Exhibit U List / Table of Contents

APPLICATION UPDATE SUMMARY

1. INTRODUCTION

Since filing its 2020-2024 Custom IR Application ("the Application") in August of 2018, Toronto Hydro has (i) received final approval for 2019 rates, (ii) closed-out its 2018 financial and operational year, and (iii) begun to execute its operational plans for the final year (2019) of the utility's 2015-2019 Custom IR rate period. This update amends Toronto Hydro's evidence to reflect these developments.

This standalone submission (Exhibit U, or "the Exhibit") provides 2018 actuals for key financial figures in the Application. These update items were previously outlined in Toronto Hydro's response to interrogatory 1A-Staff-1. The Exhibit also provides 2018 performance measure results and an updated 2018 Earnings-Sharing Mechanism calculation. For the remaining forecast period, Toronto Hydro has updated a subset of 2019 and 2020-2024 figures where the consequential impacts of 2018 actuals are material, or where the utility has made a prior commitment to update the information.[1] For example, updated items also include the 2019-2024 Load Forecast and 2020-2024 Bill Impacts. Otherwise, Toronto Hydro is not proposing any changes to its 2020-2024 business plan.

A Table of Contents for the update can be found at Exhibit U, Tab 1A, Schedule 1. For reference purposes, the Exhibit is organized to mirror the structure of the exhibits initially filed, i.e. Exhibits 1A through 9. For example, updates related to the Distribution System Plan, filed at Exhibit 2B, are provided in Tab 2; those associated with Operating Costs:

[1] Appendix A to this schedule identifies all commitments made to date with respect to updates to be included in this filing, and provides references to where this updated information can be found in this Exhibit.

OM&A, filed at Exhibit 4A, are provided in Tab 4A. Variance explanations for the updated figures are embedded throughout the respective schedules.

There are several changes to the 2019 bridge and 2020 test year forecasts that the utility expects will have an impact on the 2020 revenue requirement. These changes are discussed throughout the schedules in this Exhibit and are summarized in Tab 6. Toronto Hydro is accordingly amending its application to reflect these changes. However, the net impact to revenue requirement of these changes is estimated to be less than the utility's materiality threshold. Therefore, Toronto Hydro is not updating its 2020 revenue requirement at this time. Toronto Hydro proposes to flow these changes through the revenue requirement work form and cost allocation models as part of the Draft Rate Order process.

2. UPDATE OVERVIEW

This update reflects the completion of the fourth out of five years of the utility's 2015-2019 Custom IR period. Results from 2018 indicate that the utility remains on pace to successfully execute its five-year Distribution System Plan. This is demonstrated across outcome categories, as well as through the utility's success in managing the most challenging series of adverse weather events experienced in a single year since 2013. Tab 1B of this update provides a complete overview of outcome performance results for 2018.

2.1 Update on the Execution of the 2015-2019 Capital Expenditure Plan

Toronto Hydro's capital expenditures in 2018 were $435.6 million and the utility is on track for $443.0 million in investments in 2019. This puts the utility on pace for $2,379.4 million in total capital expenditures during the 2015-2019 period, which is virtually unchanged from the $2,383.5 previously forecast in this application. Variance analysis for 2018-2019 is provided in Tab 2, Schedule 2 of this update.

As noted in Tab 2, Schedule 1, the utility is projecting total in-service additions for the 2015-2019 period to be within one percent of the amount which formed the basis of the OEB-approved capital related revenue requirement ("CRRR") for 2015-2019. Changes in project energization timing in 2018-2019 have contributed to slightly lower than forecast rate base amounts in these years, and have generated an increase of $18.5 million in the amount that Toronto Hydro is requesting be returned to customers through disposition of the CRRR Variance Account. (For a full summary of updates to DVAs, please refer to Tab 9 of this Exhibit.) Despite these changes in project energization timing, Toronto Hydro expects the actual Net Fixed Assets component of its 2020 opening rate base to be within one percent of the originally filed amount.

2.2 2018 OM&A Results

Toronto Hydro's Operations, Maintenance, and Administration ("OM&A") expenditures in 2018 were $268.3 million, which is 2.7 percent higher than the $261.2 million initially forecasted in Exhibit 4A of this application. The Emergency Response program had the largest variance in 2018 as a result of the utility having to respond to four extreme weather events throughout the year. The financial impact due to extreme weather was offset by one-time reductions in other OM&A programs such as Supply Chain and Customer Care. Tab 4A, Schedule 1 of this update explains the material changes to the program expenditures resulting from the 2018 OM&A results.

2.3 Earnings Sharing Mechanism ("ESM") Update

The utility did not surpass its ESM threshold in 2018. Toronto Hydro has provided an updated ESM calculation for 2018 in Tab 9, Schedule 1, Section 7.

2.4 Load Forecast and Revenue Offsets Updates

Toronto Hydro updated its load and customer growth forecasts as detailed in Tab 3, Schedule 1. There is no change to the growth factor component of Toronto Hydro's proposed custom rate-setting formula for 2021-2024 rates.

Revenue offsets in 2018 were $3.3 million higher than originally forecast in this application. The difference was primarily due to higher revenues from pole attachments and accident claims. As discussed in the Revenue Offsets Variance Analysis schedule (Exhibit U, Tab 3, Schedule 2), changes to revenue offsets in 2019 are expected to carry-forward into 2020. One of these changes is driven by the recently finalized revisions to the OEB's Customer Service Rules. Toronto Hydro is requesting that these changes, which impact 2020 revenue requirement, be approved by the OEB as part of the 2020 test year.

2.5 Bill Impacts Update

As a result of the variances and forecast updates detailed in this Exhibit, there is a reduction to the proposed average annual bill impact for 2020-2024. Toronto Hydro's five-year proposal would result in an average annual increase of $0.52 (1.1 percent) on the distribution portion of the Residential bill. This compares to $0.77 (1.7 percent) set out in the originally filed application. For the first year of the plan, Residential customers would experience a decrease of $3.53. This compares to a decrease of $3.10 set out in the originally filed application. It may be possible to further smooth the effects of the rate decrease in the first year of the plan followed by successive modest increases, though to do so may involve a departure from typical deferral and variance account clearance approaches.

Table 3 provides a summary of the total bill impacts for typical customers in all classes.

Table 3: Bill Impacts – Change in Monthly Bill

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.53	0.99	1.12	1.40	1.92
	%	*-2.7*	*0.8*	*0.9*	*1.1*	*1.5*
Competitive Sector Multi-Unit Residential	$/30 days	-1.74	1.01	0.89	0.99	1.51
	%	*-2.5*	*1.5*	*1.3*	*1.4*	*2.1*
General Service <50 kW	$/30 days	-5.29	2.22	2.82	4.40	4.82
	%	*-1.6*	*0.7*	*0.9*	*1.3*	*1.4*
General Service 50-999 kW	$/30 days	-442.30	262.16	49.57	87.53	84.57
	%	*-3.1*	*1.9*	*0.4*	*0.6*	*0.6*
General Service 1,000-4,999 kW	$/30 days	-4,334.08	2,782.72	408.13	720.88	696.44
	%	*-2.8*	*1.9*	*0.3*	*0.5*	*0.5*
Large Use	$/30 days	-406.96	-1,054.39	2,102.70	3,713.96	3,588.48
	%	*-0.1*	*-0.1*	*0.3*	*0.5*	*0.5*
Street Lighting	$/30 days	-7,309.35	6,962.19	3,587.48	6,323.55	6,152.69
	%	*-2.5*	*2.5*	*1.2*	*2.2*	*2.0*
Unmetered Scattered Load	$/30 days	-6.04	0.82	0.80	1.42	1.37
	%	*-9.3*	*1.4*	*1.4*	*2.4*	*2.2*

APPENDIX A: APPLICATION UPDATE COMMITMENTS

Commitment Reference	Details	Application Update Reference
Exhibit 1A, Tab 3, Schedule 1, App B	Rate Framework (Exhibit 1B, Tab 4, Schedule 1)	No change at this time
	Income Tax/PILs Workform (Exhibit 4B, Tab 2, Schedule 2)	Exhibit U, Tab 4B, Schedule 2 and Schedule 4
	Rate Design (Exhibit 8, Tab 1, Schedule 1)	Exhibit U, Tab 8, Schedule 1
	Wireline Pole Attachment Rate (Exhibit 8, Tab 2, Schedule 1)	Exhibit U, Tab 8, Schedule 1
	Deferral and Variance Accounts – Retail Settlement Variance Accounts (Exhibit 9, tab 1, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	Deferral and Variance Accounts – Lost Revenue Adjustment Mechanism Variance Account (Exhibit 9, Tab 1, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	Carrying Charges (Exhibit 9, Tab 1, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	Earning Sharing Mechanism ("ESM") – 2018 Calculation (Exhibit 1B, Tab 4, Schedule 1)	Exhibit U, Tab 9, Schedule 1
	ESM – 2019 Calculation (Exhibit 1B, Tab 4, Schedule 1)	To be updated as part of Toronto Hydro's 2021 annual rate application
	2018 Financial Figures	Exhibit U
1A-Staff-1	Outcomes and Performance	Exhibit U, Tab 1B, Schedule 1
	Capital Expenditures (OEB Appendix 2-AA and 2-AB	Exhibit U, Tab 2, Schedule 2, App A and B
	Overhead Expense (OEB Appendix 2-D)	Exhibit U, Tab 2, Schedule 3, App A
	Fixed Asset Continuity Schedule (OEB Appendix 2-BA)	Exhibit U, Tab 2, Schedule 1, App A
	Other Operating Revenues (OEB Appendix 2-H)	Exhibit U, Tab 3, Schedule 5
	OM&A Expenditures (OEB Appendix 2-JA to 2-JC	Exhibit U, Tab 4A, Schedule 1, App A to C
	Recoverable OM&A Cost per Customer and FTE (OEB Appendix 2-L)	Exhibit U, Tab 4A, Schedule 1, App D
	Employee Costs/Compensation Table (OEB Appendix 2-K)	Exhibit U, Tab 4A, Schedule 4, App A

Commitment Reference	Details	Application Update Reference
	Shared Services and Corporate Cost Allocation (OEB Appendix 2-N)	Exhibit U, Tab 4A, Schedule 5, App A
	Year-End Deferral and Variance Account balances for 2018 actuals (Exhibit 9)	Exhibit U, Tab 9, Schedule 1
1B-BOMA-23	Year-End 2018 Financial Information	Exhibit U
1B-BOMA-28	2018 Actuals for Efficiency Assessment, Total Cost per customer, and Total Cost per km of line	Not available at this time, see Exhibit U, Tab 1B, Schedule 1 for more details.
1B-BOMA-46 (b)	Toronto Hydro's 2018 Annual Short Term Debt Portion and Expense	No change at this time
1B-SEC-8	2018 Corporate Scorecard Results	Exhibit U, Tab 1B, Schedule 1, Section 6
1C-Staff-50	Annual RRR Submission	Exhibit U, Tab 1C, Schedule 3
	2018 Audited Financial Statements	Exhibit U, Tab 1C, Schedule 2
2A-Staff-53	Appendix 2-Z	No change at this time. See Exhibit U, Tab 2, Schedule 1, Section 3 for more details.
	Updated assumptions used for the cost of power calculation	No change at this time. See Exhibit U, Tab 2, Schedule 1, Section 3 for more details.
2A-AMPCO-12	2018 Actual Depreciation Expenses	Exhibit U, Tab 4B, Schedule 1 and Schedule 3
2A-AMPCO-15	Updated OEB Appendix 2-AA	Exhibit U, Tab 2, Schedule 2, App A
2A-BOMA-48	2018 actual year-end and actual Closing PP&E	Exhibit U, Tab 4B, Schedule 1 and Schedule 3
2A-BOMA-50	2018 System Access Capital Expenditures	Exhibit U, Tab 2, Schedule 2
2A-VECC-8	2018 Actual Year-end CWIP	Exhibit U, Tab 2, Schedule 2
2B-Staff-60	Updated Capital Expenditure Forecast for the 2015-2019 period	Exhibit U, Tab 2, Schedule 2
	Updated In-Service Additions for the 2015-2019 period	Exhibit U, Tab 2, Schedule 1, App A
3-Staff-101	Load Forecast update including actual load up to December 2018 in its regression model	Exhibit U, Tab 3
3-SEC-74	OEB Appendix 2-H	Exhibit U, Tab 3, Schedule 5
3-VECC-30	2018 year to date values for the schedules set out on pages 1-2 of Exhibit 3, Tab 2, Schedule 1.	Exhibit U, Tab 3, Schedule 2

Commitment Reference	Details	Application Update Reference
4A-Staff-133 (c)	Updated 2018 actuarial assumptions (OPEB costs)	Exhibit U, Tab 4A, Schedule 1 and Schedule 2, Section 1.20
4A-AMPCO-96 (a)(b)	2018 Corporate performance results	Exhibit U, Tab 1B,
4A-AMPCO-100 (a)	Updated Appendix 2-K including 2018 actuals	Exhibit U, Tab 4A, Schedule 4, App A
4A-AMPCO-104 (b)	2018 Actuals for Exhibit 4A, Tab 4, Schedule 4, p. 15, Table 7	Exhibit U, Tab 4A, Schedule 4
4A-AMPCO-105	2018 Actuals for Exhibit 4A, Tab 4, Schedule 4, p. 15, Table 8	Exhibit U, Tab 4A, Schedule 4
4A-PWU-12 (d)	Actual 2018 data for Exhibit 4A, Tab 4, Schedule 2, p. 1 (Appendix 2-K Table	Exhibit U, Tab 4A, Schedule 4
4A-SEC-75	Updated Appendix 2-JA, JB, and JC to include 2018 Actuals	Exhibit U, Tab 4A, Schedule 1, Appendix A to C
4A-VECC-32	Updated Table 1 (Historical OM&A by Program) for 2018 actual results at Exhibit 4A, Tab 1, Schedule 1, p. 2	Exhibit U, Tab 4A, Schedule 1
6-EP-59	2018 ESM Amounts at Exhibit 6, Tab 1, Schedule 6	Exhibit U, Tab 6, Schedule 1
9-Staff-160	In its update of DVA balances for 2018, include for disposition any 2018 balances in Account 1551	Exhibit U, Tab 9, Schedule 1
9-Staff-165	Completed version of the latest OEB issued DVA continuity schedule	Exhibit U, Tab 9, Schedule 2
TC, Day 4, Feb. 22nd, pp. 110-111	Update interrogatory responses to 3-VECC-25 and 3-VECC-26	Exhibit U, Tab 3, Schedule 1, App C and D
JTC2.8	2018 Actual Performance and Reliability metrics	Exhibit U, Tab 1B, Schedule 1
JTC2.25	2018 consolidated balance sheet	Toronto Hydro committed to provide the balance, however, it is not available at the time of the Application Update
JTC4.25.4	Unit Costs for 2018	Exhibit U, Tab 1B, Schedule 1

OUTCOMES AND PERFORMANCE MEASUREMENT VARIANCE ANALYSIS

1. OVERVIEW

This Schedule provides 2018 results for Toronto Hydro's performance measures. The evidence is structured as follows:

- Section 1: Overview
- Section 2: Electricity Distributor Scorecard Updates
- Section 3: 2020-2024 Custom Performance Measures Updates
- Section 4: Service Quality Updates
- Section 5: Reliability Performance Updates
- Section 6: 2015-2019 Distribution System Plan Measures Updates
- Section 7: 2018 Corporate Scorecard Update

As demonstrated in the pages that follow, Toronto Hydro's performance trends remained stable or positive in 2018 for the majority of measures.

2. ELECTRICITY DISTRIBUTOR SCORECARD ("EDS")

Table 1 below provides an updated EDS for 2018 results. Please note that these results are preliminary. Final results will be submitted later in 2019, in accordance with the OEB's usual timelines for scorecard reporting.

Table 1: Toronto Hydro EDS Performance – 2014-2018

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Target: Industry	Target: Distributor	Average
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		91.50%	96.90%	97.70%	98.32%	99.80%	90.00%		96.84%
		Scheduled Appointments Met On Time		99.80%	99.90%	99.50%	99.37%	99.66%	90.00%		99.65%
		Telephone Calls Answered On Time		71.90%	76.80%	64.70%	77.92%	80.15%	65.00%		74.29%
	Customer Satisfaction	First Contact Resolution		81.00%	84.00%	86.00%	88.00%	89.00%			85.60%
		Billing Accuracy		96.62%	97.54%	98.86%	99.24%	99.25%	98.00%		98.30%
		Customer Satisfaction Survey Results		91.00%	91.00%	83.00%	83.00%	92.00%			88.00%
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness			71.00%	71.00%	69.00%	69.00%			70.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C		C	N/A
		Serious Electrical Incident Index	Number of General Public Incidents	3	0	0	1	6		2	2.00
			Rate per 10, 100, 1000 km of line	0.295	0	0	0.035	0.209		0.074	0.108
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		0.89	0.99	0.91	0.91	0.81		1.11	0.90
		Average Number of Times that Power to a Customer is Interrupted		1.18	1.31	1.28	1.18	1.14		1.36	1.22
	Asset Management	Distribution System Plan Implementation Progress		147%	100%	101%	99%	95%			108.40%
	Cost Control	Efficiency Assessment		5	5	5	5				
		Total Cost per Customer		$967	$1,000	$1,044	$1,042				
		Total Cost per Km of Line		$70,688	$73,309	$27,819	$27,825				
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings			12.51%	34.58%	63.11%			1,576.05 GWh	
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		97.12%	100.00%	100.00%	81.08%	100.00%			95.64%
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	92.41%	100.00%	90.00%		98.48%
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.68	0.67	0.61	0.64	0.53			0.63
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.65	1.57	1.45	1.34	1.2			1.44
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.30%	9.30%	9.30%	9.30%			N/A
			Achieved	7.41%	10.71%	12.18%	9.08%	9.33%			N/A

2.1 Service Quality: New Residential/Small Business Services Connected On Time

In 2018, Toronto Hydro continued its improved performance as exhibited over the CIR term. 2018 performance was 99.80 percent compared to 98.32 percent in 2017.

2.2 Service Quality: Schedule Appointments Met on Time

The 2018 performance improved relative to both 2016 and 2017 performance. In 2018, performance was at 99.66 percent compared to 99.37 percent in 2017 and 99.50 percent in 2016.

2.3 Service Quality: Telephone Calls Answered on Time

2018 performance continued its improved trend over the CIR term. In 2018, performance was 80.15 percent compared to the 2017 performance of 77.92 percent.

2.4 Customer Satisfaction: First Contact Resolution

In 2018, Toronto Hydro continued its improved performance trend. Over the period of 2013 to 2018 First Contact Resolution performance has improved by approximately 16 percent with 2018 performance at 89 percent.

2.5 Customer Satisfaction: Billing Accuracy

Similar to First Contact Resolution, Toronto Hydro’s focus on customer outcomes has delivered annually improved outcomes for the Billing Accuracy measure. In 2018, Billing Accuracy was 99.25 percent compared to 99.24 percent in 2017 and 98.86 percent in 2016.

2.6 Customer Satisfaction: Customer Satisfaction Survey Results

In 2018, Toronto Hydro continued its efforts to improve its customer satisfaction results. These efforts resulted in 2018 performance improving to 92 percent compared to 83 percent in 2016-2017.

2.7 Safety: Level of Public Awareness of Electrical Safety

Public awareness of electrical safety maintained its 2017 level of 69 percent in 2018.

2.8 Safety: Compliance with Ontario Regulation 22/04

In 2018, Toronto Hydro maintained a level of 'Compliant' with Ontario Regulation 22/04.

2.9 Safety: Serious Electrical Incident Index

Toronto Hydro experienced a significant increase in the number of reported incidents in 2018. This increase was primarily driven by four traffic incidents which damaged poles and brought down primary distribution lines, which qualified as serious electrical incidences.

2.10 System Reliability: SAIDI/SAIFI

Toronto Hydro achieved improvements in both SAIDI and SAIFI in 2018. SAIDI was measured at 0.81, which is a reduction from the 0.91 in 2017 and 2016. SAIFI in 2018 reduced to 1.14 versus the 1.18 in 2017 and 1.28 in 2016. Reliability performance in 2018 is discussed in further detail in Section 5 below.

2.11 Asset Management: Distribution System Plan (“DSP”) Implementation Progress

The DSP Implementation Progress metric measures Toronto Hydro’s annual progress towards completing its 2015 to 2019 capital program. In 2018, Toronto Hydro capital expenditures equalled 95 percent of planned expenditures.

2.12 Efficiency Assessment

This 2018 results for this metric will not be finalized until September 2019.

2.13 Total Cost per Customer and Total Cost per km of Line

This 2018 results for this metric will not be finalized until September 2019.

2.14 Net Cumulative Energy Savings

The 2018 results for this metric will not be finalized until September 2019.

2.15 Connection of Renewable Generation

In 2018, Toronto Hydro completed 100 percent of Renewable Generation Connection Impact Assessments on time, and connected 100 percent of new Micro-Embedded Generation Facilities on time.

2.16 Financial Ratios

2.16.1 Current Ratio

The Current Ratio in 2018 was 0.53 compared to 0.64 in 2017. The slight reduction in this ratio reflects the issuance of approximately $240 million in debt.

2.16.2 Debt to Equity Ratio

The Debt to Equity Ratio was 1.20 in 2018 compared with 1.34 in 2017. The 2018 value reflects the provision of approximately $43 million in dividends in 2018.

2.16.3 Achieved Return on Equity

In 2018, the achieved return on equity was 9.33 percent compared to the OEB Approved 9.3 percent established in Toronto Hydro's 2015 to 2019 Custom IR application.

3. TORONTO HYDRO'S 2020-2024 CUSTOM PERFORMANCE MEASURES

Toronto Hydro's pre-filed evidence at Exhibit 2B, Section C2, detailed 15 custom measures for the 2020-2024 plan period. These measures are incremental to the measures contained in the EDS and the Electricity Service Quality Requirements ("ESQR"), for a total of 44 unique measures to be reported to the OEB annually. This section provides 2013 to 2018 data for the custom measures where historical information is available.

3.1 Customer Service

3.1.1 Number of Customers on eBills

As shown in Figure 1, as of the end of 2018, over 261,000 Toronto Hydro customers opted to receive eBills, this is an increase of over 300 percent in the last six years.

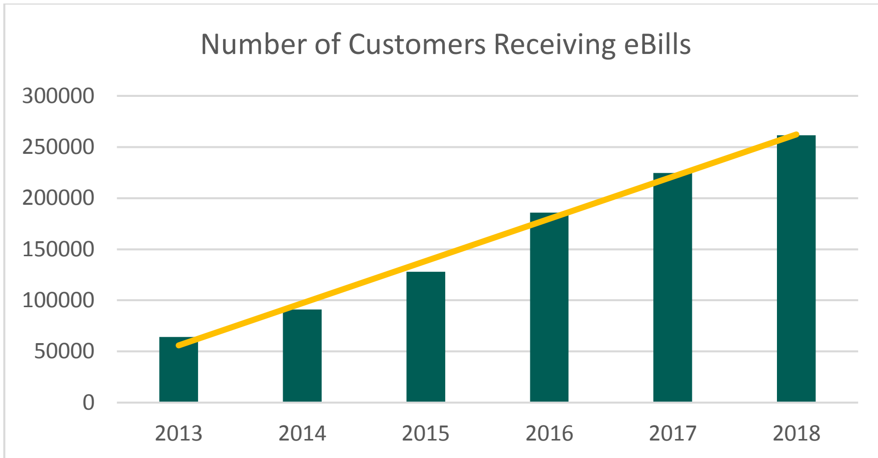


Figure 1: Number of Customers on eBills 2013 – 2018

3.2 Safety

3.2.1 Total Recordable Injury Frequency ("TRIF")

The TRIF measure tracks the proportion of recordable injuries to hours worked. Figure 2, below, illustrates Toronto Hydro's TRIF performance over the last five years.[1]

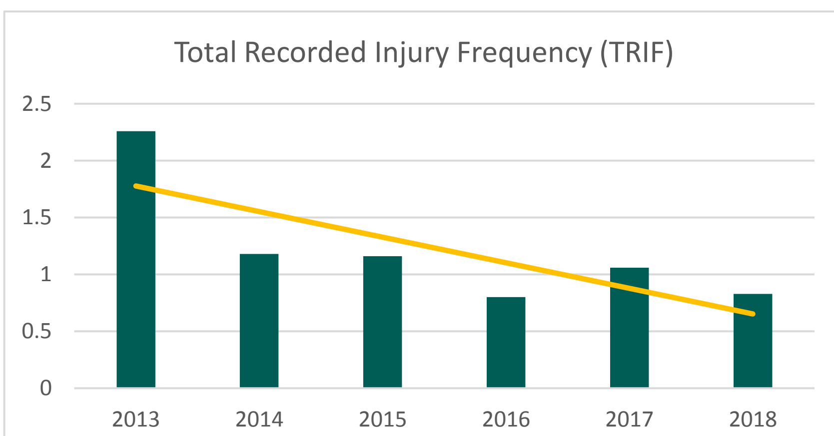


Figure 2: Total Recordable Injury Frequency Performance 2013 – 2018

[1] The TRIF is normalized to 200 hours- representing 100 workers working a 40-hour week for 50 weeks per year to allow for comparisons between companies utilizing this metric.

3.2.2 Box Construction Conversion[2]

The Box Construction Conversion measure tracks Toronto Hydro's performance on the reduction in the number of box construction poles in its distribution system. Between 2013 and 2018, the number of box construction poles were reduced from approximately 6,400 to approximately 2,900 as at the end of 2018.

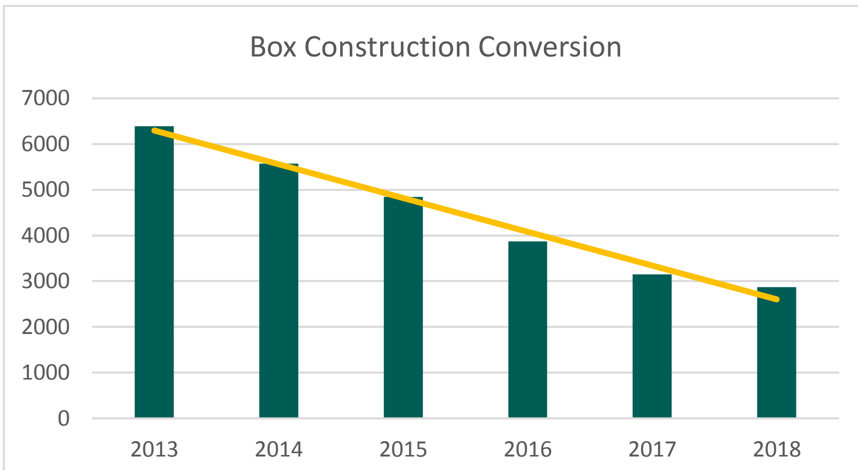


Figure 3: Box Construction Conversion Performance for 2013 - 2018

3.2.3 Network Units Modernization

The Network Units Modernization measure tracks Toronto Hydro's progress on the installation of network units that have submersible protectors. As shown in Figure 4, the percentage of modernized Network Units increased to 58 percent in 2018 from 56 percent in 2017.

---

[2] Please note that, due to recordkeeping limitations, the rate of box construction pole removals between 2013 and 2017 is inclusive of non-box framed poles on box-construction feeders.

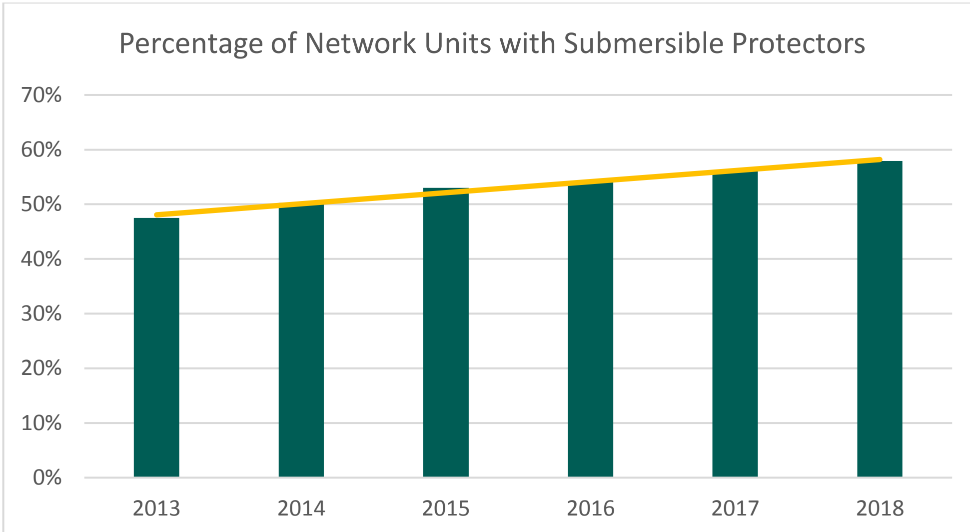


Figure 4: Network Unit Modernization: Percentage of Network Units with Submersible Protectors Performance for 2013-2018

3.3 Reliability

3.3.1 System Average Interruption Duration Index ("SAIDI") & System Average Interruption Frequency Index ("SAIFI") Resulting from Defective Equipment

As Figures 5 and 6, below, demonstrate, there was a slight improvement in the level of reliability related to Defective Equipment caused outages in these years. This is attributable to Toronto Hydro's investments in the system renewal programs. For a comprehensive discussion of Toronto Hydro's system renewal and modernization efforts, please refer to Exhibit 2B, Section E2.

