydro One Distribution's external revenues which are deducted from the revenue requirement in the derivation of rates revenue requirement. External revenues are earned through the provision of services to third parties and through joint use of Hydro One Distribution's assets by third parties. These revenues offset Hydro One Distribution's revenue requirement, reducing the required revenue to be collected from ratepayers.

External revenues are categorized as regulated and unregulated. Regulated revenues are based on OEB-approved specific service charges, which are detailed in Exhibit H1, Tab 2, Schedule 3, whereas unregulated revenues are based on charges determined by Hydro One. Section 1.1 of this Exhibit provides an overview of the costing of external work.

The Standard Supply Service charge is an OEB-set administrative fee paid by customers who purchase electricity directly from their local utility. This charge is also deducted from the revenue requirement in the derivation of rates revenue requirement.

Hydro One Distribution's strategy is to focus on core work and continue to be responsive to external work requests and accommodate customer needs. Total Hydro One Distribution external revenues are shown in Tables 1 and 2.

Table 1: Historic and Bridge Year Total Distribution External Revenues ($ Millions)

Description	Historic					Bridge	
	2014	2015		2016		2017	
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved
Regulated Revenues	25.4	37.7	39.4*	51.6	40.4*	39.0	42.5*
Unregulated Revenues	6.5	6.5	6.7	7.0	6.6	6.8	6.5
Sub-Total External Revenue	**31.9**	**44.2**	**46.1**	**58.6**	**47.0**	**45.8**	**49.0**
Standard Supply Service Charge	3.7	3.7	3.6	3.6	3.7	3.9	3.7
Total External Revenue and Other	**35.6**	**47.9**	**49.7**	**62.2**	**50.7**	**49.7**	**52.7**

*Updated approved amounts reflect the EB-2013-0416 Draft Rate Order decision for miscellaneous charges revenue and the EB-2015-0141 decision for pole attachment revenue.

Table 2: Forecast of Total Distribution External Revenues ($ Millions)

Description	Test				
	2018	2019	2020	2021	2022
	Forecast	Forecast	Forecast	Forecast	Forecast
Regulated Revenues	42.9	43.9	44.2	45.1	45.4
Unregulated Revenues	6.8	6.8	6.8	6.8	6.9
Sub-Total External Revenue	**49.7**	**50.7**	**51.0**	**51.9**	**52.3**
Standard Supply Service Charge	3.9	3.9	4.0	4.0	4.0
Total External Revenue and Other	**53.6**	**54.6**	**55.0**	**55.9**	**56.3**

External revenues are equivalent to approximately 3.0% of Hydro One Distribution's base revenue requirement over the 2018 to 2022 period. External revenues are forecast to rise from $45.8 million in 2017 to $49.7 million in 2018, driven largely by increases in joint-use telecom revenue, increased collection of account charges and reconnections of service.

1.1 COSTING AND PRICING

The cost of external work is determined on the basis of cost causality with estimates calculated in the same way for internal work, using the standard labour rates, equipment rates, material surcharge, and overhead rates. See Exhibit C1, Tab 3 Schedule 1 for details on the costing of work, generally.

Some costs associated with external work are described in Exhibit C1, Tab 1, Schedule 10, while others are reflected in other OM&A Exhibits. The costs underlying OEB-approved specific service charges are discussed in Exhibit H1, Tab 2, Schedule 3. In this Exhibit, the forecast revenues generated by OEB-approved specific service charges are based on the costs reflected in the time study discussed in Exhibit H1, Tab 2, Schedule 3 (the "Time Study").

For unregulated work, Hydro One adds an appropriate margin above its cost to cover, at a minimum, the risk of non-payment by third parties.

2. VARIANCE EXPLANATION

2.1 EXTERNAL REGULATED REVENUE

Regulated revenues for test years 2018 to 2022 are set out in Table 3 below. They account for 86% of external revenues during this period. These revenues cover a wide range of services based on rates and underlying costs as determined by the Time Study.

Table 3: Regulated Revenues ($ Millions)

Description	Historical capital years			Bridge Year	Test Years				
	2014	2015	2016	2017	2018	2019	2020	2021	2022
Retail Service capital revenues*	9.5	22.3	24.5	18.7	21.2	21.3	21.4	21.6	21.7
Sentinel Lights	2.8	3.0	3.2	3.0	2.9	2.7	2.5	2.3	2.0
Joint Use	8.0	8.2	19.5	12.1	14.9	16.1	16.4	17.3	17.6
Other External Work*	4.1	2.8	3.1	2.3	2.3	2.3	2.4	2.4	2.4
Generator Studies	1.0	1.4	1.3	3.0	1.7	1.5	1.6	1.6	1.7
Total	**25.4**	**37.7**	**51.6**	**39.0**	**42.9**	**43.9**	**44.2**	**45.1**	**45.4**

*Revenues associated with Retail Services and Other External Work have been regrouped since Hydro One's last distribution rate application (EB-2013-0416)

2.1.1 RETAIL SERVICE REVENUES

As outlined in the OEB's *2006 Electricity Distribution Rate Handbook* (the "Rate Handbook"), Chapter 11, Section 11.2, and further described in Exhibit H1, Tab 2, Schedule 3, Hydro One provides a number of customer administration services. Hydro One's retail service volumes and revenues are outlined in Table 4.

Table 4: Retail Services Revenue

		Historical Years			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
Rate Code	**Description**	**Volume / Revenue**	**Volume / Revenue**	**Volume / Revenue**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**
2	Statement of Account	N/A	N/A	9,818	4,167	$62,500	3,450	$49,439	2,800	$40,740	2,217	$32,740	1,700	$25,483	1,250	$19,013
4	Duplicate Invoices for Previous Billing	N/A	N/A	N/A	1,250	$18,750	1,013	$13,264	800	$10,640	613	$8,269	450	$6,165	313	$4,344
5	Request for other billing information	N/A	N/A	9,818	4,167	$62,500	3,450	$49,439	2,800	$40,740	2,217	$32,740	1,700	$25,483	1,250	$19,013
6a	Easement Letter (Letter Request)	1,787	1,471	1,045	727	$10,905	405	$35,195	83	$7,328	0	$0	0	$0	0	$0
6b	Easement Letter (Web Request)	2,804	3,046	3,247	3,429	$82,296	3,621	$86,904	3,812	$91,488	4,004	$96,096	4,196	$100,704	4,387	$105,288
7	Income Tax Letter	N/A	N/A	N/A	1,250	$18,750	1,013	$13,264	800	$10,640	613	$8,269	450	$6,165	313	$4,344
9	Account History	N/A	N/A	9,818	4,167	$62,500	3,450	$49,439	2,800	$40,740	2,217	$32,740	1,700	$25,483	1,250	$19,013
10	Credit Reference / Credit check (plus credit agency costs)	N/A	N/A	N/A	7,500	$112,500	5,850	$110,214	4,400	$89,232	3,150	$64,764	2,100	$43,764	1,250	$26,413
11	Returned Cheque Charge	6,521	5,677	6,270	6,026	$90,383	5,664	$41,800	5,324	$39,931	5,005	$38,136	4,704	$36,412	4,422	$34,758

		Historical Years			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
Rate Code	Description	Volume / Revenue	Volume / Revenue	Volume / Revenue	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast
14	Account Set Up Charge / Change of occupancy charge (Plus Credit Agency Costs, if applicable)	112,778	122,681	127,696	96,753	$2,902,590	92,835	$3,425,593	89,075	$3,339,411	85,467	$3,255,445	82,006	$3,174,443	78,685	$3,092,302
15	Special Meter Reads (retailer requested off-cycle read)	N/A	N/A	N/A	100	$3,000	100	$9,078	100	$9,174	100	$9,269	100	$9,371	100	$9,467
16	Collection of Account Charge - No Disconnection	926	4,826	5,695	2,000	$60,000	2,000	$197,460	1,900	$189,772	1,800	$181,836	1,700	$173,791	1,600	$165,408
18 & 19	Collection - Disconnect / Reconnect at Meter & Install/Remove Load Control Device - During Regular Hours	5,712	21,091	23,545	22,330	$1,451,450	22,775	$2,677,429	23,179	$2,758,765	23,590	$2,842,123	24,062	$2,936,045	24,542	$3,030,692
20 & 21	Collection - Disconnect / Reconnect at Meter & Install/Remove Load Control Device - After Regular Hours	110	1,038	2,051	410	$75,850	460	$192,708	485	$206,300	500	$215,910	500	$219,275	500	$222,520

		Historical Years			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
Rate Code	Description	Volume / Revenue	Volume / Revenue	Volume / Revenue	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast
22	Collection - Disconnect/Reconnect at Pole - During Regular Hours	260	1,138	1,239	1,710	$316,350	1,700	$529,992	1,800	$568,818	1,850	$592,500	1,900	$616,949	1,900	$625,081
23	Collection - Disconnect/Reconnect at Pole - After Regular Hours	N/A	N/A	N/A	168	$69,720	168	$138,608	168	$140,608	168	$142,617	168	$144,708	168	$146,724
24	Meter Dispute Charge - Measurement Canada	112	9	37	50	$1,500	50	$14,123	50	$14,331	50	$14,538	50	$14,755	50	$14,964
31a	Vacant Premise - Move in with Reconnect of Electrical Service at Meter	N/A	4,066	2,590	2,625	$0	591	$56,174	525	$50,495	459	$44,667	394	$38,814	328	$32,688
31b	Vacant Premise - Move in with Reconnect of Electrical Service at Pole	N/A	2,387	0	0	$0	0	$0	0	$0	0	$0	0	$0	0	$0

1

		Historical Years			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
Rate Code	**Description**	**Volume / Revenue**	**Volume / Revenue**	**Volume / Revenue**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**
32	Reconnect completed after regular hours (customer/ contract driven) - at Meter	N/A	N/A	0	90	$0	90	$21,601	90	$21,963	90	$22,327	90	$22,703	90	$23,069
33	Reconnect completed after regular hours (customer/contract driven) - at Pole	N/A	N/A	0	60	$0	60	$27,973	60	$28,360	60	$28,751	60	$29,156	60	$29,548
46a	Retailer Services – Establishing Service Agreements (rates as per the Handbook)	$521,796	$469,861	$413,105		$376,638		$340,638		$304,638		$268,638		$232,638		$196,638
46b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transaction Requests) as per the Handbook	$260,898	$234,930	$206,553		$188,319		$170,319		$152,319		$134,319		$116,319		$98,319
52	Late Payment Charge	$782,693	$15,492,798	$17,003,866		$12,776,871		$12,968,524		$13,163,052		$13,360,498		$13,560,906		$13,764,319
	Total					**$18,743,372**		**$21,219,175**		**$21,319,483**		**$21,427,191**		**$21,559,533**		**$21,683,922**

Call Centre Requests (Rate Codes 2, 4, 5, 7, 9, 10, 15) – Although Hydro One's customer base is expected to increase over time, the volume of requests completed through the call center is expected to decline as more customers move to online self-service tools. Volumes and associated revenues are outlined in Table 4.

Account Set Up Charge (Rate Code 14) –The volume of account set up requests completed via the call center is expected to decline as more customers move to online self-service tools as outlined in Table 4.

Returned Cheque Charge (Rate Code 11) – Returned cheque volumes are expected to decline over time as more customers switch from cheques to electronic payments (as outlined in Table 4).

Late Payment Charges (Rate Code 52) – As outlined in Section 11.3 of the Rate Handbook, when the total amount of a customer's bill has not been paid by the due date, a late payment charge may be applied to the outstanding balance. A monthly interest rate of 1.5% (19.56% per annum) has been established as the maximum level of this charge for all distributors. Hydro One customers are required to pay their bill 19 days after the billing date. Late payment revenue is expected to increase over the planning period as the customer base increases, as outlined in Table 4.

Collection Charges (Rate Code 16 to 23 and 32 to 33) – Table 4 outlines Hydro One's forecast collection volumes and the associated revenues. In most cases, volumes are projected to naturally increase as Hydro One's customer base increases over time. Charges are projected to increase significantly to accurately reflect the cost to complete the activity, as per Hydro One's recent Time Study. Hydro One is also proposing two new charges effective 2018 for customer-driven reconnection requests completed after hours at either the meter or the pole (Rate Codes 32 and 33).

Vacant Premise (Rate Code 31) – When a Hydro One account is closed, and a new property owner or occupant has not been identified, Hydro One will disconnect the electrical services at the property. Once the new property owner or occupant has been identified, electrical services will be reconnected. Volumes are expected to decline from 2018 to 2022 as a result of new smart meter and remote disconnect technology. Hydro One is proposing a new charge for this service effective 2018 (as outlined in Table 4).

Meter Disputes Charge (Rate Code 24) – Table 4 outlines Hydro One's projected volumes and the associated Meter Dispute Charge revenues. Charges are projected to increase significantly to accurately reflect the cost to undertake the activity, as per Hydro One's recent Time Study.

Retailer Services (Rate Code 46) – As outlined in the Rate Handbook, Chapter 11, Section 12.2, retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity. Table 4 outlines the anticipated revenue from retail services, including establishing service agreements and other service transaction requests.

Easement Letters (Rate Code 6) – Land in Ontario is subject to unregistered easements taken prior to April 1, 1999, in favour of the former Ontario Hydro or HEPC. Land continues to be subject to these unregistered easements until either the right expires (if there is a defined term) or until such unregistered easement is released by the holder of the right (Hydro One or any subsequent assignees). Hydro One is obliged to provide certain information with respect to unregistered easements rights upon request of any interested parties which, until 2002, was restricted to a written request and a reply within a 21-day statutory period.

In 2002, Hydro One launched the web application to enable an immediate and more cost-effective response to the existence of an unregistered right to a legally defined property. Initial uptake was slow. Hydro One made web enhancements to improve performance and further marketing efforts, including queries to law firms on performance issues and desired enhancements. These efforts have resulted in an upward trend in the use of the web application and a reduction in written inquiries as demonstrated in the Historical Years. Table 4 outlines the projected volumes and revenue.

2.1.2 SENTINEL LIGHT REVENUES

The sentinel light rental program is designed to provide rural customers with low-cost security lighting. The service is provided primarily to rural residential, farm, and cottage customers, for whom street lighting is not available.

Table 5 summarize the historical volumes of sentinel lights and poles owned and maintained by Hydro One Distribution. The decrease over the period reflects the fact that service is limited to customers already participating in the rental program.

Table 5: Sentinel Light Volumes and Revenue (Rate Code 50 & 51)

		Historical			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
OEB Rate Code	**Description**	**Volume**	**Volume**	**Volume**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**
50	Sentinel Light Rental Charge	30,110	28,905	27,201	25,558	$2,916,679	23,563	$2,819,077	21,568	$2,626,982	19,573	$2,423,920	17,578	$2,210,609	15,583	$1,987,767
51	Sentinel Light Pole Rental Charge	1,582	1,521	1,432	1,345	$66,981	1,240	$106,690	1,135	$96,293	1,030	$86,149	925	$76,146	820	$66,322
	Total					**$2,983,660**		**$2,925,767**		**$2,723,276**		**$2,510,070**		**$2,286,755**		**$2,054,089**

2.1.3 JOINT USE

Joint use revenues are generated from third parties who place attachments on Hydro One Distribution's poles. For this right, Hydro One charges an attachment fee per pole. At the end of 2016, there were approximately 558 agreements in place with joint use partners, such as reciprocal and non-reciprocal telecommunications companies, local distribution companies ("LDCs"), generators, and municipalities. About 90% of the joint use revenue comes from telecommunications companies.

Joint use telecommunications revenues increase significantly in 2016 due to the implementation of the new charges approved in Hydro One's last rate application (EB-2013-0416). Hydro One requested that the rate be increased starting in 2015. However, the implementation of the new charges was put on hold due to a separate OEB hearing reviewing the joint use telecommunications rate (EB-2015-0141). Therefore, Hydro One did not charge the rates approved in EB-2013-0416 until 2016. In 2016, Hydro One also back-billed telecommunications joint use partners to collect revenue for the previous year when revenue was under-collected. In 2017, the revenues are forecast to decrease as there is no back-billing. In 2018, the projected revenues increase again, as Hydro One is applying for a proposed increase to the joint use rates, which are calculated using the inflation rate less the proposed stretch factor described in Exhibit A, Tab 3, Schedule 2 and 2016 actual costs. For details, see Exhibit H1, Tab 2, Schedule 3.

Joint use telecom revenues increase significantly from 2020 to 2021 due to the integration of telecom attachments resulting from the acquisitions of Norfolk Power, Haldimand County Hydro and Woodstock Hydro. Refer to Table 6 below for regulated joint use volumes and revenues.

Table 6: Regulated Joint Use Forecast Volumes and Revenues

		Historical			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
OEB Rate Code	**Description**	**Volume**	**Volume**	**Volume**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**
30	Specific Charge for Access to Power Poles - Telecom	296,641	297,492	300,126	302,268	$11,178,052	303,394	$13,882,109	304,525	$14,636,175	305,660	$14,916,559	319,215	$15,804,664	320,359	$16,101,471
47	Specific Charge for Access to Power Poles - LDC	11,632	11,681	11,123	10,140	$482,439	10,144	$487,512	10,148	$870,197	10,151	$883,930	10,155	$897,880	10,159	$911,960
48	Specific Charge for Access to Power Poles - Generators	3,880	3,880	4,053	4,123	$243,209	4,123	$434,238	4,123	$440,926	4,123	$447,716	4,123	454,566	4,123	$461,475
49	Specific Charge for Access to Power Poles - Municipal Streetlights	105,842	99,460	83,238	77,341	$157,777	77,341	$157,777	77,341	$157,777	77,341	$157,777	77,341	$157,777	77,341	157,777
	Total Revenues					**$12,061,477**		**$14,961,636**		**$16,105,075**		**$16,405,982**		**$17,314,887**		**$17,632,683**

2.1.4 OTHER EXTERNAL WORK

Other external work primarily consists of new connections and service upgrades to Hydro One Distribution's system. These connections and upgrades consist primarily of subdivision and rural residential customers along with farms, cottages, and industrial customers. Upgrade services are also completed each year that involve increasing customers' existing supply capacity to meet their increased electricity requirements. These revenues are summarized in Table 7.

Table 7: Other External Work Revenues ($ Millions)

Description	Historical years			Bridge Year	Test Years				
	2014	2015	2016	2017	2018	2019	2020	2021	2022
Other External Work	4.1	2.8	3.1	2.3	2.3	2.3	2.4	2.4	2.4

Both the new connection service and the upgrade service have elements of work that must be done by Hydro One under its distribution license. This work includes installing required equipment within pre-determined boundaries of live equipment, connecting the customer to Hydro One's distribution system, and connecting the meter at the customer site.

The remainder of the new connection and upgrade work is contestable work, meaning that it may be performed by a qualified contractor of the customer's choice. As required by the Distribution System Code, at the customer's request, Hydro One will carry out this work at its fully burdened cost since its crews are usually on-site and set up. For an above ground new connection, this work would include the installation of poles, conductor, and related equipment to run from the distribution line to the meter at the customer site. Similarly, for an underground connection, this would include digging the trench and laying the cable and related equipment. This type of project contributes to the external revenues for this segment. A slight increase in requests for new connections and service upgrades are anticipated for the test years.

Regulated external revenues received from Hydro One affiliates include $0.4 million in the test years broken down as follows: $0.3 million is forecast for work related to Hydro One Telecom Inc.; $0.1 million is forecast for work related to Hydro One Remotes Communities Inc. This revenue is related to work reflected in the Distribution Business Plan, the costs for which have not been allocated to affiliates using the common cost allocation methodology described in Exhibit C1, Tab 4, Schedule 1.

Pursuant to section 2.4.3.2 of the Filing Requirements, Attachment 1 to this Exhibit details the costs paid between Hydro One and its affiliates for the services described therein.

2.1.5 DISTRIBUTION GENERATOR STUDIES

Hydro One Distribution recognizes revenues for undertaking Connection Impact Assessments ("CIAs") in response to connection requests from generation proponents in the Province of Ontario. Hydro One performs CIAs based on a customer request that includes the proposed size of the generator and where it will be located. These volumes and associated revenues are outlined in Table 8.

CIAs are technical studies that determine the impact of connecting new generation facilities to the distribution system and ensure that the generator will comply with the technical requirements. The technical requirements that generators must meet to connect to Hydro One distribution system are outlined in the document entitled "Distributed Generation Technical Interconnection Requirements ("TIR") for Generators Connecting to Hydro One's Distribution System". These TIR requirements exist to ensure public and employee safety, to protect the integrity of Hydro One's Distribution System, and to guarantee reliable and quality service. For more information on these studies, refer to Exhibit C1, Tab 1, and Schedule 3.

Net metering CIAs are expected to increase starting in 2017 contributing to the cost increase in that year. Hydro One's subdivision team has been engaged by developers with an interest in creating net zero subdivisions, where each individual unit built will require a separate CIA.

Hydro One has had high volumes of CIAs for small projects, less than or equal to 500 kilowatts during the historical years, and the bridge year. This is due to the IESO releasing a large number of FIT programs during those years. Typically, Hydro One has seen an influx of CIAs requests roughly nine months after the contracts are released. On December 16, 2016, the Ministry of Energy released a directive that the IESO will cease the acceptance of applications under the FIT program by December 31, 2016. This directive will lead to a gradual decrease of CIAs for small projects, less than or equal to 500 kilowatts over the test years.

Table 8: Distribution Generation Studies Volumes and Revenues

		Historical			Bridge Year		Test Years									
		2014	2015	2016	2017		2018		2019		2020		2021		2022	
OEB Rate Code	**Description**	**Volume**	**Volume**	**Volume**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**	**Volume Forecast**	**Revenue Forecast**
45a	CIA - Net Metering	12	5	12	220	$1,236,400	225	$707,875	250	$798,213	280	$907,116	315	$1,034,983	350	$1,165,451
45b	CIA - Embedded LDC Generators	57	44	40	45	$252,900	44	$124,309	43	$123,564	42	$122,721	41	$121,363	40	$119,879
45c	CIA - Small Projects <= 500 kW	198	207	97	180	$1,011,600	180	$578,947	110	$359,268	90	$298,425	70	$235,302	50	$170,269
45d	CIA - Small Projects <= 500 kW, Simplified	N/A	N/A	4	50	$281,000	68	$131,992	56	$110,391	64	$128,091	62	$125,763	60	$123,265
45e	CIA - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	26	12	14	10	$120,550	8	$68,150	7	$60,493	7	$61,355	7	$62,234	7	$63,083
45f	CIA - Greater Than Capacity Allocation Exempt Projects - TS Review for LDC Capacity Allocation Required Projects	8	12	10	8	$96,440	8	$45,103	8	$45,823	8	$46,542	8	$47,161	8	$47,759
	Total Revenue					**$2,998,890**		**$1,656,376**		**$1,497,751**		**$1,564,250**		**$1,626,806**		**$1,689,705**

2.2 EXTERNAL UNREGULATED REVENUES

Unregulated external revenues account for the remaining 14% of external revenues and are set out in Table 9 below.

Table 9: Unregulated Revenues ($ Millions)

Description	Historical capital years			Bridge Year	Test Years				
	2014	2015	2016	2017	2018	2019	2020	2021	2022
Joint Use	4.3	4.5	4.7	3.1	3.1	3.1	3.1	3.1	3.1
Other External Work	2.2	2.0	2.3	3.7	3.7	3.7	3.7	3.7	3.8
Total	**6.5**	**6.5**	**7.0**	**6.8**	**6.8**	**6.8**	**6.8**	**6.8**	**6.9**

2.2.1 JOINT USE REVENUE

The OEB does not regulate rates for all joint use services. Hydro One Distribution provides certain services based on negotiated prices. These services primarily consist of vegetation management.

Hydro One Distribution generates under-density billing revenues for northwestern Ontario through annual fees levied upon two large companies that use dedicated, under-density distribution lines operated and maintained by Hydro One Distribution. The load on these under-density lines does not cover the annual costs of maintenance. Therefore, an annual fee is charged to recover maintenance costs. Unregulated Joint Use revenue is anticipated to remain constant throughout the test years.

2.2.2 OTHER EXTERNAL WORK

Other external work includes the following:

External training covers a wide range of practical and classroom delivered courses. Packaged delivery of numerous trade and professional technical courses are delivered for Lines, Power Substation Electricians, Metering Technicians, and Electrical Operators. Customers include utilities and contractors from Ontario with training delivered to a cross-section of employees from various trades or disciplines.

Unregulated revenues from Hydro One affiliates include $1.5 million in the test years broken down as follows: $1.3 million is forecast for work related to Hydro One Remotes Communities Inc.; $0.2 million is forecast for work related to Hydro One Telecom. This revenue is related to work reflected in the Distribution Business Plan, the costs for which have not been allocated to affiliates using the common cost allocation methodology described in Exhibit C1, Tab 4, Schedule 1.

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2014**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOI	All subs	General Counsel & Secretary (including Corporate Exec Office)	CCC Allocation Model	793	793
HOI	All subs	President/CEO/Chairman/Board	CCC Allocation Model	3,519	3,519
HOI	All subs	Chief Financial Office Services (Including Strategic Financial Services)	CCC Allocation Model	968	968
HONI	All subs and HOI	General Counsel & Secretary	CCC Allocation Model	32,331	32,331
HONI	All subs and HOI	Financial Services	CCC Allocation Model	38,056	38,056
HONI	All subs and HOI	Corporate Services	CCC Allocation Model	188,081	188,081
HONI	All subs and HOI	Telecommunication Services	CCC Allocation Model	18,460	18,460
HONI	All subs and HOI	Other Services	CCC Allocation Model	124,298	124,298
Remotes Services	HONI	Metering and Lines Services	CCC Allocation Model	-	-

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	43%	347
HOI	HONI Dx	President/CEO/Chairman /Board	CCC Allocation Model	33%	1,594
HOI	HONI Dx	Chief Financial Office Services	CCC Allocation Model	58%	426
HOI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	49%	401
HOI	HONI Tx	President/CEO/Chairman /Board	CCC Allocation Model	38%	1,842
HOI	HONI Tx	Chief Financial Office Services	CCC Allocation Model	67%	492
HOI	Telecom	General Counsel & Secretary	CCC Allocation Model	1%	8
HOI	Telecom	President/CEO/Chairman /Board	CCC Allocation Model	1%	28
HOI	Telecom	Chief Financial Office Services	CCC Allocation Model	2%	17
HOI	Remotes	General Counsel & Secretary	CCC Allocation Model	3%	21
HOI	Remotes	President/CEO/Chairman /Board	CCC Allocation Model	0%	19
HOI	Remotes	Chief Financial Office Services	CCC Allocation Model	1%	8
HOI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	B2M	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	B2M	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	Hydro One SSM	President/CEO/Chairman /Board	CCC Allocation Model	0%	-

HOI	Hydro One SSM	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Brampton	General Counsel & Secretary	CCC Allocation Model	2%	16
HOI	Brampton	President/CEO/Chairman /Board	CCC Allocation Model	1%	35
HOI	Brampton	Chief Financial Office Services	CCC Allocation Model	3%	26
HONI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	52%	16,813
HONI	HONI Dx	Financial Services	CCC Allocation Model	41%	11,760
HONI	HONI Dx	Corporate Services	CCC Allocation Model	48%	79,832
HONI	HONI Dx	Telecommunication Services	CCC Allocation Model	48%	8,317
HONI	HONI Dx	Other Services	CCC Allocation Model	70%	90,781
HONI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	43%	14,871
HONI	HONI Tx	Financial Services	CCC Allocation Model	56%	25,415
HONI	HONI Tx	Corporate Services	CCC Allocation Model	51%	107,610
HONI	HONI Tx	Telecommunication Services	CCC Allocation Model	50%	9,746
HONI	HONI Tx	Other Services	CCC Allocation Model	29%	32,070
HONI	Telecom	General Counsel & Secretary	CCC Allocation Model	0%	101
HONI	Telecom	Financial Services	CCC Allocation Model	1%	414
HONI	Telecom	Corporate Services	CCC Allocation Model	0%	308
HONI	Telecom	Telecommunication Services	CCC Allocation Model	2%	272
HONI	Telecom	Other Services	CCC Allocation Model	1%	1,086
HONI	Remotes	General Counsel & Secretary	CCC Allocation Model	1%	343
HONI	Remotes	Financial Services	CCC Allocation Model	1%	211
HONI	Remotes	Corporate Services	CCC Allocation Model	0%	297
HONI	Remotes	Telecommunication Services	CCC Allocation Model	1%	125
HONI	Remotes	Other Services	CCC Allocation Model	0%	359
HONI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	B2M	Financial Services	CCC Allocation Model	0%	-
HONI	B2M	Corporate Services	CCC Allocation Model	0%	-
HONI	B2M	Telecommunication Services	CCC Allocation Model	0%	-
HONI	B2M	Other Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Financial Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Corporate Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Other Services	CCC Allocation Model	0%	-
HONI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	202
HONI	Brampton	Financial Services	CCC Allocation Model	0%	256
HONI	Brampton	Corporate Services	CCC Allocation Model	0%	34
HONI	Brampton	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Brampton	Other Services	CCC Allocation Model	0%	2

Legend

"HOI"	Hydro One Inc.
"HONI"	Hydro One Networks Inc.
"Brampton"	Hydro One Brampton Networks Inc.
"B2M"	B2M Limited Partnership
"Telecom"	Hydro One Telecom Inc.
"Hydro One SSM"	Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)
"Remotes"	Hydro One Remote Communities Inc.
"HONI Dx"	Hydro One Distribution
"HONI Tx"	HONI's transmission business

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2015**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOI	All subs	General Counsel & Secretary (including Corporate Exec Office)	CCC Allocation Model	1,910	1,910
HOI	All subs	President/CEO/Chairman/Board	CCC Allocation Model	2,506	2,506
HOI	All subs	Chief Financial Office Services (Including Strategic Financial Services)	CCC Allocation Model	940	940
HONI	All subs and HOI	General Counsel & Secretary	CCC Allocation Model	33,396	33,396
HONI	All subs and HOI	Financial Services	CCC Allocation Model	41,103	41,103
HONI	All subs and HOI	Corporate Services	CCC Allocation Model	189,687	189,687
HONI	All subs and HOI	Telecommunication Services	CCC Allocation Model	17,295	17,295
HONI	All subs and HOI	Other Services	CCC Allocation Model	122,420	122,420
Remotes Services	HONI	Metering and Lines Services	CCC Allocation Model	148	148

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	73%	852
HOI	HONI Dx	President/CEO/Chairman /Board	CCC Allocation Model	16%	1,107
HOI	HONI Dx	Chief Financial Office Services	CCC Allocation Model	35%	402
HOI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	86%	1,001
HOI	HONI Tx	President/CEO/Chairman /Board	CCC Allocation Model	19%	1,301
HOI	HONI Tx	Chief Financial Office Services	CCC Allocation Model	41%	473
HOI	Telecom	General Counsel & Secretary	CCC Allocation Model	1%	12
HOI	Telecom	President/CEO/Chairman /Board	CCC Allocation Model	1%	41
HOI	Telecom	Chief Financial Office Services	CCC Allocation Model	2%	26
HOI	Remotes	General Counsel & Secretary	CCC Allocation Model	2%	28
HOI	Remotes	President/CEO/Chairman /Board	CCC Allocation Model	0%	21
HOI	Remotes	Chief Financial Office Services	CCC Allocation Model	1%	13
HOI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	B2M	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	B2M	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	Hydro One SSM	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	Hydro One SSM	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Brampton	General Counsel & Secretary	CCC Allocation Model	1%	17

HOI	Brampton	President/CEO/Chairman /Board	CCC Allocation Model	1%	36
HOI	Brampton	Chief Financial Office Services	CCC Allocation Model	2%	26
HONI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	52%	17,250
HONI	HONI Dx	Financial Services	CCC Allocation Model	41%	14,566
HONI	HONI Dx	Corporate Services	CCC Allocation Model	48%	84,359
HONI	HONI Dx	Telecommunication Services	CCC Allocation Model	48%	7,768
HONI	HONI Dx	Other Services	CCC Allocation Model	70%	87,586
HONI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	43%	15,461
HONI	HONI Tx	Financial Services	CCC Allocation Model	56%	25,496
HONI	HONI Tx	Corporate Services	CCC Allocation Model	51%	104,754
HONI	HONI Tx	Telecommunication Services	CCC Allocation Model	50%	9,102
HONI	HONI Tx	Other Services	CCC Allocation Model	29%	33,607
HONI	Telecom	General Counsel & Secretary	CCC Allocation Model	0%	102
HONI	Telecom	Financial Services	CCC Allocation Model	1%	536
HONI	Telecom	Corporate Services	CCC Allocation Model	0%	271
HONI	Telecom	Telecommunication Services	CCC Allocation Model	2%	284
HONI	Telecom	Other Services	CCC Allocation Model	1%	964
HONI	Remotes	General Counsel & Secretary	CCC Allocation Model	1%	383
HONI	Remotes	Financial Services	CCC Allocation Model	1%	247
HONI	Remotes	Corporate Services	CCC Allocation Model	0%	269
HONI	Remotes	Telecommunication Services	CCC Allocation Model	1%	141
HONI	Remotes	Other Services	CCC Allocation Model	0%	263
HONI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	0
HONI	B2M	Financial Services	CCC Allocation Model	0%	0
HONI	B2M	Corporate Services	CCC Allocation Model	0%	0
HONI	B2M	Telecommunication Services	CCC Allocation Model	0%	-
HONI	B2M	Other Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Financial Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Corporate Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Other Services	CCC Allocation Model	0%	-
HONI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	200
HONI	Brampton	Financial Services	CCC Allocation Model	0%	258
HONI	Brampton	Corporate Services	CCC Allocation Model	0%	34
HONI	Brampton	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Brampton	Other Services	CCC Allocation Model	0%	-

Legend

"HOI"	Hydro One Inc.
"HONI"	Hydro One Networks Inc.
"Brampton"	Hydro One Brampton Networks Inc.
"B2M"	B2M Limited Partnership
"Telecom"	Hydro One Telecom Inc.
"Hydro One SSM"	Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)
"Remotes"	Hydro One Remote Communities Inc.
"HONI Dx"	Hydro One Distribution
"HONI Tx"	HONI's transmission business

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2016

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOI	All subs	General Counsel & Secretary (including Corporate Exec Office)	CCC Allocation Model	773	773
HOI	All subs	President/CEO/Chairman/Board	CCC Allocation Model	5,486	5,486
HOI	All subs	Chief Financial Office Services (Including Strategic Financial Services)	CCC Allocation Model	1,279	1,279
HONI	All subs and HOI	General Counsel & Secretary	CCC Allocation Model	33,694	33,694
HONI	All subs and HOI	Financial Services	CCC Allocation Model	40,060	40,060
HONI	All subs and HOI	Corporate Services	CCC Allocation Model	205,915	205,915
HONI	All subs and HOI	Telecommunication Services	CCC Allocation Model	425	425
HONI	All subs and HOI	Other Services	CCC Allocation Model	1,227	1,227
Remotes Services	HONI	Metering and Lines Services	CCC Allocation Model	148	148

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	20%	230
HOI	HONI Dx	President/CEO/Chairman /Board	CCC Allocation Model	38%	2,681
HOI	HONI Dx	Chief Financial Office Services	CCC Allocation Model	79%	913
HOI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	42%	486
HOI	HONI Tx	President/CEO/Chairman /Board	CCC Allocation Model	39%	2,707
HOI	HONI Tx	Chief Financial Office Services	CCC Allocation Model	26%	301
HOI	Telecom	General Counsel & Secretary	CCC Allocation Model	1%	12
HOI	Telecom	President/CEO/Chairman /Board	CCC Allocation Model	1%	41
HOI	Telecom	Chief Financial Office Services	CCC Allocation Model	2%	26
HOI	Remotes	General Counsel & Secretary	CCC Allocation Model	2%	28
HOI	Remotes	President/CEO/Chairman /Board	CCC Allocation Model	0%	21
HOI	Remotes	Chief Financial Office Services	CCC Allocation Model	1%	13
HOI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	B2M	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	B2M	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	-