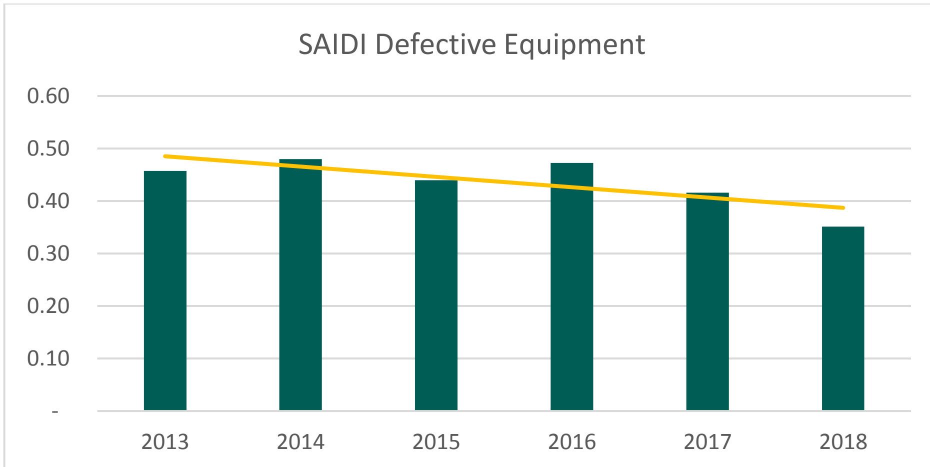


Figure 5: SAIDI (Defective Equipment) Performance 2013-2018

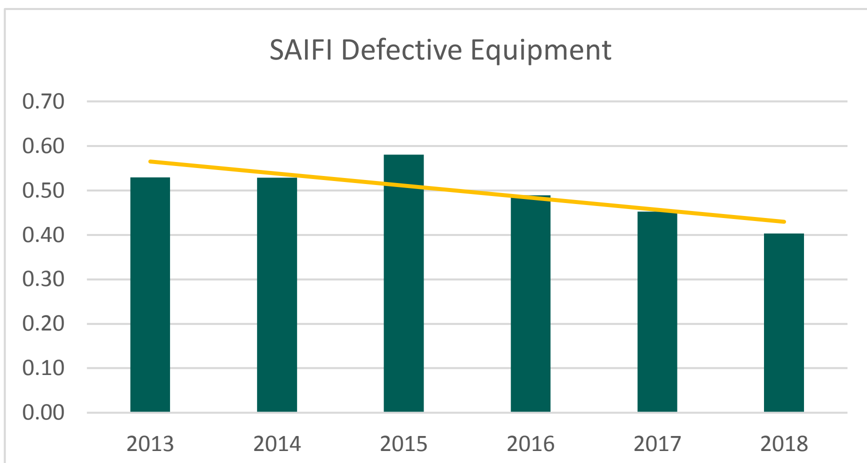


Figure 6: SAIFI (Defective Equipment) Performance 2013-2018

3.3.2 Feeders Experiencing Sustained Interruptions (FESI-7/6) - Worst Performing Feeders

FESI-7 System and FESI-6 Large Customer measures track the performance of feeders that experience the highest number of outages.[3] Between 2013 and 2018, FESI-7 System and

[3] These measures exclude interruptions caused by Major Event Days, Loss of Supply, scheduled outages, station bus-level interruptions and on the secondary side of the distribution transformer (e.g. on service wires or secondary bus).

FESI-6 Large Customers performance experienced a demonstrable improvement, as shown in Figures 7 and 8 below.

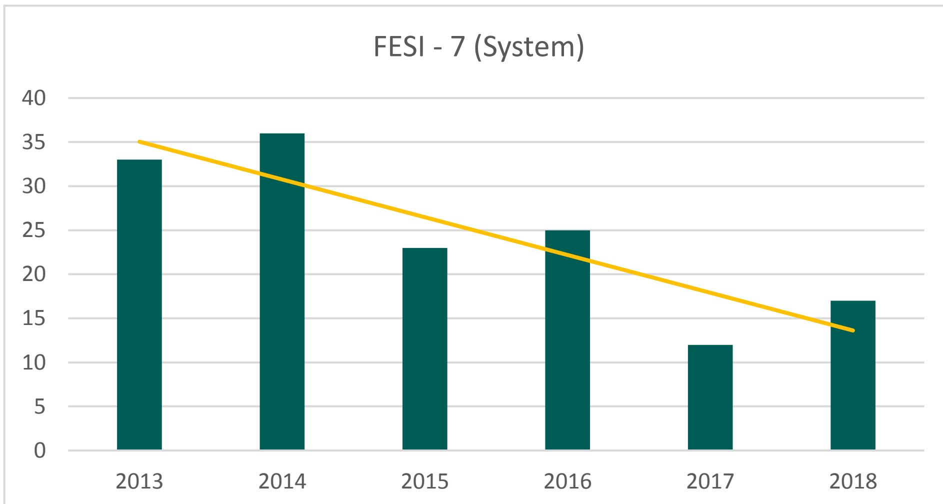


Figure 7: FESI-7 System Performance between 2013 and 2018

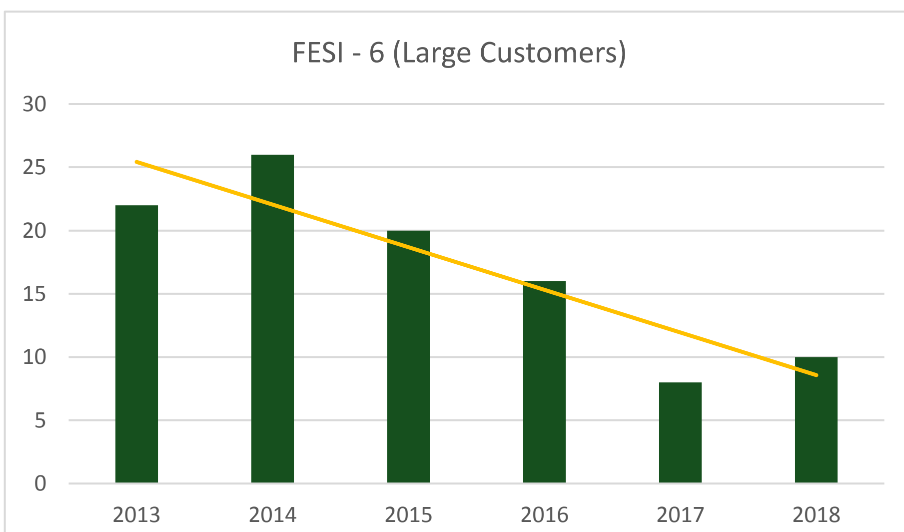


Figure 8: FESI-6 Large Customer Performance between 2013 and 2018

3.3.3 System Capacity

The System Capacity measure tracks potential capacity constraints at the station level by measuring the ability of each station to connect at least one large customer.[4] As seen in Figure 9 below, Toronto Hydro has averaged 15 stations with capacity constraints between 2013 and 2018, with a moderate deterioration in performance in 2018.

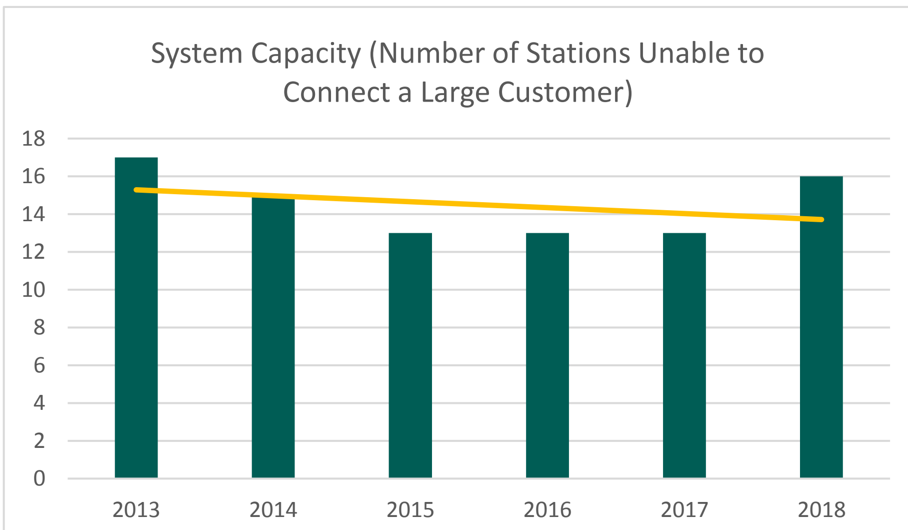


Figure 9: System Capacity (Number of Stations Unable To Connect a Large Customer) Performance for 2013 – 2018

3.3.4 System Health – Asset Condition (Wood Poles)

Toronto Hydro does not have updated asset condition assessment results at this time. As noted elsewhere in this update, Toronto Hydro migrated its data – including core asset data – to a new enterprise software system partway through 2018. As a result of this unique situation, the current state assessment of the distribution system assets for 2019 has not been completed as of this submission.

[4] Large customer for the purposes of this measure is defined as a customer with a peak load of approximately 10 MVA or higher.

3.3.5 Direct Buried Cable Replacement

The Direct Buried Cable Replacement measure will track the number of circuit-kilometres of direct buried cable that remains in the distribution system during the 2020-2024 plan period. As shown in Figure 10, as of year-end 2018, Toronto Hydro's underground distribution system contained approximately 774 circuit-kilometres of direct buried cable.

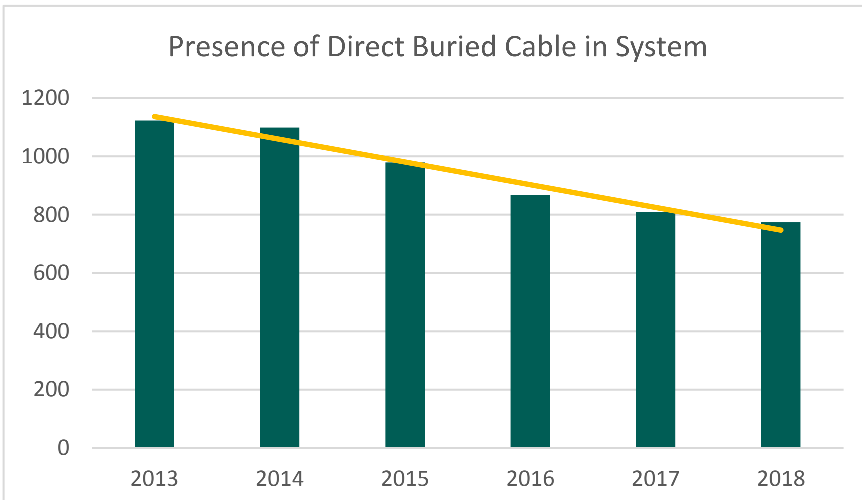


Figure 10: Presence of Direct Buried Cable 2013-2018

3.4 Financial

Toronto Hydro plans to monitor and publically report on the Average Wood Pole Replacement Cost and the Vegetation Management Cost per Kilometre over the 2020-2024 period. In its response to undertaking JTC4.25.4, Toronto Hydro committed to provide 2018 data for the unit costs reported into the UMS Unit Cost Study, which is inclusive of the aforementioned unit categories. See Table 2 below for the 2018 unit costs and an updated three-year average. While there is significant volatility in the year-over-year results, the data nonetheless demonstrates stable or improving unit cost performance over the last three years

Table 2: 2018 Unit Costs

	Category	Category (THESL Asset Name)	Per Unit of Measurement (i.e., each, per meter/foot, per kilometre/mile, per hectar, etc.)	2016		2017		2018		Updated 3-Yr Weighted Average Unit Cost
				Number of Units (if known)	Unit Costs (2016)	Number of Units (if known)	Unit Costs (2017)	Number of Units (if known)	Unit Costs (2017)	
1	Wooden Pole Replacement	Wooden Poles	Each	3592	$7,538	2759	$6,454	2066	$6,255	$6,868
3	UG XLPE Replacement	U-G Pri Cable- XLPE (In Duct)	Meter	311,618	$96	355284	$125	340874	$109	$110
5	Vegetation Management - Tree Trimming		Km	1,649	$2,137.0	1676	$2,147	1,364	$2,158	$2,147
7	Pole Test and Treat		Each	15,986	$17.55	14671	$18	10,308	$18	$18
8	Overhead Line Patrol & IR Scan		Kilometer	7,497	$44.0	7045	$44	7,147	$44	$44
9	Vault Inspection	Network Vault Inspection	Each	3,090	$345.0	3095	$355	3,101	$365	$355
		Submersible Vault Inspection	Each	2,770	$145.0	3073	$155	2,689	$165	$155
		Building Vault Inspection	Each	1,450	$320.0	1211	$330	1,576	$340	$330
10	OH Manual Switches	O-H Switches	Each	360	$26,359	371	$18,336	395	$17,967	$20,772
11	OH Remote/Motor Operated Switches									
12	Overhead (Poletop) Transformer Replacement	O-H Transformers	Each	804	$12,220	716	$10,969	465	$10,280	$11,314
13	Padmount Transformer Replacement	U-G Transformers	Each	579	$23,091	1060	$20,596	506	$29,100	$23,275
14	Underground (submersible and vault) Transformer Replacement									
15	Network Transformer Replacement	Network Unit (Tx & Protector)	Each	63	$106,034	62	$90,666	45	$84,846	$94,821
16	Network Protector Replacement									
17	Oil Breaker Replacement	Subst Eq Indr Brk	Each	4	$92,213	0	$-	6	$78,573	$84,029
18	SF6 Breaker Replacement									
19	Vacuum Breaker Replacement									
20	Station Switchgear (Air) Replacement	Subst Eq Swtch Air	Each	1	$1,374,809	2	$1,264,981	$1	$1,443,643	$1,337,111.37

3.5 Environment

3.5.1 Oil Spills Containing Polychlorinated Biphenyl ('PCB')

The Oil Spills Containing PCBs measure tracks Toronto Hydro's progress towards reducing the risk of oil spills containing PCBs. Figure 11, below, displays the number of oil spills containing PCBs during 2013 and 2018.

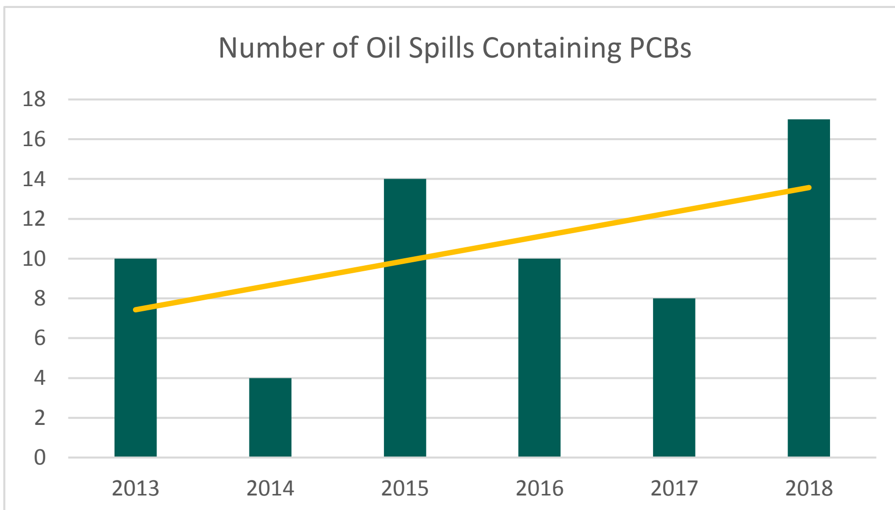


Figure 11: Oil Spills Containing PCBs 2013-2018

3.5.2 Waste Diversion

As stated in Exhibit 2B, Section C2, Toronto Hydro intends to begin reporting on the new Waste Diversion Rate performance measure during the 2020-2024 period.

4. 2015-2019 DSP PERFORMANCE MEASURES

4.1 Reliability

4.1.1 Customer Average Interruption Duration Index ("CAIDI")

Figure 12 shows the performance for this measure over the 2013-2018 period. Toronto Hydro's CAIDI performance improved in 2018, returning to its 2016 performance level.

Toronto Hydro's improvement in this reliability measure can be attributed to the utility's distribution system investments, grid operations performance, and various external factors that affect average outage duration.

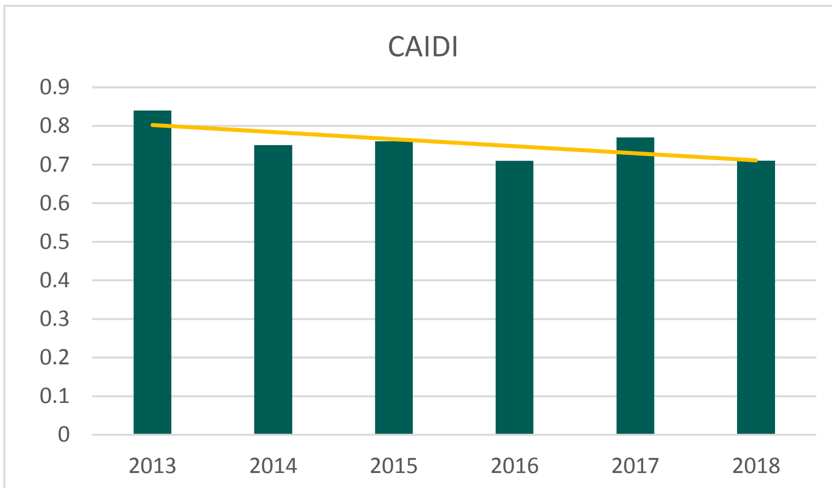


Figure 12: CAIDI Performance from 2013 – 2018

4.1.2 Momentary Average Interruption Frequency Index ("MAIFI")

MAIFI measures the average frequency of momentary interruptions (i.e. less than one minute) that affect Toronto Hydro's customers. Figure 13, below, shows the utility's performance for this measure over the 2013-2018 period. The five-year annual frequency value for the period 2014 to 2018 is 2.64 compared to the corresponding value of 2.74 reported in the utility's last Rate Application (for the period 2009 to 2013). For 2018, MAIFI was 2.78. This result represents an increase from the prior years, which is due to a number of drivers including weather.

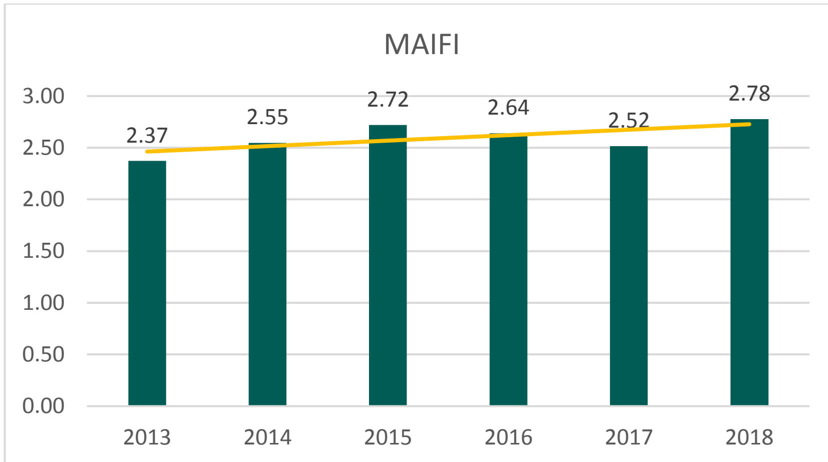


Figure 13: MAIFI Performance from 2013 – 2018

4.1.3 Outages caused by Defective Equipment

Figure 14, below, shows the utility's performance in this measure over the 2013-2018 period. In 2018, Toronto Hydro recorded 441 outages caused by defective equipment. The overall declining trend is indicative of Toronto Hydro's achievements in directing capital expenditures toward the renewal and modernization of its core distribution system assets.

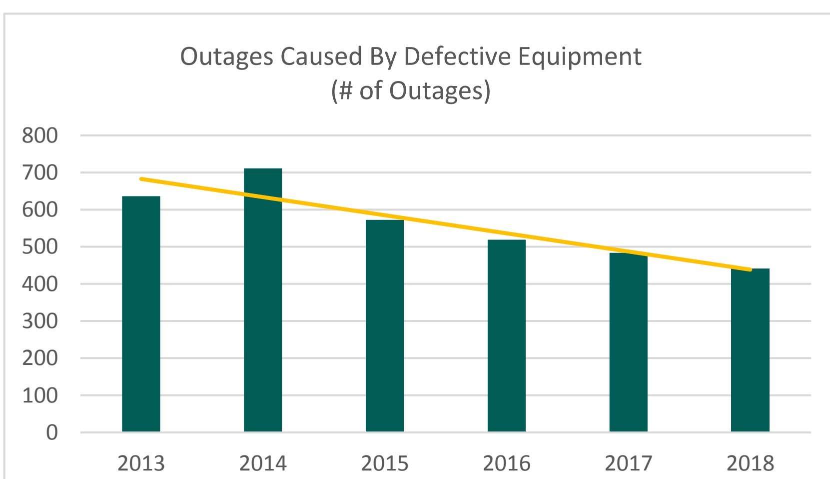


Figure 14: Outages by Defective Equipment Performance from 2013 – 2018

4.2 Stations Capacity Availability

The Stations Capacity Availability tracks the number of Transformer Stations where station demand is forecasted to exceed 90 percent of the station's firm capacity within the next five years. Figure 15 below shows the utility's performance in this measure over the 2013-2018 period. Two stations are forecasted to be loaded > 90% in the next five years.[5]

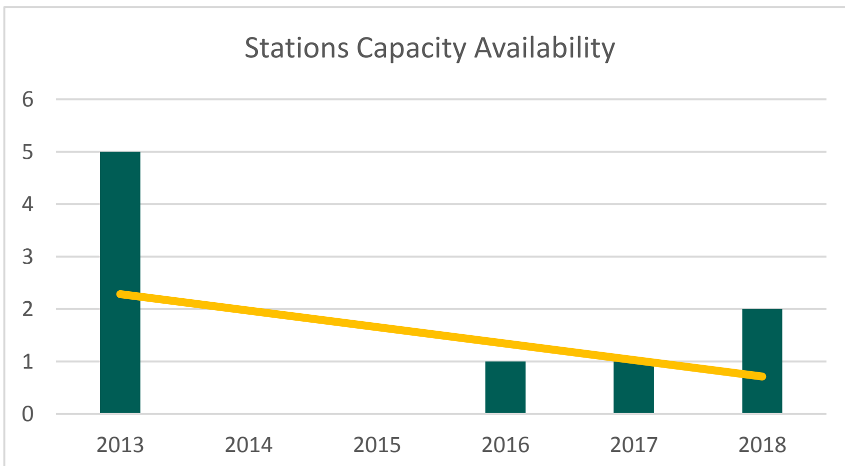


Figure 15: Stations from 2013 – 2018

4.3 Planning Efficiency: Engineering and Support Costs

This measure monitors the proportion of capital project expenditures attributable to indirect labour costs. The result of 10 percent for 2018 was comparable to the 2017 result of 9 percent.

[5] Please note that these are preliminary results and are subject to change based on additional loading analysis. Final results will be published in Toronto Hydro's final 2018 EDS.

4.4 Supply Chain Efficiency: Materials Handling On-Cost

This measure monitors the proportion capital project expenditures attributable to indirect supply chain and warehousing costs. The 2018 rate has remained flat at 10 percent when compared to 2017.

4.5 Construction Efficiency

4.5.1 Internal vs. Contractor Cost Benchmarking

Toronto Hydro expects to finalize the 2018 Contractor Efficiency: Internal vs Contractor Benchmarking measure value by the end of Q3, 2019. This time span is needed to accommodate two dependencies. The first is the need to use Audited Financial information, which was completed in March, 2019. The second is the fact that the calculation process typically takes two to three months given the comprehensive nature of the underlying analysis. The timeline for 2018 results is further extended due to the fact that Toronto Hydro migrated enterprise software systems partway through 2018, resulting in a longer lead time to gather a quality data extract from which the metric's analysis is performed.

4.5.2 Standard Asset Assembly Labour Input

This annual progress report addresses the status of Toronto Hydro's framework for standardizing the estimation, management and reporting of construction work progress by the utility's internal crews. In 2018, Toronto Hydro migrated enterprise software systems and is now working toward implementing its asset assembly processes in this new environment.

5. SERVICE QUALITY PERFORMANCE

As stated in Exhibit 1B, Tab 2, Schedule 3, Toronto Hydro monitors and reports its performance results for the Electricity Service Quality Requirements ("ESQRs") in accordance with the OEB's Reporting and Record-keeping Requirements ("RRR"). This section provides the reported Service Quality Requirements for the last six years (2013 - 2018).

Table 3: Summary of Toronto Hydro's ESQR Performance

ESQR	OEB Standard	Avg. 2014-2018	2013	2014	2015	2016	2017	2018
Connection of New Services-Low Voltage ("LV")	90	96.8	94.2	91.5	96.9	97.7	98.3	99.8
Connection of New Service-High Voltage ("HV")	90	99.7	100.0	100.0	100.0	100.0	98.4	100.0
Micro Embedded Generation Facilities	90	98.5	100.0	100.0	100.0	100.0	92.4	100.0
Appointment Scheduling	90	84.2	96.6	96.2	89.0	72.0	81.8	82.4
Appointment Met	90	99.7	99.6	99.8	99.9	99.5	99.4	99.7
Rescheduling a Missed Appointment	100	98.9	98.4	94.6	100.0	100.0	100.0	100.0
Telephone Accessibility	65	74.3	82.0	71.9	76.8	64.7	77.9	80.2
Telephone Call Abandon Rate	10	1.9	1.2	1.7	1.6	3.1	1.9	1.4
Written Response to Enquires	80	94.7	98.9	85.8	97.5	93.1	99.0	98.30
Billing Accuracy	98	98.3	NA	96.6	97.5	98.9	99.2	99.3
Emergency Response (Urban)	80	90.3	74.4	92.0	87.2	91.8	93.6	88.6
Reconnection Performance Standard	85	99.8	100.0	100.0	100.0	99.7	99.4	99.7

5.1 Connections of New Services – Low Voltage

In 2018, Toronto Hydro continued the trend of improving its results in this measure. The 2018 result of 99.8 percent is a half a percent increase from the 2017 result of 99.3 percent.

5.2 Connections of New Service – High Voltage

The 2018 result for high voltage new service connections was 100 percent. This is a return to the results for the years of 2013 to 2016.

5.3 Micro-Embedded Generation Facilities

The 2018 result for Micro Embedded Generation Facilities was 100 percent. This is a return to the results for the years of 2013 to 2016.

5.4 Appointments Scheduling

Appointments scheduled in 2018 increased to 82.40 percent compared to 81.8 percent in 2017. As described in the pre-filed evidence Exhibit 1B, Tab 2, Schedule 3, pages 4 and 5, Toronto Hydro has made several process improvements to increase performance in this measure. Over the two years of 2017 and 2018, performance in this commitment to improve has resulted in the measure increasing from 72 percent in 2016 to 82.4 percent in 2018.

5.5 Appointments Met

In 2018, the appointments met performance was 99.66 percent which is an increase from the 2017 result of 99.40 percent.

5.6 Rescheduling a Missed Appointment

In 2018, Toronto Hydro rescheduled 100 percent of the missed appointments within the OEB prescribed timeline. The 100 percent in 2018 for this measure marks the fourth year in a row where the utility has met the OEB standard.

5.7 Telephone Accessibility

Telephone accessibility in 2018 was 80.15 percent which is an improvement over the 2017 result of 77.9 percent and 2016 result of 64.7 percent. The continued improved performance of this measure over the 2017 and 2018 years is partially attributable to Toronto Hydro extending its Call Centre weekday business hours which has resulted in more manageable call volumes

5.8 Telephone Call Abandon Rate

The telephone call abandon rate went down to 1.4 in 2018 when compared with 2017's 1.9 and 2016's 3.1.

5.9 Written Responses to Enquiries

In 2018, the Written Response to Enquires measure performance was 98.30 percent which is comparable to the 2017 performance of 98.96 percent.

5.10 Billing Accuracy

The Billing Accuracy performance continued its five year improvement trend in 2018. The 2018 performance was 99.25 percent, which is a significant improvement from the 2013 performance of 96.6 percent.

5.11 Emergency Response

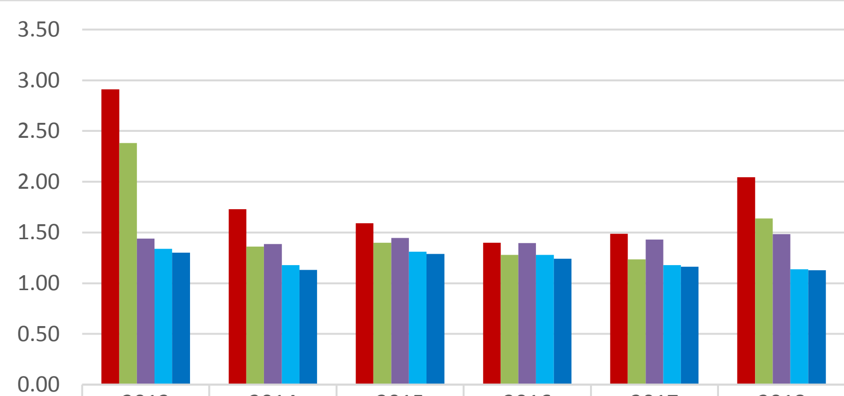
Toronto Hydro's Emergency Response performance decreased in 2018 when compared to the prior year. The 86.63 percent performance in 2018 compares to 93.6 percent in 2017. Over the course of 2018, Toronto Hydro experienced 11 significant weather events as compared to five in 2017. The total number of calls during a number of these events surpassed the number of field resources available for the company to respond within sixty minutes.