HOI	Hydro One SSM	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	Hydro One SSM	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Brampton	General Counsel & Secretary	CCC Allocation Model	1%	17
HOI	Brampton	President/CEO/Chairman /Board	CCC Allocation Model	1%	36
HOI	Brampton	Chief Financial Office Services	CCC Allocation Model	2%	26
HONI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	52%	17,511
HONI	HONI Dx	Financial Services	CCC Allocation Model	41%	12,701
HONI	HONI Dx	Corporate Services	CCC Allocation Model	48%	91,073
HONI	HONI Dx	Telecommunication Services	CCC Allocation Model	48%	
HONI	HONI Dx	Other Services	CCC Allocation Model	70%	
HONI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	43%	15,698
HONI	HONI Tx	Financial Services	CCC Allocation Model	56%	26,576
HONI	HONI Tx	Corporate Services	CCC Allocation Model	51%	114,302
HONI	HONI Tx	Telecommunication Services	CCC Allocation Model	50%	
HONI	HONI Tx	Other Services	CCC Allocation Model	29%	
HONI	Telecom	General Counsel & Secretary	CCC Allocation Model	0%	102
HONI	Telecom	Financial Services	CCC Allocation Model	1%	536
HONI	Telecom	Corporate Services	CCC Allocation Model	0%	271
HONI	Telecom	Telecommunication Services	CCC Allocation Model	2%	284
HONI	Telecom	Other Services	CCC Allocation Model	1%	964
HONI	Remotes	General Counsel & Secretary	CCC Allocation Model	1%	383
HONI	Remotes	Financial Services	CCC Allocation Model	1%	247
HONI	Remotes	Corporate Services	CCC Allocation Model	0%	269
HONI	Remotes	Telecommunication Services	CCC Allocation Model	1%	141
HONI	Remotes	Other Services	CCC Allocation Model	0%	263
HONI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	0
HONI	B2M	Financial Services	CCC Allocation Model	0%	0
HONI	B2M	Corporate Services	CCC Allocation Model	0%	0
HONI	B2M	Telecommunication Services	CCC Allocation Model	0%	-
HONI	B2M	Other Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Financial Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Corporate Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Other Services	CCC Allocation Model	0%	-
HONI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	Brampton	Financial Services	CCC Allocation Model	0%	-
HONI	Brampton	Corporate Services	CCC Allocation Model	0%	-
HONI	Brampton	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Brampton	Other Services	CCC Allocation Model	0%	-

Legend

"HOI"	Hydro One Inc.
"HONI"	Hydro One Networks Inc.
"Brampton"	Hydro One Brampton Networks Inc.
"B2M"	B2M Limited Partnership
"Telecom"	Hydro One Telecom Inc.
"Hydro One SSM"	Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)
"Remotes"	Hydro One Remote Communities Inc.
"HONI Dx"	Hydro One Distribution
"HONI Tx"	HONI's transmission business

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2017**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOI	All subs	General Counsel & Secretary (including Corporate Exec Office)	CCC Allocation Model	1,162	1,162
HOI	All subs	President/CEO/Chairman/Board	CCC Allocation Model	6,980	6,980
HOI	All subs	Chief Financial Office Services (Including Strategic Financial Services)	CCC Allocation Model	1,150	1,150
HONI	All subs and HOI	General Counsel & Secretary	CCC Allocation Model	32,625	32,625
HONI	All subs and HOI	Financial Services	CCC Allocation Model	37,227	37,227
HONI	All subs and HOI	Corporate Services	CCC Allocation Model	209,167	209,167
HONI	All subs and HOI	Telecommunication Services	CCC Allocation Model	18,199	18,199
HONI	All subs and HOI	Other Services	CCC Allocation Model	114,345	114,345
Remotes Services	HONI	Metering and Lines Services	CCC Allocation Model	148	148

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	42%	497
HOI	HONI Dx	President/CEO/Chairman /Board	CCC Allocation Model	51%	3,987
HOI	HONI Dx	Chief Financial Office Services	CCC Allocation Model	24%	544
HOI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	53%	620
HOI	HONI Tx	President/CEO/Chairman /Board	CCC Allocation Model	37%	2,897
HOI	HONI Tx	Chief Financial Office Services	CCC Allocation Model	23%	524
HOI	Telecom	General Counsel & Secretary	CCC Allocation Model	1%	12
HOI	Telecom	President/CEO/Chairman /Board	CCC Allocation Model	1%	41
HOI	Telecom	Chief Financial Office Services	CCC Allocation Model	1%	26
HOI	Remotes	General Counsel & Secretary	CCC Allocation Model	2%	28
HOI	Remotes	President/CEO/Chairman /Board	CCC Allocation Model	0%	21
HOI	Remotes	Chief Financial Office Services	CCC Allocation Model	1%	13
HOI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	B2M	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	B2M	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	4

HOI	Hydro One SSM	President/CEO/Chairman /Board	CCC Allocation Model	0%	35
HOI	Hydro One SSM	Chief Financial Office Services	CCC Allocation Model	2%	43
HOI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	Brampton	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	Brampton	Chief Financial Office Services	CCC Allocation Model	0%	-
HONI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	52%	16,981
HONI	HONI Dx	Financial Services	CCC Allocation Model	41%	15,318
HONI	HONI Dx	Corporate Services	CCC Allocation Model	48%	101,096
HONI	HONI Dx	Telecommunication Services	CCC Allocation Model	48%	8,649
HONI	HONI Dx	Other Services	CCC Allocation Model	70%	80,490
HONI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	43%	14,143
HONI	HONI Tx	Financial Services	CCC Allocation Model	56%	20,949
HONI	HONI Tx	Corporate Services	CCC Allocation Model	51%	107,365
HONI	HONI Tx	Telecommunication Services	CCC Allocation Model	50%	9,124
HONI	HONI Tx	Other Services	CCC Allocation Model	29%	32,628
HONI	Telecom	General Counsel & Secretary	CCC Allocation Model	0%	102
HONI	Telecom	Financial Services	CCC Allocation Model	1%	536
HONI	Telecom	Corporate Services	CCC Allocation Model	0%	271
HONI	Telecom	Telecommunication Services	CCC Allocation Model	2%	284
HONI	Telecom	Other Services	CCC Allocation Model	1%	964
HONI	Remotes	General Counsel & Secretary	CCC Allocation Model	1%	383
HONI	Remotes	Financial Services	CCC Allocation Model	1%	247
HONI	Remotes	Corporate Services	CCC Allocation Model	0%	269
HONI	Remotes	Telecommunication Services	CCC Allocation Model	1%	141
HONI	Remotes	Other Services	CCC Allocation Model	0%	263
HONI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	0
HONI	B2M	Financial Services	CCC Allocation Model	0%	0
HONI	B2M	Corporate Services	CCC Allocation Model	0%	0
HONI	B2M	Telecommunication Services	CCC Allocation Model	0%	-
HONI	B2M	Other Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	71
HONI	Hydro One SSM	Financial Services	CCC Allocation Model	0%	104
HONI	Hydro One SSM	Corporate Services	CCC Allocation Model	0%	166
HONI	Hydro One SSM	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Other Services	CCC Allocation Model	0%	-
HONI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	Brampton	Financial Services	CCC Allocation Model	0%	-
HONI	Brampton	Corporate Services	CCC Allocation Model	0%	-
HONI	Brampton	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Brampton	Other Services	CCC Allocation Model	0%	-
HONI	HOI	General Counsel & Secretary	CCC Allocation Model	3%	944
HONI	HOI	Financial Services	CCC Allocation Model	0%	72
HONI	HOI	Corporate Services	CCC Allocation Model	0%	-
HONI	HOI	Telecommunication Services	CCC Allocation Model	0%	-
HONI	HOI	Other Services	CCC Allocation Model	0%	-

Note: **Exhibit C1, Tab 4, Schedule 1 provides a breakdown of Shared Service and Common Corporate Cost allocations, as derived by applying the Black & Veatch Review of Allocation of Common Corporate Costs for 2016. Exhibit C1, Tab 4, Schedule 1 provides the lines of business' costs in a similar format to that found in past rate applications. For test years, the affiliate allocations outlined in this Attachment use the same cost base, but are grouped differently. As a result, a direct reconciliation is not possible by comparing the two Exhibits.**

Legend

"HOI"	Hydro One Inc.
"HONI"	Hydro One Networks Inc.
"Brampton"	Hydro One Brampton Networks Inc.
"B2M"	B2M Limited Partnership
"Telecom"	Hydro One Telecom Inc.
"Hydro One SSM"	Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)
"Remotes"	Hydro One Remote Communities Inc.
"HONI Dx"	Hydro One Distribution
"HONI Tx"	HONI's transmission business

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2018**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOI	All subs	General Counsel & Secretary (including Corporate Exec Office)	CCC Allocation Model	1,185	1,185
HOI	All subs	President/CEO/Chairman/Board	CCC Allocation Model	7,045	7,045
HOI	All subs	Chief Financial Office Services (Including Strategic Financial Services)	CCC Allocation Model	1,168	1,168
HONI	All subs and HOI	General Counsel & Secretary	CCC Allocation Model	33,064	33,064
HONI	All subs and HOI	Financial Services	CCC Allocation Model	35,620	35,620
HONI	All subs and HOI	Corporate Services	CCC Allocation Model	209,862	209,862
HONI	All subs and HOI	Telecommunication Services	CCC Allocation Model	18,248	18,248
HONI	All subs and HOI	Other Services	CCC Allocation Model	111,691	111,691
Remotes Services	HONI	Metering and Lines Services	CCC Allocation Model	148	148

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	42%	507
HOI	HONI Dx	President/CEO/Chairman /Board	CCC Allocation Model	51%	4,029
HOI	HONI Dx	Chief Financial Office Services	CCC Allocation Model	24%	552
HOI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	53%	633
HOI	HONI Tx	President/CEO/Chairman /Board	CCC Allocation Model	37%	2,918
HOI	HONI Tx	Chief Financial Office Services	CCC Allocation Model	23%	533
HOI	Telecom	General Counsel & Secretary	CCC Allocation Model	1%	12
HOI	Telecom	President/CEO/Chairman /Board	CCC Allocation Model	1%	42
HOI	Telecom	Chief Financial Office Services	CCC Allocation Model	1%	26
HOI	Remotes	General Counsel & Secretary	CCC Allocation Model	2%	29
HOI	Remotes	President/CEO/Chairman /Board	CCC Allocation Model	0%	21
HOI	Remotes	Chief Financial Office Services	CCC Allocation Model	1%	13
HOI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	B2M	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	B2M	Chief Financial Office Services	CCC Allocation Model	0%	-
HOI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	4

HOI	Hydro One SSM	President/CEO/Chairman /Board	CCC Allocation Model	0%	35
HOI	Hydro One SSM	Chief Financial Office Services	CCC Allocation Model	2%	43
HOI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	-
HOI	Brampton	President/CEO/Chairman /Board	CCC Allocation Model	0%	-
HOI	Brampton	Chief Financial Office Services	CCC Allocation Model	0%	-
HONI	HONI Dx	General Counsel & Secretary	CCC Allocation Model	52%	17,238
HONI	HONI Dx	Financial Services	CCC Allocation Model	41%	14,656
HONI	HONI Dx	Corporate Services	CCC Allocation Model	48%	101,314
HONI	HONI Dx	Telecommunication Services	CCC Allocation Model	48%	8,673
HONI	HONI Dx	Other Services	CCC Allocation Model	71%	79,416
HONI	HONI Tx	General Counsel & Secretary	CCC Allocation Model	43%	14,331
HONI	HONI Tx	Financial Services	CCC Allocation Model	56%	20,044
HONI	HONI Tx	Corporate Services	CCC Allocation Model	51%	107,846
HONI	HONI Tx	Telecommunication Services	CCC Allocation Model	50%	9,149
HONI	HONI Tx	Other Services	CCC Allocation Model	28%	31,082
HONI	Telecom	General Counsel & Secretary	CCC Allocation Model	0%	103
HONI	Telecom	Financial Services	CCC Allocation Model	1%	514
HONI	Telecom	Corporate Services	CCC Allocation Model	0%	268
HONI	Telecom	Telecommunication Services	CCC Allocation Model	2%	285
HONI	Telecom	Other Services	CCC Allocation Model	1%	937
HONI	Remotes	General Counsel & Secretary	CCC Allocation Model	1%	388
HONI	Remotes	Financial Services	CCC Allocation Model	1%	236
HONI	Remotes	Corporate Services	CCC Allocation Model	0%	269
HONI	Remotes	Telecommunication Services	CCC Allocation Model	1%	141
HONI	Remotes	Other Services	CCC Allocation Model	0%	255
HONI	B2M	General Counsel & Secretary	CCC Allocation Model	0%	0
HONI	B2M	Financial Services	CCC Allocation Model	0%	0
HONI	B2M	Corporate Services	CCC Allocation Model	0%	0
HONI	B2M	Telecommunication Services	CCC Allocation Model	0%	-
HONI	B2M	Other Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	General Counsel & Secretary	CCC Allocation Model	0%	71
HONI	Hydro One SSM	Financial Services	CCC Allocation Model	0%	104
HONI	Hydro One SSM	Corporate Services	CCC Allocation Model	0%	166
HONI	Hydro One SSM	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Hydro One SSM	Other Services	CCC Allocation Model	0%	-
HONI	Brampton	General Counsel & Secretary	CCC Allocation Model	0%	-
HONI	Brampton	Financial Services	CCC Allocation Model	0%	-
HONI	Brampton	Corporate Services	CCC Allocation Model	0%	-
HONI	Brampton	Telecommunication Services	CCC Allocation Model	0%	-
HONI	Brampton	Other Services	CCC Allocation Model	0%	-
HONI	HOI	General Counsel & Secretary	CCC Allocation Model	3%	933
HONI	HOI	Financial Services	CCC Allocation Model	0%	67
HONI	HOI	Corporate Services	CCC Allocation Model	0%	-
HONI	HOI	Telecommunication Services	CCC Allocation Model	0%	-
HONI	HOI	Other Services	CCC Allocation Model	0%	-

Note: **Exhibit C1, Tab 4, Schedule 1 provides a breakdown of Shared Service and Common Corporate Cost allocations, as derived by applying the Black & Veatch Review of Allocation of Common Corporate Costs for 2016. Exhibit C1, Tab 4, Schedule 1 provides the lines of business' costs in a similar format to that found in past rate applications. For test years, the affiliate allocations outlined in this Attachment use the same cost base, but are grouped differently. As a result, a direct reconciliation is not possible by comparing the two Exhibits.**

Legend

"HOI"	Hydro One Inc.
"HONI"	Hydro One Networks Inc.
"Brampton"	Hydro One Brampton Networks Inc.
"B2M"	B2M Limited Partnership
"Telecom"	Hydro One Telecom Inc.
"Hydro One SSM"	Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)
"Remotes"	Hydro One Remote Communities Inc.
"HONI Dx"	Hydro One Distribution
"HONI Tx"	HONI's transmission business

LOAD FORECAST AND METHODOLOGY

1. INTRODUCTION

This Exhibit discusses Hydro One Distribution's load forecast and methodology. The load forecast provides information on total distribution load and number of customers. This information assists Hydro One in planning work programs that align with the forecast electricity needs of its customers and accommodating new customer connections.

Hydro One Distribution uses a number of methods, such as econometric models, end-use models, and customer forecast surveys to produce the forecasts required for its distribution business. Similar methods are used by major utilities throughout North America.

All forecasts presented in this section are weather-normal, and the numbers are 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. The weather correction methodology used by Hydro One Distribution is a proven technique that has performed well in past years. The same methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0317) and for Hydro One's previous distribution rate cases (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, and EB-2013-0416).

All forecasts are internally consistent; all customer groups add up to the total customer base served by Hydro One Distribution.

Hydro One Distribution's load forecasting team has significant experience in preparing provincial and local electricity demand forecasts and load profiles. The load forecast methodology described in this Exhibit is the same as Hydro One's previous distribution rate cases (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, and EB-2013-0416). Since the restructuring of Ontario Hydro into its successor companies, the performance of Hydro One Distribution's system load forecast has been accurate, as shown in Table 1.

Between 1997 and 2001, the average variance of customers' energy purchase forecast compared to the weather corrected actual energy consumed is within one standard deviation of the forecast, despite large variances resulting from unusual events such as the ice storm in 1998 and September 11, 2001. One standard deviation, an accepted standard in the utility industry, signifies there is a one-in-three chance that the actual will be outside the plus or minus range; (alternatively, there is a two-in-three chance that the actual will fall within the plus or minus range). The performance of the forecast in subsequent years, namely 2002 to 2016, shows that the forecast is well within one standard deviation band for the corresponding energy purchases.

Table 2 compares the accuracy of the load forecast for retail customers approved in the last distribution rate case (EB-2013-0416) with the weather corrected actuals. Detailed comparisons between the forecasts provided in the previous four Hydro One Distribution rate applications (EB-2005-378, EB-2007-0681 EB-2009-0096, and EB-2013-0416) with the weather corrected actuals are presented in Appendix E to this Exhibit, Table E.1.

Table 1: Comparison of Hydro One Distribution Forecast with Actual
(Variance of forecast expressed as percent of actual on weather corrected basis)

Forecast made for Plan Year	Variance for Plan Year	Variance for 2nd Year	Variance for 3rd Year
1997	0.12	-2.03	1.91
1998	-2.03	-3.39	-2.02
1999	-0.85	0.73	-0.15
2000	0.46	-0.03	0.76
2001	-1.80	-1.56	-2.44
2002	1.98	2.39	2.12
2003	-0.82	-1.37	-0.74
2004	0.14	0.62	0.76
2005	0.25	0.12	0.46
2006	-0.06	-0.12	0.99
2007	-0.09	0.93	1.59
2008	-0.57	0.54	0.70
2009	-0.14	-0.25	-0.78
2010	1.24	0.28	-0.73
2011	0.22	0.34	-0.24
2012	0.54	-0.51	0.32
2013	-0.39	0.15	0.46
2014	0.72	1.45	2.71
2015	0.60	1.81	N/A
2016	0.07	N/A	N/A
Mean (1997-2001)	-0.82	-1.26	-0.39
One standard deviation (+/-)	1.13	2.57	3.00
Mean (2002-2013)	0.25	0.55	1.01
One standard deviation (+/-)	1.14	2.49	2.88

Note: The forecast performance pertains to Hydro One retail purchases, which account for about 97 percent of its distribution revenue requirements in the year 2016.

Table 2:

Comparison of 2014 Forecast with Actual
(GWh)

Year	Retail Forecast	Weather Corrected Actual	Variance (%)
2014	20,413	20,267	0.72
2015	20,497	20,203	1.45
2016	20,630	20,085	2.71

Section 2 discusses in detail the various economic factors taken into consideration when applying the methodology for deriving the load forecasts.

Hydro One Distribution's forecasting methodology uses a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards. Economic inputs were based on analyses prepared by major economic institutions, such as IHS Global Insight, Conference Board of Canada, Centre for Spatial Economics, University of Toronto, Canada Mortgage and Housing Corporation, and Altus Group. Inputs from the institutions noted above form the economic database (hereafter, the "economic forecast") that is used to establish Hydro One Distribution's load forecast.

Section 3 of this Exhibit details the methodology Hydro One uses to develop its load forecasts. Detailed modeling equations and definitions are presented in the Appendices to this Exhibit. Details of the consensus forecast for Gross Domestic Product ("GDP") and housing starts are provided in Appendix E, Table E.1.