5.12 Reconnection Performance Standard

In 2018, Toronto Hydro's reconnection performance standard result was 99.65 percent, which is a slight increase from the 99.38 percent in 2017.

6. RELIABILITY PERFORMANCE

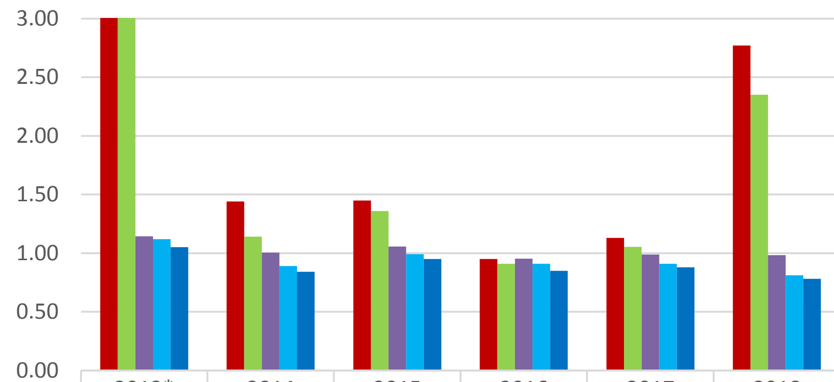
6.1 System Overview



	2013	2014	2015	2016	2017	2018
Total SAIFI	2.91	1.73	1.59	1.40	1.49	2.04
SAIFI Excluding LoS	2.38	1.36	1.40	1.28	1.24	1.64
SAIFI Excluding MED's	1.44	1.39	1.45	1.40	1.43	1.48
SAIFI Excluding MED's and LoS	1.34	1.18	1.31	1.28	1.18	1.14
SAIFI Excluding MED's, LoS and Scheduled Outages	1.30	1.13	1.29	1.24	1.16	1.13

Figure 16: System Level SAIFI

Toronto Hydro's 2018 System Level SAIFI performance decreased relative to 2017. This decrease in performance can be attributed to an increase in adverse weather events and loss of supply events.



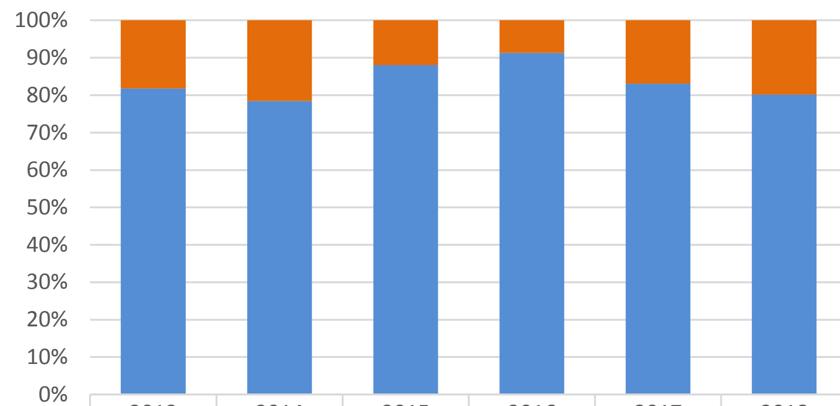
	2013*	2014	2015	2016	2017	2018
Total SAIDI	21.07	1.44	1.45	0.95	1.13	2.77
SAIDI Excluding LoS	17.70	1.14	1.36	0.91	1.05	2.35
SAIDI Excluding MED's	1.14	1.00	1.06	0.95	0.99	0.98
SAIDI Excluding MED's and LoS	1.12	0.89	0.99	0.91	0.91	0.81
SAIDI Excluding MED's, LoS and Scheduled Outages	1.05	0.84	0.95	0.85	0.88	0.78

* 2013 Values cut off above the chart due to the high SAIFI and SAIDI values prior to excluding MEDs.

Figure 17: System Level SAIDI

Toronto Hydro's 2018 System Level SAIDI performance decreased relative to 2017. This decrease in performance can be attributed to an increase in adverse weather events and loss of supply events.

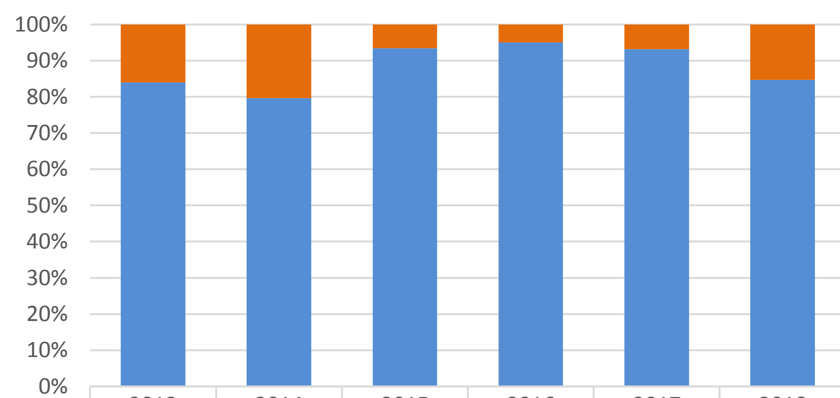
6.2 Loss of Supply ("LoS")



	2013	2014	2015	2016	2017	2018
Loss of Supply	18%	22%	12%	9%	17%	20%
System	82%	78%	88%	91%	83%	80%

Figure 18: Loss of Supply Impact on Total SAIFI

Figure 18 above shows a slight increase from 2017 to 2018 in the Loss of Supply impact on SAIFI.



	2013	2014	2015	2016	2017	2018
Loss of Supply	16%	20%	7%	5%	7%	15%
System	84%	80%	93%	95%	93%	85%

Figure 19: Loss of Supply Impact on Total SAIDI

Figure 19 above shows an increase from 2017 to 2018 in the Loss of Supply impact on SAIDI.

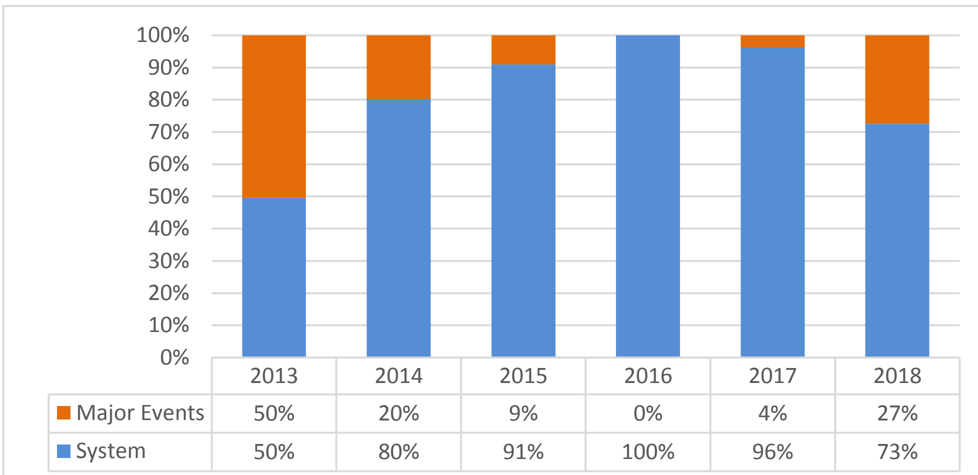
6.3 Major Event Days

Major Event Days ("MEDs") experienced by Toronto Hydro since 2013 are shown in Table 4, below, including those in 2018.

Table 4: Major Event Days (including 2018)

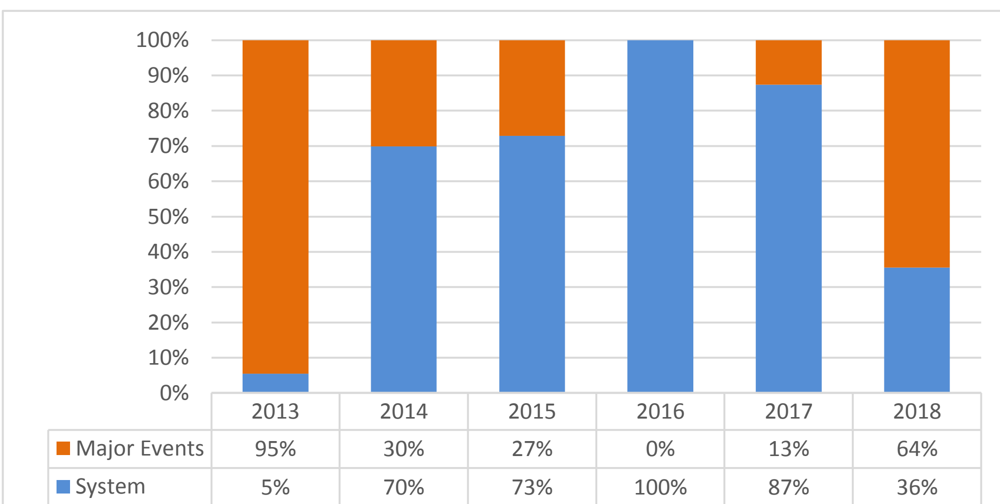
Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
July 8, 2013	Major Storm (Thunderstorm)	56	324,672	2,377,913
July 9, 2013	Major Storm (Thunderstorm)	44	41,502	91,646
December 21, 2013	Freezing Rain Ice Storm	42	175,928	3,204,481
December 22, 2013	Freezing Rain Ice Storm	208	441,547	8,295,093
December 23, 2013	Freezing Rain Ice Storm	25	29,530	196,633
December 24, 2013	Freezing Rain Ice Storm	23	13,983	149,337
December 25, 2013	Freezing Rain Ice Storm	18	20,225	92,924
December 26, 2013	Freezing Rain Ice Storm	20	19,147	91,458
April 15, 2014	Loss of Supply to Manby TS	27	113,035	129,479
June 17, 2014	Major Thunderstorm	38	55,442	88,496
November 24, 2014	Wind Storm	46	82,053	99,027
March 3, 2015	Freezing Rain	49	107,242	291,672
October 15, 2017	Wind Storm	31	43,175	107,846
April 4, 2018	Wind Storm	68	97,378	112,230
April 15, 2018	Freezing Rain	47	85,281	164,214
May 4, 2018	Wind Storm	98	164,261	800,390
June 13, 2018	Wind Storm	31	35,366	96,504
July 28, 2018	Loss of Supply Finch TS (Tx Fire)	22	45,475	192,195

Toronto Hydro experienced its highest number of Major Event Days (MED) in 2018 since 2013. This increase in MEDs significantly affected 2018 performance on SAIDI and SAIFI as shown in the following two Figures 20 and 21 below. These events include a number of major weather events, as well as a loss of supply to one of Toronto Hydro's transformer stations.



	2013	2014	2015	2016	2017	2018
Major Events	50%	20%	9%	0%	4%	27%
System	50%	80%	91%	100%	96%	73%

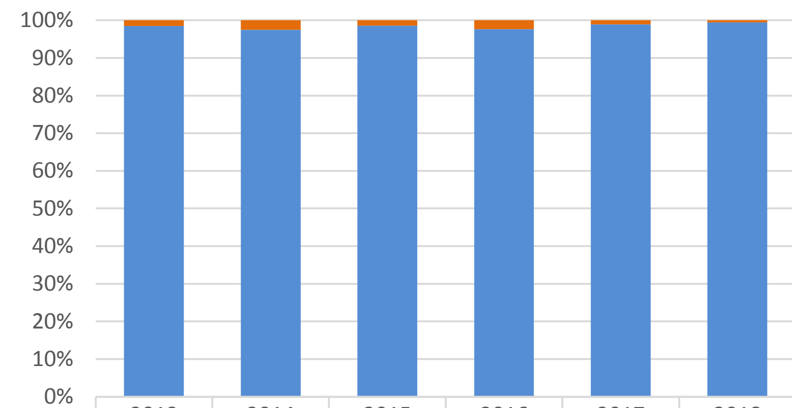
Figure 20: Major Event Days Impact on Total SAIFI



	2013	2014	2015	2016	2017	2018
Major Events	95%	30%	27%	0%	13%	64%
System	5%	70%	73%	100%	87%	36%

Figure 21: Major Event Days Impact on Total SAIDI

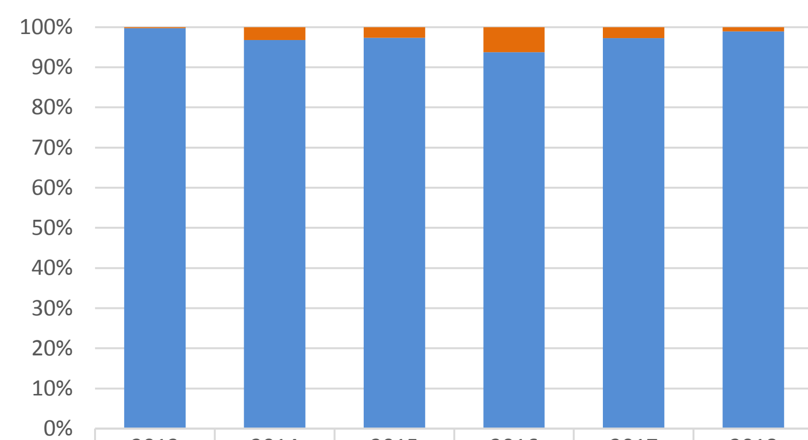
6.4 Scheduled Outages



	2013	2014	2015	2016	2017	2018
Scheduled Outages	1%	3%	1%	2%	1%	1%
System	99%	97%	99%	98%	99%	99%

Figure 22: Scheduled Outages Impact on Total SAIFI

As shown in Figure 22, there was no significant variance in 2018 compared to prior years in the impact of scheduled outages on Total SAIFI.



	2013	2014	2015	2016	2017	2018
Scheduled Outages	0%	3%	3%	6%	3%	1%
System	100%	97%	97%	94%	97%	99%

Figure 23: Scheduled Outages Impact on Total SAIDI

As shown in Figure 23, there was an improvement in performance in 2018 with the impact of scheduled outages on Total SAIDI.

6.5 System Reliability Excluding Loss of Supply, Major Event Days, and Scheduled Outages

Figure 24 and 25 below show the continuing stable performance with a gradual downward trend in SAIDI and SAIFI when Loss of Supply, MED's and Scheduled Outages are excluded.

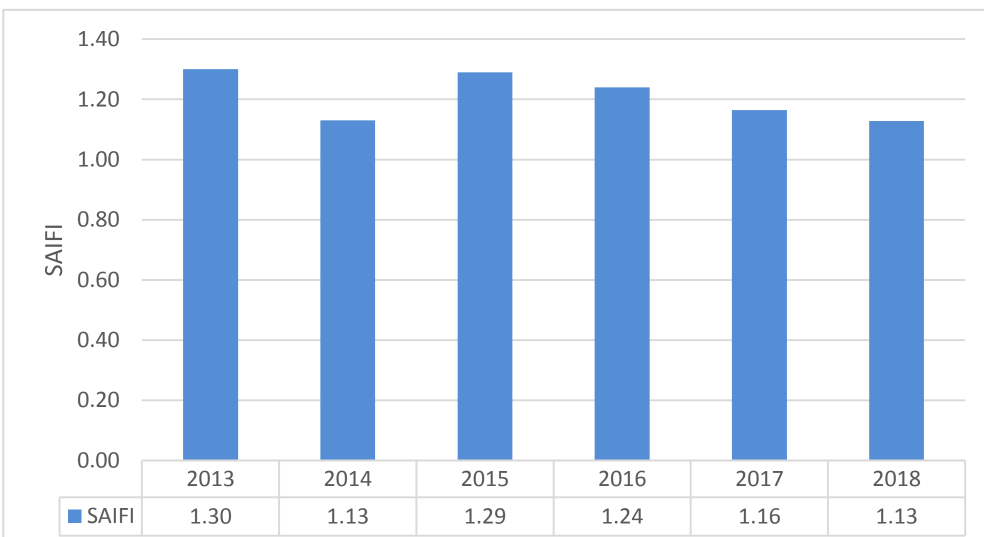
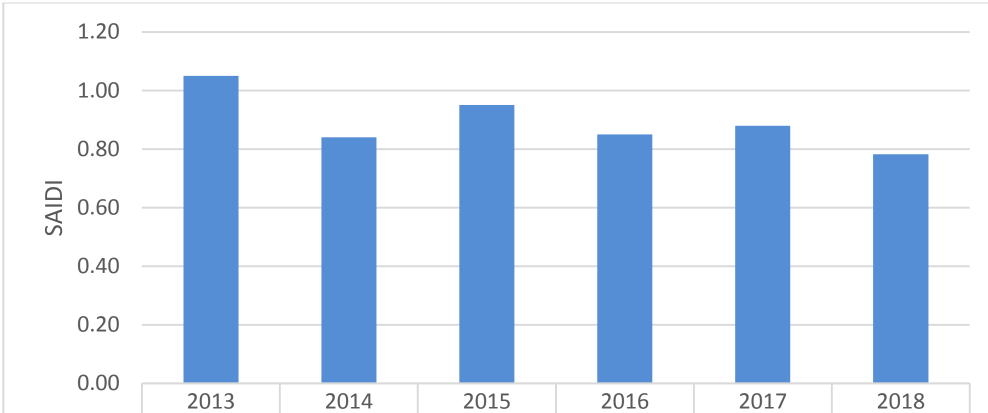


Figure 24: System SAIFI Excluding MEDs, Loss of Supply and Scheduled Outages

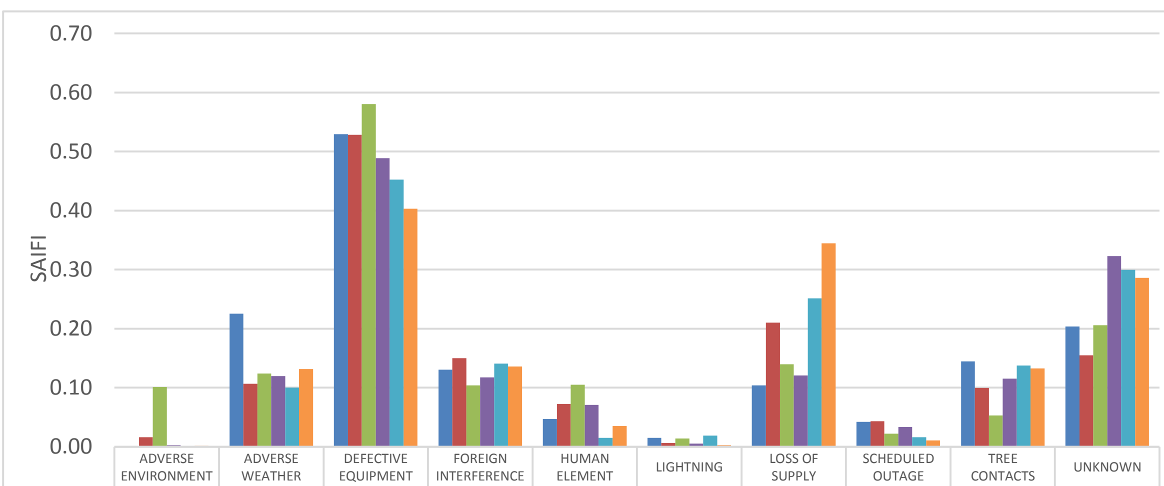


	2013	2014	2015	2016	2017	2018
SAIDI	1.05	0.84	0.95	0.85	0.88	0.78

Figure 25: System SAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

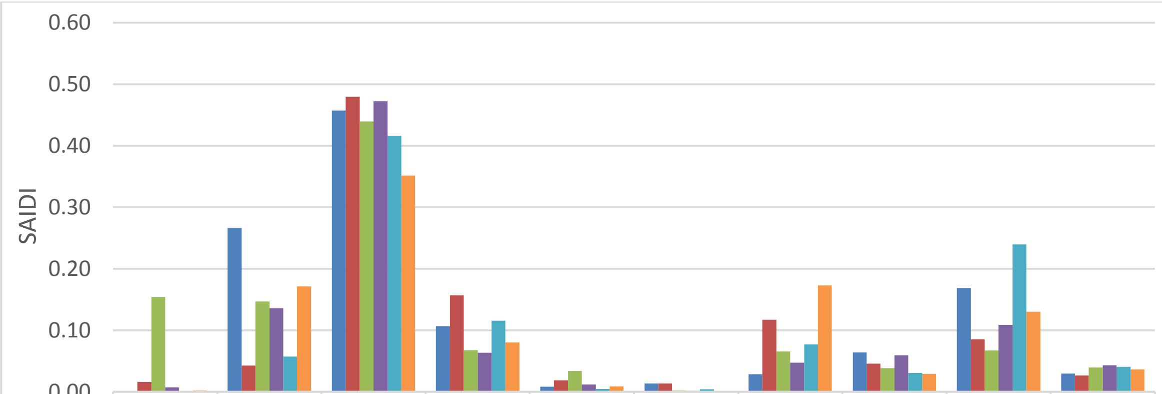
6.6 Cause Code Analysis

Figures 26 and 27 provide an updated set of Cause Code Analysis for SAIDI and SAIFI excluding MEDs.



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.23	0.53	0.13	0.05	0.02	0.10	0.04	0.14	0.20
2014	0.02	0.11	0.53	0.15	0.07	0.01	0.21	0.04	0.10	0.16
2015	0.10	0.12	0.58	0.10	0.10	0.01	0.14	0.02	0.05	0.21
2016	0.00	0.12	0.49	0.12	0.07	0.00	0.12	0.03	0.12	0.32
2017	0.00	0.10	0.45	0.14	0.02	0.02	0.25	0.02	0.14	0.30
2018	0.00	0.13	0.40	0.14	0.04	0.00	0.34	0.01	0.13	0.29

Figure 26: SAIFI Cause Code Breakdown (Excluding MEDs)

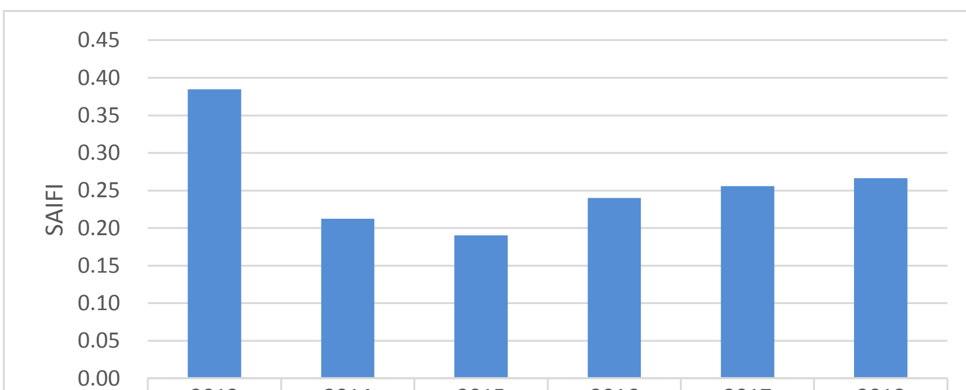


	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.27	0.46	0.11	0.01	0.01	0.03	0.06	0.17	0.03
2014	0.02	0.04	0.48	0.16	0.02	0.01	0.12	0.05	0.09	0.03
2015	0.15	0.15	0.44	0.07	0.03	0.00	0.07	0.04	0.07	0.04
2016	0.01	0.14	0.47	0.06	0.01	0.00	0.05	0.06	0.11	0.04
2017	0.00	0.06	0.42	0.12	0.00	0.00	0.08	0.03	0.24	0.04
2018	0.00	0.17	0.35	0.08	0.01	0.00	0.17	0.03	0.13	0.04

Figure 27: SAIDI Cause Code Breakdown (Excluding MEDs)

6.7 Weather Impacts

Figures 28 and 29 below illustrate the cumulative weather reliability impacts on the system. Of note is the continuing impact of weather on Toronto Hydro's SAIDI and SAIFI performance.



	2013	2014	2015	2016	2017	2018
SAIFI	0.38	0.21	0.19	0.24	0.26	0.27

Figure 28: Weather Impacts to SAIFI

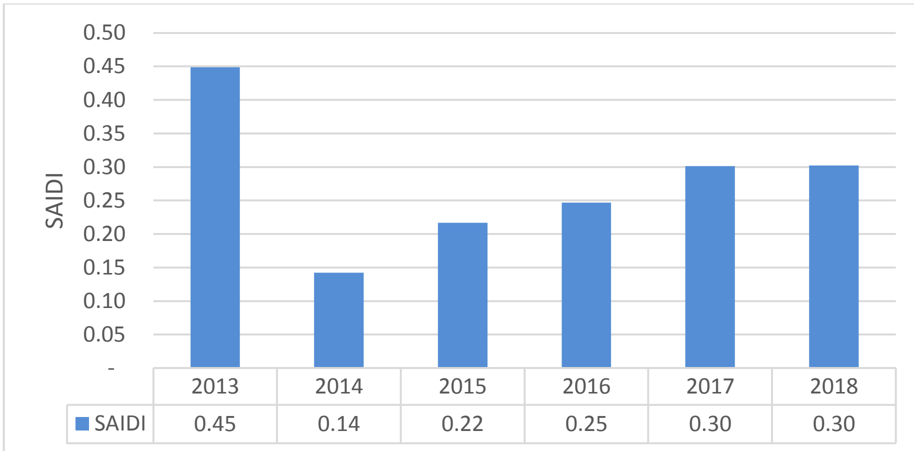


Figure 29: Weather Impacts to SAIDI

6.8 Foreign Interference Impacts

Figures 30 and 31 below illustrate the impact of animal contact, dig-ins, vehicles, and other foreign objects on SAIDI and SAIFI. The 2018 cause analysis is consistent with prior year's results.

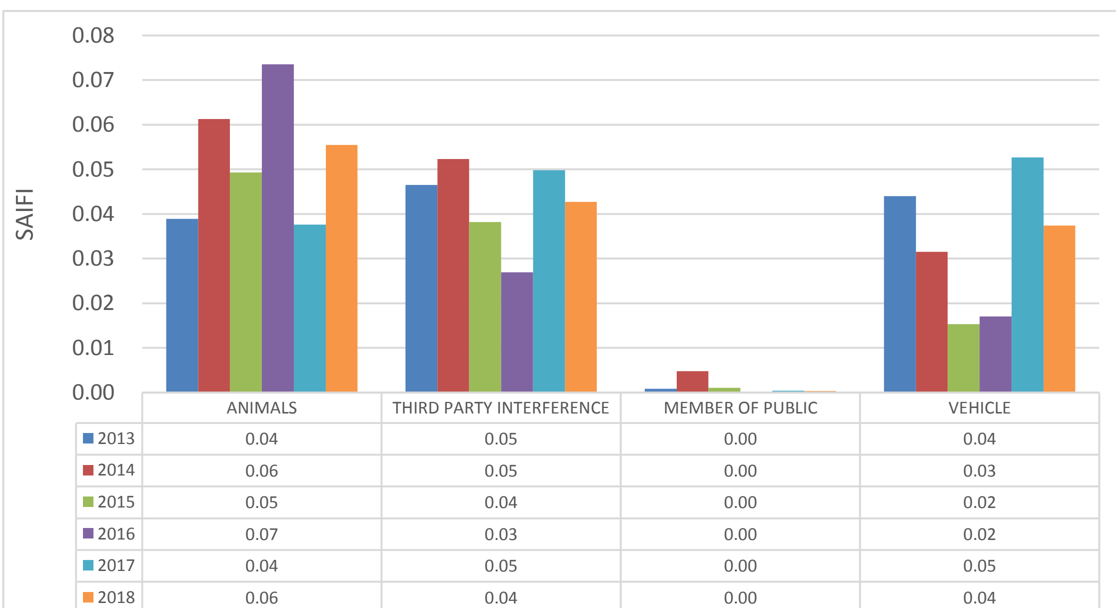
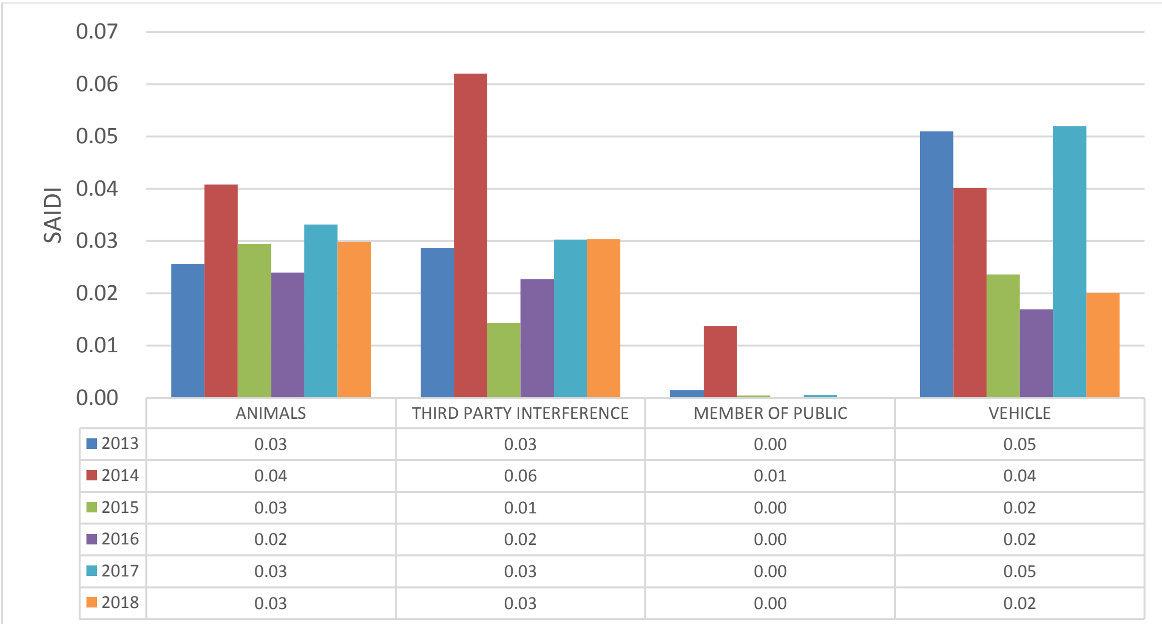


Figure 30: Foreign Interference – Root Cause SAIFI

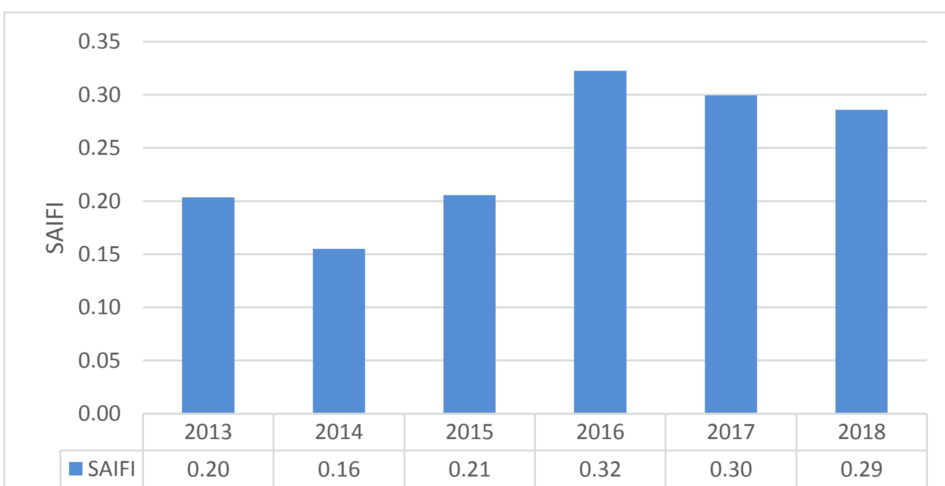


	ANIMALS	THIRD PARTY INTERFERENCE	MEMBER OF PUBLIC	VEHICLE
2013	0.03	0.03	0.00	0.05
2014	0.04	0.06	0.01	0.04
2015	0.03	0.01	0.00	0.02
2016	0.02	0.02	0.00	0.02
2017	0.03	0.03	0.00	0.05
2018	0.03	0.03	0.00	0.02

Figure 31: Foreign Interference – Root Cause SAIDI

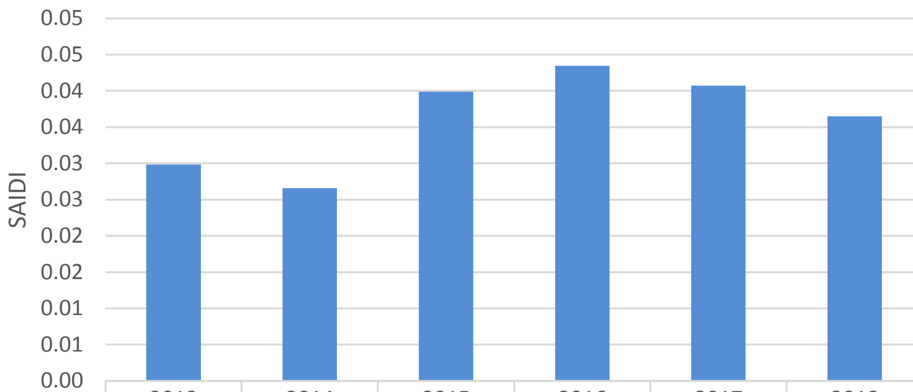
6.9 Unknown Impacts

Figures 32 and 33 below illustrate the impact of Unknown Impacts to SAIDI and SAIFI. The 2018 results are consistent with prior years.



	2013	2014	2015	2016	2017	2018
SAIFI	0.20	0.16	0.21	0.32	0.30	0.29

Figure 32: Unknown Impacts to SAIFI

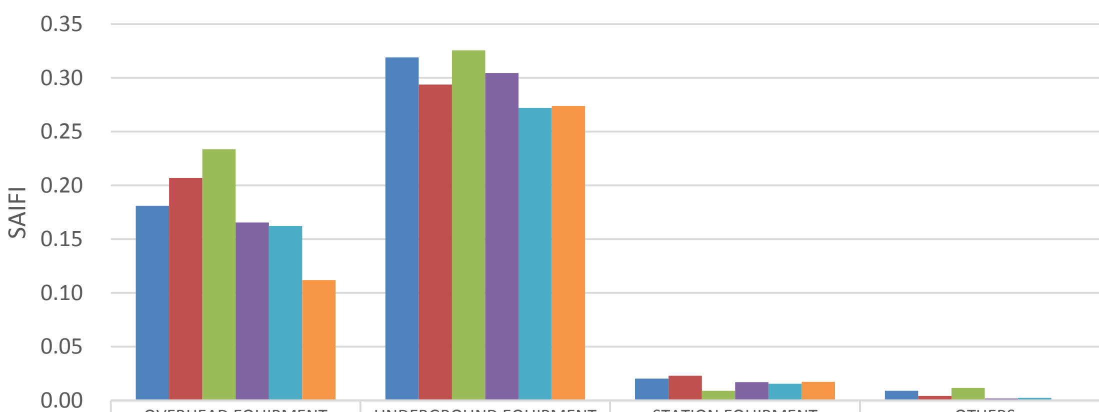


	2013	2014	2015	2016	2017	2018
SAIDI	0.03	0.03	0.04	0.04	0.04	0.04

Figure 33: Unknown Impacts to SAIDI

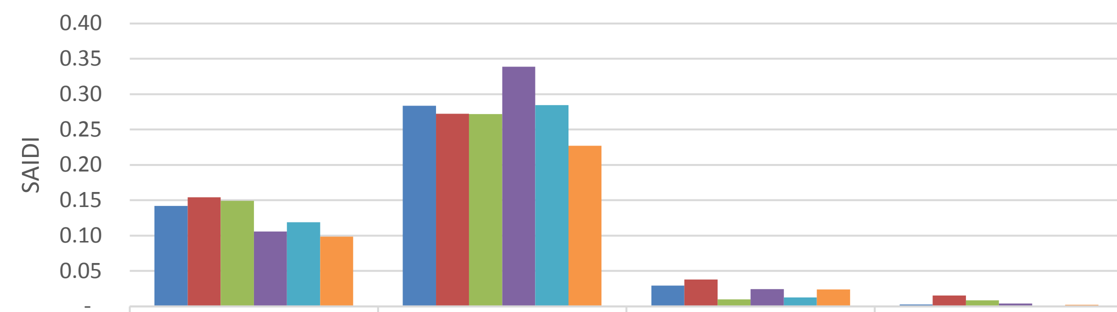
6.10 Defective Equipment Impacts

As shown in Figures 34 and 35, Defective Equipment Impacts on SAIDI and SAIFI have improved over the CIR period.



	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	OTHERS
2013	0.18	0.32	0.02	0.01
2014	0.21	0.29	0.02	0.00
2015	0.23	0.33	0.01	0.01
2016	0.17	0.30	0.02	0.00
2017	0.16	0.27	0.02	0.00
2018	0.11	0.27	0.02	0.00

Figure 35: Defective Equipment SAIFI

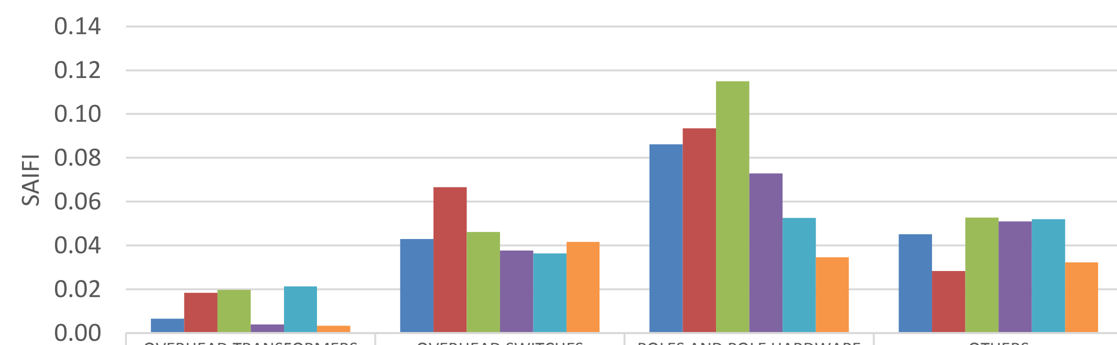


	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	OTHERS
2013	0.14	0.28	0.03	0.00
2014	0.15	0.27	0.04	0.02
2015	0.15	0.27	0.01	0.01
2016	0.11	0.34	0.02	0.00
2017	0.12	0.28	0.01	0.00
2018	0.10	0.23	0.02	0.00

Figure 35: Defective Equipment SAIDI

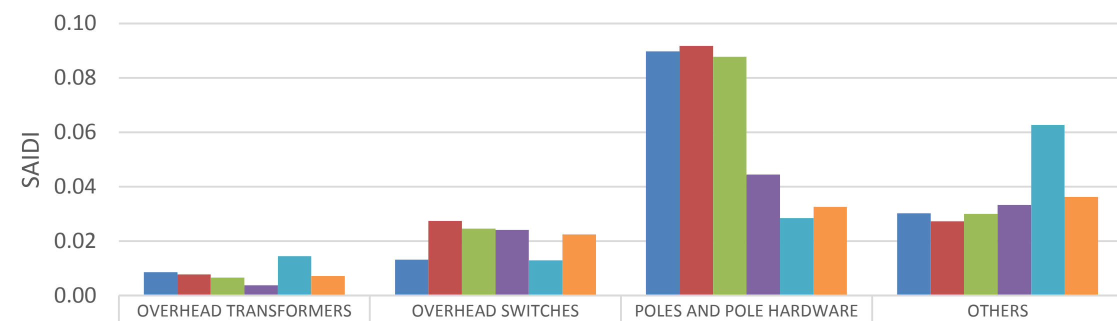
6.10.1 Overhead Defective Equipment

Figures 36 and 37 illustrate the trend of stable or improving outcomes continuing under most of the categories of Overhead Defective Equipment.



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OTHERS
2013	0.01	0.04	0.09	0.05
2014	0.02	0.07	0.09	0.03
2015	0.02	0.05	0.12	0.05
2016	0.00	0.04	0.07	0.05
2017	0.02	0.04	0.05	0.05
2018	0.00	0.04	0.03	0.03

Figure 36: Defective Equipment SAIFI – Overhead

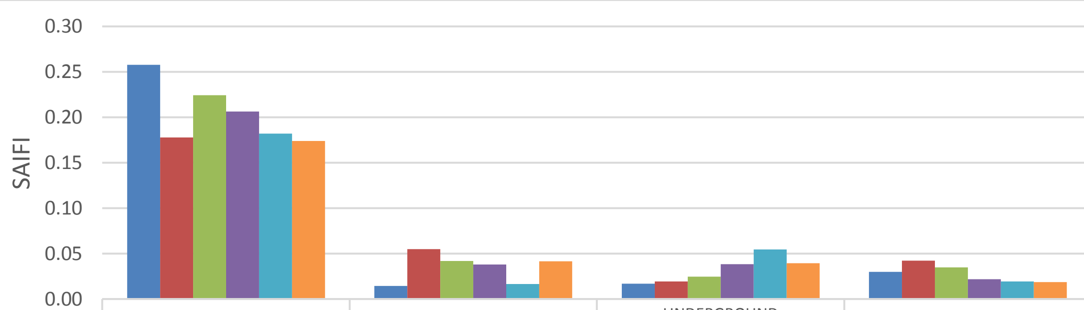


	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OTHERS
2013	0.01	0.01	0.09	0.03
2014	0.01	0.03	0.09	0.03
2015	0.01	0.02	0.09	0.03
2016	0.00	0.02	0.04	0.03
2017	0.01	0.01	0.03	0.06
2018	0.01	0.02	0.03	0.04

Figure 37: Defective Equipment SAIDI – Overhead

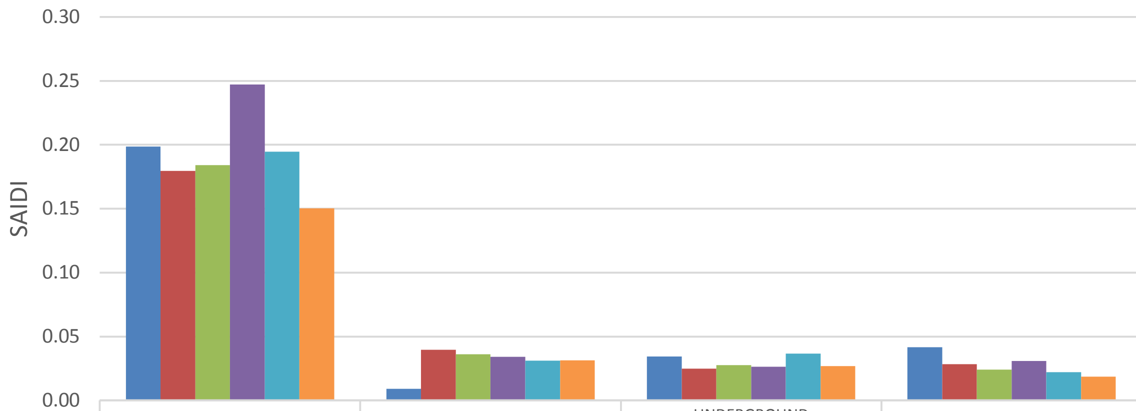
6.10.2 Underground Defective Equipment

Figures 38 and 39, the cause codes for Underground Defective Equipment, illustrate the continuing stable or improving outcomes across all categories, with the exception of underground transformers, which have demonstrated a slight worsening trend in SAIFI.



	UNDERGROUND CABLES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS	OTHERS
2013	0.26	0.01	0.02	0.03
2014	0.18	0.05	0.02	0.04
2015	0.22	0.04	0.02	0.03
2016	0.21	0.04	0.04	0.02
2017	0.18	0.02	0.05	0.02
2018	0.17	0.04	0.04	0.02

Figure 38: Defective Equipment SAIFI – Underground



	UNDERGROUND CABLES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS	OTHERS
2013	0.20	0.01	0.03	0.04
2014	0.18	0.04	0.02	0.03
2015	0.18	0.04	0.03	0.02
2016	0.25	0.03	0.03	0.03
2017	0.19	0.03	0.04	0.02
2018	0.15	0.03	0.03	0.02

Figure 39: Defective Equipment SAIDI – Underground

7. 2018 CORPORATE SCORECARD UPDATE

In response to interrogatories 1B-SEC-8 and 4A-AMPCO-96, Toronto Hydro committed to providing the 2018 Corporate Scorecard. Table 5 below is the 2018 Corporate Scorecard updated to include 2018 results.

Table 5: 2018 Corporate Scorecard

<table>
<tr><th>Key Performance Indicator</th><th colspan="2">2018 Target</th><th>2018 Result</th></tr>
<tr><td>New Services Connected on Time</td><td colspan="2">96.5%</td><td>99.8%</td></tr>
<tr><td>Bill Accuracy</td><td colspan="2">98.8%</td><td>99.3%</td></tr>
<tr><td>First Contact Resolution</td><td colspan="2">86%</td><td>89%</td></tr>
<tr><td>Total Recordable Injury Frequency (TRIF)</td><td colspan="2">1.45</td><td>0.83</td></tr>
<tr><td>Employee Engagement</td><td colspan="2">6.0</td><td>7.1</td></tr>
<tr><td>SAIFI (# - Defective Equipment Only)</td><td colspan="2">0.54</td><td>0.40</td></tr>
<tr><td>SAIDI (Minutes - Defective Equipment Only)</td><td colspan="2">29.00</td><td>21.08</td></tr>
<tr><td rowspan="2">1-Year Distribution System Plan Investment ($M)</td><td>Lower Target</td><td>Upper Target</td><td rowspan="2">435.8</td></tr>
<tr><td>418.0</td><td>451.0</td></tr>
<tr><td rowspan="2">5-Year CIR Distribution System Plan Investment ($M)</td><td>Lower Target</td><td>Upper Target</td><td rowspan="2">1943.8</td></tr>
<tr><td>1928.0</td><td>1957.2</td></tr>
<tr><td>Consolidated Net Income ($M)</td><td colspan="2">148.0</td><td>167.3</td></tr>
</table>

FINANCIAL INFORMATION OVERVIEW

In accordance with section 2.1.9 of the OEB's Filing Requirements,[1] Exhibit U, Tab 1C provides the following updated financial information:

- Toronto Hydro's Audited Financial Statements for 2018 (Schedule 2);
- Reconciliation of the financial results shown in the Audited Financial Statements with regulatory financial results for 2018 (Schedule 3);
- Toronto Hydro Corporation's Management's Discussion & Analysis for 2018 (Schedule 4); and
- Toronto Hydro Corporation's Annual Information Form for 2018 (Schedule 5).

Please note that at the time of the application update there is no updated public debt offering information.

[1] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 (July 12, 2018).

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2018 and 2017

KPMG LLP
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, ON M5H 2S5
Canada
Tel 416-777-8500
Fax 416-777-8818

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

Opinion

We have audited the financial statements of Toronto Hydro-Electric System Limited (the Entity), which comprise:

- the balance sheets as at December 31, 2018 and December 31, 2017
- the statements of income for the years then ended
- the statements of comprehensive income for the years then ended
- the statements of changes in equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018 and December 31, 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 5, 2019

Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	**2018 $**	2017 $
ASSETS		
Current		
Accounts receivable *[notes 4 and 14[b]]*	**210.4**	217.2
Unbilled revenue *[note 14[b]]*	**279.7**	276.0
Materials and supplies	**8.1**	9.3
Other assets *[note 5]*	**10.7**	12.7
Assets held for sale	**-**	8.7
Total current assets	**508.9**	523.9
Property, plant and equipment *[note 6]*	**4,349.9**	4,107.8
Intangible assets *[note 7]*	**318.9**	296.2
Deferred tax assets *[note 20]*	**0.3**	57.0
Other assets *[note 5]*	**5.8**	3.0
Total assets	**5,183.8**	4,987.9
Regulatory balances *[note 8]*	**125.9**	199.9
Total assets and regulatory balances	**5,309.7**	5,187.8
LIABILITIES AND EQUITY		
Current		
Bank indebtedness	**21.5**	125.0
Accounts payable and accrued liabilities *[note 9]*	**521.7**	513.3
Income tax payable	**4.8**	12.5
Customer deposits	**48.1**	49.2
Deferred revenue *[note 10]*	**12.4**	9.9
Deferred conservation credit *[note 3[c]]*	**8.2**	9.3
Notes payable to related party *[notes 11 and 22]*	**304.9**	60.0
Other liabilities *[note 23]*	**0.3**	1.5
Total current liabilities	**921.9**	780.7
Notes payable to related party *[notes 11 and 22]*	**1,785.7**	2,029.9
Customer deposits	**31.7**	8.9
Deferred revenue *[note 10]*	**277.7**	178.8
Post-employment benefits *[note 12]*	**275.9**	313.0
Other liabilities *[note 23]*	**2.0**	0.2
Total liabilities	**3,294.9**	3,311.5
Equity		
Share capital *[note 16]*	**556.3**	556.3
Retained earnings	**1,267.5**	1,147.2
Contributed surplus	**12.8**	12.8
Total equity	**1,836.6**	1,716.3
Total liabilities and equity	**5,131.5**	5,027.8
Regulatory balances *[note 8]*	**178.2**	160.0
Total liabilities, equity and regulatory balances	**5,309.7**	5,187.8

Commitments, contingencies and subsequent events *[notes 2, 23 and 24]*

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 $ *[note 25[p]]*
Revenues		
Energy sales *[note 17]*	**2,704.1**	2,810.2
Distribution revenue *[note 17]*	**674.2**	724.2
Other *[note 17]*	**80.5**	96.7
	3,458.8	3,631.1
Expenses		
Energy purchases	**2,646.3**	2,855.9
Operating expenses *[note 18]*	**297.1**	284.2
Depreciation and amortization *[notes 6 and 7]*	**235.9**	222.3
	3,179.3	3,362.4
Finance costs *[note 19]*	**(78.3)**	(81.0)
Gain on disposals of property, plant and equipment	**108.6**	9.8
Income before income taxes	**309.8**	197.5
Income tax expense *[note 20]*	**(81.6)**	(44.2)
Net income	**228.2**	153.3
Net movements in regulatory balances *[note 8]*	**(111.9)**	(13.1)
Net movements in regulatory balances arising from deferred tax assets *[note 8]*	**47.0**	13.2
Net income after net movements in regulatory balances	**163.3**	153.4

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 $
Net income after net movements in regulatory balances	**163.3**	153.4
Other comprehensive income		
Items that will not be reclassified to income or loss		
Remeasurements of post-employment benefits, net of tax [2018 - ($9.9), 2017 - $6.7] *[note 12]*	**27.3**	(18.4)
Net movements in regulatory balances related to OCI, net of tax [2018 - ($9.9), 2017 - $6.7] *[note 12]*	**(27.3)**	18.4
Other comprehensive income, net of tax	**-**	-
Total comprehensive income	**163.3**	153.4

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 **$**
Share capital ***[note 16]***	**556.3**	556.3
Retained earnings, beginning of year	**1,147.2**	995.9
Transition adjustment *[note 25[p]]*	**(0.3)**	-
Net income after net movements in regulatory balances	**163.3**	153.4
Dividends *[notes 16 and 22]*	**(42.7)**	(2.1)
Retained earnings, end of year	**1,267.5**	1,147.2
Contributed surplus	**12.8**	12.8
Total equity	**1,836.6**	1,716.3

See accompanying notes to the financial statements.

Toronto Hydro-Electric System Limited

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	**2018** **$**	2017 $
OPERATING ACTIVITIES		
Net income after net movements in regulatory balances	**163.3**	153.4
Net movements in regulatory balances *[note 8]*	**111.9**	13.1
Net movements in regulatory balances arising from deferred tax assets *[note 8]*	**(47.0)**	(13.2)
Adjustments		
Depreciation and amortization *[notes 6 and 7]*	**235.9**	222.3
Amortization of deferred revenue *[note 10]*	**(5.3)**	(4.7)
Finance costs	**78.3**	81.0
Income tax expense	**81.6**	44.2
Post-employment benefits	**0.1**	7.4
Gain on disposals of property, plant and equipment	**(108.6)**	(9.8)
Other	**0.6**	1.1
Capital contributions received *[note 10]*	**106.5**	50.8
Net change in other non-current assets and liabilities	**(2.6)**	(6.5)
Increase in customer deposits	**21.7**	4.0
Changes in non-cash working capital balances *[note 21]*	**3.5**	60.7
Income tax paid	**(41.8)**	(22.1)
Net cash provided by operating activities	**598.1**	581.7
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 21]*	**(431.8)**	(433.8)
Purchase of intangible assets *[note 21]*	**(54.5)**	(93.4)
Proceeds on disposals of property, plant and equipment	**117.4**	12.5
Net cash used in investing activities	**(368.9)**	(514.7)
FINANCING ACTIVITIES		
Issuance of notes payable to related party *[note 11]*	**-**	198.6
Repayment of notes payable to related party *[note 11]*	**-**	(245.1)
Repayment of lease liability	**(1.8)**	(3.0)
Dividends paid *[note 16]*	**(42.7)**	(2.1)
Interest received	**0.6**	0.3
Interest paid	**(81.8)**	(90.2)
Net cash used in financing activities	**(125.7)**	(141.5)
Net decrease (increase) in bank indebtedness during the year	**103.5**	(74.5)
Bank indebtedness, beginning of year	**(125.0)**	(50.5)
Bank indebtedness, end of year	**(21.5)**	(125.0)

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited was incorporated on June 23, 1999 under the *Business Corporations Act (Ontario)* in accordance with *the Electricity Act*. LDC is wholly-owned by the Corporation and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the City and is subject to rate regulation. LDC is also engaged in the delivery of CDM activities.

2. BASIS OF PRESENTATION

LDC's audited financial statements for the years ended December 31, 2018 and 2017 have been prepared in accordance with IFRS as issued by the IASB.

The financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for post-employment benefits which are recorded at actuarial value.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 5, 2019 when LDC's financial statements were authorized for issuance by LDC's Board of Directors, and identified no events and transactions which required recognition in the LDC's financial statements and/or disclosure in the notes to the LDC's financial statements.

The summary of significant accounting policies has been disclosed in note 25.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

a) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions.

On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020.

b) Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP, which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the financial statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

c) CDM Activities

The objective of the CDM programs is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ["Oakville Hydro"] for the delivery of CDM programs over the 2015-2020 period. The IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, including a mid-term incentive based on a review of the 2015-2017 period.

[All tabular amounts in millions of Canadian dollars]

The joint CDM plan provides combined funding of approximately $421.0 million, including participant incentives and program administration costs, with an energy savings target of approximately 1,648 GWh. The program for Oakville Hydro under the joint CDM plan started on January 1, 2016. LDC received $162.4 million from the IESO as at December 31, 2018 [2017 - $102.3 million] to deliver the CDM programs. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred conservation credit. On September 26, 2018, $15.8 million was confirmed by the IESO as the joint mid-term incentive, of which $14.9 million representing LDC's portion was received in November 2018.

4. ACCOUNTS RECEIVABLE

Accounts receivable consist of the following:

	2018 $	2017 $
Trade receivables	**200.2**	188.6
Due from related parties *[note 22]*	**5.8**	14.8
CDM mid-term incentive *[note 3[c]]*	**—**	12.2
Other	**4.4**	1.6
	210.4	217.2

5. OTHER ASSETS

Other assets consist of the following:

	2018 $	2017 $
Prepaid expenses	**9.4**	11.3
Deferred financing costs	**1.6**	1.6
Other	**5.5**	2.8
Total other assets	**16.5**	15.7
Less: Current portion of other assets relating to:		
Prepaid expenses	**9.4**	11.3
Deferred financing costs	**0.4**	0.4
Other	**0.9**	1.0
Current portion of other assets	**10.7**	12.7
Non-current portion of other assets	**5.8**	3.0

[All tabular amounts in millions of Canadian dollars]

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets $	Land and buildings $	Equipment and other $	Construction in progress $	Total $
Cost					
Balance as at January 1, 2017	3,376.3	321.5	173.9	448.2	4,319.9
Additions/(Transfers)	404.4	84.8	32.8	(77.1)	444.9
Assets held for sale *[note 8[d]]*	—	(11.8)	—	—	(11.8)
Disposals and retirements	(31.5)	(3.2)	(0.3)	—	(35.0)
Balance as at December 31, 2017	3,749.2	391.3	206.4	371.1	4,718.0
Additions/(Transfers)	**363.6**	**18.7**[(1)]	**20.3**	**51.1**	**453.7**
Disposals and retirements	**(32.0)**	**(0.4)**	**(0.6)**	—	**(33.0)**
Balance as at December 31, 2018	**4,080.8**	**409.6**	**226.1**	**422.2**	**5,138.7**
Accumulated depreciation					
Balance as at January 1, 2017	347.3	26.3	70.0	—	443.6
Depreciation	138.1	13.6	24.7	—	176.4
Assets held for sale *[note 8[d]]*	—	(3.1)	—	—	(3.1)
Disposals and retirements	(5.9)	(0.5)	(0.3)	—	(6.7)
Balance as at December 31, 2017	479.5	36.3	94.4	—	610.2
Depreciation	**147.6**	**15.0**	**25.3**	—	**187.9**
Disposals and retirements	**(8.4)**	**(0.3)**	**(0.6)**	—	**(9.3)**
Balance as at December 31, 2018	**618.7**	**51.0**	**119.1**	—	**788.8**
Carrying amount					
Balance as at December 31, 2017	3,269.7	355.0	112.0	371.1	4,107.8
Balance as at December 31, 2018	**3,462.1**	**358.6**	**107.0**	**422.2**	**4,349.9**

(1) Includes transitional adjustment for the recognition of the right-of-use assets upon adoption of IFRS 16 *Leases* ["IFRS 16"] on January 1, 2018 *[note 25[p]]*.

As at December 31, 2018, "Land and buildings" included right-of-use assets related to leases of land and office space with cost of $8.8 million [December 31, 2017 - $7.2 million], accumulated depreciation of $0.7 million [December 31, 2017 - $0.4 million], and carrying amount of $8.1 million [December 31, 2017 - $6.8 million]. For the year ended December 31, 2018, LDC recorded depreciation expense of $0.3 million [2017 - $0.1 million] related to the right-of-use assets.

As at December 31, 2018, "Equipment and other" included right-of-use assets with cost of $11.0 million [December 31, 2017 - $11.0 million], accumulated depreciation of $11.0 million [December 31, 2017 - $10.0 million], and carrying amount of $nil [December 31, 2017 - $1.0 million]. For the year ended December 31, 2018, LDC recorded depreciation expense of $1.0 million [2017 - $2.0 million] related to the right-of-use assets.