Using Hydro One Distribution's approved forecasting methodology, the forecast for the period 2018 – 2022 is presented below:

Table 3: Hydro One Distribution Load and Number of Customers

Year	GWh Delivery Forecast	Distribution Customer Count
2018	36,019	1,300,516
2019	35,680	1,309,216
2020	35,673	1,317,967
2021*	36,363	1,386,522
2022*	36,373	1,395,578

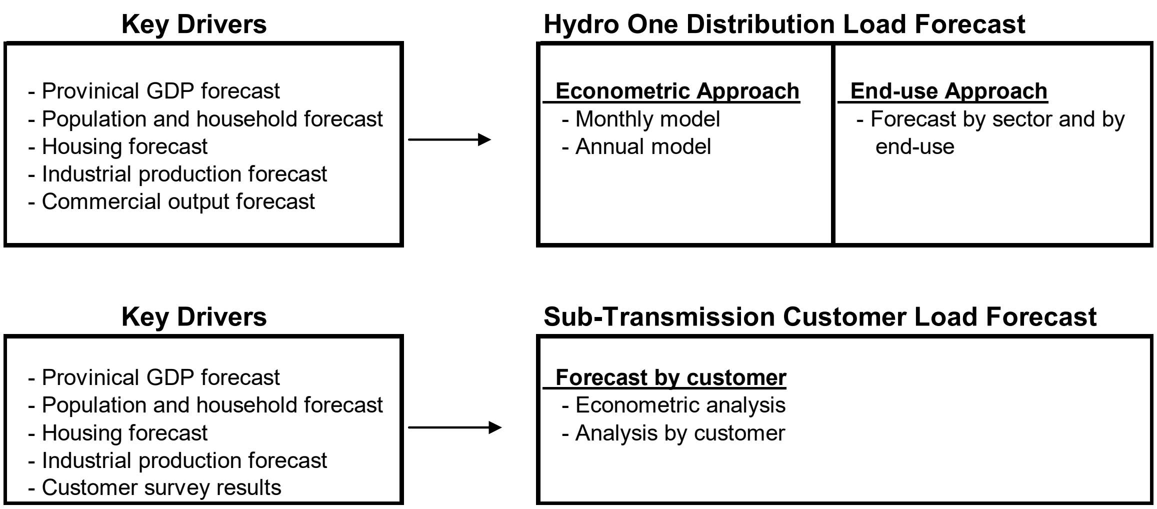
* The figures include the impact of integrating Acquired Utilities into Hydro One Distribution.

The figures in Table 3 and for 2017 reflect: (a) the impact of amendments to the Distribution System Code related to the elimination of load transfer arrangements between electricity distributors (EB-2015-0006), and (b) the impact of integrating load and customer numbers of Norfolk, Haldimand and Woodstock (the "Acquired Utilities") into Hydro One Distribution. Relative to the latest forecast of 2017 figures, Hydro One forecasts a decrease of 0.6% in its load forecast and an increase of 0.7% in the customer count forecast for 2018. The small decrease in load is mainly due to the impact of conservation and demand management ("CDM") and economic factors. Relative to currently approved 2017 figures, Hydro One forecasts a decrease of 5.5% in its load forecast and a decrease of 0.8% in the customer count for 2018. Section 4 provides a more detailed discussion comparing forecasts for 2018 to 2022 with historic years 2015 to 2016 and bridge year 2017.

2. DISCUSSION OF THE ECONOMIC CONSIDERATIONS THAT INFLUENCE HYDRO ONE DISTRIBUTION'S LOAD FORECASTS

This section discusses some of the key economic considerations in developing load forecasts and the application of forecasting methodologies. The elements of the forecasting process used by Hydro One Distribution are, for the most part, based on the relationship between major economic drivers and electricity demand over the forecast period 2017 to 2022. Consequently, the load forecast will reflect the impact of such drivers on load. The major economic drivers used in the analysis are summarized in Figure 1.

Figure 1
Hydro One Distribution Load Forecast Methodology



Key information used in the analysis includes the Ontario GDP, provincial demographic, industrial production and commercial output forecasts and regional analysis included in the economic forecast. Also taken into consideration are Hydro One Distribution CDM plans, which have a direct impact on distribution system electricity demand.

The load forecast in support of this Application is based on the latest economic information and forecasts that were available in January 2017. The load forecast also takes into account 2016 actual load, CDM detailed information consistent with the IESO Ontario Planning Outlook (OPO), and the planned cuts to electricity bills announced by the provincial government on March 2, 2017. The timing of the load forecast is driven by the needs of the business planning process which is geared to match the timeline for this submission.

2.1 PROVINCIAL GDP FORECAST

The provincial GDP forecast is a key driver for the load forecast. Ontario GDP grew 1.5% in 2013 and then accelerated to 2.7% in 2014, 2.5% in 2015 and is expected to have grown by 2.5% in 2016. The Ontario economy is expected to grow moderately in the next two years. Based on the consensus forecast, the Ontario economy is projected to grow by about 2.3% in 2017 and about 2.1% in 2018. From 2019 through 2022, the provincial GDP is forecast to grow on average 2.0% per year. Details of annual forecast for GDP, population and housing starts are provided in Appendix E, Table E.3.

2.2 PROVINCIAL POPULATION FORECAST

Ontario's population grew on average by about 1.0% per year between 2013 and 2016. Population growth in Ontario is forecast to grow at about the same pace as the rest of Canada in the forecast period. Ontario population is expected to grow by about 1.0% per year over the 2017 to 2022 period. Steady population growth contributes positively to the load forecast.

2.3 PROVINCIAL HOUSING FORECAST

Helped by population growth and low interest rates, housing demand in Ontario continued to grow at a moderate pace over the last four years. The number of housing starts increased by

59,000 in 2013, 58,000 in 2014 and 70,000 in 2015. Housing starts are expected to increase by 74,700 in 2016. The consensus forecast calls for 70,400 housing starts in 2017, and an average of 70,500 per year over the test years (2018-2022).

2.4 COMMERCIAL OUTPUT FORECAST

Commercial activities follow closely with the general economic conditions. After growing 1.6% in 2013, commercial output accelerated to 2.3% in 2014, 2.7% in 2015, and is expected to grow by 3.0% in 2016. The growth is expected to continue in 2017 at a rate of 2.4%. Commercial output is projected to have moderate growth over the 2018 to 2022 period, increasing by an average of about 2.2% per year. Commercial output is important to the load forecast because commercial load comprises about 25% of Hydro One Distribution's load.

2.5 INDUSTRIAL PRODUCTION FORECAST

Industrial GDP declined by 0.1% in 2013, increased by 3.8% in 2014, and declined by 1.1% in 2015. The economic forecast calls for a 0.2% decline in industrial production in 2016, followed by a 1.2% increase in 2017. The economic forecast calls for moderate growth of 1.0% per annum over the 2018 to 2022 period. The industrial production forecast is important to the load forecast because industrial activity comprises about 10% of total load and is also sensitive to the impact of economic cycles.

2.6 CONSERVATION AND DEMAND MANAGEMENT

Table 4 summarizes the CDM impact assumed in Hydro One's distribution system load forecast. Details of CDM forecast by rate class are provided in Appendix E, Table E.9.

Table 4: CDM Impact on Hydro One Distribution Load (GWh)

Year	Retail Customers	ST Customers Direct	ST Customers LDC	Total
2015	1,619	169	856	2,644
2016	1,810	195	929	2,935
2017	1,983	208	1,052	3,243
2018	2,171	228	1,154	3,553
2019	2,378	251	1,264	3,892
2020	2,505	265	1,334	4,104
2021*	2,642	277	1,322	4,241
2022*	2,698	284	1,352	4,334

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

The CDM figures for all years are consistent with IESO Ontario Planning Outlook ("OPO"), including the load impact of LDC energy efficiency programs for the years 2015-2020. The methodology for incorporating CDM into the load forecast is described in Section 3 of this Exhibit.

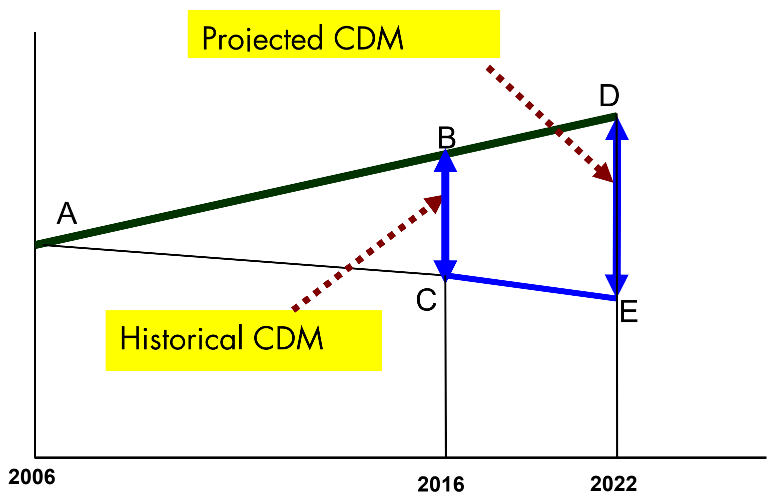
2.7 CUSTOMER FORECAST

Through its distribution system, Hydro One is expected to serve about 1.283 million customers in 2016 and 1.292 million customers in 2017. These totals reflect the impact of amendments to the Distribution System Code on Hydro One, related to the elimination of load transfer arrangements between electricity distributors (EB-2015-0006). The customer base is forecast to reach 1.301, 1.309, and 1.318 million, respectively, over the 2018 to 2020 period. With the integration of the Acquired Utilities, the customer base is forecast to increase to 1.387 million in 2021, and 1.396 million in 2022. Detailed customer information is retained in the customer information system for billing and account management. Customer data is extracted from the system regularly for tracking, analysis and reporting. The customer forecast was developed on an as-required basis to support the annual business planning process, system development plans, and rate submissions to the Board. Active customer accounts and service points are used as the basis to prepare the customer forecast by rate class. The customer forecast takes into consideration new customers requiring distribution services, existing customers moving out, provincial housing demand, population and household forecasts, vacancy rates and specific growth patterns of various customer groups.

Customer growth in Hydro One Distribution averaged about 7,000 per year from 2013 to 2016, which is consistent with the economic conditions during that period. Customer growth, excluding the Acquired Utilities, for the forecast period is expected to increase to 9,000 per year over the 2017 to 2022 period. In addition, in 2021 about 59,000 customers from the Acquired Utilities are included in the customer forecast. Details of the customer forecast by rate class over the forecast period are provided in Appendix E, Table E.4.

3. LOAD FORECASTING METHODOLOGY

Hydro One Distribution's load forecast is developed using both econometric and end-use approaches. The load impacts of CDM are added back to the historical values during the modeling process (see Figure 2 below).



A: 2006 actual load

B: Estimated Load without CDM impacts in 2016

C: 2016 actual load

Figure 2: Incorporation of CDM in the Load Forecast

The forecast base-year is corrected for abnormal weather conditions and the forecast growth rates are applied to the normalized base-year value. The forecast is weather-normal in the sense that it predicts the future load under normal weather conditions.

3.1 WEATHER CORRECTION ANALYSIS

Weather correction is a statistical process designed to remove the abnormal or extreme weather effects from the load data to yield average conditions that reflect the more normal or expected weather conditions experienced over 31 years used in the forecast. It is essential that impacts of abnormal and extreme weather are removed before establishing the base-case load data, from which the load forecast will be developed. The volatility of abnormal or extreme weather conditions can adversely impact the ability to provide a consistent and meaningful forecast for load growth. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.

Hydro One Distribution's weather correction methodology was developed jointly by forecasting and meteorology staff of the former Ontario Hydro. This weather correction method has been used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One Distribution is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0378) and in previous Hydro One Distribution Rate applications (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, and EB-2013-0416).

As shown in Table 5, using a fewer number of years for historic weather normalization has only a small impact on the total weather corrected energy consumption. This is an expected outcome since weather normalization has a more significant impact on peak than it does on energy due to the fact that energy consumption is less sensitive to short-term weather conditions. In Hydro One Distribution's rate case, weather normal energy (and not peak) is a key measure for the load forecast.

Table 5: Comparison of Different Time Periods Used for Weather Normalization (GWh)

Number of Years Used to Calculate Normal Weather	Actual Load for Hydro One Retail Customers in 2016	Weather Correction required for Hydro One Retail Customers in 2016	Weather Corrected Load for Hydro One Retail Customers in 2016
Last 31 Years *	19,862	223	20,085
Last 20 Years	19,862	181	20,043
Last 10 Year	19,862	191	20,054

* Used by Hydro One Distribution to normalize the base year (2016) load.

Hydro One Distribution's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than weekly, monthly or annually.

Daily weather-correction is preferred because the timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than would be the case if the same weather conditions prevailed over a much longer period of time.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the penetration rate of such loads varies widely, which means the weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay. It is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects. Forecasts using 31-year, 20-year and 10-year weather-normalization are presented in Table 6.

Table 6: Load Forecast for Hydro One Retail -Using Different Normalization Periods (GWh)

	2018	2019	2020	2021*	2022*
31 years	19,963	19,790	19,789	20,702	20,693
20 years	19,921	19,748	19,747	20,658	20,649
10 years	19,931	19,759	19,757	20,669	20,661

* Includes the load impact of integrating Acquired Utilities into Hydro One Distribution.

3.2 HYDRO ONE DISTRIBUTION FORECASTING METHODOLOGY

Both econometric (top-down) and end-use (bottom-up) models are used to prepare load forecast for Hydro One Distribution. Both monthly and annual econometric models are used to forecast Hydro One Distribution's total distribution system load. End-use models are used to analyse the distribution system load by customer rate class (i.e. various residential and general service customers). Key information used in the analysis includes economic, demographic, industrial production and commercial output forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. The load impacts of CDM are added back to the historical data set during the modelling process.

Monthly Econometric Model

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the distribution system load. The model links monthly energy consumption to Ontario GDP and residential building permits. Appendix A provides the detailed regression equations and definitions.

Annual Econometric Model

The annual econometric model uses personal disposable income per household, relative energy price, and cooling and heating degree-days to prepare the forecast. Appendix B provides the detailed regression equations and definitions.

End-Use Model

The end-use models cover the residential (year round and seasonal), commercial, industrial and agricultural sectors. Detailed equations of the end-use models are provided in Appendix C.

The above models are used to prepare forecast for the following 19 rate classes:

- Urban residential (high density)
- R1 Residential, medium density
- R2 Residential, low density
- Seasonal
- Urban general service, energy-billed
- Urban general service, demand-billed
- General service, energy-billed
- General service, demand-billed
- Sub-transmission
- Street lighting
- Sentinel lighting
- Unmetered scatter load
- Distributed generation

- Acquired residential
- Acquired general service – energy billed
- Acquired general service – demand billed
- Acquired urban residential
- Acquired urban general service – energy billed
- Acquired urban general service – demand billed

3.3 METHODOLOGY FOR SUB-TRANSMISSION CUSTOMERS

This section discusses the load forecasting methodology used for Sub-Transmission ("ST") customers. ST customers (or embedded customers) are directly connected to Hydro One's ST system or have a delivery point embedded in Hydro One's distribution service territory. ST customers include distribution utilities, industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

In 2016, Hydro One Distribution conducted a customer load forecast survey with the embedded distribution utilities and embedded industrial customers with more than 5 MW of loads. In addition to questions relating to the total load of the customer, information at each of the delivery points was also collected. The customer survey results are used in preparing the customer forecast.

For embedded distribution utility customers, an annual econometric model is used to prepare the load forecast as a group. The model used number of households, energy prices and heating and cooling degree-days to prepare the forecast.

For industrial customers, several information sources are used to prepare the forecast. These include:

- historical load profile of the customer;
- knowledge of the customer through industry monitoring;
- forecast provided by customer through the survey;
- company information through Hydro One Distribution account executives, industry and company forecasts from industry associations and government agencies; and
- production and industry forecasts provided in the economic forecast.

The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from the customer survey were taken into account in developing the forecast.

3.4 METHODOLOGY FOR HOURLY LOAD PROFILES

This section discusses the methodology for generating the hourly load profiles by customer class and for specific customer delivery points.

<u>Hourly Load Shape by Rate Class</u>

The Electricity Power Research Institute ("EPRI")'s Hourly Electric Load Model ("HELM") was used to develop the hourly load shape for each rate class, taking out abnormal weather effects and load patterns. Actual 2015 hourly smart meter data from the IESO and interval meter data from Hydro One's customer information system were used as a basis to develop the hourly load shapes. For rate classes that hourly data was not available for all customers, the hourly data was scaled to add up to the actual load for that rate class in 2015. Similarly, the hourly forecast for each rate class adds up to annual forecast for that rate class. Consequently, the forecast takes into account the share of each rate class in the total load and its dynamics over time. In particular, the load profiles for the years 2018-2022 take into account reclassification of some customers between rate classes in accordance with the annual forecast. No shift between seasonal customers and other residential rate classes is assumed. Appendix D provides more details for the methodology used by Hydro One to weather-normalize the total utility load and for each rate class.

Hourly Load Shape by Customer Delivery Point

Similarly, the HELM is used to normalize the hourly load for each of the customer delivery points, taking out abnormal weather effects and load patterns. The customer forecast is used to drive the customer delivery point forecast. Key information used in the analysis includes hourly load and weather data.

The most up to date customer totalization table is used to retrieve hourly electricity demand data for each of the customer delivery points connected to the Sub Transmission (ST) system. The totalization table reflects the latest records from Hydro One Distribution. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis. Weather data analyzed includes temperature, wind speed, cloud cover and humidity. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

In preparing the database for the load shape analysis, missing values are estimated by load on a similar day and hour during the same month. For weather-sensitive load, weather conditions are also taken into account in estimating the missing values. To perform the latter task, an hourly regression model (relating load to weather conditions) for each delivery point with missing values was developed.

EPRI's HELM is used to prepare the hourly weather response analysis for each delivery point. The model takes into account differences in load depending upon time of use (i.e. weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such is forecast in relation to load on a similar day and hour during the historical period.

4. LOAD FORECAST FOR 2017-2022

Hydro One's distribution system delivered a total of 36,419 GWh in 2015 and 36,139 GWh in 2016 on a weather-normal basis. Table 7 presents the load forecast before and after deducting the impact of CDM.

Before deducting the impact of CDM, Hydro One's distribution system is forecast to deliver 39,487 GWh in 2017. Load before deducting the CDM impacts over the years 2018 to 2022 is expected to continue to grow with the load forecast reaching 39,572, 39,573, 39,778, 40,604, 40,706 GWh, respectively, on a weather-normal basis. The forecast reflects the continuation of economic recovery in 2017 and moderate economic growth over the 2018 to 2022 period as well as the impact of integrating the Acquired Utilities into Hydro One Distribution in 2021.