For the year ended December 31, 2018, borrowing costs in the amount of $3.7 million [2017 - $6.2 million] were capitalized to PP&E and credited to finance costs, with an average capitalization rate of 3.61% [2017 - 3.73%].

"Construction in progress" additions are net of transfers to the other PP&E categories.

[All tabular amounts in millions of Canadian dollars]

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software $	Contributions $	Software in development $	Contributions for work in progress $	Total $
Cost					
Balance as at January 1, 2017	113.5	75.5	20.2	70.1	279.3
Additions/(Transfers)	23.4	—	34.0	44.0	101.4
Balance as at December 31, 2017	136.9	75.5	54.2	114.1	380.7
Additions/(Transfers)	**73.8**	**88.6**	**(39.2)**	**(74.6)**	**48.6**
Disposals and retirement	**(2.9)**	**—**	**—**	**—**	**(2.9)**
Balance as at December 31, 2018	**207.8**	**164.1**	**15.0**	**39.5**	**426.4**
Accumulated amortization					
Balance as at January 1, 2017	57.4	4.1	—	—	61.5
Amortization	20.0	3.0	—	—	23.0
Balance as at December 31, 2017	77.4	7.1	—	—	84.5
Amortization	**20.9**	**3.6**	—	—	**24.5**
Disposals and retirements	**(1.5)**	**—**	—	—	**(1.5)**
Balance as at December 31, 2018	**96.8**	**10.7**	—	—	**107.5**
Carrying amount					
Balance as at December 31, 2017	59.5	68.4	54.2	114.1	296.2
Balance as at December 31, 2018	**111.0**	**153.4**	**15.0**	**39.5**	**318.9**

For the year ended December 31, 2018, borrowing costs in the amount of $5.2 million [2017 - $3.6 million] were capitalized to intangible assets and credited to finance costs, with an average capitalization rate of 3.61% [2017 - 3.73%].

“Software in development” and “Contributions for work in progress” additions are net of transfers to the other intangible asset categories.

“Computer software” is externally acquired. The remaining amortization periods for computer software and contributions range from less than one year to 10 years, and from 10 to 25 years, respectively.

“Contributions” represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities.

[All tabular amounts in millions of Canadian dollars]

8. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2018 $	Balances arising in the period $	Recovery/ reversal $	Other movements $	December 31, 2018 $	Remaining recovery/ reversal period (months)	Carrying charges applicable
OPEB net actuarial loss	**85.3**	**(37.2)**	**—**	**—**	**48.1**	note 8[a]	—
LRAM	**16.7**	**18.7**	**(6.4)**	**—**	**29.0**	note 8[b]	(1)
Foregone revenue	**44.0**	**—**	**(20.8)**	**—**	**23.2**	12	—
Gain on disposal	**19.1**	**—**	**—**	**(19.1)**	**—**	note 8[d]	(1)
IFRS transitional adjustments	**15.0**	**—**	**(8.0)**	**—**	**7.0**	12	—
OPEB cash versus accrual	**4.2**	**1.2**	**—**	**—**	**5.4**	note 8[f]	—
Stranded meters	**7.5**	**—**	**(3.9)**	**—**	**3.6**	12	(1)
Named properties	**3.1**	**—**	**(1.5)**	**—**	**1.6**	12	—
Capital contributions	**1.0**	**—**	**(0.5)**	**—**	**0.5**	12	—
Other	**4.0**	**3.5**	**—**	**—**	**7.5**	—	(1)
	199.9	**(13.8)**	**(41.1)**	**(19.1)**	**125.9**		

	January 1, 2017 $	Balances arising in the period $	Recovery/ reversal $	Other movements $	December 31, 2017 $	Remaining recovery/ reversal period (months)	Carrying charges applicable
OPEB net actuarial loss	60.2	25.1	—	—	85.3	note 8[a]	—
LRAM	10.5	11.0	(4.8)	—	16.7	note 8[b]	(1)
Foregone revenue	64.3	—	(20.3)	—	44.0	24	—
Gain on disposal	8.6	(8.1)	18.6	—	19.1	note 8[d]	(1)
IFRS transitional adjustments	22.8	—	(7.8)	—	15.0	24	—
OPEB cash versus accrual	2.9	1.3	—	—	4.2	note 8[f]	—
Stranded meters	11.4	—	(3.9)	—	7.5	24	(1)
Named properties	4.6	—	(1.5)	—	3.1	24	—
Capital contributions	1.5	—	(0.5)	—	1.0	24	—
Smart meters	2.1	—	(3.1)	1.0	—	—	—
Other	1.9	2.1	—	—	4.0	—	(1)
	190.8	31.4	(23.3)	1.0	199.9		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 1.50% for January 1, 2018 to March 31, 2018, 1.89% for April 1, 2018 to September 30, 2018 and 2.17% for October 1, 2018 to December 31, 2018 [January 1, 2017 to September 30, 2017 - 1.10% and October 1, 2017 to December 31, 2017 - 1.50%].

[All tabular amounts in millions of Canadian dollars]

Credit balances consist of the following:

	January 1, 2018 $	Balances arising in the period $	Recovery/ reversal $	Other movements $	December 31, 2018 $	Remaining recovery/ reversal period (months)	Carrying charges applicable
Gain on disposal	**—**	**99.0**	**(18.1)**	**(19.1)**	**61.8**	note 8[d]	(1)
Capital-related revenue requirement	**25.0**	**31.5**	**—**	**—**	**56.5**	note 8[j]	(1)
Derecognition	**15.9**	**5.9**	**—**	**—**	**21.8**	note 8[k]	(1)
Settlement variances [2]	**41.0**	**58.2**	**(80.0)**	**—**	**19.2**	note 8[l]	(1)
Development charges	**5.3**	**2.6**	**—**	**—**	**7.9**	note 8[m]	(1)
Deferred taxes	**58.8**	**(56.9)**	**—**	**—**	**1.9**	note 8[n]	—
Tax-related variances	**9.3**	**—**	**(8.2)**	**—**	**1.1**	—	(1)
Smart meters	**0.3**	**—**	**—**	**—**	**0.3**	—	—
Other	**4.4**	**3.7**	**(0.4)**	**—**	**7.7**	—	(1)
	160.0	**144.0**	**(106.7)**	**(19.1)**	**178.2**		

	January 1, 2017 $	Balances arising in the period $	Recovery/ reversal $	Other movements $	December 31, 2017 $	Remaining recovery/ reversal period (months)	Carrying charges applicable
Capital-related revenue requirement	8.8	16.2	—	—	25.0	note 8[j]	(1)
Derecognition	12.8	3.1	—	—	15.9	note 8[k]	(1)
Settlement variances	62.8	(45.2)	23.4	—	41.0	note 8[l]	(1)
Development charges	—	5.3	—	—	5.3	note 8[m]	(1)
Deferred taxes	65.3	(6.5)	—	—	58.8	note 8[n]	—
Tax-related variances	17.5	—	(8.2)	—	9.3	12	(1)
Smart meters	—	—	(0.7)	1.0	0.3	—	—
Other	2.2	2.7	(0.5)	—	4.4	—	(1)
	169.4	(24.4)	14.0	1.0	160.0		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 1.50% for January 1, 2018 to March 31, 2018, 1.89% for April 1, 2018 to September 30, 2018 and 2.17% for October 1, 2018 to December 31, 2018 [January 1, 2017 to September 30, 2017 - 1.10% and October 1, 2017 to December 31, 2017 - 1.50%].
(2) In 2018, a reclassification between settlement variances and accounts payable, with a corresponding impact to energy purchases and net movements in regulatory balances, was recorded in the amount of $50.4 million. The immaterial adjustment arose in 2017 and was reflected prospectively in 2018.

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. There was no impairment recorded for the year ended December 31, 2018.

[All tabular amounts in millions of Canadian dollars]

Reconciliation between the net movements in regulatory balances shown in the regulatory debit and credit balances tables and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2018 $	2017 $
Total movements per regulatory debit balances table	**(74.0)**	9.1
Total movements per regulatory credit balances table	**(18.2)**	9.4
Total net movements	**(92.2)**	18.5
Net movements per financial statements:		
Net movements in regulatory balances	**(111.9)**	(13.1)
Net movements in regulatory balances arising from deferred tax assets	**47.0**	13.2
Net movements in regulatory balances related to OCI, net of tax	**(27.3)**	18.4
Total net movements per financial statements	**(92.2)**	18.5

Regulatory developments in Ontario's electricity industry and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management’s judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) OPEB net actuarial loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2018 of $37.2 million is related to the actuarial gain recorded for the year [2017 – $25.1 million actuarial loss] *[note 13[a]]*. The net position is an actuarial loss that is recoverable in future rates. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

b) Lost revenue adjustment mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC’s load forecast used to set approved rates and the actual impact of CDM activities achieved. New variances are accrued based on current CDM activities. Approved variances for 2017 will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2019. Variances pertaining to years subsequent to 2017 have yet to be applied for disposition.

c) Foregone revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 and 2016 if new OEB-approved rates were implemented as of May 1, 2015 and January 1, 2016, respectively. In the 2015 - 2019 CIR decision and rate order, the OEB approved foregone revenue rate riders over 46 months commencing on March 1, 2016 for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates.

d) Gain on disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings (credits) and the after-tax gain realized on two significant LDC properties (credits). As part of the 2015 – 2019 CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on both properties back to ratepayers, effective from March 1, 2016 to December 31, 2018. The gain on disposal of the two properties was realized by LDC in 2015 and 2018, respectively. In the second quarter of 2017, LDC realized a gain in connection with the disposal of a third property.

The balance arising during the year ended December 31, 2018 relates to a realized gain of $98.6 million (net of tax and selling costs of $14.9 million), in connection with the disposal of the second property by LDC in 2018. The proceeds on the disposition of this property were $122.2 million. The actual realized gain and tax savings that exceeded the approved rate riders reduce future electricity distribution rates for customers. LDC is seeking disposition of this incremental balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the incremental balance is currently unknown.

e) IFRS transitional adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of the balance over 46 months commencing on March 1, 2016.

f) OPEB cash versus accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans. The OEB directed LDC to track the difference as a temporary arrangement, pending the OEB's conclusion on the sector-wide policy consultation it initiated on the regulatory treatment of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the consultation and established the use of the accrual accounting method as the default method on which to set rates for OPEB costs. LDC will continue to track the cash versus accrual difference until December 2019. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

g) Stranded meters and smart meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario.

The net book value of stranded meters related to the deployment of smart meters was reclassified from PP&E to a new regulatory balance as at December 31, 2013. In the 2015 – 2019 CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of the stranded meters as at December 31, 2014 over 46 months commencing on March 1, 2016.

On January 16, 2014, the OEB approved LDC's request for incremental revenue and disposition of the smart meter regulatory balances to be recovered through rates over 36 months commencing on May 1, 2014. The OEB ruling on smart meters also permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allows LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base.

h) Named properties

As part of 2010 rates, LDC had forecasted net gains on certain properties which were planned for sale between 2007 and 2011. This regulatory balance relates to the excess of those forecasted net gains over the actual net gains realized upon the sale of the named properties. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

i) Capital contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions made in 2010 and 2011. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

j) Capital-related revenue requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. If the cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeds the actual capital-related revenue requirement over the same rate period, LDC must apply for disposition of this account in order to clear the balance to ratepayers through a rate rider. This account was approved by the OEB in the 2015 – 2019 CIR decision and rate order. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown

k) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. This account was approved by the OEB in the 2015 – 2019 CIR decision and rate order. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

l) Settlement variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. New variances are accrued based on current charges while approved variances up to 2017, including carrying charges forecasted to the end of 2018, will be disposed through OEB-approved rate riders over 12 months commencing on January 1, 2019. Settlement variances pertaining to years subsequent to 2017 have yet to be applied for disposition.

m) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits on offers to connect from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not materialize by the end of the connection horizon, LDC retains the excess expansion deposit not otherwise returned to the connecting customer.

The excess expansion deposits were recorded as a regulatory balance on the balance sheets, with a corresponding offset in net movements in regulatory balances. LDC is seeking disposition of the balance in the 2020 – 2024 rate application *[note 3[a]]*. The timing of disposition of the balance is currently unknown.

[All tabular amounts in millions of Canadian dollars]

n) Deferred taxes

This regulatory credit balance relates to both deferred tax amounts reclassified under IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"] *[note 25[a]]* and the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. LDC did not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets.

The amounts reclassified under IFRS 14 include the deferred tax asset related to regulatory balances of $1.1 million as at December 31, 2018 [December 31, 2017 - $34.9 million deferred tax liability], and the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $1.0 million as at December 31, 2018 [December 31, 2017 - $8.5 million]. The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $4.0 million as at December 31, 2018 [December 31, 2017 - $32.4 million].

o) Tax-related variance accounts

This regulatory credit balance arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates. In the 2015 – 2019 CIR decision and rate order, the OEB approved disposition of the balance over 10-34 months commencing on March 1, 2016.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2018 $	2017 $
Trade payables	**335.1**	323.7
Accrued liabilities	**124.1**	129.6
Due to related parties *[note 22]*	**60.5**	58.3
Other	**2.0**	1.7
	521.7	513.3

[All tabular amounts in millions of Canadian dollars]

10. DEFERRED REVENUE

Deferred revenue consists of capital contributions received from electricity customers and developers to construct or acquire PP&E and revenue from ancillary services which have not yet been recognized into other revenue *[note 25[i]]*.

	2018 $	2017 $
Capital contributions, beginning of year	**187.8**	143.2
Capital contributions received	**106.5**	50.8
Amortization	**(5.3)**	(4.7)
Other	**(0.8)**	(1.5)
Capital contributions, end of year	**288.2**	187.8
Other, beginning of year	**0.9**	1.0
Other received	**8.3**	7.9
Revenue recognized	**(7.3)**	(8.0)
Other, end of year	**1.9**	0.9
Total deferred revenue	**290.1**	188.7
Less: Current portion of deferred revenue relating to:		
Capital contributions	**10.5**	9.0
Other	**1.9**	0.9
Current portion of deferred revenue	**12.4**	9.9
Non-current portion of deferred revenue	**277.7**	178.8

[All tabular amounts in millions of Canadian dollars]

11. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2018 $	2017 $
Notes payable to related party:		
4.54% Long-term note payable to the Corporation due November 12, 2019	**245.1**	245.1
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**300.0**	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	200.0
3.535% Long-term note payable to the Corporation due February 28, 2048	**200.0**	200.0
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0
Total notes payable to related party	**2,100.1**	2,100.1
Less: Unamortized debt issuance costs	**9.5**	10.2
Current portion of notes payable to related party *[note 22]*	**304.9**	60.0
Long-term portion of notes payable to related party *[note 22]*	**1,785.7**	2,029.9

All notes payable to the Corporation are unsecured, rank equally and will be settled in cash.

On November 14, 2017, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on February 28, 2048, which bears interest at a rate of 3.535% per annum. Interest is calculated and payable semi-annually in arrears on February 28 and August 28 of each year. The net proceeds from the promissory note were used to repay certain existing indebtedness of LDC and for general corporate purposes.

12. EMPLOYEE FUTURE BENEFITS

Pension

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2018, the OMERS plan was 96.0% funded [December 31, 2017 - 94.0%]. OMERS has a strategy to return the plan to a fully funded position. LDC is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2018, LDC's contributions were $18.0 million [2017 - $17.5 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $19.8 million to the OMERS plan in 2019.

[All tabular amounts in millions of Canadian dollars]

Post-employment benefits other than pension

a) Benefit obligation

	2018 $	2017 $
Balance, beginning of year	**313.0**	280.5
Current service cost	**4.6**	4.0
Interest cost	**10.8**	11.0
Benefits paid	**(10.9)**	(11.0)
Experience loss (gain) [(1)]	**(8.2)**	1.9
Actuarial gain arising from changes in demographic assumptions [(1)]	**(22.4)**	—
Actuarial loss (gain) arising from changes in financial assumptions [(1)]	**(11.4)**	26.3
Transfer from related parties	**0.4**	0.3
Balance, end of year	**275.9**	313.0

[(1)] Actuarial loss (gain) on accumulated sick leave credits of ($4.7) million [2017 - $3.1 million] is recognized in benefit cost *[note 12[c]]* and $(0.1) million in transfer from related parties [2017 - $nil], and actuarial loss (gain) on medical, dental and life insurance benefits of ($37.2) million [2017 - $25.1 million] is recognized in OCI *[note 12[d]]*.

b) Amounts recognized in regulatory balances

As at December 31, 2018, the amount recognized in regulatory balances related to net actuarial loss was $48.1 million [December 31, 2017 - $85.3 million] *[note 8[a]]*.

c) Benefit cost recognized

	2018 $	2017 $
Current service cost	**4.6**	4.0
Interest cost	**10.8**	11.0
Actuarial loss (gain) on other employee benefits *[note 12[a]]*	**(4.7)**	3.1
Benefit cost	**10.7**	18.1
Capitalized to PP&E and intangible assets	**4.8**	8.1
Charged to operating expenses	**5.9**	10.0

d) Amounts recognized in OCI

	2018 $	2017 $
Actuarial loss (gain) *[note 12[a]]*	**(37.2)**	25.1
Income tax expense (recovery) in OCI *[note 20]*	**9.9**	(6.7)
Remeasurements of post-employment benefits, net of tax	**(27.3)**	18.4
Net movements in regulatory balances related to OCI, net of tax	**27.3**	(18.4)
OCI, net of tax	**—**	—

[All tabular amounts in millions of Canadian dollars]

e) Significant assumptions

	2018	2017
Discount rate (%) used in the calculation of:		
Benefit obligation as at December 31	**3.75**	3.50
Assumed medical and dental cost trend rates (%) as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.50
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2015**	2015
For other retirements	**2018**	2018

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The weighted average duration of the benefit obligation as at December 31, 2018 was 16.7 [2017 – 16.7]. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2018 $	2017 $
Benefit obligation		**275.9**	313.0
Discount rate	1% ↑	**(41.3)**	(46.8)
	1% ↓	**53.1**	60.2
Medical and dental cost trend rate	1% ↑	**35.7**	40.2
	1% ↓	**(31.9)**	(36.0)

13. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents or borrowings through TH Energy or the Corporation) to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

[All tabular amounts in millions of Canadian dollars]

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2018, LDC's definition of capital included equity, bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, and has remained unchanged from the definition as at December 31, 2017. As at December 31, 2018, equity amounted to $1,836.6 million [December 31, 2017 - $1,716.3 million], and bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, amounted to $2,113.6 million [December 31, 2017 - $2,216.4 million].

14. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2018 and December 31, 2017, the fair values of cash and cash equivalents, accounts receivable, unbilled revenue, bank indebtedness, and accounts payable approximated their carrying amounts due to the short maturity of these instruments *[note 25[j]]*. The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable to related party consist of the following:

	2018 $		**2017 $**	
	Carrying amount	**Fair value (1)**	**Carrying amount**	**Fair value (1)**
Long-term notes payable to the Corporation				
4.54% due November 12, 2019	**244.9**	**249.5**	244.7	255.6
5.59% due May 21, 2040	**198.9**	**249.3**	198.9	263.9
3.59% due November 18, 2021	**299.4**	**307.6**	299.2	313.9
2.96% due April 10, 2023	**249.4**	**250.7**	249.2	255.8
4.01% due April 9, 2063	**198.7**	**201.1**	198.7	217.4
4.13% due September 16, 2044	**198.5**	**208.0**	198.5	221.1
3.60% due July 28, 2045	**198.7**	**190.7**	198.7	202.9
3.988% due April 9, 2063	**44.5**	**45.0**	44.5	48.7
2.572% due August 25, 2026	**199.0**	**192.4**	198.9	195.4
3.535% due February 28, 2048	**198.6**	**187.9**	198.6	202.5
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**15.3**	15.0	15.6
	2,090.6	**2,142.5**	2,089.9	2,237.8

(1) The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 25[k]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

[All tabular amounts in millions of Canadian dollars]

Credit risk

LDC is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC is subject to credit risk with respect to customer non-payment of electricity bills. As at December 31, 2018, LDC had approximately 772,000 customers. LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2018, LDC held security deposits in the amount of $79.8 million [December 31, 2017 - $58.2 million], of which $51.9 million [December 31, 2017 - $29.8 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. LDC's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2018, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2018 and December 31, 2017.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2018 $	2017 $
Accounts receivable (net of loss allowance)		
Outstanding for not more than 30 days	**185.7**	180.3
Outstanding for more than 30 days and not more than 120 days	**20.2**	32.6
Outstanding for more than 120 days	**4.5**	4.3
Total accounts receivable	**210.4**	217.2
Unbilled revenue (net of loss allowance)	**279.7**	276.0
Total accounts receivable and unbilled revenue	**490.1**	493.2

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered in conjunction with accounts receivable and is included in the loss allowance as at December 31, 2018 and December 31, 2017.

LDC has a broad base of customers. As at December 31, 2018 and December 31, 2017, LDC's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional loss allowance was required for these balances.

Reconciliation between the opening and closing loss allowance balances for accounts receivable and unbilled revenue is as follows:

	2018 $	2017 $
Balance, beginning of year	**(10.2)**	(9.7)
Transitional adjustment *[note 25[p]]*	**(0.3)**	—
Loss allowance	**(4.3)**	(6.2)
Write-offs	**4.4**	5.9
Recoveries	**(0.2)**	(0.2)
Balance, end of year	**(10.6)**	(10.2)

c) Market risks

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2018, aside from the valuation of its post-employment benefit obligations, LDC was exposed to interest rate risk predominately from cash and cash equivalents (bank indebtedness) and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $1.0 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

[All tabular amounts in millions of Canadian dollars]

Liquidity risks associated with financial commitments are as follows:

2018						
	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Bank indebtedness	21.5	—	—	—	—	—
Accounts payable and accrued liabilities [1]	502.3	—	—	—	—	—
Obligations under lease	0.3	0.3	0.3	0.2	0.1	0.1
Long-term notes payable to the Corporation						
4.54% due November 12, 2019	245.1	—	—	—	—	—
5.59% due May 21, 2040	—	—	—	—	—	300.0
3.59% due November 18, 2021	—	—	300.0	—	—	—
2.96% due April 10, 2023	—	—	—	—	250.0	—
4.01% due April 9, 2063	—	—	—	—	—	200.0
4.13% due September 16, 2044	—	—	—	—	—	200.0
3.60% due July 28, 2045	—	—	—	—	—	200.0
3.988% due April 9, 2063	—	—	—	—	—	45.0
2.572% due August 25, 2026	—	—	—	—	—	200.0
3.535% due February 28, 2048	—	—	—	—	—	200.0
Demand note payable to the Corporation due on demand	45.0	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	15.0	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	79.8	67.3	67.3	56.3	52.4	1,092.7
	909.0	67.6	367.6	56.5	302.5	2,437.8

[1] Accounts payable and accrued liabilities exclude $19.4 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2018, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

15. FINANCIAL ASSISTANCE

As at December 31, 2018, $33.3 million [December 31, 2017 - $38.4 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $75.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

[All tabular amounts in millions of Canadian dollars]

16. SHARE CAPITAL

Share capital consists of the following:

	2018 $	2017 $
Authorized The authorized share capital of LDC consists of an unlimited number of common shares without par value.		
Issued and outstanding 1,000 common shares, of which all were fully paid.	**556.3**	556.3

Dividends

On May 14, 2018, the Board of Directors of LDC declared dividends in the amount of $42.7 million to the Corporation [2017 - $2.1 million], which was paid out on June 29, 2018.

17. REVENUES

Revenues consist of the following:

	2018 $	2017 $ Restated *[note 25[p]]*
Revenue from contracts with customers		
Energy sales	**2,704.1**	2,810.2
Distribution revenue	**674.2**	724.2
Ancillary services revenue	**22.9**	17.6
Street lighting services	**8.0**	9.2
Pole and duct rentals	**15.7**	15.8
Other regulatory service charges	**11.7**	13.3
Miscellaneous	**9.0**	13.7
Revenue from other sources		
Capital contributions	**5.3**	4.7
CDM mid-term incentive *[note 3[c]]*	**2.7**	12.2
Other	**5.2**	10.2
	3,458.8	3,631.1

[All tabular amounts in millions of Canadian dollars]

Energy sales and Distribution revenue by customer class are as follows:

	2018 $	2017 $
		Restated *[note 25[p]]*
Residential service [(1)]	**815.4**	902.3
General service [(2)]	**2,337.3**	2,394.5
Large users [(3)]	**225.6**	237.6
Total energy sales and distribution revenue	**3,378.3**	3,534.4

[(1)] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multifamily units and seasonal occupancy.
[(2)] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.
[(3)] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

18. OPERATING EXPENSES

Operating expenses consist of the following:

	2018 $	2017 $
Salaries and benefits	**230.1**	225.4
External services	**143.5**	131.9
Other support costs [(1)]	**21.9**	21.6
Materials and supplies	**20.2**	21.3
Less: Capitalized costs	**(118.6)**	(116.0)
	297.1	284.2

[(1)] Includes taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2018, LDC recognized operating expenses of $11.7 million related to materials and supplies used to service electricity distribution assets [2017 - $13.0 million].

[All tabular amounts in millions of Canadian dollars]

19. FINANCE COSTS

Finance costs consist of the following:

	2018 $	2017 $
Interest income	**(0.6)**	(0.3)
Interest expense		
Interest on long-term debt [1]	**82.2**	87.1
Interest on short-term debt	**4.7**	3.3
Other interest	**0.9**	0.7
Capitalized borrowing costs	**(8.9)**	(9.8)
	78.3	81.0

[1] Includes amortization of debt issuance costs, discounts and premiums.

20. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2018 $	2017 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**309.8**	197.5
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**82.1**	52.3
Non-taxable amounts	**(9.4)**	(10.0)
Gain on disposal	**8.0**	1.3
Other	**0.9**	0.6
Income tax expense	**81.6**	44.2
Effective tax rate	**26.3%**	22.4%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [1]	**197.9**	184.4
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**52.4**	48.9
Temporary differences recoverable in future rates	**(25.5)**	(17.4)
Gain on disposal	**8.0**	1.3
Other	**(0.3)**	(1.8)
Income tax expense and income tax recorded in net movements in regulatory balances	**34.6**	31.0
Effective tax rate	**17.5%**	16.8%

[1] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

[All tabular amounts in millions of Canadian dollars]

Income tax expense as presented in the statements of income and statements of comprehensive income are as follows:

	2018 $	2017 $
Income tax expense	**81.6**	44.2
Income tax recorded in net movements in regulatory balances	**(47.0)**	(13.2)
Income tax expense and income tax recorded in net movements in regulatory balances	**34.6**	31.0
Income tax expense (recovery) in OCI *[note 12[d]]*	**9.9**	(6.7)
Income tax expense (recovery) in OCI recorded in net movements in regulatory balances	**(9.9)**	6.7
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2018 $	2017 $
Current tax expense		
Current year	**35.3**	32.0
Adjustment for tax positions taken in prior periods	**(0.6)**	(1.1)
	34.7	30.9
Deferred tax expense		
Origination and reversal of temporary differences	**(0.1)**	0.1
Income tax expense and income tax recorded in net movements in regulatory balances	**34.6**	31.0

Deferred tax assets consist of the following:

	Net balance January 1, 2018 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2018 $
PP&E and intangible assets	**(14.9)**	**(31.0)**	**—**	**(45.9)**
Post-employment benefits	**82.9**	**—**	**(9.9)**	**73.0**
Other taxable temporary differences	**(11.0)**	**(15.8)**	**—**	**(26.8)**
	57.0	**(46.8)**	**(9.9)**	**0.3**

	Net balance January 1, 2017 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2017 $
PP&E and intangible assets	11.7	(26.6)	—	(14.9)
Post-employment benefits	74.3	1.9	6.7	82.9
Other taxable temporary differences	(22.2)	11.2	—	(11.0)
	63.8	(13.5)	6.7	57.0

[All tabular amounts in millions of Canadian dollars]

LDC had recorded a net deferred tax asset as it expects to earn sufficient taxable income to realize the future reversal of deductible temporary differences.

21. STATEMENTS OF CASH FLOWS

Changes in non-cash working capital provided (used) cash as follows:

	2018 $	2017 $
Accounts receivable	**6.8**	8.7
Unbilled revenue	**(4.6)**	43.7
Materials and supplies	**1.2**	0.4
Other current assets	**2.0**	0.8
Accounts payable and accrued liabilities	**5.6**	(4.2)
Income tax payable	**(7.7)**	3.5
Deferred revenue	**2.5**	5.6
Deferred conservation credit	**(1.1)**	3.8
Other current liabilities	**(1.2)**	(1.6)
	3.5	60.7

Reconciliation between the amounts presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2018 $	2017 $
Purchase of PP&E, cash basis	**431.8**	433.8
Net change in accruals related to PP&E	**19.3**	9.5
Other	**2.6**	1.6
Total additions to PP&E	**453.7**	444.9
Purchase of intangible assets, cash basis	**54.5**	93.4
Net change in accruals related to intangible assets	**(5.9)**	8.0
Total additions to intangible assets	**48.6**	101.4

[All tabular amounts in millions of Canadian dollars]

Summary of changes in liabilities arising from financing activities:

	2017 $	Cash flows [(1)] $	Non-cash changes $		2018 $
			Foreign exchange	Other	
Year ended December 31					
Dividends payable	**—**	**(42.7)**	**—**	**42.7**	**—**
Notes payable to related party *[note 11]*	**2,089.9**	**—**	**—**	**0.7**	**2,090.6**
Accrued interest [(2)]	**17.7**	**(81.8)**	**—**	**83.5**	**19.4**
Lease liability [(3)]	**1.5**	**(1.8)**	**—**	**1.6**	**1.3**
	2,109.1	**(126.3)**	**—**	**128.5**	**2,111.3**

	2016 $	Cash flows [(1)] $	Non-cash changes $		2017 $
			Foreign exchange	Other	
Year ended December 31					
Dividends payable	—	(2.1)	—	2.1	—
Notes payable to related party *[note 11]*	2,135.5	(46.5)	—	0.9	2,089.9
Accrued interest [(2)]	18.5	(90.2)	—	89.4	17.7
Lease liability [(3)]	4.6	(3.0)	(0.1)	—	1.5
	2,158.6	(141.8)	(0.1)	92.4	2,109.1

(1) Cash inflows and cash outflows arising from notes payable to related parties are presented on a net basis.
(2) Included within accounts payable and accrued liabilities *[note 14[c]]*.
(3) Included within other liabilities.

[All tabular amounts in millions of Canadian dollars]

22. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which is the sole shareholder of the Corporation, the Corporation, and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For period ended December 31, 2018			
Revenues	**255.5**	**—**	**8.4**
Operating expenses (recoveries) and capital expenditures	**18.1**	**2.0**	**(0.8)**
Finance costs	**—**	**84.5**	**—**
Dividends declared and paid	**—**	**42.7**	**—**
As at December 31, 2018			
Accounts receivable	**4.5**	**—**	**1.3**
Unbilled revenue	**22.6**	**—**	**—**
Accounts payable and accrued liabilities	**40.3**	**20.2**	**—**
Current portion of notes payable to related party	**—**	**304.9**	**—**
Long-term portion of notes payable to related party	**—**	**1,785.7**	**—**
Customer deposits	**17.3**	**—**	**—**
Deferred revenue	**2.1**	**—**	**—**

	City $	Corporation $	TH Energy $
For period ended December 31, 2017			
Revenues	263.1	—	10.7
Operating expenses and capital expenditures	22.1	1.6	(1.1)
Finance costs	—	87.0	—
Dividends declared and paid	—	2.1	—
As at December 31, 2017			
Accounts receivable	12.7	—	2.1
Unbilled revenue	24.7	—	—
Accounts payable and accrued liabilities	40.0	18.3	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	2,029.9	—
Customer deposits	15.7	—	—
Deferred revenue	1.5	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Finance costs represent interest charged by the Corporation on the notes payable *[note 19]*. Dividends are paid to the Corporation *[note 16]*.

Accounts receivable represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation. Notes payable to related party represent amounts borrowed from the Corporation *[note 11]*. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

[All tabular amounts in millions of Canadian dollars]

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2018 $	2017 $
Short-term employee benefits	**4.5**	4.3
Post-employment benefits	**1.0**	1.1
Termination benefits	**1.8**	—
	7.3	5.4

23. COMMITMENTS

Capital projects

As at December 31, 2018, the future minimum payments for capital projects and other commitments were as follows:

	Capital projects [(1)] and other $
Less than one year	**25.4**
Between one and five years	**10.1**
Total amount of future minimum payments [(2)]	**35.5**

(1) Mainly commitments for construction services.
(2) Refer to note 14 for financial commitments excluded from the table above.

Leases

As at December 31, 2018, the contractual undiscounted cash flows related to leases were as follows:

	2018 $		
	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**0.3**	**—**	**0.3**
Between one and five years	**1.0**	**0.1**	**0.9**
More than five years	**0.1**	**—**	**0.1**
	1.4	**0.1**	**1.3**
Current portion included within other liabilities			**0.3**
Non-current portion included within other liabilities			**1.0**

24. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any applicable liability insurance policies which LDC believes would cover any damages which may become payable by LDC in connection with these actions, subject to such claim not being disputed by the insurers.

25. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14:

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC’s financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the “Accounting Procedures Handbook for Electricity Distributors”. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC’s regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC’s balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management’s judgment, the balances are recorded in LDC’s statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the balance sheets and are presented on the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB’s regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents (bank indebtedness) include bank overdrafts that are repayable on demand and form an integral part of LDC’s cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through a loss allowance, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, adjusted for forward-looking factors specific to the current economic and credit conditions.

Effective January 1, 2018, LDC measures the loss allowance at an amount equal to the lifetime expected credit losses ["ECL"] for all trade receivables or contract assets that result from transactions with customers and do not contain a significant financing component. A provision matrix is used by LDC to measure the lifetime ECL of accounts receivable from individual customers. Loss rates are calculated using a 'roll rate' method based on the probability of a trade receivable progressing through successive stages of delinquency to write-off and are based on the average of actual credit loss experience over the past three years, as it more accurately reflects anticipated credit loss. Roll rates are calculated separately for exposures in different customer classes.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

[All tabular amounts in millions of Canadian dollars]

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Other capital assets	4.0% to 25.0%
Right-of-use assets	1.0% to 21.1%

Right-of-use assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term, in which case they are depreciated to the end of the useful life of the underlying assets. Right-of-use assets are recognized for contracts that are, or contain, leases. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in the cost of PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

LDC assesses each contract with the customer to identify the performance obligation. Revenue is recognized when the control of the goods or services has been transferred to the customer at a point of time or over time. The transaction price and the payment terms are agreed upon in the contract between LDC and the customer.

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. The performance obligation is satisfied over time when the electricity is simultaneously received and consumed by the customer. The majority of billings cycle and payment terms are on a monthly basis. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. LDC has primary responsibility for the delivery of electricity to the customer. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

Capital contributions received in advance from electricity customers and developers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Capital contributions received from developers to construct or acquire PP&E for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15 *Revenue from Contracts with Customers* ["IFRS 15"].

Revenues and costs associated with CDM programs are presented using the net basis of accounting and recorded in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

LDC has not incurred any additional costs to obtain or fulfil contracts with its customers nor any kind of variable considerations from the above mentioned revenue generating activities.

j) Financial instruments

All financial assets and financial liabilities are classified as “Amortized cost”. These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm’s length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash and cash equivalents are classified as “Amortized cost” and are measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as “Amortized cost” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as “Amortized cost” and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable are classified as “Amortized cost” and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Customer deposits are classified as “Amortized cost” and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under leases are classified as “Amortized cost” and are initially measured at fair value, or the present value of the minimum lease payments if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as “Amortized cost” and are initially measured at fair value. The carrying amounts are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC’s current borrowing rate for similar debt instruments *[note 14[a]]*. Debt issuance costs incurred in connection with LDC’s debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits other than pension

LDC has a number of unfunded benefit plans providing post-employment benefits (other than pension) to its employees. LDC pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on medical, dental and life insurance benefits are recognized in OCI as they arise. Actuarial gains and losses related to rate-regulated activities are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2018.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the *Electricity Act*, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[i] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 25[a] – Recognition and measurement of regulatory balances;
- Note 25[i] – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 25[e] and 25[f] – Determination of useful lives of depreciable assets;
- Notes 25[l] and 12 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 25[n] and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 24 – Recognition and measurement of provisions and contingencies.

p) Changes in accounting policies

Effective January 1, 2018, LDC has adopted new IFRS standards and applied the following new accounting policies in preparing the financial statements:

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 effective for annual periods beginning on or after January 1, 2018, which replaced existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a five step model that applies to contracts with customers that specifies that revenue is recognized when or as an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. Depending on whether certain criteria are met, revenue is recognized at a point in time or over time.

LDC adopted IFRS 15 using the modified retrospective approach with the following practical expedients:

- LDC did not restate completed contracts that began and ended in the same annual reporting period or completed contracts at the beginning of the earliest period presented; and
- LDC did not disclose the amount of consideration allocated to the remaining performance obligations nor did it provide an explanation of when LDC expects to recognize that amount as revenue for comparative periods presented in the financial statements.

LDC recognizes revenue in the amount that it has a right to invoice when the amount directly corresponds with the value of LDC's performance to date.

The adoption of IFRS 15 resulted in a $207.6 million income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017, and had no impact to opening retained earnings as at January 1, 2018. LDC updated the impact previously disclosed in the audited financial statements for the year ended December 31, 2017 to include the additional income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017.

[All tabular amounts in millions of Canadian dollars]

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ["IFRS 9"] effective for annual periods beginning on or after January 1, 2018, which replaced IAS 39 *Financial Instruments: Recognition and Measurement* ["IAS 39"]. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. LDC adopted IFRS 9 retrospectively on January 1, 2018. Despite the retrospective adoption of IFRS 9, LDC is not required, upon initial application, to restate comparatives.

i) Classification and measurement of financial instruments

IFRS 9 largely retains the existing requirements in IAS 39 for the classification and measurement of financial liabilities. However, it eliminates the previous IAS 39 categories for financial assets of held to maturity, loans and receivables and available for sale.

Under IFRS 9, on initial recognition, a financial asset is classified and measured at amortized cost, fair value through other comprehensive income, or fair value through profit or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics.

The adoption of IFRS 9 has not had a significant effect on LDC's accounting policies related to financial instruments. The impact of IFRS 9 on the classification and measurement of financial instruments is set out below.

Financial Instrument	IAS 39 Measurement basis	IFRS 9 Measurement basis
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Unbilled revenue	Loans and receivables	Amortized cost
Bank indebtedness	Financial liability – amortized cost	Amortized cost
Customer deposits	Financial liability – amortized cost	Amortized cost
Leases	Financial liability – amortized cost	Amortized cost
Notes payable to related party	Financial liability – amortized cost	Amortized cost
Accounts payable	Financial liability – amortized cost	Amortized cost

Financial Instrument	IAS 39 Carrying amount as at January 1, 2018 $	IFRS 9 Carrying amount as at January 1, 2018 $
Cash and cash equivalents	—	—
Accounts receivable	217.2	217.8
Unbilled revenue	276.0	275.1
Bank indebtedness	125.0	125.0
Customer deposits	58.1	58.1
Leases (1)	3.1	3.1
Notes payable to related party	2,029.9	2,029.9
Accounts payable	323.7	323.7

(1) Includes transitional adjustment for the recognition of new leases upon adoption of IFRS 16 on January 1, 2018 *[note 25[q]]*.

ii) Impairment of financial assets

Loss allowances for accounts receivable and unbilled revenue are always measured at an amount equal to lifetime ECL. Lifetime ECL are the ECL that result from all possible default events over the expected life of a financial instrument.

When determining whether the credit risk of a financial asset has increased significantly since initial recognition and when estimating ECL, LDC considers reasonable and supportable information that is relevant and available without undue cost or effort. This includes both quantitative and qualitative information and analysis, based on LDC's historical experience, adjusted for forward-looking factors specific to the current credit environment.

LDC assumes that credit risk on a financial asset has increased if it is more than 30 days past due date.

LDC considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to LDC in full, without recourse by LDC, such as realising security (if any is held).

If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Leases

In January 2016, the IASB issued IFRS 16, which replaced IAS 17 *Leases* ["IAS 17"] and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the previous distinction between finance and operating leases. IFRS 16 requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. Lessor accounting remained substantially unchanged.

Although IFRS 16 is effective for annual periods beginning on or after January 1, 2019, LDC early adopted IFRS 16 on January 1, 2018 using the modified retrospective approach, in accordance with the transitional provisions in IFRS 16. The comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4 *Determining whether an Arrangement contains a Lease*. In applying this approach, LDC elected to use practical expedients that allowed it to exclude the initial direct costs from the measurement of the right-of use assets at the date of the initial application, and to use hindsight in determining the lease term. As a practical expedient permitted by IFRS 16, LDC applied IFRS 16 to existing contracts that were previously identified as leases applying IAS 17 and IFRIC 4 *Determining whether an Arrangement contains a Lease*, and did not apply IFRS 16 to contracts that were not previously identified as containing a lease.

The adoption of IFRS 16 resulted in an increase of $1.6 million in total assets and total liabilities each for recognition of right-of-use assets and lease liabilities, respectively, and had no impact to opening retained earnings as at January 1, 2018.

The adoption of IFRS 15, IFRS 9 and IFRS 16 resulted in no changes to the balance sheet as at December 31, 2017 and statements of cash flows for the year ended December 31, 2017.

[All tabular amounts in millions of Canadian dollars]

Transition to IFRS 15

STATEMENTS OF INCOME	Note	December 31, 2017 $	Transitional adjustments $	December 31, 2017 $
				Restated
Revenues				
Energy sales	A	3,017.8	(207.6)	**2,810.2**
Distribution revenue		724.2	—	**724.2**
Other		96.7	—	**96.7**
		3,838.7	(207.6)	**3,631.1**
Expenses				
Energy purchases	A	3,063.5	(207.6)	**2,855.9**
Operating expenses		284.2	—	**284.2**
Depreciation and amortization		222.3	—	**222.3**
		3,570.0	(207.6)	**3,362.4**
Finance costs		(81.0)	—	**(81.0)**
Gain on disposals of property, plant and equipment		9.8	—	**9.8**
Income before income taxes		197.5	—	**197.5**
Income tax expense		(44.2)	—	**(44.2)**
Net income		153.3	—	**153.3**
Net movements in regulatory balances		(13.1)	—	**(13.1)**
Net movements in regulatory balances arising from deferred tax assets		13.2	—	**13.2**
Net income after net movements in regulatory balances		153.4	—	**153.4**

A. Energy sales and energy purchases

Energy sales are based on the cost and usage of electricity by the customer. For Regulated Price Plan [“RPP”] customers, the OEB has set a fixed rate which should approximate the cost of energy purchased. LDC recovers the difference between amounts billed to RPP customers for electricity charges and the cost to purchase the energy from the IESO [“RPP Settlement Amount”].

In 2017, the Government of Ontario announced the Ontario’s Fair Hydro Plan, which included a number of initiatives aimed at decreasing electricity bills. For eligible non-RPP customers, the bill reduction was implemented through a reduction in the Global Adjustment charges that they would have otherwise paid [“GA Modifier”]. LDC recovers the GA Modifier from the IESO.

The RPP Settlement Amount and the GA Modifier will be recorded differently under IFRS 15 than they were under IAS 18. Under IAS 18, energy sales were recorded at the fair value of the consideration received or receivable, including amounts received from the electricity customers and the IESO. Consequently, both the RPP Settlement Amount and the GA Modifier were recorded as energy sales. Under IFRS 15, revenue is recognized at the transaction price as per the contract with electricity customers only, and would therefore exclude amounts that are received or receivable from the IESO. As such, the RPP Settlement Amount and the GA Modifier received or receivable from IESO will be recorded as a reduction/addition from/to energy purchases instead of energy sales.

[All tabular amounts in millions of Canadian dollars]

Transition to IFRS 9

Reconciliation of loss allowance balance from IAS 39 to IFRS 9:

	Note	Loss allowance under IAS 39 as at December 31, 2017 $	Transitional adjustments $	Loss allowance under IFRS 9 as at January 1, 2018 $
ASSETS				
Current				
Loss allowance	A	(10.2)	(0.3)	**(10.5)**

A. Impairment of financial assets

Under IAS 39, accounts receivable would first be provisioned for when it is deemed that the collection is unlikely. Upon adoption of IFRS 9, LDC measures the loss allowance at an amount equal to the lifetime ECL for trade receivables or contract assets that result from transactions that are within the scope of IFRS 15, and do not contain a significant financing component. LDC uses a provision matrix to measure the lifetime ECL of accounts receivable from individual customers which accounts for exposures in different customer classes. The revised impairment allowance resulted in a restatement of opening retained earnings as at January 1, 2018.

Transition to IFRS 16

LDC determined the cumulative effect of applying IFRS 16 on January 1, 2018 to be $nil impact in opening retained earnings and recorded $1.6 million as right-of-use assets and $1.6 million as lease liabilities.

The office space leases were recognized as operating leases under IAS 17, and the corresponding lease payments were recorded as expenses on a straight-line basis over the lease term. Upon transition, LDC recognized right-of-use assets and lease liabilities for these leases. The lease liabilities were measured at the present value of the remaining lease payments, discounted at the incremental borrowing rate as at January 1, 2018. The right-of-use assets were measured at an amount equal to the lease liabilities.

	Operating leases as at December 31, 2017 $	Transitional adjustments $	Leases as at January 1, 2018 $
ASSETS			
Current			
Property, plant and equipment	—	1.6	**1.6**
Total assets	—	1.6	**1.6**
LIABILITIES AND EQUITY			
Current			
Other liabilities	—	0.3	**0.3**
Total current liabilities	—	0.3	**0.3**
Other liabilities	—	1.3	**1.3**
Total liabilities	—	1.6	**1.6**

The weighted average incremental borrowing rate applied to the lease liabilities was 1.92%.

q) Future accounting pronouncements

A number of new interpretations and amendments to existing standards have been issued but are not yet effective for the year ended December 31, 2018, and have not been applied in preparing the financial statements.

IFRIC 23 *Uncertainty over Income Tax Treatments*

On June 7, 2017, the IASB issued IFRIC 23 *Uncertainty over Income Tax Treatments*. The interpretation provides guidance on the accounting for current and deferred tax assets and liabilities in situations in which there is uncertainty over income tax treatments. The interpretation is applicable for annual reporting periods beginning on or after January 1, 2019.

Annual Improvements to IFRS Standards 2015-2017 Cycle

On December 12, 2017, as part of its annual improvements process, the IASB issued narrow-scope amendments to the following standards:

IFRS 3 *Business Combinations* – the amendments clarify that when an entity obtains control of a business that is a joint operation, it re-measures previously held interests in that business.

IFRS 11 *Joint Arrangements* – the amendments clarify that when an entity obtains joint control of a business that is a joint operation, it does not re-measure previously held interests in that business.

IAS 12 *Income Taxes* – the amendments clarify that an entity recognizes income tax consequences of dividends in profit or loss, other comprehensive income or equity, depending on where the entity recognized the originating transaction or event that generated the distributable profits giving rise to the dividend.

IAS 23 *Borrowing Costs* – the amendments clarify that an entity treats as general borrowings any borrowings made specifically to obtain a qualifying asset that remain outstanding when the asset is ready for its intended use or sale.

The amendments are effective for annual reporting periods beginning on or after January 1, 2019.

Definition of Material (Amendments to IAS 1 *Presentation of Financial Statements* and IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors)*

On October 31, 2018, the IASB issued amendments to IAS 1 and IAS 8 – the amendments clarify the definition of 'material' and align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

LDC anticipates that the adoption of these accounting pronouncements will not have a material impact on LDC's financial statements, if any.

GLOSSARY

CDM – Conservation and demand management

CIR – Custom Incentive Rate-setting

City – City of Toronto

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

GAAP – Generally Accepted Accounting Principles

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator. The IESO and the Ontario Power Authority were merged under the name Independent Electricity System Operator on January 1, 2015.

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* (Canada), as amended

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

OCI – Other comprehensive income

OEB – Ontario Energy Board

OFHP – Ontario's Fair Hydro Plan

OFHA – *Fair Hydro Act, 2017* (Ontario)

OMERS – Ontario Municipal Employees Retirement System

OPA – Ontario Power Authority. The IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015.

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

US GAAP – United States Generally Accepted Accounting Principles

WMS – Wholesale Market Service

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets									
Current Assets									
Cash and cash equivalents	1005_Cash	-	-						
	1010_Cash Advances and Working Funds	-	-						
		-	-	36,075	(36,075)	-	-	-	
Accounts receivable	1100_Customer Accounts Receivable	184,241,206	184,241						
	1104_Accounts Receivable - Recoverable Work	8,852,448	8,852						
	1110_Other Accounts Receivable	22,359,139	22,359						
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	(9,684,040)	(9,684)						
	1200_Accounts Receivable from Associated Companies	1,271,934	1,272						
		207,040,687	207,041	15,087	(11,850)	210,277	210,277	(0)	
Unbilled revenue	1120_Accrued Utility Revenues	279,551,573	279,552	1,094		280,645			
	1130_Accumulated Provision for Uncollectible Accounts-- Credit	(938,144)	(938)			(938)			
		278,613,429	278,613	1,094		279,707	279,707	0	
Income tax receivable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	-	-			-	-	-	
Materials and supplies	1330_Plant Materials and Operating Supplies	8,067,927	8,068			8,068	8,068	-	
Other assets	1180_Prepayments	10,690,150	10,690			10,690	10,690	-	
	1190_Miscellaneous Current and Accrued Assets	1,005,039	1,005			1,005		(1,005)	Note 1
		19,763,117	19,763	-	-	19,763	18,758	(1,005)	
Property, plant and equipment	1805_Land	7,006,432	7,006						
	1808_Buildings and Fixtures	137,260,787	137,261						
	1815_Transformer Station Equipment - Normally Primary above 50 kV	37,862,575	37,863						
	1820_Distribution Station Equipment - Normally Primary below 50 kV	213,516,777	213,517						
	1830_Poles Towers and Fixtures	380,783,918	380,784						
	1835_Overhead Conductors and Devices	428,315,901	428,316						
	1840_Underground Conduit	1,205,589,193	1,205,589						
	1845_Underground Conductors and Devices	862,204,571	862,205						
	1850_Line Transformers	566,668,052	566,668						
	1855_Services	124,625,454	124,625						
	1860_Meters	220,072,783	220,073						
	1905_Land	17,358,657	17,359						
	1908_Buildings and Fixtures	239,369,154	239,369						
	1910_Leasehold Improvements	753,840	754						
	1915_Office Furniture and Equipment	19,990,318	19,990						
	1920_Computer Equipment - Hardware	66,761,063	66,761						
	1930_Transportation Equipment	36,083,642	36,084						
	1935_Stores Equipment	7,066	7						
	1940_Tools Shop and Garage Equipment	23,350,605	23,351						
	1945_Measurement and Testing Equipment	480,243	480						
	1950_Power Operated Equipment	1,265,194	1,265						
	1955_Communication Equipment	49,888,402	49,888						
	1960_Miscellaneous Equipment	270,978	271						
	1970_Load Management Controls - Customer Premises	3,022,834	3,023						
	1975_Load Management Controls - Utility Premises	-	-						
	1980_System Supervisory Equipment	39,715,786	39,716						
	1995_Contributions and Grants - Credit	-	-						
	1612_Land Rights	-	-						
	2005_Property Under Finance Leases	19,747,714	19,748						
	2055_Construction Work in Progress--Electric	421,490,336	421,490						
	2075_Non-Rate Regulated Property Owned or Under Finance Leases	2,002,023	2,002						
	2105_Accum. Depreciation of Electric Utility Plant - Property Plant & Equipment	(785,786,375)	(785,786)						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	-	-						
	2180_Accumulated Depreciation of Non Rate-Regulated Property	(166,835)	(167)						
		4,339,511,084	4,339,511	10,397	-	4,349,909	4,349,909	(0)	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets									
Intangible assets	1609_Capital Contributions Paid	164,168,403	164,168						
	1611_Computer Software	207,911,095	207,911						
	2055_Construction Work in Progress--Electric	54,308,043	54,308						
	2120_Accumulated Amortization of Electric Utility Plant - Intangibles	(107,489,135)	(107,489)						
		318,898,406	318,898	-	-	318,898	318,898	-	
Deferred tax assets	1495_Deferred Taxes - Non-Current Assets	3,983,368	3,983	-	-	3,983	301	(3,682)	Note 2
Other assets	1460_Other Non-Current Assets	5,827,697	5,828	-	-	5,828	5,828	(0)	
Regulatory balances	1508_Other Regulatory Assets	88,334,901	88,335						
	1520_Power Purchase Variance Account	-	-						
	1521_Special Purpose Chg Assessment Variance Account	-	-						
	1533_Renewable Generation Connection Funding Adder Deferral Account	(4,300,876)	(4,301)						
	1550_Low Voltage Variance Acct	727,114	727						
	1551_Smart Metering Entity Charge Variance Acct	(851,633)	(852)						
	1555_Smart Meter Capital Offset Variance	3,605,333	3,605						
	1556_Smart Meter Operating Variance	-	-						
	1562_Deferred Payments in Lieu of Taxes	-	-						
	1563_Deferred PILs Contra Account	-	-						
	1568_LRAM Variance Account	28,403,169	28,403						
	1575_IFRS-UGAAP Transitional PPE Amounts	5,690,456	5,690						
	1580_RSVAWMS	(30,044,735)	(30,045)						
	1584_RSVANW	17,296,882	17,297						
	1586_RSVACN	26,023,060	26,023						
	1588_RSVAPOWER	(8,935,056)	(8,935)						
	1589_RSVAGA	(16,850,741)	(16,851)						
	1592_PILs and Tax Variance for 2006 and Subsequent Years	(0)	(0)						
	1595_Disposition Recovery Reg Balances Control Acct	18,497,244	18,497						
		127,595,118	127,595	-	-	127,595	125,975	(1,620)	Note 3
Total Assets		5,301,232,906	5,301,233	62,653	(47,925)	5,315,961	5,309,653	(6,307)	
Liabilities and Equity									
Joint Bank indebtedness	2225_Notes and Loans Payable	(57,600,892)	(57,601)	-	36,075	(21,526)	(21,526)	-	
Advance from related party		-	-	-	-	-	-	-	
Accounts payable and accrued liabilities	2205_Accounts Payable	(394,839,788)	(394,840)						
	2208_Customer Credit Balances	(19,126,616)	(19,127)						
	2220_Miscellaneous Current and Accrued Liabilities	(17,971,051)	(17,971)						
	2240_Accounts Payable to Associated Companies Notes	(32,037,213)	(32,037)						
	2250_Debt Retirement Charges(DRC) Payable	7,983	8						
	2290_Commodity Taxes	(15,547,903)	(15,548)						
	2292_Payroll Deductions / Expenses Payable	(48,257,724)	(48,258)						
		(527,772,312)	(527,772)	(5,737)	11,850	(521,659)	(521,659)	0	
Income tax payable	2294_Accrual for Taxes Payments in Lieu of Taxes Etc.	(4,628,278)	(4,628)	-		(4,628)	(4,823)	(195)	Note 4
Customer deposits	2210_Customer Deposits	(48,133,787)	(48,134)			(48,134)	(48,134)		
Deferred revenue	2220_Miscellaneous Current and Accrued Liabilities	(1,920,833)	(1,921)	-		(1,921)			
	2210_Customer Deposits	(5,777,407)	(5,777)			(5,777)			
		(7,698,240)	(7,698)	-	-	(7,698)	(12,450)	(4,752)	Note 5
Deferred conservation credit		-	-	(8,199)		(8,199)	(8,199)	-	
Other liabilities	2285_Obligations Under Finance Leases--Current	(276,781)	(277)			(277)			
	2220_Miscellaneous Current and Accrued Liabilities	(54,792)	(55)			(55)			
		(331,573)	(332)	-	-	(332)	(332)	-	
Notes payable to related party	2242_ Payable to Associated Companies	(304,883,415)	(304,883)			(304,883)	(304,883)		
	2260_Current Portion of Long Term Debt	-	-	-		-	-		
			-						
		(304,883,415)	(304,883)	-	-	(304,883)	(304,883)	-	
Notes payable to related party	2550_Advances from Associated Companies	(1,785,725,107)	(1,785,725)			(1,785,725)	(1,785,725)	0	
	2505_Debentures Outstanding - Long Term Portion	-	-			-	-	-	
		(1,785,725,107)	(1,785,725)	-	-	(1,785,725)	(1,785,725)	0	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets									
Customer deposits	2335_Non-Current Customer Deposits	(31,741,951)	(31,742)			(31,742)	(31,742)	-	
Deferred revenue	2440_Deferred Revenues	(218,352,047)	(218,352)			(218,352)			
	2320_Other Miscellaneous Non-Current Liabilities	-	-			-			
	2335_Non-Current Customer Deposits	(64,075,330)	(64,075)			(64,075)			
		(282,427,378)	(282,427)	-	-	(282,427)	(277,676)	4,752	Note 5
Post-employment benefits	2306_POEB Liability	(274,566,000)	(274,566)	(1,294)		(275,860)	(275,860)	0	
Other liabilities	2325_Obligations Under Finance Lease--Non-Current	(1,029,726)	(1,030)			(1,030)			
	2320_Other Miscellaneous Non-Current Liabilities	(19,270,253)	(19,270)	(773)		(20,044)			
		(20,299,979)	(20,300)	(773)	-	(21,073)	(1,954)	19,120	Note 6
Total Liabilities		(3,345,808,911)	(3,345,809)	(16,003)	47,925	(3,313,886)	(3,294,962)	18,925	
Share Capital	3005_Common Shares Issued	(527,816,668)	(527,817)	(28,461)		(556,278)	(556,278)	0	
Retained Earnings	3045_Unappropriated Retained Earnings	(1,451,906,538)	(1,451,907)						
	3046_Balance Transferred From Income	(159,610,982)	(159,611)						
	3049_Dividends Payable-Common Shares	366,326,000	366,326						
	3055_Adjustment to Retained Earnings	(5,687,746)	(5,688)						
		(1,250,879,266)	(1,250,879)	(18,189)	-	(1,269,069)	(1,267,442)	1,626	Note 7
Contributed Surplus	3010_Contributed Surplus	(12,757,392)	(12,757)			(12,757)	(12,757)	-	
Regulatory balances	1508_Other Regulatory Assets	(158,923,922)	(158,924)						
	1595_Disposition Recovery Reg Balances Control Acct	(1,063,378)	(1,063)						
	2350_Deferred Tax - Non-Current Liability	(3,983,369)	(3,983)						
		(163,970,669)	(163,971)	-	-	(163,971)	(178,214)	(14,244)	Note 8
Total liabilities, equity and regulatory balances		(5,301,232,906)	(5,301,233)	(62,653)	47,925	(5,315,961)	(5,309,653)	6,307	
		-	-	-	-	-	-	(0)	

Toronto Hydro-Electric System Limited - 2.1.13
Balance Sheet
December 31, 2018

Filing: April 30, 2019

	Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Assets								

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note 1: This relates to the CIR Costs Deferral re-instatement on the Balance Sheet.
For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L.
For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years. The current portion re-instated CIR costs on the balance sheet was $1,005.