Hydro One Distribution served about 1,274,000 customers in 2015 and 1,283,000 customers in 2016. Hydro One Distribution is forecast to serve about 1,292,000 customers in 2017. The customer numbers are forecast to be 1,301,000, 1,309,000, 1,318,000, 1,387,000, and 1,396,000 respectively over the 2018 to 2022 period. The figures for 2021 and 2022 include the impact of integrating the Acquired Utilities into Hydro One Distribution in 2021.

After applying the impact of CDM, Hydro One Distribution's load declines from 36,419 GWh in 2015 to 36,139 GWh in 2016, and is forecast to increase to 36,244 GWh in 2017, on a weather-normalized basis. Over the years 2018 to 2022, the weather-normalized total distribution load is forecast to be 36,019, 35,680, 35,673, 36,363, and 36,373 GWh, respectively. Detailed tables for actual and weather-normalized total load, energy and peak by rate class are provided in Appendix E, Tables E.5 to E.9. Results by rate class in Appendix E reflect changes due to customer classification in 2015 (see Exhibit G1, Tab 2, Schedule 1 of Hydro One's last distribution application EB-2013-0416) and continuation of these changes over the years 2018 to 2022 as discussed in Exhibit G1, Tab 2, Schedule 1 of the current Application.

Table 7: Hydro One Distribution Load Forecast Before and After Deducting CDM Impact (GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2015	21,822	17,241	39,063
2016	21,896	17,178	39,074
2017	22,071	17,416	39,487
2018	22,134	17,438	39,572
2019	22,168	17,405	39,573
2020	22,294	17,484	39,778
2021*	23,344	17,260	40,604
2022*	23,391	17,315	40,706
Load Impact of CDM			
2015	1,619	1,025	2,644
2016	1,810	1,124	2,935
2017	1,983	1,260	3,243
2018	2,171	1,382	3,553
2019	2,378	1,514	3,892
2020	2,505	1,599	4,104
2021*	2,642	1,599	4,241
2022*	2,698	1,636	4,334
Load Forecast After Deducting Impact of CDM			
2015	20,203	16,216	36,419
2016	20,085	16,054	36,139
2017	20,088	16,156	36,244
2018	19,963	16,056	36,019
2019	19,790	15,890	35,680
2020	19,789	15,885	35,673
2021*	20,702	15,661	36,363
2022*	20,693	15,679	36,373

Note. All figures are weather-normal.
* Includes Acquired Utilities.

Since the forecast is weather-normal, the actual load could be below or above the forecast depending on the weather conditions and/or a different economic growth pattern. Table 8 presents the upper and lower bands of one standard deviation for the Hydro One Distribution system load forecast. Based on historical data, there is a two-in-three chance that the actual load over the forecast years (2017-2022) will fall within the upper and lower bands. The bands are derived using a Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

Table 8: One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)

Year	Lower Bound	Forecast	Upper Bound
2016	36,139	36,139	36,139
2017	35,615	36,244	36,855
2018	35,168	36,019	36,884
2019	34,684	35,680	36,681
2020	34,431	35,673	36,903
2021*	34,857	36,363	37,923
2022*	34,569	36,373	38,245

* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

Note. 2016 figures are actuals

APPENDIX A

MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses the State-Space approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that could affect the energy estimates because these events would likely cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LRTLT = f (LGDPONT, LBPONT, D98Jan)

where:

LRTLT = logarithm of retail load,

LGDPONT = logarithm of Ontario GDP in constant 1997 dollars,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix E

LBPONT = logarithm of Ontario residential building permits in constant dollar,

- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

D98Jan = dummy variable to account for the load impact of 1998 Ice Storm, equals 1 in January 1998 and zero elsewhere,

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal Factors	State-Space (SS) parameters:
A[1]	-0.142346
K[1]	-0.551101

Non-Seasonal Factors	SS parameters:
A[1]	0.511914
K[1]	-0.368871
GDPONT[-4]	0.0613034
BPONT[-8]	0.00488088
D98JAN	-0.0143867

R-squared = 0.987, R-squared corrected for mean = 0.987, Durbin-Watson Statistics = 2.24.

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain for the variations in load. In fact, the results show that in this case the fit is very good, and therefore there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the above parameters are used in the monthly regression equation described on the previous page to generate the forecast for Hydro One Distribution load.

APPENDIX B
ANNUAL ECONOMETRIC MODELS

Retail Load

Annual econometric model for retail load uses personal disposable income per household, relative energy price, and heating degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-4)-LPGASRES(-4))+C(4)
*LHDD+C(5)*LRTLT(-1)-C(4)*C(5)*LHDD+C(6)*D99A+C(7)*TR
+C(8)*TR2+C(9)*D08ON

where:

LRTLT = logarithm of retail load,

LYPDPHH = logarithm of Ontario personal disposable income per household / house in constant dollar,

- History is based on disposable income in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada and divided by the number of households / houses based on IHS Global Insight housing starts
- Forecast is based on forecasts of disposable income from C4SE, University of Toronto (PEAP) and Conference Board of Canada deflated by CPI from IHS Global Insight and divided by the number of household / houses based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016 Outlook
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

TR2 = TR to power 2,

D08ON = a dummy variable to account for economic changes, equals zero prior to 2008 and 1 elsewhere.

C(1) – C(9) = variable coefficients.

The estimated coefficients and associated statistics are presented below:

	Estimated Coefficient	Standard Error	t-ratio
C(1)	4.914638	1.590352	3.090282
C(2)	0.533056	0.133115	4.004472
C(3)	-0.013723	0.013173	-1.041790
C(4)	0.091895	0.064810	1.417908
C(5)	0.304920	0.127806	2.385794
C(6)	-0.024411	0.010245	-2.382720
C(7)	-0.090754	0.031109	-2.917279
C(8)	0.002377	0.000705	3.372269
C(9)	-0.013658	0.008849	-1.543412

R-squared = 0.989, Adjusted R-squared = 0.985, Durbin-Watson Statistic = 1.57.

Similar to the regression analysis in the case of the Monthly Econometric model above, the goodness of fit, measured by (Adjusted) R-square for the Annual Econometric Model for retail load, is also found to be close to 1. Therefore the assessment on an annual basis also leads to a forecast outcome which provides consistent results, thus giving confidence to the econometric method.

The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for personal disposable income per household / house, energy prices, and heating degree days and dummy variables, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Distribution load.

Embedded LDC Load

Annual econometric model for embedded LDC load uses number of houses / households, relative energy price, and heating and cooling degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LEMBLDCS=C(1)+C(2)*D(LHHOLD)+C(3)*(LPELRES(-1)-LPGASRES(-1))
+C(4)*LCDD+C(5)*LHDD+C(6)*LEMBLDCS(-1)-C(4)*C(6)
*LCDD(-1)-C(5)*C(6)*LHDD(-1)+C(7)*TR

where:

LEMBLDCS = logarithm of Embedded LDC load,

LHHOLD = logarithm of Ontario number of households / houses,

- History from IHS Global Insight housing starts
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016 Outlook
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

C(1) – C(7) = variable coefficients.

The estimated coefficients and associated statistics are presented below:

	Estimated Coefficient	Standard Error	t-ratio
C(1)	1.763528	0.621723	2.836516
C(2)	1.586283	0.916446	1.730908
C(3)	-0.046937	0.016798	-2.794270
C(4)	0.007978	0.009718	0.820939
C(5)	0.012515	0.058312	0.214612
C(6)	0.781907	0.076054	10.28089
C(7)	0.010703	0.004228	2.531607

R-squared = 0.981, Adjusted R-squared = 0.977, Durbin-Watson Statistic = 1.87.

Similar to the regression analysis in the case of the other econometric models noted above, the goodness of fit, measured by (Adjusted) R-square for the Embedded LDC Model, is also found to be close to 1 leading to a forecast outcome which provides consistent results, thus giving confidence to the econometric method. The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for Ontario number of households / houses, energy prices, and cooling and heating degree days and dummy variable, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Embedded LDC load.

APPENDIX C
END-USE MODEL

The following briefly describes the methodology used in the end-use model.

<u>Residential Sector</u>

The residential energy forecast is determined by forecasting the number of accounts times appliance saturation rates and unit energy consumption expressed in the following equation:

$$USE_{Res} = \sum_i \sum_j N_{i,j} * S_{i,j} * UEC_{i,j}$$

Where

- USE_{Res} is residential energy consumption
- N is the number of residential accounts
- S is the residential appliance saturation rate
- UEC is the unit energy consumption per end use
- I is the index for appliances (space heating, space cooling, water heater and base load)
- J is the index for customer types—year-round residential customers and seasonal residential customers

The following section describes each component of the equation in detail.

- The base-year number of households is taken from Hydro One Distribution billing system. The forecast in the growth of the number of residential accounts is based on a forecast of housing starts. The number of residential accounts is the current number of residential accounts plus the forecast of net additional accounts to be added each year.
- The base-year end-use shares (space heating, water heating and air conditioning) information is based on the latest customer and conservation survey results undertaken by Hydro One for year-round and seasonal customers.

- The base-year end-use UEC's are based on the provincial residential end-use model with adjustments for heating degree-days, cooling degree-days, income, household size, square footage and household vintage.

Commercial Sector

The commercial energy forecast is based on the following equation:

$$USEcom = USEcom(-1) * (1+\text{Expected annual growth rate})$$

Where

- $USEcom$ is the commercial energy consumption for the forecast year
- $USEcom(-1)$ is the commercial energy consumption for the previous year. The base year consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on commercial GDP growth by segment. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.

Industrial Sector

The industrial energy forecast is based on the following equation:

$USEind = USEind$ (-1) * (1+Expected annual growth rate)

Where

- $USEind$ is the industrial energy consumption for the forecast year
- $USEind$ (-1) is the industrial energy consumption for the previous year. The base year consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on industrial GDP growth by segment. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.

Agricultural Sector

The Agricultural sector forecast is based on the following equation:

$USEagri = USEagri$ (-1) * (1+Expected annual growth rate)

Where

- $USEagri$ is the agricultural energy consumption for the forecast year
- $USEagri$ (-1) is the agricultural energy consumption for the previous year. The base year consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on the GDP growth for agriculture and forestry. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.

APPENDIX D

WEATHER NORMALIZATION FOR TOTAL LOAD AND BY RATE CLASS

<u>Weather Normalization for Total Utility Load</u>

Hydro One's weather normalization methodology for total utility load is summarized as follows:

- An equation relating daily energy and daily weather conditions is developed using the latest four years of data. This time frame allows the analysis to reflect the most recent load mix while having sufficient data to quantify its weather sensitivity. For example, the share of space cooling energy relative to total energy has increased rapidly over the past decade; using too long a time series of historical data may lead to significant under-estimation of the weather sensitivity of load in the summer.

- To better isolate the impact of weather, systematic changes in daily loads are identified and filtered out before the regression analysis begins. The systematic effects removed include growth trends, cyclical variations, day-of-the-week effects and holiday effects. The objective is to filter the data to weather-related load and noise (random effect).

- Different types of weather data are used in the analysis. For winter loads, weather data include temperature, wind speed and cloud opacity. For summer loads, weather data include temperature, humidity and cloud opacity. Because weather effects accumulate over several days, the temperatures for the current day as well as the previous three or four days are also used as explanatory variables in the model. The relationship between energy and weather may be represented by the following function:

  Weather- Related Energy = f (Weather Conditions) + Random Term (1) where the random term reflects any remaining variations that are not explained systematically by weather. The random term is assumed to be distributed independently, identically and normally with mean equals to zero.

- The coefficients from Equation (1) are estimated using the most recent four years of daily load and weather data. These coefficients indicate the sensitivity of load in the service territory relative to today's temperature, yesterday's temperature and all other weather variables included in the equation. The estimated coefficients are multiplied by the actual weather data for the corresponding weather variable in the equation to determine the estimated weather-related energy for the day. This process is repeated for each day of the period for which the weather-correction is performed.

Estimated Weather-Related Energy = f (Actual Weather Conditions and Estimated Coefficients) (2)

- Equation (2) is used to determine what "normal" weather-related loads would be for each day of the year given the current mix of weather-sensitive loads in that service territory. This is done by running the equation with each of the last 31 years of daily weather data for that day plus the seven days on either side of it. The average of the estimated weather-related loads for the 15 days times 31 years (465 observations) is deemed to be the "normal" weather-related energy for that day. Using 31 years of weather history is considered adequate to approximate normal weather.

Normal Weather-Related Energy (for each day) = Average (31 years of Estimated Weather-Related Energy for that Day +/- 7 Days) (3)

- On a daily basis, the weather correction is derived as the difference between the estimated and normal weather- related energy:

  Weather Correction for Energy = Normal Weather-Related Energy – Estimated Weather-Related Energy (4)

- Weather-corrected energy is defined to be actual energy plus the weather correction in any given period. For any period that is more than one day (e.g., a month), the total weather correction is the sum of the daily weather correction.

  Weather-Corrected Energy = Actual Energy + Weather Correction for Energy (5)

- For example, a summer day for which the combination of temperature and humidity are above normal yields a negative weather correction. The weather correction in this case should be viewed as the amount to be subtracted from the above normal actual to get the weather-corrected energy. Similarly, a warm winter day would have a positive weather correction as the weather corrected value for that day should be higher than the below normal actual.

<u>Weather Normalization by Rate Class</u>

Weather correction by rate class is derived from weather correction for the total utility using the electric space heating and cooling shares by rate class or segment as detailed below.

- Weather correction for the total load is discussed above using daily energy for the utility. The amount of weather correction is measured on a daily basis.

- Using average daily temperature for each day, the daily weather correction is grouped into "weather correction for space heating" and "weather correction for space cooling".

For example, if average daily temperature is less than 15 degrees C., the weather correction for that day is allocated to “weather correction for space heating” load. The daily weather correction results are aggregated into annual or monthly weather correction estimates.

- Using load shape analysis and residential appliance saturation estimates, the amount of space heating and cooling load over a year or month are estimated for each rate class. Next, for each rate class, the cooling and heating weather correction amount are calculated using the total cooling and heating weather correction amount multiplied by the corresponding cooling and heating shares. The weather-corrected load for each rate class is estimated by adding the weather correction estimates by rate class to the corresponding (actual) load for each rate class.

APPENDIX E
STATISTICAL APPENDIX

Table E.1: Comparison of Forecasts for Previous Rate Submissions with Actual (GWh)

Year	2005 Forecast (EB-2005-0378)	2007 Forecast (EB-2007-0681)	2009 Forecast (EB-2009-0096)	2013 Forecast EB-2013-0416	Weather Corrected Actual	Actual	% Difference from Weather Corrected Actual 2005 Forecast	2007 Forecast	2009 Forecast	2014 Forecast
2005	23,027				22,969	23,182	0.25			
2006	22,950				22,921	22,485	0.13			
2007	23,074	22,945			22,966	22,909	0.47	-0.09		
2008		23,062			22,845	22,624		0.95		
2009		23,029	22,629		22,660	22,299		1.62	-0.14	
2010			22,007		22,062	21,977			-0.25	
2011			21,851		22,023	21,718			-0.78	
2012					20,434	19,964				
2013					20,439	20,668				
2014				20,413	20,267	20,639				0.72
2015				20,497	20,203	20,343				1.45
2016				20,630	20,085	19,862				2.71
3-Year Average							0.28	0.83	-0.39	1.63

1 **Table E.2: Consensus Forecast for Ontario GDP and Housing Starts**

2

Survey of Ontario GDP Forecast (annual growth rate in %)

	2016	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2016)	2.5	2.2	2.2	2.2	2.0	2.1	2.1
Conference Board (Nov 2016)	2.7	2.3	1.9	1.9	1.9	1.9	
U of T (Jan 2017)	2.6	2.5	2.5	2.4	2.3	2.2	2.2
C4SE (Sep 2016)	2.6	2.3	1.8	1.6	1.6	1.7	1.5
CIBC (Nov 2016)	2.5	2.1	2.3				
BMO (Jan 2017)	2.6	2.2	1.9				
RBC (Dec 2016)	2.5	2.3	1.9				
Scotia (Jan 2017)	2.6	2.3	2.3				
TD (Dec 2016)	2.6	2.1	1.7				
Desjardins (Jan 2017)	2.7	2.3	2.2				
Central 1 (Jan 2017)	2.5	2.4	2.4				
National Bank (Dec 2016)	2.5	2.3	2.2				
Laurentian Bank (Aug 2016)	2.7	2.4	2.4				
Average	**2.6**	**2.3**	**2.1**	**2.0**	**1.9**	**2.0**	**1.9**

Survey of Ontario Housing Starts Forecast (in 000's)

	2016	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2016)	76.1	70.3	65.8	63.4	61.2	59.4	58.0
Conference Board (Nov 2016)	73.9	65.2	64.3	68.5	71.8	74.0	
U of T (Jan 2017)	75.0	69.4	68.1	69.2	70.2	71.1	71.9
C4SE (Sep 2016)	73.7	80.2	79.4	81.4	81.8	81.1	79.7
CIBC (Nov 2016)	75.0	68.0	66.0				
BMO (Jan 2017)	75.1	68.5	65.0				
RBC (Dec 2016)	75.4	72.5	62.5				
Scotia (Jan 2017)	75.0	71.0	68.0				
TD (Dec 2016)	75.3	68.6	63.2				
Desjardins (Jan 2017)	73.8	73.4	63.9				
Central 1 (Jan 2017)	75.2	73.7	77.5	81.1			
National Bank (Dec 2016)	74.5	64.5	60.0				
Laurentian Bank (Aug 2016)	73.3	69.8	71.1				
Average	**74.7**	**70.4**	**67.3**	**72.7**	**71.3**	**71.4**	**69.9**

3 **Forecast updated on January 25, 2016**

Table E.3: Economic Variables for Ontario

Year	GDP (2007 M$)	% change	Population (1,000's)	% change	Housing (1,000's)	% change
2005	585,843	3.2	12,528	1.1	77.8	-7.9
2006	596,797	1.9	12,662	1.1	74.4	-4.4
2007	601,735	0.8	12,764	0.8	68.0	-8.6
2008	601,723	0.0	12,883	0.9	75.6	11.2
2009	582,904	-3.1	12,998	0.9	49.5	-34.5
2010	600,131	3.0	13,135	1.1	61.2	23.7
2011	614,606	2.4	13,264	1.0	68.5	11.9
2012	622,717	1.3	13,414	1.1	63.2	-7.8
2013	631,871	1.5	13,556	1.1	59.3	-6.3
2014	648,890	2.7	13,685	1.0	58.3	-1.7
2015	665,034	2.5	13,797	0.8	69.9	20.0
2016	682,213	2.6	13,983	1.3	74.7	6.8
2017	697,790	2.3	14,144	1.2	70.4	-5.8
2018	712,665	2.1	14,305	1.1	67.3	-4.4
2019	727,128	2.0	14,452	1.0	72.7	8.1
2020	741,175	1.9	14,584	0.9	71.3	-2.0
2021	756,002	2.0	14,709	0.9	71.4	0.2
2022	770,631	1.9	14,847	0.9	69.9	-2.2

Table E.4: Number of Customers History and Forecast

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	106	248	477	633	893	907	1,034	1,152	1,272	1,396	1,508	1,608
General Service - Demand Billed	7,183	6,550	6,669	6,504	6,098	5,323	5,379	5,406	5,457	5,511	5,563	5,612
General Service - Energy Billed	98,095	98,513	98,568	95,503	87,686	88,878	88,817	88,484	88,423	88,405	88,435	88,515
Residential - Medium Density	402,173	403,304	409,901	416,493	432,519	441,836	446,636	446,102	449,958	453,821	457,608	461,272
Residential - Low Density	368,479	370,995	373,980	373,551	328,170	328,766	330,695	328,410	330,076	331,741	333,473	335,223
Seasonal	157,017	153,653	153,253	153,957	153,498	148,991	149,166	149,485	149,813	150,145	150,445	150,701
Sub-transmission *	794	795	800	882	838	804	806	808	811	814	825	828
Urban General Service - Demand Billed	1,272	1,185	1,184	1,167	1,893	1,715	1,715	1,744	1,753	1,762	1,772	1,783
Urban General Service - Energy Billed	11,650	12,308	12,307	10,807	17,703	17,780	17,763	18,074	18,166	18,268	18,380	18,501
Urban Residential	159,086	167,672	169,795	170,796	208,639	213,199	214,934	225,944	228,666	231,390	234,088	236,737
Street Light *	4,771	4,724	4,804	5,104	5,118	5,251	5,286	5,323	5,364	5,401	5,445	5,481
Sentinel Light *	31,447	30,504	30,380	26,670	25,689	24,364	24,166	23,987	23,822	23,645	23,719	23,605
Unmetered Scattered Load *	5,504	5,512	5,562	5,104	5,624	5,537	5,567	5,597	5,633	5,667	5,944	5,975
Acquired Residential	35,434	35,562	35,892	36,212	36,382	36,487	36,745	37,000	37,257	37,514	37,769	38,018
Acquired General Service - Energy Billed	4,361	4,357	4,340	4,349	4,350	4,348	4,347	4,345	4,343	4,341	4,339	4,337
Acquired General Service - Demand Billed	307	309	322	321	330	336	342	348	353	359	365	371
Acquired Urban Residential	13,709	13,862	14,020	14,175	14,353	14,515	14,676	14,834	14,994	15,153	15,312	15,467
Acquired Urban General Service - Energy Billed	1,180	1,207	1,222	1,243	1,246	1,263	1,280	1,295	1,310	1,324	1,339	1,352
Acquired Urban General Service - Demand Billed	193	185	182	189	193	193	193	193	193	194	194	194
Sum: Includes Newly Acquired for 2021-2022 only	1,247,577	1,255,963	1,267,680	1,267,171	1,274,369	1,283,351	1,291,963	1,300,516	1,309,216	1,317,967	1,386,522	1,395,578

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.5: Hydro One Distribution Load History and Forecast in GWh

Year	Actual/Forecast GWh	Growth	Normalized Weather GWh	Growth
2011	37,641	-0.8	38,062	3.2
2012	37,627	0.0	37,419	-1.7
2013	37,621	0.0	37,418	0.0
2014	37,798	0.5	37,091	-0.9
2015	36,686	-2.9	36,419	-1.8
2016	35,856	-2.3	36,139	-0.8
2017	36,244	1.1	36,244	0.3
2018	36,019	-0.6	36,019	-0.6
2019	35,680	-0.9	35,680	-0.9
2020	35,673	0.0	35,673	0.0
2021*	36,363	1.9	36,363	1.9
2022*	36,373	0.0	36,373	0.0

* Includes Acquired Utilities.

Table E.6: Actual Sales and Forecast in GWh

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	18	18	19	20	20	21
General Service - Demand Billed	3,100	2,888	2,825	2,928	2,394	2,343	2,378	2,342	2,317	2,312	2,302	2,297
General Service - Energy Billed	2,306	2,518	2,398	2,358	2,189	2,132	2,146	2,104	2,064	2,043	2,018	1,999
Residential - Medium Density	4,402	4,396	4,553	4,499	4,930	4,851	4,939	4,924	4,917	4,953	4,971	4,998
Residential - Low Density	5,491	5,515	5,563	5,541	4,767	4,614	4,640	4,539	4,478	4,457	4,426	4,408
Seasonal	701	666	699	682	671	641	643	632	620	613	605	600
Sub-transmission *	16,787	17,082	16,395	16,599	15,806	15,468	15,625	15,528	15,368	15,362	15,132	15,149
Urban General Service - Demand Billed	686	677	607	628	1,064	1,036	1,046	1,058	1,048	1,047	1,044	1,044
Urban General Service - Energy Billed	397	415	400	382	600	589	594	598	592	591	589	589
Urban Residential	1,541	1,563	1,564	1,528	1,983	1,947	1,975	2,047	2,047	2,064	2,075	2,090
Street Light *	125	127	125	122	122	122	121	121	122	123	133	133
Sentinel Light *	19	19	20	20	21	21	21	20	20	20	21	20
Unmetered Scattered Load *	23	23	23	23	24	24	24	24	25	25	26	26
Acquired Residential	308	302	305	303	301	300	298	295	292	290	287	284
Acquired General Service - Energy Billed	114	111	110	111	110	109	110	108	107	105	104	102
Acquired General Service - Demand Billed	270	233	232	241	235	237	241	239	237	236	236	236
Acquired Urban Residential	105	106	107	106	102	100	98	96	95	94	93	92
Acquired Urban General Service - Energy Billed	41	43	44	43	43	43	44	44	43	43	43	44
Acquired Urban General Service - Demand Billed	164	128	129	136	136	138	142	143	142	141	142	143
Sum: Includes Acquired Utilities for 2021-2022 only	35,587	35,901	35,186	35,327	34,586	33,804	34,170	33,957	33,637	33,631	34,267	34,276

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.7: Weather Corrected Sales and Forecast in GWh

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	18	18	19	20	20	21
General Service - Demand Billed	3,150	2,959	2,803	2,769	2,373	2,368	2,378	2,342	2,317	2,312	2,302	2,297
General Service - Energy Billed	2,343	2,580	2,380	2,229	2,169	2,155	2,146	2,104	2,064	2,043	2,018	1,999
Residential - Medium Density	4,466	4,495	4,528	4,453	4,901	4,907	4,939	4,924	4,917	4,953	4,971	4,998
Residential - Low Density	5,571	5,640	5,532	5,485	4,738	4,668	4,640	4,539	4,478	4,457	4,426	4,408
Seasonal	711	681	695	675	667	648	643	632	620	613	605	600
Sub-transmission *	16,901	16,427	16,421	16,271	15,683	15,526	15,625	15,528	15,368	15,362	15,132	15,149
Urban General Service - Demand Billed	697	694	602	594	1,054	1,047	1,046	1,058	1,048	1,047	1,044	1,044
Urban General Service - Energy Billed	404	425	397	362	595	595	594	598	592	591	589	589
Urban Residential	1,563	1,599	1,555	1,513	1,971	1,969	1,975	2,047	2,047	2,064	2,075	2,090
Street Light *	125	127	125	122	122	122	121	121	122	123	133	133
Sentinel Light *	19	19	20	20	21	21	21	20	20	20	21	20
Unmetered Scattered Load *	23	23	23	23	24	24	24	24	25	25	26	26
Acquired Residential	312	309	303	300	299	300	298	295	292	290	287	284
Acquired General Service - Energy Billed	115	114	109	105	109	109	110	108	107	105	104	102
Acquired General Service - Demand Billed	274	239	230	228	233	237	241	239	237	236	236	236
Acquired Urban Residential	107	108	107	105	101	100	98	96	95	94	93	92
Acquired Urban General Service - Energy Billed	42	44	43	40	42	43	44	44	43	43	43	44
Acquired Urban General Service - Demand Billed	167	132	128	128	135	138	142	143	142	141	142	143
Sum: Includes Acquired Utilities for 2021-2022 only	35,982	35,680	35,094	34,531	34,334	34,068	34,170	33,957	33,637	33,631	34,267	34,276

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.8a: Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,331,311	1,964,583	35,730,299	671,097	458,532	48,092,490
2012	80,371	10,060,780	1,914,575	36,409,471	587,036	374,718	48,465,197
2013	127,613	9,893,511	1,878,538	35,537,470	669,854	390,595	47,437,132
2014	161,733	9,883,885	1,872,751	35,781,683	675,645	395,502	47,700,052
2015	165,405	8,536,187	3,076,837	35,473,518	662,107	393,100	47,251,947
2016	171,973	8,118,010	2,846,792	33,699,203	665,454	397,953	44,835,978
2017	178,213	8,149,966	2,842,412	33,699,242	677,233	409,686	44,869,833
2018	184,739	8,025,918	2,832,322	33,491,228	672,386	414,168	44,534,208
2019	191,107	7,940,259	2,797,926	33,144,837	667,563	410,184	44,074,129
2020	198,809	7,924,744	2,787,731	33,133,111	664,084	408,125	44,044,395
2021	204,487	7,887,971	2,771,740	33,111,381	663,644	410,749	45,049,972
2022	210,569	7,871,666	2,764,065	33,152,081	662,981	411,710	45,073,072

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.8b: Weather Corrected Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,030,850	1,907,448	34,691,170	651,580	445,197	46,695,764
2012	80,371	9,909,510	1,885,788	35,862,030	578,209	369,084	47,737,698
2013	127,613	9,807,861	1,862,275	35,229,815	664,055	387,214	47,027,563
2014	161,733	9,849,440	1,866,224	35,656,983	673,290	394,123	47,534,380
2015	165,405	8,484,670	3,058,267	35,259,430	658,111	390,728	46,967,772
2016	171,973	8,116,669	2,846,321	33,693,637	665,344	397,887	44,828,600
2017	178,213	8,149,966	2,842,412	33,699,242	677,233	409,686	44,869,833
2018	184,739	8,025,918	2,832,322	33,491,228	672,386	414,168	44,534,208
2019	191,107	7,940,259	2,797,926	33,144,837	667,563	410,184	44,074,129
2020	198,809	7,924,744	2,787,731	33,133,111	664,084	408,125	44,044,395
2021	204,487	7,887,971	2,771,740	33,111,381	663,644	410,749	45,049,972
2022	210,569	7,871,666	2,764,065	33,152,081	662,981	411,710	45,073,072

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.9: Hydro One Distribution CDM Impacts (GWh) by Rate Class

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Service - Demand Billed	191.0	225.3	271.8	329.5	295.3	328.5	364.5	397.3	436.5	461.5	469.6	480.2
General Service - Energy Billed	193.8	270.1	317.3	367.1	373.6	418.1	454.9	493.5	537.6	563.2	568.8	577.6
Residential - Medium Density	116.6	115.2	114.2	176.6	238.6	269.9	296.7	325.4	358.4	379.6	387.2	396.7
Residential - Low Density	145.4	144.5	139.6	217.5	230.7	256.7	278.7	300.0	326.4	341.6	344.7	349.9
Seasonal	18.6	17.5	17.5	26.8	32.5	35.7	38.6	41.8	45.2	47.0	47.2	47.6
Sub-transmission *	551.2	667.1	731.7	922.0	991.8	1,087.5	1,218.2	1,336.7	1,464.4	1,546.4	1,546.5	1,582.0
Urban General Service - Demand Billed	42.2	52.8	58.3	70.6	131.2	145.2	160.4	179.4	197.4	208.9	213.0	218.2
Urban General Service - Energy Billed	33.4	44.5	52.9	59.5	102.4	115.5	126.0	140.3	154.2	163.0	166.1	170.0
Urban Residential	40.8	41.0	39.2	60.0	96.0	108.3	118.6	135.3	149.2	158.2	161.7	165.9
Acquired Residential	0.9	1.6	2.5	4.2	5.7	6.5	9.2	11.9	14.1	16.5	19.3	20.2
Acquired General Service - Energy Billed	0.7	1.7	2.6	3.9	4.8	5.9	8.4	10.9	12.9	15.1	17.7	18.5
Acquired General Service - Demand Billed	1.0	2.1	3.7	4.8	5.6	7.6	10.8	13.9	16.5	19.3	22.7	23.7
Acquired Urban Residential	0.4	0.7	1.0	1.6	2.1	1.8	2.3	2.8	3.1	3.6	4.1	4.2
Acquired Urban General Service - Energy Billed	0.5	1.0	1.4	2.3	2.9	2.5	3.1	3.8	4.3	4.9	5.6	5.9
Acquired Urban General Service - Demand Billed	4.0	4.3	5.8	7.6	10.9	10.8	13.7	16.6	19.0	21.5	24.6	25.6
Sum: Includes Acquired Utilities for 2021-2022 only	1,333	1,578	1,743	2,230	2,492	2,765	3,056	3,350	3,669	3,870	3,999	4,086

* Includes Acquired Utilities corresponding figure in 2021 and 2022 only.

Note: All savings are at end-use level

STATISTICAL DATA FOR LOAD FORECAST

This exhibit has been filed separately in MS Excel.

Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells:		
	Data input	Drop-down List
	No data entry required	Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2017 Cost of Service		Consumption (kWh) (3)				
				Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*		Actual	35,901,241,906	35,679,686,907		
Historical	*2013*		Actual	35,185,681,224	35,093,864,088		
Historical	*2014*		Actual	35,327,036,116	34,531,149,022		
Historical	*2015*		Actual	34,586,096,806	34,333,747,141	Board-approved	35940245368
Historical	*2016*		Actual	33,804,018,904	34,068,250,092		
Bridge Year	*2017*		Forecast		34,169,571,900		
Test Year	*2018*		Forecast		33,957,468,361		

Variance Analysis	Year	Year-over-year			Versus Board-approved
	2012				
	2013	-2.0%	-1.6%		
	2014	0.4%	-1.6%		
	2015	-2.1%	-0.6%		
	2016	-2.3%	-0.8%		
	2017		0.3%		
	2018		-0.6%		-5.5%
	Geometric Mean	-2.0%	-1.0%		-5.5%

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: R1   Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service	Customers			
Historical	2012	Actual	403,304		
Historical	2013	Actual	409,901		
Historical	2014	Actual	416,493		
Historical	2015	Actual	432,519	Board-approved	445,243
Historical	2016	Actual	441,836		
Bridge Year	2017	Forecast	446,636		
Test Year	2018	Forecast	446,102		

	Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	4395940935	4495296324		
Historical	2013	Actual	4553314588	4527827068		
Historical	2014	Actual	4499007979	4453012862		
Historical	2015	Actual	4929829657	4900578643	Board-approved	5105111619
Historical	2016	Actual	4851170977	4907416958		
Bridge Year	2017	Forecast		4938598661		
Test Year	2018	Forecast		4924068303		

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	10899.82	11146.1734		
Historical	2013	Actual	11108.334	11046.1545	0	
Historical	2014	Actual	10802.121	10691.6872	0	
Historical	2015	Actual	11397.941	11330.3121	Board-approved	11465.90212
Historical	2016	Actual	10979.574	11106.8744	0	
Bridge Year	2017	Forecast	0	11057.3162	0	
Test Year	2018	Forecast	0	11037.9996	0	

Variance Analysis

Year	Customers Year-over-year	Test Year Versus Board-approved
2012		
2013	1.6%	
2014	1.6%	
2015	3.8%	
2016	2.2%	
2017	1.1%	
2018	-0.1%	0.2%
Geometric Mean	2.0%	0.2%

Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	3.6%	0.7%	
2014	-1.2%	-1.7%	
2015	9.6%	10.1%	
2016	-1.6%	0.1%	
2017		0.6%	
2018		-0.3%	-3.5%
Geometric Mean	3.3%	1.8%	-3.5%

Year	Per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	1.9%	-0.9%	
2014	-2.8%	-3.2%	
2015	5.5%	6.0%	
2016	-3.7%	-2.0%	
2017		-0.4%	
2018		-0.2%	-3.7%
Geometric Mean	0.2%	-0.2%	-3.7%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 241,251,219		
Historical	2013	Actual	$ 250,704,503		
Historical	2014	Actual	$ 253,224,378		
Historical	2015	Actual	$ 298,279,090	Board-approved	$ 297,624,053
Historical	2016	Actual	$ 304,694,196		
Bridge Year (Foreca	2017	Forecast	$ 294,582,658		
Test Year (Forecast)	2018	Forecast	$ 311,034,450		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	3.9%	
2014	1.0%	
2015	17.8%	
2016	2.2%	
2017	-3.3%	
2018	5.6%	4.5%
Geometric Mean	5.2%	4.5%

2 Customer Class: R2 — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service	Customers				Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	370,995			Actual	5515270826	5639924884			Actual	14866.159	15202.1587		
Historical	2013	Actual	373,980			Actual	5563324778	5532183651			Actual	14875.98	14792.7106		
Historical	2014	Actual	373,551			Actual	5541400403	5484748501			Actual	14834.388	14682.7301		
Historical	2015	Actual	328,170	Board-approved	334,551	Actual	4766551990	4738269780	Board-approved	4816260166	Actual	14524.632	14438.4506	Board-approved	14396.20124
Historical	2016	Actual	328,766			Actual	4614396337	4667897079			Actual	14035.503	14198.2355		
Bridge Year	2017	Forecast	330,695			Forecast		4639677876			Forecast	0	14030.0896		
Test Year	2018	Forecast	328,410			Forecast		4539367306			Forecast	0	13822.2418		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	0.8%		2013	0.9%	-1.9%		2013	0.1%	-2.7%	
	2014	-0.1%		2014	-0.4%	-0.9%		2014	-0.3%	-0.7%	
	2015	-12.1%		2015	-14.0%	-13.6%		2015	-2.1%	-1.7%	
	2016	0.2%		2016	-3.2%	-1.5%		2016	-3.4%	-1.7%	
	2017	0.6%		2017		-0.6%		2017		-1.2%	
	2018	-0.7%	-1.8%	2018		-2.2%	-5.7%	2018		-1.5%	-4.0%
	Geometric Mean	-2.4%	-1.8%	Geometric Mean	-5.8%	-4.2%	-5.7%	Geometric Mean	-1.9%	-1.9%	-4.0%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 446,478,288		
Historical	2013	Actual	$ 460,610,081		
Historical	2014	Actual	$ 464,605,028		
Historical	2015	Actual	$ 460,122,373	Board-approved	$ 502,406,980
Historical	2016	Actual	$ 484,019,973		
Bridge Year (Foreca	2017	Forecast	$ 492,300,527		
Test Year (Forecast)	2018	Forecast	$ 514,470,306		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	3.2%	
	2014	0.9%	
	2015	-1.0%	
	2016	5.2%	
	2017	1.7%	
	2018	4.5%	2.4%
	Geometric Mean	2.9%	2.4%