Note 2: Difference in "Deferred tax assets" of ($3,682): Calculated balance of $3,983 & AFS balance of $301, a difference of ($3,682), as follows:
a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS.
For purposes of RRR reporting, these balances are reclassified to deferred tax assets in the amount of ($2,175).
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets in the amount of ($1,507).

Note 3: Difference in "Regulatory balances - deferred debits" of ($1,620): Calculated balance of $127,595 & AFS balance of $125,975, a difference of ($1,620),
is due to balances considered regulatory balances for the AFS but not for the purpose of RRR reporting in accordance with APH.

Note 4: Difference in "Income tax payable" of ($195): Calculated balance of ($4,628) & AFS balance of ($4,823), a difference of ($195), as follows:
The difference represents the non-regulated business income tax payable included in the AFS.

Note 5: Difference in "Deferred revenue - current", offset by difference in "Deferred revenue - long-term" of $4,752 as follows:
For the AFS the Deferred revenue was split between current and long-term. For the RRR purposes, the Deferred revenue is not split between current and long-term.

Note 6: Difference in "Other liabilities" of $19,120: Calculated balance of ($21,073) & AFS balance of ($1,954), a difference of $19,120, primarily related to a deferral of gain on sale of surplus property in a regulatory account for the AFS and recorded as miscellaneous liability for RRR reporting and deferral of excess expansion deposits withholdings in a regulatory account for the AFS and recorded as miscellaneous liability for RRR reporting.

Note 7: Difference in "Retained Earnings" of $1,626: Calculated balance of ($1,269,069) & AFS balance of ($1,267,442), a difference of $1,626.
Adjustments have been made to certain AFS income statement items to arrive at the RRR reporting as follows:

<u>A. Adjustments made to certain AFS income statement items in prior years as follows:</u>	
a. Reduction for prior years' AFS Distribution revenue booked for Smart Meter "net revenue requirement" on the disposition of Account 1555 "Smart Meter Capital & Recovery" and 1556 "Smart Meter OM&A Variance account" balances. The amount is recorded to Distribution revenue for RRR reporting, to OEB account 4080 as the amount is billed to THESL customers in the future.	$ 284
b. For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets related to prior year.	1,968
c. This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base. For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755k. As such, for 2015 RRR purposes, the $4,755k accrual was reversed. As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.	(2,599)
d. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	2,010
e. The difference represents the non-regulated business current income tax expense included in the AFS.	3,445
<u>B. Adjustments made to certain AFS income statement items in 2018, with these differences as explained in the Income Statement attached.</u>	
a. The total impact on net income or difference for the year 2018 was ($3,482), per the Income Statement attached.	(3,482)
Total difference:	1,626

Note 8: Difference in "Regulatory balances - deferred credits" of ($14,244): Calculated balance of ($163,971) & AFS balance of ($178,214), a difference of ($14,244), as follows:

a. The deferred tax balance related to regulatory balances and gross up in respect of deferred tax assets are recorded in regulatory balances in accordance with IFRS 14 for AFS. For purposes of RRR reporting, these balances are reclassified to deferred tax assets.

b. Deferral of gain on sale of surplus property in a regulatory account for the AFS and recorded as miscellaneous liabilities for RRR reporting.

c. Deferral of excess expansion deposit withholdings in a regulatory account for the AFS and recorded as miscellaneous liabilities for RRR reporting.

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue										
Energy sales	4006_Residential Energy Sales	(461,396,285)	(461,396)							
	4010_Commercial Energy Sales	(1,481,101,528)	(1,481,102)							
	4020_Energy Sales to Large Users	(171,948,906)	(171,949)							
	4025_Street Lighting Energy Sales	(7,014,632)	(7,015)							
	4035_General Energy Sales	(231,514,879)	(231,515)							
	4050_Revenue Adjustment	(1,608,619)	(1,609)							
	4055_Energy Sales For Retailers/Others	-	-							
	4062_Billed WMS	(93,145,209)	(93,145)							
	4066_Billed NW	(156,049,886)	(156,050)							
	4068_Billed CN	(126,606,946)	(126,607)							
	4075_Billed LV	-	-							
	4076_Billed Smart Metering Entity Charge	(5,619,840)	(5,620)							
		(2,736,006,729)	(2,736,007)	-	(84,473)	-	(2,820,479)	(2,704,128)	116,352	Note 1
Distribution revenue	4080_Distribution Services Revenue	(729,185,740)	(729,186)		53,786	-	(675,400)	(674,164)	1,235	Note 2
		(3,465,192,469)	(3,465,192)	-	(30,686)	-	(3,495,879)	(3,378,292)	117,587	
Other income	4082_Retail Services Revenues	(238,364)	(238)							
	4084_Service Transaction Requests (STR) Revenues	(11,492)	(11)							
	4086_SSS Administration Revenue	(2,313,558)	(2,314)							
	4090_Electric Services Incidental to Energy Sales	-	-							
	4210_Rent from Electric Property	(15,325,972)	(15,326)							
	4215_Other Utility Operating Income	(1,106,826)	(1,107)							
	4220_Other Electric Revenues	(8,035,739)	(8,036)							
	4225_Late Payment Charges	(3,323,433)	(3,323)							
	4235_Miscellaneous Service Revenues	(5,961,505)	(5,962)							
	4245_ Government Assistance Directly Credited to Income	(5,263,537)	(5,264)							
	4325_Revenues from Merchandise Jobbing Etc.	(32,130,502)	(32,131)							
	4310_Regulatory Credits	(6,740,860)	(6,741)							
	4330_Costs and Expenses of Merchandising Jobbing Etc.	27,406,949	27,407							
		(53,044,837)	(53,045)	(3,957)	(3,284)	203	(60,083)	(80,570)	(20,488)	Note 3
Costs										
Energy purchases	4705_Power Purchased	1,225,222,495	1,225,222							
	4707_Charges - Global Adjustment	1,129,362,354	1,129,362							
	4708_Charges-WMS	85,665,853	85,666							
	4714_Charges-NW	156,049,886	156,050							
	4716_Charges-CN	126,606,946	126,607							
	4730_Rural Rate Assistance Expense	7,479,356	7,479							
	4750_Charges LV	-	-							
	4751_Charges Smart Metering Entity Chg	5,619,840	5,620							
		2,736,006,729	2,736,007	-	26,631	-	2,762,638	2,646,286	(116,352)	Note 4

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue										
Operating expenses	4380_Expenses of Non-Rate Regulated Operations	6,250,355	6,250							
	4398_Foreign Exchange Gains and Losses Including Amortization	128,336	128							
	5005_Distribution Operation Supervision and Engineering	25,122,607	25,123							
	5010_Distribution Load Dispatching	8,911,483	8,911							
	5012_Station Buildings and Fixtures Expense	-	-							
	5014_Transformer Station Equipment - Operation Labour	260,644	261							
	5015_Transformer Station Equipment - Operation Supplies and Expenses	39,487	39							
	5016_Distribution Station Equipment - Operation Labour	2,950,453	2,950							
	5017_Distribution Station Equipment - Operation Supplies and Expenses	5,721,842	5,722							
	5020_Overhead Distribution Lines and Feeders - Operation Labour	559,171	559							
	5025_Overhead Distribution Lines & Feeders - Operation Supplies and Exper	2,442,860	2,443							
	5035_Overhead Distribution Transformers- Operation	-	-							
	5040_Underground Distribution Lines and Feeders - Operation Labour	633,763	634							
	5045_Underground Distribution Lines & Feeders - Operation Supplies & Expe	2,701,801	2,702							
	5055_Underground Distribution Transformers - Operation	28,678	29							
	5065_Meter Expense	844,093	844							
	5070_Customer Premises - Operation Labour	884,921	885							
	5075_Customer Premises - Materials and Expenses	620,652	621							
	5085_Miscellaneous Distribution Expense	5,999,047	5,999							
	5105_Maintenance Supervision and Engineering	18,384,920	18,385							
	5110_Maintenance of Buildings and Fixtures - Distribution Stations	14,766,343	14,766							
	5112_Maintenance of Transformer Station Equipment	855,947	856							
	5114_Maintenance of Distribution Station Equipment	4,106,595	4,107							
	5120_Maintenance of Poles Towers and Fixtures	580,620	581							
	5125_Maintenance of Overhead Conductors and Devices	22,912,643	22,913							
	5130_Maintenance of Overhead Services	293,614	294							
	5135_Overhead Distribution Lines and Feeders - Right of Way	3,309,297	3,309							
	5145_Maintenance of Underground Conduit	12,201	12							
	5150_Maintenance of Underground Conductors and Devices	6,429,793	6,430							
	5155_Maintenance of Underground Services	8,874	9							
	5160_Maintenance of Line Transformers	-	-							
	5165_Maintenance of Street Lighting and Signal Systems	2,317,467	2,317							
	5305_Supervision	508,240	508							
	5310_Meter Reading Expense	4,349,216	4,349							
	5315_Customer Billing	9,626,222	9,626							
	5320_Collecting	13,746,474	13,746							
	5335_Bad Debt Expense	4,304,579	4,305							
	5410_Community Relations - Sundry	-	-							
	5415_Energy Conservation	-	-							
	5420_Community Safety Program	2,392,140	2,392							
	5605_Executive Salaries and Expenses	6,153,303	6,153							
	5610_Management Salaries and Expenses	-	-							
	5615_General Administrative Salaries and Expenses	50,745,406	50,745							
	5620_Office Supplies and Expenses	38,532	39							
	5625_Administrative Expense Transferred Credit	-	-							
	5630_Outside Services Employed	8,352,546	8,353							
	5635_Property Insurance	1,527,244	1,527							
	5640_Injuries and Damages	2,101,422	2,101							
	5655_Regulatory Expenses	4,924,577	4,925							
	5660_General Advertising Expenses	-	-							
	5665_Miscellaneous General Expenses	34,805	35							
	5675_Maintenance of General Plant	13,777,820	13,778							
	5680_Electrical Safety Authority Fees	353,541	354							
	5685_Independent Electricity System Operator Fees and Penalties	200,000	200							
	6105_Taxes Other Than Income Taxes	4,889,126	4,889							
	6205_Donations	1,058,655	1,059							
	4375_Revenues from Non-Utility Operations	(5,670,327)	(5,670)							
		261,492,029	261,492	3,775	5,876	(203)	270,939	297,163	26,224	Note 5

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

		Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue										
Depreciation and amortization	5705_Depreciation Expense - Property Plant and Equipment	216,029,011	216,029							
	5715_Amortization of Intangibles and Other Electric Plant	25,816,258	25,816							
	4380_Expenses of Non-Rate Regulated Operations	133,468	133							
		241,978,737	241,979	622		-	242,600	235,860	(6,741)	Note 6
		(278,759,812)	(278,760)	440	(1,464)	-	(279,784)	(279,554)	230	
Finance costs										
Interest Income	4375_Revenues from Non-Utility Operations	-	-							
	4405_Interest and Dividend Income	-	-							
		-	-	(594)		-	(594)	(594)	-	
Interest Expense, Long-term Debt	6030_Interest on Debt to Associated Companies	82,216,266	82,216	-			82,216	82,216	-	
Interest Expense, Other	5615_General Administrative Salaries and Expenses	2,132,679	2,133					-	-	
	5420_Community Safety Program	30,892	31					-	-	
	6035_Other Interest Expense	5,887,403	5,887			-			-	
	6040_Allowance for Borrowed Funds Used During Construction--Credit	(8,902,534)	(8,903)					-	-	
		(851,560)	(852)		(2,428)	-	(3,280)	(3,280)	-	
Gain on disposals of property, plant and equipment	4355_Gain on Disposition of Utility and Other Property	(576,205)	(576)							
	4335_Profits and Losses from Financial Instrument Hedges	-	-							
		(576,205)	(576)	-	(108,050)		(108,627)	(108,627)	-	
Income Tax Expense	6110_Income Taxes	34,553,535	34,554	-		-	34,554	34,748	195	Note 7
	6115_Provision for Deferred Taxes - Income Statement	3,806,795	3,807		46,994		50,801	46,894	(3,907)	Note 8
Net Income		(159,610,982)	(159,611)	(154)	(64,948)	-	(224,713)	(228,195)	(3,482)	
Net movements in regulatory balances, net of tax		-			64,948		64,948	64,948	-	
Net income after net movements in regulatory balances		(159,610,982)	(159,611)	(154)	-	-	(159,765)	(163,247)	(3,482)	

Toronto Hydro-Electric System Limited - 2.1.13
Statement of Income
December 31, 2018

Filing: April 30, 2019

	Regulated 2018 Actual OEB Acct TB	Regulated 2018 Actual (in thousands)	Unregulated 2018 Actual (in thousands)	Net Movement Adj 2018 Actual (in thousands)	Consol Adj 2018 Actual (in thousands)	Calculated THESL Consol 2018 Actual (in thousands)	Audited THESL Consol 2018 Actual (in thousands)	Diff	Comment
Revenue									

Notes: The Uniform System of Account balances are mapped and reconciled to the audited financial statements (AFS) (in dollars thousands).

Note	Diff
Note 1: Difference in "Energy sales" of $116,352: Calculated balance of ($2,820,479) & AFS balance of ($2,704,128), a difference of $116,352, as follows:	
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.	110,732
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	5,620
	116,352
Note 2: Difference in "Distribution revenue" of $1,235: Calculated balance of ($675,400) & AFS balance of ($674,164), a difference of $1,235, as follows:	
This relates to the reversal of the Account 1575 IFRS-GAAP Transitional PP&E Return on Rate Base.	1,235
For RRR purposes, as per the APH, Article 510, "The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement." In the AFS, the return on rate base was accrued at year-end 2015 since the OEB approved the disposition of Account 1575 with the return on rate base of $4,755. For 2015 RRR purposes, the $4,755 accrual has been reversed. As such, in the AFS, the disposition of the account 1575 includes offsetting entries on the balance sheet related to the disposition of the return on rate base, whereas for RRR purposes, the collection of the return on rate base is recorded in the income statement in accordance with the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6.	
Note 3: Difference in "Other income" of ($20,488): Calculated balance of ($60,083) & AFS balance of ($80,570), a difference of ($20,488), as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	(27,407)
b. As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.	6,741
c. Relates to entry recorded for IFRS that should have been reclassed between Other income and Operating expenses but was considered immaterial for the AFS There is no net income impact in IFRS. For RRR, the differences have already been corrected.	178
Total difference:	(20,488)
Note 4: Difference in "Energy purchases" of ($116,352): Calculated balance of $2,762,638 & AFS balance of $2,646,286, a difference of ($116,352), as follows:	
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.	(110,732)
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge"	(5,620)
	(116,352)
Note 5: Difference in "Operating expenses" of $26,224: Calculated balance of $270,939 & AFS balance of $297,163, a difference of $26,224, as follows:	
a. Demand Billable Charges: As per AFS GAAP, THESL booked demand billable charges on a gross basis while for RRR it is reported on a net basis:	27,407
b. This relates to the CIR Costs Deferral re-instatement on the Balance Sheet. For OSC purposes, as a result of the OEB's Decision with regards to the DRO, the CIR costs were considered no longer recoverable, and as such it was considered impaired and written-off to the P&L. For RRR purposes, since the CIR Costs were approved to be recovered over the 5 year term in the original OEB Decision on December 29, 2015 with regards to the 2015-2019 CIR Application, the CIR costs were re-instated on the balance sheet and will be amortized over the 5 years.	(1,005)
c. Relates to entry recorded for IFRS that should have been reclassed between Other income and Operating expenses but was considered immaterial for the AFS There is no net income impact in IFRS. For RRR, the differences have already been corrected.	(178)
Total difference:	26,224
Note 6: Difference in "Depreciation and amortization" of ($6,741): Calculated balance of $242,600 & AFS balance of $235,860, a difference of ($6,741), as follows: As per the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, the approved disposition of the account balance for both Account 1575 and Account 1576 would be reflected as an offset to depreciation expense over the approved amortization period." As well, based on the OEB's Accounting Procedures Handbook Guidance - March 2015 - #6, to ensure that only the return on rate base component is recorded in distribution revenues, the offsetting credit entry is recorded in OEB Account 4310 Regulatory Credits.	(6,741)
Note 7: Difference in "Income tax expense - Income taxes" of $195: Calculated balance of $34,554 & AFS balance of $34,748, a difference of $195, as follows: The difference represents the non-regulated business current income tax expense included in the AFS.	195
Note 8: Difference in "Income tax expense - Provision for deferred taxes" of ($3,907): Calculated balance of $50,801 & AFS balance of $46,894, a difference of ($3,907), as follows: For purposes of RRR reporting, an adjustment was made to remove deferred income tax asset in respect of the non-rate regulated assets.	(3,907)

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit U
Tab 1C
Schedule 4
FILED: April 30, 2019
(38 pages)

FINANCIAL REPORT
DECEMBER 31, 2018

TORONTO HYDRO CORPORATION

TABLE OF CONTENTS

GLOSSARY

CDM – Conservation and demand management

CIR – Custom Incentive Rate-setting

City – City of Toronto

Copeland Station – The Clare R. Copeland transformer station, formerly called "Bremner Station"

Corporation – Toronto Hydro Corporation

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

ERM – Enterprise risk management

ERP – Enterprise resource planning

GWh – Gigawatt hour

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator

IFRIC – International Financial Reporting Interpretations Committee

IFRS – International Financial Reporting Standards

ITA – Income Tax Act (Canada), as amended

kW – Kilowatt

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

MD&A – Management's Discussion and Analysis

MEU – Municipal electricity utility

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – Ontario Energy Board Act, 1998

(Ontario), as amended

OFHP – Ontario's Fair Hydro Plan

OPEB – Other post-employment benefits

OREC – *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – Taxation Act, 2007 (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

WMS – Wholesale Market Service

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

Executive Summary

- Net income after net movements in regulatory balances for the three months and year ended December 31, 2018 was $31.9 million and $167.3 million, respectively, compared to $35.1 million and $156.5 million for the comparable periods in 2017;
- Capital expenditures were primarily related to the renewal of the electricity infrastructure of LDC and were $157.3 million and $511.3 million for the three months and year ended December 31, 2018, respectively, compared to $148.9 million and $552.9 million for the comparable periods in 2017;
- On January 16, 2018, the Corporation entered into an agreement to sell a property, including land and building, to a third party and closed the sale on April 17, 2018. The gain of $98.6 million, net of tax and selling costs, was recognized and deferred as a regulatory credit balance, which reduces future electricity distribution rates for customers;
- On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions;
- On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020; and
- On March 6, 2019, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $25.1 million with respect to the first quarter of 2019, payable to the City by March 29, 2019.

Introduction

This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2018 and 2017, which were prepared in accordance with IFRS (the "Consolidated Financial Statements").

Copies of these documents are available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly owns two subsidiaries:

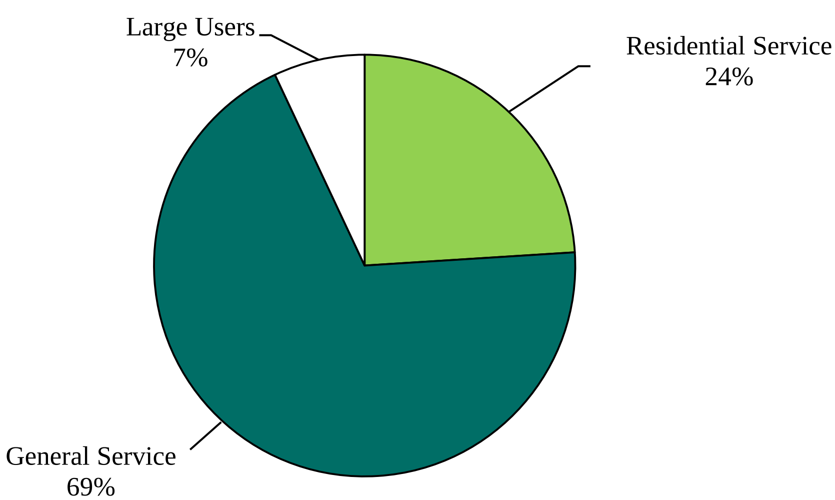
- LDC - distributes electricity and engages in CDM activities; and
- TH Energy - provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries. The City is the sole shareholder of the Corporation.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, delivering electricity to approximately 772,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in Ontario. The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. For the year ended December 31, 2018, LDC earned energy sales and distribution revenue of $3,378.3 million from general service users[1], residential service users[2] and large users[3].

LDC Energy Sales and Distribution Revenue by Class

Year ended December 31, 2018



[1] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.

[2] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

Electricity Distribution – Industry Overview

In April 1999, the Government of Ontario began restructuring the province's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs from customers in accordance with rate-setting procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through back to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through back to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the ITA if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

Results of Operations

Net Income after Net Movements in Regulatory Balances

Consolidated Statements of Income
Three months ended December 31
(in millions of Canadian dollars)

	2018 **$**	**2017** **$**	**Change** **$**
		[Restated][1]	
Revenues			
Energy sales	660.2	638.9	21.3
Distribution revenue	163.9	181.7	(17.8)
Other	23.4	27.7	(4.3)
	847.5	848.3	(0.8)
Expenses			
Energy purchases	621.6	660.7	(39.1)
Operating expenses	73.5	77.8	(4.3)
Depreciation and amortization	67.3	62.0	5.3
	762.4	800.5	(38.1)
Finance costs	(18.8)	(18.9)	0.1
Gain on disposals of PP&E	0.2	0.2	-
Income before income taxes	66.5	29.1	37.4
Income tax expense	(16.2)	(11.1)	(5.1)
Net income	50.3	18.0	32.3
Net movements in regulatory balances	(26.3)	10.9	(37.2)
Net movements in regulatory balances arising from deferred tax assets	7.9	6.2	1.7
Net income after net movements in regulatory balances	31.9	35.1	(3.2)

[1] These numbers have been restated to account for the impact of adopting IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"). Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

The decrease in net income after net movements in regulatory balances for the three months ended December 31, 2018 was primarily due to higher depreciation related to new in-service asset additions ($5.3 million), amounts being deferred into capital related regulatory accounts for future refunds to customers ($4.2 million) and higher income taxes (including regulatory balances arising from deferred tax assets) ($3.4 million). These variances were partially offset by higher 2018 electricity distribution rates ($8.9 million) and higher electricity consumption ($0.6 million).

The net decrease in distribution revenue is due to the implementation of the OEB-approved 2018 rate riders, which returned $27.5 million to customers. However, the 2018 rate riders do not impact net income after net movements in regulatory balances as there are corresponding offsets in net movements in regulatory balances, given IFRS treatment.

Consolidated Statements of Income
Year ended December 31
(in millions of Canadian dollars)

	2018 $	2017 $	Change $
		[Restated][1]	
Revenues			
Energy sales	2,704.1	2,810.2	(106.1)
Distribution revenue	674.2	724.2	(50.0)
Other	94.4	107.7	(13.3)
	3,472.7	3,642.1	(169.4)
Expenses			
Energy purchases	2,646.3	2,855.9	(209.6)
Operating expenses	307.5	293.0	14.5
Depreciation and amortization	238.3	224.2	14.1
	3,192.1	3,373.1	(181.0)
Finance costs	(74.6)	(77.7)	3.1
Gain on disposals of PP&E	108.6	9.8	98.8
Income before income taxes	314.6	201.1	113.5
Income tax expense	(82.4)	(44.7)	(37.7)
Net income	232.2	156.4	75.8
Net movements in regulatory balances	(111.9)	(13.1)	(98.8)
Net movements in regulatory balances arising from deferred tax assets	47.0	13.2	33.8
Net income after net movements in regulatory balances	167.3	156.5	10.8

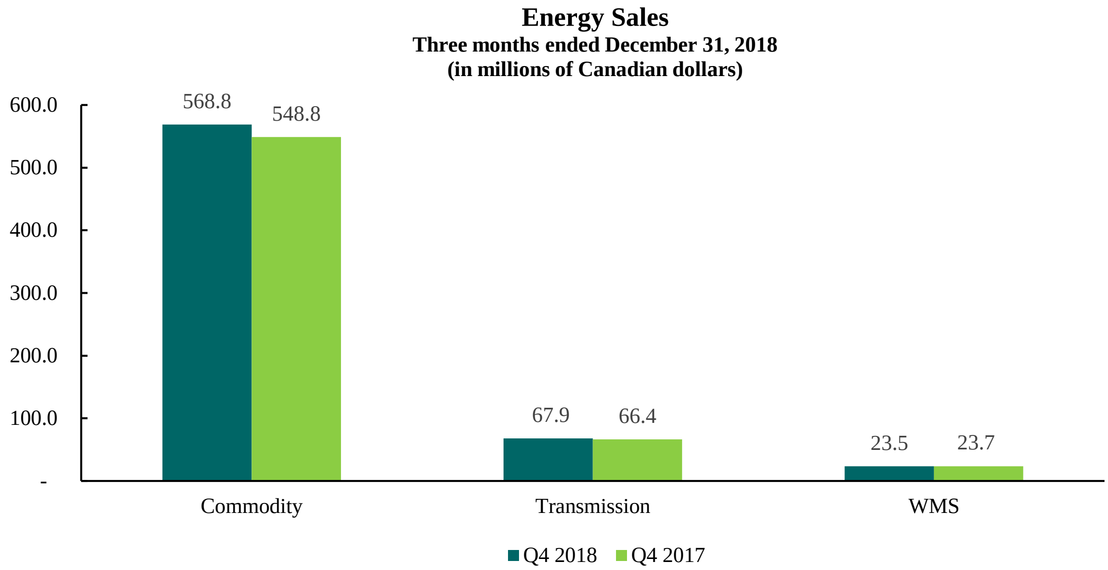
[1] These numbers have been restated to account for the impact of adopting IFRS 15. Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

The increase in net income after net movements in regulatory balances for the year ended December 31, 2018 was primarily due to higher 2018 electricity distribution rates ($33.1 million), higher electricity consumption ($21.0 million), higher LRAM ($7.7 million) and lower finance costs due to a lower average amount of outstanding debentures in the current year ($3.1 million). These variances were partially offset by amounts being deferred into capital related regulatory accounts for future refunds to customers ($18.1 million), higher operating expenses related to emergency power restoration due to major storms in 2018 and system maintenance ($14.5 million), higher depreciation related to new in-service asset additions ($14.1 million) and lower other revenue related to the recognition of the CDM mid-term incentive in 2017 ($9.5 million).

The net decrease in distribution revenue is due to the implementation of the OEB-approved 2018 rate riders, which returned $102.2 million to customers. The gain on disposals of PP&E is primarily due to the gain realized on a property sale deferred as a regulatory credit balance, which reduces future electricity distribution rates for customers. The 2018 rate riders and gain on disposal do not impact net income after net movements in regulatory balances as there are corresponding offsets in net movements in regulatory balances, given IFRS treatment.

Energy Sales

LDC's energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing amounts to be recovered from or refunded to customers through future rates approved by the OEB. In accordance with IFRS 14 *Regulatory Deferral Accounts* ("IFRS 14"), this settlement variance is presented within regulatory balances on the Corporation's consolidated balance sheets ("Consolidated Balance Sheets") and within net movements in regulatory balances on the Corporation's consolidated statements of income ("Consolidated Statements of Income").



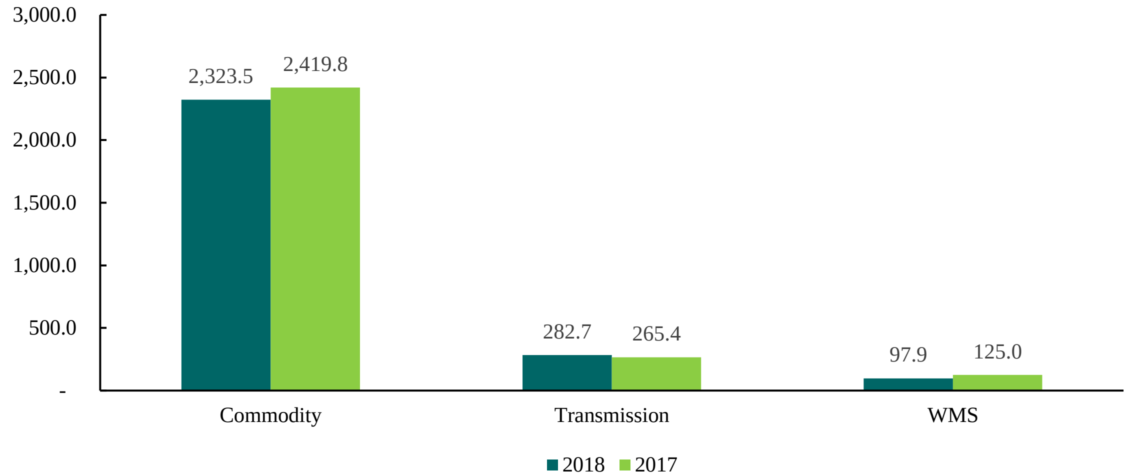
Energy sales for the three months ended December 31, 2018 were $660.2 million compared to $638.9 million for the comparable period in 2017. The increase was primarily due to higher commodity charges ($20.0 million) and higher retail transmission charges ($1.5 million).