3 Customer Class: Seasonal residential

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service	Customers			
Historical	2012	Actual	153,653		
Historical	2013	Actual	153,253		
Historical	2014	Actual	153,957		
Historical	2015	Actual	153,498	Board-approved	155,033
Historical	2016	Actual	148,991		
Bridge Year	2017	Forecast	149,166		
Test Year	2018	Forecast	149,485		

	Calendar Year (for 2017 Cost of Service	Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	666289262.2	681348479.3		
Historical	2013	Actual	698670248.1	694759389		
Historical	2014	Actual	682201960.5	675227543.3		
Historical	2015	Actual	670946952.6	666965906.6	Board-approved	668804952.4
Historical	2016	Actual	640771663.4	648200968.7		
Bridge Year	2017	Forecast		642811540.1		
Test Year	2018	Forecast		631921216		

	Calendar Year (for 2017 Cost of Service	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	4336.3245	4434.33242		
Historical	2013	Actual	4558.9222	4533.40334		
Historical	2014	Actual	4431.1201	4385.81905		
Historical	2015	Actual	4371.0484	4345.11289	Board-approved	4313.94079
Historical	2016	Actual	4300.7407	4350.60486		
Bridge Year	2017	Forecast	0	4309.38463		
Test Year	2018	Forecast	0	4227.33185		

Variance Analysis	Year	Customers Year-over-year	Test Year Versus Board-approved	Year	Consumption Year-over-year		Test Year Versus Board-approved	Year	Per Customer Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	-0.3%		2013	4.9%	2.0%		2013	5.1%	2.2%	
	2014	0.5%		2014	-2.4%	-2.8%		2014	-2.8%	-3.3%	
	2015	-0.3%		2015	-1.6%	-1.2%		2015	-1.4%	-0.9%	
	2016	-2.9%		2016	-4.5%	-2.8%		2016	-1.6%	0.1%	
	2017	0.1%		2017		-0.8%		2017		-0.9%	
	2018	0.2%	-3.6%	2018		-1.7%	-5.5%	2018		-1.9%	-2.0%
	Geometric Mean	-0.5%	-3.6%	Geometric Mean	-1.3%	-1.5%	-5.5%	Geometric Mean	-0.3%	-1.0%	-2.0%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 91,011,042		
Historical	2013	Actual	$ 92,572,355		
Historical	2014	Actual	$ 92,395,403		
Historical	2015	Actual	$ 103,977,682	Board-approved	$ 109,982,640
Historical	2016	Actual	$ 105,982,574		
Bridge Year (Foreca	2017	Forecast	$ 105,759,228		
Test Year (Forecast)	2018	Forecast	$ 111,219,385		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	1.7%	
	2014	-0.2%	
	2015	12.5%	
	2016	1.9%	
	2017	-0.2%	
	2018	5.2%	1.1%
	Geometric Mean	4.1%	1.1%

4 Customer Class: Urban residential

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service		Customers		
Historical	2012	Actual	167,672		
Historical	2013	Actual	169,795		
Historical	2014	Actual	170,796		
Historical	2015	Actual	208,639	Board-approved	213,918
Historical	2016	Actual	213,199		
Bridge Year	2017	Forecast	214,934		
Test Year	2018	Forecast	225,944		

	Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1563487621	1598824975		
Actual	1563685332	1554932487		
Actual	1528243770	1512619937		
Actual	1982901015	1971135524	Board-approved	2039119237
Actual	1946676571	1969246943		
Forecast		1974838401		
Forecast		2047262889		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	9324.6793	9535.43213		
Actual	9209.2406	9157.69123		
Actual	8947.7726	8856.29603		
Actual	9503.964	9447.5725	Board-approved	9532.253165
Actual	9130.796	9236.66126		
Forecast	0	9188.09856		
Forecast	0	9060.92306		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	1.3%	
	2014	0.6%	
	2015	22.2%	
	2016	2.2%	
	2017	0.8%	
	2018	5.1%	5.6%
	Geometric Mean	6.1%	5.6%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.0%	-2.7%	
2014	-2.3%	-2.7%	
2015	29.8%	30.3%	
2016	-1.8%	-0.1%	
2017		0.3%	
2018		3.7%	0.4%
Geometric Mean	7.6%	5.1%	0.4%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-1.2%	-4.0%	
2014	-2.8%	-3.3%	
2015	6.2%	6.7%	
2016	-3.9%	-2.2%	
2017		-0.5%	
2018		-1.4%	-4.9%
Geometric Mean	-0.7%	-1.0%	-4.9%

	Calendar Year (for 2017 Cost of Service		Revenues		
Historical	2012	Actual	$ 74,837,738		
Historical	2013	Actual	$ 65,177,893		
Historical	2014	Actual	$ 65,147,495		
Historical	2015	Actual	$ 88,989,373	Board-approved	$ 82,834,573
Historical	2016	Actual	$ 88,562,629		
Bridge Year (Foreca	2017	Forecast	$ 82,476,373		
Test Year (Forecast)	2018	Forecast	$ 91,429,002		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	-12.9%	
	2014	0.0%	
	2015	36.6%	
	2016	-0.5%	
	2017	-6.9%	
	2018	10.9%	10.4%
	Geometric Mean	4.1%	10.4%

5 Customer Class: Dgen

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2017 Cost of Service	Customers			
Historical	2012	Actual	248		
Historical	2013	Actual	477		
Historical	2014	Actual	633		
Historical	2015	Actual	893	Board-approved	1,523
Historical	2016	Actual	907		
Bridge Year	2017	Forecast	1,034		
Test Year	2018	Forecast	1,152		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	11204107.55	11204107.55		
Actual	14430262.69	14430262.69		
Actual	16080620.56	16080620.56		
Actual	16445768.67	16445768.67	Board-approved	23930287.85
Actual	17087058.82	17087058.82		
Forecast		17719239.45		
Forecast		18368070.33		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	45177.853	45177.853		
Actual	30243.24	30243.2405		
Actual	25403.824	25403.8239		
Actual	18423.527	18423.5274	Board-approved	15712.98116
Actual	18839.095	18839.0946		
Forecast	0	17143.2689		
Forecast	0	15937.8292		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	92.4%	
2014	32.7%	
2015	41.0%	
2016	1.6%	
2017	14.0%	
2018	11.5%	-24.3%
Geometric Mean	36.0%	-24.3%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	28.8%	28.8%	
2014	11.4%	11.4%	
2015	2.3%	2.3%	
2016	3.9%	3.9%	
2017		3.7%	
2018		3.7%	-23.2%
Geometric Mean	15.1%	10.4%	-23.2%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-33.1%	-33.1%	
2014	-16.0%	-16.0%	
2015	-27.5%	-27.5%	
2016	2.3%	2.3%	
2017		-9.0%	
2018		-7.0%	1.4%
Geometric Mean	-25.3%	-18.8%	1.4%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 583,323		
Historical	2013	Actual	$ 973,865		
Historical	2014	Actual	$ 1,260,680		
Historical	2015	Actual	$ 1,788,357	Board-approved	$ 4,399,243
Historical	2016	Actual	$ 2,350,533		
Bridge Year (Foreca	2017	Forecast	$ 3,108,766		
Test Year (Forecast)	2018	Forecast	$ 3,858,080		

Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	80370.7	80370.7		
Actual	127612.7527	127612.7527		
Actual	161732.8794	161732.8794		
Actual	165405.4028	165405.4028	Board-approved	240222.9605
Actual	171973.0549	171973.0549		
Forecast		178213.4965		
Forecast		184739.1954		

Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	0.1377809	0.13778089		
Actual	0.1310374	0.13103744		
Actual	0.1282902	0.12829022		
Actual	0.0924901	0.09249013	Board-approved	0.054605524
Actual	0.0731634	0.07316344		
Forecast	0	0.05732612		
Forecast	0	0.04788372		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	67.0%	
2014	29.5%	
2015	41.9%	
2016	31.4%	
2017	32.3%	
2018	24.1%	-12.3%
Geometric Mean	45.9%	-12.3%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	58.8%	58.8%	
2014	26.7%	26.7%	
2015	2.3%	2.3%	
2016	4.0%	4.0%	
2017		3.6%	
2018		3.7%	-23.1%
Geometric Mean	28.9%	18.1%	-23.1%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-4.9%	-4.9%	
2014	-2.1%	-2.1%	
2015	-27.9%	-27.9%	
2016	-20.9%	-20.9%	
2017		-21.6%	
2018		-16.5%	-12.3%
Geometric Mean	-19.0%	-19.1%	-12.3%

6 Customer Class: GSd

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2017 Cost of Service		Customers		
Historical	2012	Actual	6,550		
Historical	2013	Actual	6,669		
Historical	2014	Actual	6,504		
Historical	2015	Actual	6,098	Board-approved	6,282
Historical	2016	Actual	5,323		
Bridge Year	2017	Forecast	5,379		
Test Year	2018	Forecast	5,406		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	2888223792	2958751309		
Actual	2824861285	2803003340		
Actual	2928197395	2768572055		
Actual	2394433987	2372932206	Board-approved	2468895806
Actual	2343008053	2368460344		
Forecast		2378176583		
Forecast		2341979038		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	440950.2	451717.757		
Actual	423595.28	420317.628		
Actual	450214.85	425672.21		
Actual	392653.85	389127.855	Board-approved	393040.2048
Actual	440166.83	444948.402		
Forecast	0	442144.587		
Forecast	0	433246.548		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	1.8%	
	2014	-2.5%	
	2015	-6.2%	
	2016	-12.7%	
	2017	1.0%	
	2018	0.5%	-13.9%
	Geometric Mean	-3.8%	-13.9%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-2.2%	-5.3%	
2014	3.7%	-1.2%	
2015	-18.2%	-14.3%	
2016	-2.1%	-0.2%	
2017		0.4%	
2018		-1.5%	-5.1%
Geometric Mean	-6.7%	-4.6%	-5.1%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-3.9%	-7.0%	
2014	6.3%	1.3%	
2015	-12.8%	-8.6%	
2016	12.1%	14.3%	
2017		-0.6%	
2018		-2.0%	10.2%
Geometric Mean	-0.1%	-0.8%	10.2%

	Calendar Year (for 2017 Cost of Service		Revenues		
Historical	2012	Actual	$ 109,378,925		
Historical	2013	Actual	$ 116,626,527		
Historical	2014	Actual	$ 117,694,832		
Historical	2015	Actual	$ 117,944,121	Board-approved	$ 142,665,292
Historical	2016	Actual	$ 127,081,779		
Bridge Year (Foreca	2017	Forecast	$ 136,367,266		
Test Year (Forecast)	2018	Forecast	141,234,147		

	Demand (kW) Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	10060780.33	9909509.7		
Actual	9893510.971	9807860.705		
Actual	9883885.439	9849439.909		
Actual	8536187.078	8484669.802	Board-approved	8541960.169
Actual	8118009.847	8116668.973		
Forecast		8149966.341		
Forecast		8025918.034		

	Demand (kW) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	0.091981	0.09059798		
Actual	0.0848307	0.08409631		
Actual	0.0839789	0.08368626		
Actual	0.0723748	0.07193805	Board-approved	0.05987413
Actual	0.0638802	0.06386965		
Forecast	0	0.05976483		
Forecast	0	0.05682704		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	6.6%	
	2014	0.9%	
	2015	0.2%	
	2016	7.7%	
	2017	7.3%	
	2018	3.6%	-1.0%
	Geometric Mean	5.2%	-1.0%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-1.7%	-1.0%	
2014	-0.1%	0.4%	
2015	-13.6%	-13.9%	
2016	-4.9%	-4.3%	
2017		0.4%	
2018		-1.5%	-6.0%
Geometric Mean	-6.9%	-4.1%	-6.0%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-7.8%	-7.2%	
2014	-1.0%	-0.5%	
2015	-13.8%	-14.0%	
2016	-11.7%	-11.2%	
2017		-6.4%	
2018		-4.9%	-5.1%
Geometric Mean	-11.4%	-8.9%	-5.1%

7 Customer Class: GSe

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service		Customers		
Historical	2012	Actual	98,513		
Historical	2013	Actual	98,568		
Historical	2014	Actual	95,503		
Historical	2015	Actual	87,686	Board-approved	94,081
Historical	2016	Actual	88,878		
Bridge Year	2017	Forecast	88,817		
Test Year	2018	Forecast	88,484		

	Calendar Year (for 2017 Cost of Service		Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	2518375402	2579871593		
Historical	2013	Actual	2398320353	2379762856		
Historical	2014	Actual	2357937162	2229398518		
Historical	2015	Actual	2188738020	2169083369	Board-approved	2215826849
Historical	2016	Actual	2131696814	2154853613		
Bridge Year	2017	Forecast		2145791592		
Test Year	2018	Forecast		2104034980		

	Calendar Year (for 2017 Cost of Service		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	25563.889	26188.1335		
Historical	2013	Actual	24331.726	24143.4541		
Historical	2014	Actual	24689.666	23343.7538		
Historical	2015	Actual	24961.053	24736.9053	Board-approved	23552.3009
Historical	2016	Actual	23984.527	24245.0732		
Bridge Year	2017	Forecast	0	24159.636		
Test Year	2018	Forecast	0	23778.7325		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.1%	
	2014	-3.1%	
	2015	-8.2%	
	2016	1.4%	
	2017	-0.1%	
	2018	-0.4%	-5.9%
	Geometric Mean	-2.1%	-5.9%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-4.8%	-7.8%	
2014	-1.7%	-6.3%	
2015	-7.2%	-2.7%	
2016	-2.6%	-0.7%	
2017		-0.4%	
2018		-1.9%	-5.0%
Geometric Mean	-5.4%	-4.0%	-5.0%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-4.8%	-7.8%	
2014	1.5%	-3.3%	
2015	1.1%	6.0%	
2016	-3.9%	-2.0%	
2017		-0.4%	
2018		-1.6%	1.0%
Geometric Mean	-2.1%	-1.9%	1.0%

	Calendar Year (for 2017 Cost of Service		Revenues		
Historical	2012	Actual	$ 141,128,340		
Historical	2013	Actual	$ 137,904,580		
Historical	2014	Actual	$ 136,462,236		
Historical	2015	Actual	$ 144,167,215	Board-approved	$ 155,656,013
Historical	2016	Actual	$ 149,813,546		
Bridge Year (Foreca	2017	Forecast	$ 149,868,359		
Test Year (Forecast)	2018	Forecast	$ 155,943,148		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	-2.3%	
	2014	-1.0%	
	2015	5.6%	
	2016	3.9%	
	2017	0.0%	
	2018	4.1%	0.2%
	Geometric Mean	2.0%	0.2%

8 Customer Class: ST

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2017 Cost of Service	Customers			
Historical	2012	Actual	795		
Historical	2013	Actual	800		
Historical	2014	Actual	882		
Historical	2015	Actual	838	Board-approved	822
Historical	2016	Actual	804		
Bridge Year	2017	Forecast	806		
Test Year	2018	Forecast	808		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	17081825497	16426608038		
Actual	16395428276	16421104489		
Actual	16598660010	16271249297		
Actual	15805759536	15682785288	Board-approved	16730826230
Actual	15467672027	15525899648		
Forecast		15624829942		
Forecast		15528383151		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	21486573	20662400		
Actual	20502407	20534514.6		
Actual	18819342	18448128.5		
Actual	18866309	18719522.3	Board-approved	20360625.73
Actual	19238398	19310820.5		
Forecast	0	19385645.1		
Forecast	0	19212429.5		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	0.6%		2013	-4.0%	0.0%		2013	-4.6%	-0.6%	
	2014	10.3%		2014	1.2%	-0.9%		2014	-8.2%	-10.2%	
	2015	-5.0%		2015	-4.8%	-3.6%		2015	0.2%	1.5%	
	2016	-4.0%		2016	-2.1%	-1.0%		2016	2.0%	3.2%	
	2017	0.2%		2017		0.6%		2017		0.4%	
	2018	0.3%	-1.6%	2018		-0.6%	-7.2%	2018		-0.9%	-5.6%
	Geometric Mean	0.3%	-1.6%	Geometric Mean	-3.3%	-1.1%	-7.2%	Geometric Mean	-3.6%	-1.4%	-5.6%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 33,471,626		
Historical	2013	Actual	$ 33,053,790		
Historical	2014	Actual	$ 33,674,534		
Historical	2015	Actual	$ 42,687,571	Board-approved	$ 49,968,729
Historical	2016	Actual	$ 45,485,979		
Bridge Year (Forecas	2017	Forecast	$ 46,707,827		
Test Year (Forecast)	2018	Forecast	$ 53,197,161		

Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	36409471	35862030		
Actual	35537470.19	35229814.62		
Actual	35781682.57	35656982.72		
Actual	35473518.17	35259429.72	Board-approved	36051950.4
Actual	33699203.3	33693637.11		
Forecast		33699241.86		
Forecast		33491227.84		

Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1.0877712	1.07141584		
Actual	1.0751405	1.06583282		
Actual	1.062574	1.05887087		
Actual	0.8310034	0.82598819	Board-approved	0.721490246
Actual	0.7408701	0.74074776		
Forecast	0	0.72149025		
Forecast	0	0.62956796		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	-1.2%		2013	-2.4%	-1.8%		2013	-1.2%	-0.5%	
	2014	1.9%		2014	0.7%	1.2%		2014	-1.2%	-0.7%	
	2015	26.8%		2015	-0.9%	-1.1%		2015	-21.8%	-22.0%	
	2016	6.6%		2016	-5.0%	-4.4%		2016	-10.8%	-10.3%	
	2017	2.7%		2017		0.0%		2017		-2.6%	
	2018	13.9%	6.5%	2018		-0.6%	-7.1%	2018		-12.7%	-12.7%
	Geometric Mean	9.7%	6.5%	Geometric Mean	-2.5%	-1.4%	-7.1%	Geometric Mean	-12.0%	-10.1%	-12.7%

9 **Customer Class:** UGd

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2017 Cost of Service		Customers		
Historical	2012	Actual	1,185		
Historical	2013	Actual	1,184		
Historical	2014	Actual	1,167		
Historical	2015	Actual	1,893	Board-approved	1,913
Historical	2016	Actual	1,715		
Bridge Year	2017	Forecast	1,715		
Test Year	2018	Forecast	1,744		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	677205538.3	693742215.6		
Actual	606535860.3	601842664.4		
Actual	627727054.8	593507659.3		
Actual	1063583543	1054032667	Board-approved	1085625236
Actual	1035844242	1047096704		
Forecast		1046372418		
Forecast		1057526028		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	571481.47	585436.469		
Actual	512450.51	508485.317		
Actual	537898.08	508575.544		
Actual	561725.42	556681.185	Board-approved	567596.7332
Actual	603990.81	610552.014		
Forecast	0	610275.511		
Forecast	0	606297.397		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	-0.1%	
2014	-1.4%	
2015	62.2%	
2016	-9.4%	
2017	0.0%	
2018	1.7%	-8.8%
Geometric Mean	8.0%	-8.8%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-10.4%	-13.2%	
2014	3.5%	-1.4%	
2015	69.4%	77.6%	
2016	-2.6%	-0.7%	
2017		-0.1%	
2018		1.1%	-2.6%
Geometric Mean	15.2%	8.8%	-2.6%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-10.3%	-13.1%	
2014	5.0%	0.0%	
2015	4.4%	9.5%	
2016	7.5%	9.7%	
2017		0.0%	
2018		-0.7%	6.8%
Geometric Mean	1.9%	0.7%	6.8%

	Calendar Year (for 2017 Cost of Service		Revenues		
Historical	2012	Actual	$ 16,125,897		
Historical	2013	Actual	$ 13,391,582		
Historical	2014	Actual	$ 13,492,584		
Historical	2015	Actual	$ 25,300,089	Board-approved	$ 29,852,702
Historical	2016	Actual	$ 26,335,521		
Bridge Year (Forecas	2017	Forecast	$ 28,037,297		
Test Year (Forecast)	2018	Forecast	$ 29,300,516		

	Demand (kW) Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1914574.928	1885788		
Actual	1878537.918	1862275.008		
Actual	1872750.882	1866224.309		
Actual	3076836.709	3058267.499	Board-approved	3048496.231
Actual	2846791.519	2846321.306		
Forecast		2842411.666		
Forecast		2832322.444		

	Demand (kW) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	0.1187267	0.11694159		
Actual	0.1402775	0.13906311		
Actual	0.1387985	0.13831482		
Actual	0.1216137	0.12087971	Board-approved	0.102117934
Actual	0.108097	0.10807917		
Forecast	0	0.10137966		
Forecast	0	0.09666459		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	-17.0%	
2014	0.8%	
2015	87.5%	
2016	4.1%	
2017	6.5%	
2018	4.5%	-1.8%
Geometric Mean	12.7%	-1.8%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-1.9%	-1.2%	
2014	-0.3%	0.2%	
2015	64.3%	63.9%	
2016	-7.5%	-6.9%	
2017		-0.1%	
2018		-0.4%	-7.1%
Geometric Mean	14.1%	8.5%	-7.1%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	18.2%	18.9%	
2014	-1.1%	-0.5%	
2015	-12.4%	-12.6%	
2016	-11.1%	-10.6%	
2017		-6.2%	
2018		-4.7%	-5.3%
Geometric Mean	-3.1%	-3.7%	-5.3%

10 Customer Class: UGe

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service)	Customers			
Historical	2012	Actual	12,308		
Historical	2013	Actual	12,307		
Historical	2014	Actual	10,807		
Historical	2015	Actual	17,703	Board-approved	17,851
Historical	2016	Actual	17,780		
Bridge Year	2017	Forecast	17,763		
Test Year	2018	Forecast	18,074		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	415217868.3	425357070.5		
Actual	399648117.1	396555757.6		
Actual	382434769.9	361587035.9		
Actual	600045628	594657277.5	Board-approved	613,411,739
Actual	588747807.5	595143423.8		
Forecast		594362748.3		
Forecast		598366765.4		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	33735.608	34559.398		
Actual	32472.016	32220.7569		
Actual	35387.69	33458.595		
Actual	33894.86	33590.488	Board-approved	34362.89067
Actual	33112.925	33472.6335		
Forecast	0	33460.7996		
Forecast	0	33106.7241		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
2012			2012				2012			
2013	0.0%		2013	-3.7%	-6.8%		2013	-3.7%	-6.8%	
2014	-12.2%		2014	-4.3%	-8.8%		2014	9.0%	3.8%	
2015	63.8%		2015	56.9%	64.5%		2015	-4.2%	0.4%	
2016	0.4%		2016	-1.9%	0.1%		2016	-2.3%	-0.4%	
2017	-0.1%		2017		-0.1%		2017		0.0%	
2018	1.8%	1.2%	2018		0.7%	-2.5%	2018		-1.1%	-3.7%
Geometric Mean	8.0%	1.2%	Geometric Mean	12.3%	7.1%	-2.5%	Geometric Mean	-0.6%	-0.9%	-3.7%

	Calendar Year (for 2017 Cost of Service)	Revenues			
Historical	2012	Actual	$ 11,733,375		
Historical	2013	Actual	$ 8,148,325		
Historical	2014	Actual	$ 7,762,978		
Historical	2015	Actual	$ 17,940,417	Board-approved	$ 21,051,994
Historical	2016	Actual	$ 19,590,106		
Bridge Year (Forecas	2017	Forecast	$ 20,538,827		
Test Year (Forecast)	2018	Forecast	$ 21,929,437		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	-30.6%	
2014	-4.7%	
2015	131.1%	
2016	9.2%	
2017	4.8%	
2018	6.8%	4.2%
Geometric Mean	13.3%	4.2%

11 Customer Class: Street Lighting

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service	Customers				Consumption (kWh) [3]					Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	4,724			Actual	126725176.1	126725176.1			Actual	26825.821	26825.8205		
Historical	2013	Actual	4,804			Actual	124806098.2	124806098.2			Actual	25982.115	25982.1146		
Historical	2014	Actual	5,104			Actual	122222252.8	122222252.8			Actual	23946.366	23946.3662		
Historical	2015	Actual	5,118	Board-approved	4,973	Actual	122362125	122362125	Board-approved	125123039.9	Actual	23908.192	23908.1917	Board-approved	25160.97373
Historical	2016	Actual	5,251			Actual	122143172.7	122143172.7			Actual	23260.936	23260.9356		
Bridge Year	2017	Forecast	5,286			Forecast		121496045.4			Forecast	0	22985.2863		
Test Year	2018	Forecast	5,323			Forecast		121367847.7			Forecast	0	22799.6969		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	1.7%		2013	-1.5%	-1.5%		2013	-3.1%	-3.1%	
	2014	6.3%		2014	-2.1%	-2.1%		2014	-7.8%	-7.8%	
	2015	0.3%		2015	0.1%	0.1%		2015	-0.2%	-0.2%	
	2016	2.6%		2016	-0.2%	-0.2%		2016	-2.7%	-2.7%	
	2017	0.7%		2017		-0.5%		2017		-1.2%	
	2018	0.7%	7.0%	2018		-0.1%	-3.0%	2018		-0.8%	-9.4%
	Geometric Mean	2.4%	7.0%	Geometric Mean	-1.2%	-0.9%	-3.0%	Geometric Mean	-4.6%	-3.2%	-9.4%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 6,673,309		
Historical	2013	Actual	$ 9,080,853		
Historical	2014	Actual	$ 8,997,592		
Historical	2015	Actual	$ 10,353,957	Board-approved	$ 11,813,032
Historical	2016	Actual	$ 11,393,784		
Bridge Year (Forecas	2017	Forecast	$ 11,495,811		
Test Year (Forecast)	2018	Forecast	$ 12,150,056		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	36.1%	
	2014	-0.9%	
	2015	15.1%	
	2016	10.0%	
	2017	0.9%	
	2018	5.7%	2.9%
	Geometric Mean	12.7%	2.9%

12 Customer Class: Sentinel Lighting

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

Customers

	Calendar Year (for 2017 Cost of Service		Customers		
Historical	2012	Actual	30,504		
Historical	2013	Actual	30,380		
Historical	2014	Actual	26,670		
Historical	2015	Actual	25,689	Board-approved	29,671
Historical	2016	Actual	24,364		
Bridge Year	2017	Forecast	24,166		
Test Year	2018	Forecast	23,987		

Consumption (kWh) [3]

	Calendar Year		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	18671752.13	18671752.13		
Historical	2013	Actual	19652645.62	19652645.62		
Historical	2014	Actual	20010585.89	20010585.89		
Historical	2015	Actual	20521609.5	20521609.5	Board-approved	22080536.46
Historical	2016	Actual	21025925.18	21025925.18		
Bridge Year	2017	Forecast		20656296.14		
Test Year	2018	Forecast		20385578.16		

Consumption (kWh) per Customer

	Calendar Year		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	612.10832	612.108318		
Historical	2013	Actual	646.89022	646.890224		
Historical	2014	Actual	750.30318	750.303183		
Historical	2015	Actual	798.84813	798.848126	Board-approved	744.1755286
Historical	2016	Actual	862.99151	862.991511		
Bridge Year	2017	Forecast	0	854.770113		
Test Year	2018	Forecast	0	849.864977		

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2012								
2013	-0.4%		5.3%	5.3%		5.7%	5.7%	
2014	-12.2%		1.8%	1.8%		16.0%	16.0%	
2015	-3.7%		2.6%	2.6%		6.5%	6.5%	
2016	-5.2%		2.5%	2.5%		8.0%	8.0%	
2017	-0.8%			-1.8%			-1.0%	
2018	-0.7%	-19.2%		-1.3%	-7.7%		-0.6%	14.2%
Geometric Mean	-4.7%	-19.2%	4.0%	1.8%	-7.7%	12.1%	6.8%	14.2%

Revenues

	Calendar Year (for 2017 Cost of Service		Revenues		
Historical	2012	Actual	$ 1,686,145		
Historical	2013	Actual	$ 2,480,644		
Historical	2014	Actual	$ 2,478,317		
Historical	2015	Actual	$ 2,837,116	Board-approved	$ 3,568,109
Historical	2016	Actual	$ 3,196,141		
Bridge Year (Forecas	2017	Forecast	$ 3,219,187		
Test Year (Forecast)	2018	Forecast	$ 3,299,513		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013	47.1%	
2014	-0.1%	
2015	14.5%	
2016	12.7%	
2017	0.7%	
2018	2.5%	-7.5%
Geometric Mean	14.4%	-7.5%

13 Customer Class: USL

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2017 Cost of Service	Customers			
Historical	2012	Actual	5,512		
Historical	2013	Actual	5,562		
Historical	2014	Actual	5,104		
Historical	2015	Actual	5,624	Board-approved	5,734
Historical	2016	Actual	5,537		
Bridge Year	2017	Forecast	5,567		
Test Year	2018	Forecast	5,597		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	22804129.18	23360983.05		
Actual	23003379.71	23003379.71		
Actual	22912154.02	22912154.02		
Actual	23976975.35	23976975.35	Board-approved	25229668.99
Actual	23778254.02	23778254.02		
Forecast		24240556.81		
Forecast		24437189.6		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	4136.9987	4238.02006		
Actual	4135.6056	4135.60562		
Actual	4489.0584	4489.05839		
Actual	4263.4202	4263.42025	Board-approved	4400.380236
Actual	4294.4291	4294.42912		
Forecast	0	4354.46113		
Forecast	0	4365.92103		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.9%	
	2014	-8.2%	
	2015	10.2%	
	2016	-1.5%	
	2017	0.5%	
	2018	0.5%	-2.4%
	Geometric Mean	0.3%	-2.4%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.9%	-1.5%	
2014	-0.4%	-0.4%	
2015	4.6%	4.6%	
2016	-0.8%	-0.8%	
2017		1.9%	
2018		0.8%	-3.1%
Geometric Mean	1.4%	0.9%	-3.1%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.0%	-2.4%	
2014	8.5%	8.5%	
2015	-5.0%	-5.0%	
2016	0.7%	0.7%	
2017		1.4%	
2018		0.3%	-0.8%
Geometric Mean	1.3%	0.6%	-0.8%

	Calendar Year (for 2017 Cost of Service	Revenues			
Historical	2012	Actual	$ 2,820,255		
Historical	2013	Actual	$ 2,876,133		
Historical	2014	Actual	$ 2,740,667		
Historical	2015	Actual	$ 3,221,323	Board-approved	$ 3,140,590
Historical	2016	Actual	$ 3,188,316		
Bridge Year (Forecas	2017	Forecast	$ 3,040,950		
Test Year (Forecast)	2018	Forecast	$ 3,058,397		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	2.0%	
	2014	-4.7%	
	2015	17.5%	
	2016	-1.0%	
	2017	-4.6%	
	2018	0.6%	-2.6%
	Geometric Mean	1.6%	-2.6%

Note: If there are more than ten (10) customer classes, please contact OEB Staff to add tables for additional customer classes.

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2017)

Appendix 2-I was initially developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that

2017 is the third year of the six-year (2015-2020) Conservation First program. Final results for the 2011-14 program were issued in the fall of 2015, and the program in completed, although in some instances disposition of the amounts has been deferred. For the purposes of the

The new six year (2015-2020) CDM program works similarly to the previous 2011-2014 CDM program, meaning that distributors will offer programs each year that, over the six years (from January 1, 2015 to December 31, 2020) will strive to cumulatively achieve savings

2015-2020 CDM Program - 2017, third year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the IESO will encourage

	6 Year (2015-2020) kWh Target: 1,159,020,000						
	2015	2016	2017	2018	2019	2020	Total
			%				
2015 CDM Programs	16.67%	16.67%	16.67%	16.67%	16.67%	16.67%	16.67%
2016 CDM Programs		16.67%	16.67%	16.67%	16.67%	16.67%	16.67%
2017 CDM Programs			16.67%	16.67%	16.67%	16.67%	16.67%
2018 CDM Programs				16.67%	16.67%	16.67%	16.67%
2019 CDM Programs					16.67%	16.67%	16.67%
2020 CDM Programs						16.67%	16.67%
Total in Year	**16.67%**	**33.33%**	**50.00%**	**66.67%**	**83.33%**	**100.00%**	**100.00%**
			kWh				
2015 CDM Programs	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00
2016 CDM Programs		193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00
2017 CDM Programs			193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00
2018 CDM Programs				193,170,000.00	193,170,000.00	193,170,000.00	193,170,000.00
2019 CDM Programs					193,170,000.00	193,170,000.00	193,170,000.00
2020 CDM Programs						193,170,000.00	193,170,000.00
Total in Year	**193,170,000.00**	**386,340,000.00**	**579,510,000.00**	**772,680,000.00**	**965,850,000.00**	**1,159,020,000.00**	**1,159,020,000.00**

Note: The default formulae in the above table assume that 1/21 of the 2015-2020 kWh CDM target is required each year so that, including persistence, 100% of the kWh target is achieved by the end of 2020. The distributor can input the 2015 CDM savings, including persistence from 2016 to 2020, once the reports become available. The distributor can also input estimates or forecasts of the 2016 and 2017 CDM programs if it believes that these are more realistic; such information would typically be derived from the CDM plans that the distributor has filed with the IESO. Similarly, CDM savings and persistence into future years can be estimated for 2018, 2019 and 2020 CDM programs. However, the distributor will have to support its proposals for estimated or forecasted savings, particularly beyond the 2017 test year. The sum of cumulative savings, including persistence, should equal the target entered into cell A25.

Determination of 2017 Load Forecast Adjustment

The Board determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2014 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012, 2013, 2014 and 2015 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D84 to E88. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

Net-to-Gross Conversion

Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2015	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program	**125,397,607**	**85,659,571**	**39,738,036**	
2012 CDM program	**81,864,854**	**59,957,751**	**21,907,103**	
2013 CDM program	**104,555,410**	**80,075,123**	**24,480,287**	
2014 CDM program	**246,423,234**	**211,669,008**	**34,754,226**	
2015 CDM program	**254,562,799**	**229,733,480**	**24,829,319**	
2006 to 2015 OPA CDM programs: Persistence to 2017	812803904	667094933	145708971	0.00%

The default values below represent the factor used for how each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for historical years that are used to derive the load forecast prior to any manual CDM

Weight Factor for Inclusion in CDM Adjustment to 2017 Load Forecast

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	
Weight Factor for each year's CDM program impact on 2014 load forecast	1	1	1	1	1	1	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Default is 0, but one option is for full year impact of persistence of 2015 CDM programs on 2017 load forecast, but 50% impact in base forecast (first year impact of 2014 CDM programs on 2014 actuals, which is part of the data for the load forecast.*	*Full year impact of persistence of 2015 programs on 2015 load forecast. 2015 CDM program impacts are not in the base forecast.*	*Only 50% of 2016 CDM programs are assumed to impact the 2016 load forecast based on the "half-year" rule.*	*2018, 2019 and 2020 are future years beyond the 2017 test year. No impacts of CDM programs beyond the 2017 test year are factored into the test year load forecast.*			

2015-2020 LRAMVA and 2017 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2017 load forecast is made. There is a different but related threshold amount that is used for the 2017 LRAMVA amount for Account 1568.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2017, for assessing performance against the five-year target.

If used to determine the manual CDM adjustment for the system purchased kWh, the proposed loss factor should correspond with the proposed total loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2017 Load Forecast is the amount manually subtracted from the system-wide load forecast (either based on a purchased or billed basis) derived from the base forecast from historical data.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on a system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what IESO-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load

	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Amount used for CDM threshold for LRAMVA (2017)	193,170,000.00	386,340,000.00	579,510,000.00	772,680,000.00	965,850,000.00	1,159,020,000.00
Manual Adjustment for 2017 Load Forecast (billed basis)	193,170,000.00	386,340,000.00	579,510,000.00	772,680,000.00	965,850,000.00	1,159,020,000.00
Proposed Loss Factor (TLF)	7.40%	Format: X.XX%				
Manual Adjustment for 2017 Load Forecast (system purchased basis)	207,464,580.00	414,929,160.00	622,393,740.00	829,858,320.00	1,037,322,900.00	1,244,787,480.00

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used to calculate the impact of each year's program on the CDM adjustment to the 2017 load forecast.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Revenue Requirement
Year Ending December 31
($ Millions)

Line No.	Particulars		2018
			(a)
	Cost of Service		
1	Operating, maintenance & administrative	$	584.8
2	Depreciation & amortization		392.6
3	Income taxes		61.5
4	Cost of service excluding return on Capital	$	1,038.9
5	Return on capital		461.1
6	Total revenue requirement	$	1,499.9

Witness: Joel Jodoin

REVENUE REQUIREMENT WORK FORM

This exhibit has been filed separately in MS Excel.