Energy Purchases, Energy Sales, and Settlement Variances
Three months ended December 31, 2018
(in millions of Canadian dollars)

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity charges	536.3	568.8	(32.5)
Retail transmission charges	69.4	67.9	1.5
WMS charges	15.9	23.5	(7.6)
Total	621.6	660.2	(38.6)

For the three months ended December 31, 2018, LDC recognized $660.2 million in energy sales to customers and was billed $621.6 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $38.6 million settlement variance for the period. The settlement variance was recorded as an increase to the regulatory credit balance ($39.4 million including carrying charges on the accumulated settlement variance balance) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Energy Sales
Year ended December 31, 2018
(in millions of Canadian dollars)



Energy sales for the year ended December 31, 2018 were $2,704.1 million compared to $2,810.2 million for the comparable period in 2017. The decrease was due to lower commodity charges ($96.3 million) and lower WMS charges ($27.1 million), partially offset by retail transmission charges ($17.3 million).

Energy Purchases, Energy Sales, and Settlement Variances
Year ended December 31, 2018
(in millions of Canadian dollars)

	Energy Purchases **$**	**Energy Sales** **$**	**Settlement Variances** **$**
Commodity charges	2,244.2	2,323.5	(79.3)
Retail transmission charges	309.0	282.7	26.3
WMS charges	93.1	97.9	(4.8)
Total	2,646.3	2,704.1	(57.8)

For the year ended December 31, 2018, LDC recognized $2,704.1 million in energy sales to customers and was billed $2,646.3 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $57.8 million settlement variance for the period. The settlement variance was recorded as an increase to the regulatory credit balance ($58.2 million including carrying charges on the accumulated settlement variance balance; see the regulatory credit balance table in note 8 to the Consolidated Financial Statements) on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

Distribution Revenue

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers, and includes revenue collected through OEB-approved rate riders.

Distribution revenue for the three months and year ended December 31, 2018 was $163.9 million and $674.2 million, respectively, compared to $181.7 million and $724.2 million for the comparable periods in 2017.

The net decrease in distribution revenue for the three months ended December 31, 2018 was primarily due to lower revenue collected through OEB-approved rate riders ($27.5 million), partially offset by higher electricity distribution rates ($8.9 million) and higher electricity consumption ($0.6 million).

The net decrease in distribution revenue for the year ended December 31, 2018 was primarily due to lower revenue collected through OEB-approved rate riders ($104.6 million), partially offset by higher electricity distribution rates ($33.1 million) and higher electricity consumption ($21.0 million). The OEB-approved rate riders do not impact net income after net movements in regulatory balances as there is an offsetting increase in net movements in regulatory balances.

Other Revenue

Other revenue includes revenue from services ancillary to electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

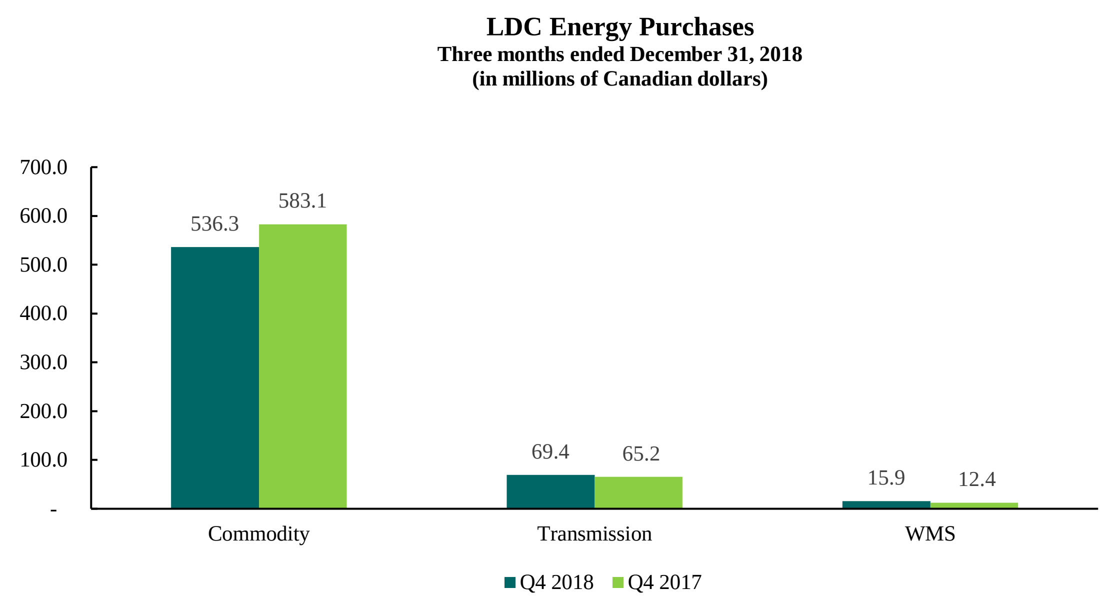
Other revenue for the three months and year ended December 31, 2018 was $23.4 million and $94.4 million, respectively, compared to $27.7 million and $107.7 million for the comparable periods in 2017.

The decrease in other revenue for the three months ended December 31, 2018 was primarily due to lower revenue in connection with ancillary services and the recognition of the CDM mid-term incentive in 2017.

The decrease in other revenue for the year ended December 31, 2018 was primarily due to the recognition of the CDM mid-term incentive in 2017.

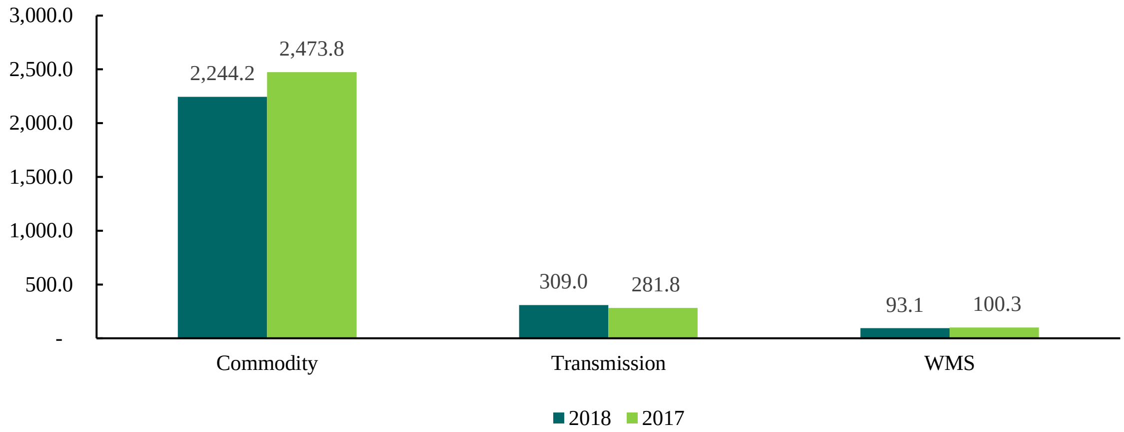
Energy Purchases

LDC's energy purchases consist of actual charges for electricity generated by third parties, which are passed through to customers over time in the form of energy sales. Energy purchases are billed monthly by the IESO and include commodity charges, retail transmission charges and WMS charges.



Energy purchases for the three months ended December 31, 2018 were $621.6 million compared to $660.7 million for the comparable period in 2017. The decrease was primarily due to lower commodity charges ($46.8 million), partially offset by higher retail transmission charges ($4.2 million) and higher WMS charges ($3.5 million).

LDC Energy Purchases
Year ended December 31, 2018
(in millions of Canadian dollars)



Energy purchases for the year ended December 31, 2018 were $2,646.3 million compared to $2,855.9 million for the comparable period in 2017. The decrease was primarily due to lower commodity charges ($229.6 million) and lower WMS charges ($7.2 million), partially offset by higher retail transmission charges ($27.2 million).

Operating Expenses

Operating expenses for the three months and year ended December 31, 2018 were $73.5 million and $307.5 million, respectively, compared to $77.8 million and $293.0 million for the comparable periods in 2017.

The decrease in operating expenses for the three months ended December 31, 2018 was primarily due to lower ancillary service costs and lower contractor costs, partially offset by higher system maintenance costs.

The increase in operating expenses for the year ended December 31, 2018 was primarily due to costs related to emergency power restoration due to major storms in 2018 and higher system maintenance costs.

Depreciation and Amortization

Depreciation and amortization expense for the three months and year ended December 31, 2018 was $67.3 million and $238.3 million, respectively, compared to $62.0 million and $224.2 million for the comparable periods in 2017.

The increase in depreciation and amortization for the three months ended December 31, 2018 was primarily due to new in-service asset additions in 2018 and higher derecognition of assets removed from service, partially offset by certain assets being fully depreciated.

The increase in depreciation and amortization for the year ended December 31, 2018 was primarily due to new in-service asset additions in 2018, partially offset by certain assets being fully depreciated and a decrease in derecognition of assets removed from service.

Finance Costs

Finance costs for the three months and year ended December 31, 2018 were $18.8 million and $74.6 million, respectively, compared to $18.9 million and $77.7 million for the comparable periods in 2017. The decrease was primarily due to a lower average amount of outstanding debentures ($2,034.5 million) in 2018 compared with 2017 ($2,078.4 million).

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and year ended December 31, 2018 was $0.2 million and $108.6 million, respectively, compared to $0.2 million and $9.8 million for the comparable periods in 2017. The variance in gain on disposals of PP&E for the year ended December 31, 2018 was primarily due to the gain realized on the sale of a property in the second quarter of 2018 ($108.1 million). The realized gain of $98.6 million, net of tax and selling costs, was recorded as a regulatory credit balance on the Consolidated Balance Sheets with a corresponding offset in net movements in regulatory balances. LDC has been returning the total forecasted net gains on sale of certain properties along with the future tax savings back to rate payers through a rate rider effective from March 1, 2016 to December 31, 2018 as part of the 2015 - 2019 CIR decision and rate order. The actual realized gain and tax savings that exceeded the approved rate riders reduce future electricity distribution rates for customers. LDC has requested disposition of this incremental balance in the 2020 – 2024 rate application over a 60-month period commencing on January 1, 2020.

Income Tax Expense and Income Tax Recorded in Net Movements in Regulatory Balances

Income tax expense and income tax recorded in net movements in regulatory balances for the three months and year ended December 31, 2018 were $8.3 million and $35.4 million, respectively, compared to $4.9 million and $31.5 million for the comparable periods in 2017.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the three months ended December 31, 2018 was primarily due to lower net deductions for permanent and temporary differences between accounting and tax treatments.

The unfavourable variance in income tax expense and income tax recorded in net movements in regulatory balances for the year ended December 31, 2018 was primarily due to the tax recognized on property disposition and higher income before taxes (including net movements in regulatory balance), offset by higher net deductions for permanent and temporary differences between accounting and tax treatments.

Net Movements in Regulatory Balances

In accordance with IFRS 14, the Corporation separately presents regulatory balances and related net movements on the Consolidated Balance Sheets and Consolidated Statements of Income.

The decrease in the regulatory debit ($74.0 million) and increase in the regulatory credit ($18.2 million) balances for the year ended December 31, 2018 equals the sum ($92.2 million) of net movements in regulatory balances, net movements in regulatory balances arising from deferred tax assets and net movements in regulatory balances related to OCI, shown for the period (see “Financial Position” below). Energy purchases record the actual cost of power purchased which varies from month to month. Since the selling price of power within energy sales is fixed for set periods of time, a gain or loss usually results, and is part of the calculation of net income. However, per OEB regulations, such gains or losses on energy sales are deferred within balance sheet regulatory variance accounts for later disposition to or from rate payers via rate riders after approval by the OEB. Deferrals of gains or losses on energy sales (see discussion on “settlement variance” under “Results of Operations” above), or disposition of past deferrals in electricity rates will usually represent the largest single element of the net movements in regulatory balances for a given period.

Net movements in regulatory balances for the three months and year ended December 31, 2018 were a charge of $26.3 million and a charge of $111.9 million, respectively, compared to a recovery of $10.9 million and a charge of $13.1 million for the comparable periods in 2017. The charge of $26.3 million for the three months ended December 31, 2018 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC’s billing to customers and amounts being deferred into capital-related regulatory accounts for future refunds to customers, partially offset by amounts disposed through OEB-approved rate riders. The recovery of $10.9 million for the three months ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC’s billing to customers, partially offset by amounts disposed through OEB-approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers.

The charge of $111.9 million for the year ended December 31, 2018 was primarily due to the gain realized on disposal of a property in the second quarter of 2018, the timing difference between the electricity costs billed monthly by the IESO and LDC’s billing to customers and amounts being deferred into capital-related regulatory accounts for future refunds to customers, partially offset by amounts disposed through OEB-approved rate riders, and LRAM. The charge of $13.1 million for the year ended December 31, 2017 was primarily due to the timing difference between the electricity costs billed monthly by the IESO and LDC’s billing to customers, partially offset by amounts disposed through OEB-approved rate riders and amounts being deferred into capital-related regulatory accounts for future refunds to customers.

Summary of Quarterly Results of Operations

The table below presents a summary of the Corporation's results of operations for eight quarters including and immediately preceding December 31, 2018.

Summary of Quarterly Results of Operations
(in millions of Canadian dollars)

	December 31, 2018 $	September 30, 2018 $	June 30, 2018 $	March 31, 2018 $
Energy sales	660.2	741.1	660.4	642.4
Distribution revenue	163.9	175.8	162.9	171.6
Other	23.4	21.7	28.0	21.3
Revenues	847.5	938.6	851.3	835.3
Net income after net movements in regulatory balances	31.9	50.4	42.5	42.5
	December 31, 2017 $ *[Restated]* [1]	**September 30, 2017 $** *[Restated]* [1]	**June 30, 2017 $** *[Restated]* [1]	**March 31, 2017 $** *[Restated]* [1]
Energy sales	638.9	738.4	662.1	770.8
Distribution revenue	181.7	186.1	178.2	178.2
Other	27.7	36.6	23.0	20.4
Revenues	848.3	961.1	863.3	969.4
Net income after net movements in regulatory balances	35.1	46.8	35.0	39.6

[1] These numbers have been restated to account for the impact of adopting IFRS 15. Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

The Corporation's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. The Corporation's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders. The variation from the seasonal trend for the first quarter of 2018 was due to lower energy sales primarily related to lower commodity charges.

Financial Position

The following table outlines the significant changes in the Consolidated Balance Sheets as at December 31, 2018 as compared to the Consolidated Balance Sheets as at December 31, 2017.

Consolidated Balance Sheets Data
(in millions of Canadian dollars)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
PP&E and intangible assets	271.4	The increase was primarily due to capital expenditures, partially offset by depreciation and derecognition.
Deferred tax assets	(56.7)	The decrease was primarily due to lower net deductible temporary differences between tax and accounting values of PP&E and intangible assets, and regulatory balances.
Liabilities and Equity		
Commercial paper	(46.0)	The decrease was primarily due to proceeds received on disposition of a property in the second quarter of 2018 offset by issuances required for general corporate purposes (see "Liquidity and Capital Resources" below).
Accounts payable and accrued liabilities	9.1	The decrease was primarily due to timing of payments, partially offset by the cessation of debt retirement charges.
Customer deposits	21.7	The increase was primarily due to expansion security deposits received, net of refunds.
Deferred revenue	101.1	The increase was primarily due to capital contributions received.
Post-employment benefits	(37.1)	The decrease was primarily due to the recognized actuarial gain driven by the updated actuarial assumptions.
Retained earnings	73.1	The increase was due to net income after net movements in regulatory balances ($167.3 million), offset by dividends paid ($93.9 million).
Regulatory Balances		
Regulatory debit balances	(74.0)	The decrease was primarily due to the amounts disposed through OEB-approved rate riders and the actuarial gain incurred on the valuation of post-employment benefit obligation recorded as a decrease to the regulatory debit balance.

Consolidated Balance Sheets Data (in millions of Canadian dollars)		
Balance Sheet Account	**Increase (Decrease) $**	**Explanation of Significant Change**
Regulatory credit balances	18.2	The increase was primarily due to the balance of gain realized on disposal of a property in the second quarter of 2018 and higher amounts being deferred into capital-related regulatory accounts, partially offset by amounts disposed through OEB-approved rate riders and deferred taxes.

Liquidity and Capital Resources

The Corporation's current assets and current liabilities amounted to $517.1 million and $975.4 million, respectively, as at December 31, 2018, resulting in a working capital deficit of $458.3 million. The deficit is attributable to the Corporation's preference for utilizing its Commercial Paper Program and Working Capital Facility (both defined below) before issuing additional debentures to fulfill the Corporation's ongoing liquidity requirements, including funding of significant capital spending in the current year. The Corporation seeks to maintain an optimal mix of short-term and long-term debt in order to lower overall financing costs and to enhance borrowing flexibility.

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, issuances of commercial paper, amounts available to be drawn against its credit facilities, and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, for energy purchases and to meet financing obligations.

The amount available under the Revolving Credit Facility (defined below) and the outstanding borrowings under the Revolving Credit Facility and Commercial Paper Program are as follows:

(in millions of Canadian dollars)	**Revolving Credit Facility Limit $**	**Revolving Credit Facility Borrowings $**	**Commercial Paper Outstanding $**	**Revolving Credit Facility Availability $**
December 31, 2018	800.0	-	113.0	687.0
December 31, 2017	800.0	-	159.0	641.0

The Corporation is a party to a $20.0 million demand facility with a Canadian chartered bank for the purpose of working capital management ("Working Capital Facility"). As at December 31, 2018, $12.6 million had been drawn under the Working Capital Facility, compared to $11.7 million as at December 31, 2017.

Consolidated Statements of Cash Flow Data
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2018 **$**	**2017** **$**	**2018** **$**	**2017** **$**
Working capital facility, beginning of period	(7.4)	(10.1)	(11.7)	(7.1)
Net cash provided by operating activities	277.2	211.4	596.7	584.7
Net cash used in investing activities	(106.4)	(132.3)	(376.9)	(520.9)
Net cash used in financing activities	(176.0)	(80.7)	(220.7)	(68.4)
Working capital facility, end of period	(12.6)	(11.7)	(12.6)	(11.7)

Operating Activities

Net cash provided by operating activities for the three months and year ended December 31, 2018 was $277.2 million and $596.7 million, respectively, compared to $211.4 million and $584.7 million for the comparable periods in 2017. The increase in net cash provided by operating activities for the three months ended December 31, 2018 was primarily due to higher working capital related to timing differences in the settlement of receivables and payables and changes in regulatory balances.

The increase in net cash provided by operating activities for the year ended December 31, 2018 was primarily due to higher capital contributions, higher customer deposits, higher net income after net movements in regulatory balances and changes in non-cash items, partially offset by lower working capital related to timing differences in the settlement of receivables and higher income taxes paid.

Investing Activities

Net cash used in investing activities for the three months and year ended December 31, 2018 was $106.4 million and $376.9 million, respectively, compared to $132.3 million and $520.9 million for the comparable periods in 2017.

The decrease in net cash used in investing activities for the three months ended December 31, 2018 was primarily due to lower cash spending on capital projects in the fourth quarter of 2018.

The decrease in net cash used in investing activities for the year ended December 31, 2018 was primarily due to proceeds received on disposition of a property in the second quarter of 2018 and lower cash spending on capital projects in 2018.

Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure to address safety, reliability and customer service requirements.

The following table summarizes the Corporation's capital expenditures (on an accrual basis), both PP&E and intangible assets, for the periods indicated.

Capital Expenditures
(in millions of Canadian dollars)

	Three months ended December 31		Year ended December 31	
	2018 $	**2017 $**	**2018 $**	**2017 $**
Regulated LDC				
Distribution system				
Planned [1]	120.6	103.1	369.7	373.0
Reactive	13.1	12.8	63.8	48.1
Copeland Station	2.2	4.9	9.9	23.2
Facilities consolidation	-	-	-	35.2
Technology assets	14.9	20.3	54.4	54.9
Other [2]	1.4	5.3	4.0	10.5
Regulated capital expenditures	152.2	146.4	501.8	544.9
Unregulated capital expenditures [3]	5.1	2.5	9.5	8.0
Total capital expenditures	157.3	148.9	511.3	552.9

1 Includes, among other initiatives, the replacement of underground and overhead infrastructures, station programs, and the delivery of customer connections.
2 Includes fleet capital and buildings.
3 Primarily relates to street lighting and generation equipment.

The total regulated capital expenditures for the three months and year ended December 31, 2018 were $152.2 million and $501.8 million, respectively, compared to $146.4 million and $544.9 million for the comparable periods in 2017.

For the three months ended December 31, 2018, the increase in regulated capital expenditures was primarily related to higher spending on customer connections ($11.0 million), partially offset by lower spending on the ERP project ($5.1 million). The ERP project relates to the implementation of an ERP system, which is an information system that performs critical back-office processes, such as finance, human resources and supply chain activities to support the Corporation's operations. The Corporation completed the implementation of the ERP system on October 1, 2018.

For the year ended December 31, 2018, the decrease in regulated capital expenditures was primarily related to lower spending on the facilities consolidation program ($35.2 million) which was completed by the end of 2017, station programs related to the renewal of aging station infrastructure ($23.0 million) and underground infrastructure ($16.0 million), partially offset by higher spending on customer connections ($24.8 million).

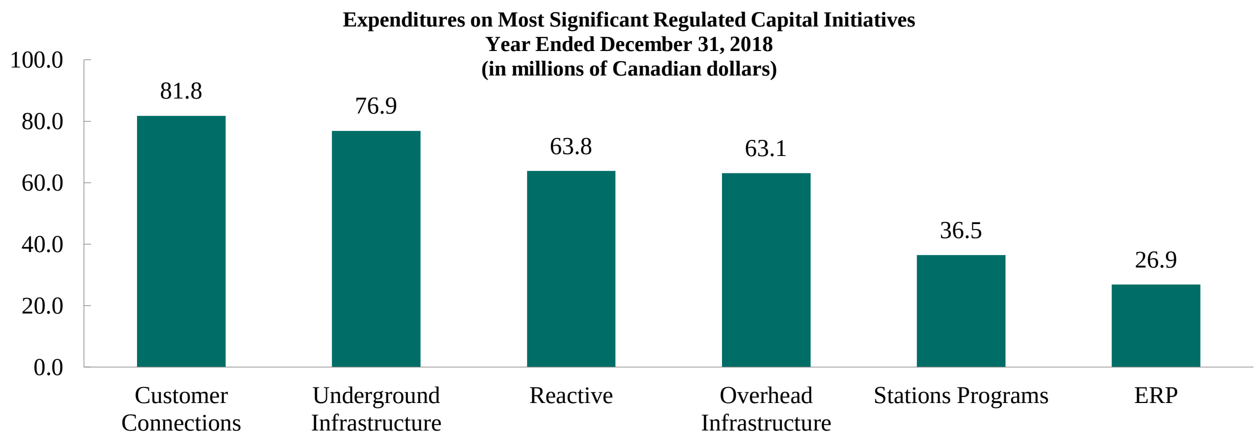
The largest capital initiatives in 2018 include the delivery of customer connections, and the replacement of underground and overhead infrastructures.

The delivery of customer connections includes spending related to new service and upgrades to existing service for specific commercial customers. For the year ended December 31, 2018, capital expenditures for the delivery of customer connections were $81.8 million.

The replacement of underground infrastructure includes replacing direct buried cables, transformer switches, handwells and other aging underground infrastructure. The replacement of overhead infrastructure includes replacing poles, overhead transformers, conductors, overhead switches and other aging overhead infrastructure and equipment. Both initiatives will allow LDC to continue to provide ongoing safe and reliable service to its customers. For the year ended December 31, 2018, capital expenditures for the underground and overhead infrastructures were $76.9 million and $63.1 million, respectively.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. When in service, it will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During the fourth quarter of 2018, the Corporation received approval from HONI, the electricity transmission provider, and the IESO for energization of the project and successfully energized one of two Copeland Station power transformers with associated cables and switchgear, as well as the station service transformer and equipment. The second power transformer and associated switchgear is anticipated to be energized in the first half of 2019 following HONI's completion of additional servicing to some of their equipment. As at December 31, 2018, the cumulative capital expenditures on the Copeland Station project amounted to $202.6 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E.

Copeland Station is one of the most complex projects ever undertaken by the Corporation and the expected completion date is in the first half of 2019. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. The increase in costs and delay in completion date are attributable to a variety of factors, including contractor performance and construction delays. On January 25, 2018, the Corporation was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom. Other contractors have taken on part of the remaining work to contribute to the completion of the project. See "Risk Management and Risk Factors" below for further information on the Copeland Station project.



Financing Activities

Net cash used in financing activities for the three months and year ended December 31, 2018 was $176.0 million and $220.7 million, respectively, compared to $80.7 million and $68.4 million for the comparable periods in 2017.

The increase in cash used in financing activities for the three months ended December 31, 2018 was primarily due to the Corporation's Series 13 debenture issuance in November 2017, higher repayment of commercial paper, net of issuances in 2018 and higher dividends paid compared to the prior year due to a change in the timing of the dividend payments, partially offset by the repayment of the Corporation's Series 2 debenture in 2017. In 2017, the dividends consisted of two instalments of $6.25 million each paid in the first and second quarter and a final instalment of $62.5 million paid in the third quarter in connection with receipt of the equity investment from the City. The Corporation's Dividend Policy was then amended for fiscal 2018 and subsequent fiscal years to provide that dividends be declared and paid in four equal quarterly instalments.

The increase in cash used in financing activities for the year ended December 31, 2018 was primarily due to the funding from the equity injection received from the City in June 2017, the Corporation's Series 13 debenture issuance in November 2017 and higher dividends paid, partially offset by the repayment of the Corporation's Series 2 debentures in 2017 and lower commercial paper, net of issuances.

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility expiring on October 10, 2022 ("Revolving Credit Facility"), pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. As at December 31, 2018, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

On August 23, 2018, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2022 to October 10, 2023.

The Corporation has a commercial paper program allowing up to $600.0 million of unsecured short-term promissory notes ("Commercial Paper Program") to be issued in various maturities of no more than one year. The Commercial Paper Program is backstopped by the Revolving Credit Facility; hence, available borrowing under the Revolving

Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the Commercial Paper Program are used for general corporate purposes. Borrowings under the Commercial Paper Program bear interest based on the prevailing market conditions at the time of issuance.

For the three months and year ended December 31, 2018, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and Commercial Paper Program were $289.2 million and $239.6 million, respectively, with a weighted average interest rate of 1.92% and 1.68% (compared to $140.2 million and $210.3 million, respectively, with a weighted average interest rate of 1.21% and 0.93% for the comparable periods in 2017).

Additionally, the Corporation is a party to a $75.0 million demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ("Prudential Facility"). As at December 31, 2018, $33.3 million of letters of credit had been issued against the Prudential Facility.

The Corporation filed a base shelf prospectus dated May 8, 2017 with the securities commissions or similar regulatory authorities in each of the provinces of Canada. These filings allow the Corporation to make offerings of unsecured debt securities of up to $1.0 billion during the 25-month period following the date of the prospectus.

As at December 31, 2018, the Corporation had debentures outstanding in the principal amount of $2.0 billion. These debentures will mature between 2019 and 2063. As at December 31, 2018, the Corporation was in compliance with all covenants included in its trust indenture and supplemental trust indentures.

The following table sets out the current credit ratings of the Corporation:

Credit Ratings
As at December 31, 2018

	DBRS		**Standard & Poor's**	
	Credit Rating	Trend	Credit Rating	Outlook
Issuer rating	A	Stable	A	Stable
Senior unsecured debentures	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

The Corporation believes that it has sufficient available sources of liquidity and capital to satisfy working capital requirements for the next twelve months.

For the year ended December 31, 2018, the Board of Directors of the Corporation declared and the Corporation paid dividends to the City totalling $93.9 million (2017 - $75.0 million).

On March 6, 2019, the Board of Directors of the Corporation declared a quarterly dividend in the amount of $25.1 million, payable to the City by March 29, 2019.

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2018
(in millions of Canadian dollars)

	Total $	2019 $	2020/2021 $	2022/2023 $	After 2023 $
Commercial paper [1]	113.0	113.0	-	-	-
Debentures – principal repayment	2,045.0	250.0	300.0	250.0	1,245.0
Debentures – interest payments	1,395.6	77.2	131.9	107.0	1,079.5
Capital projects [2] and other	35.5	25.4	9.9	0.2	-
Leases	1.4	0.3	0.6	0.4	0.1
Total contractual obligations and other commitments	3,590.5	465.9	442.4	357.6	2,324.6

1 The notes under the Commercial Paper Program were issued at a discount and are repaid at their principal amount.
2 Primarily commitments for construction services.

Corporate Developments

Appointment of Chief Financial Officer

On August 27, 2018, the Corporation appointed Aida Cipolla to the position of Executive Vice-President and Chief Financial Officer ("CFO"). Ms. Cipolla replaced Sean Bovingdon, the former CFO who left the Corporation. Ms. Cipolla had been formerly the Corporation's Controller since December 2015.

Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions.

On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020.

CDM Activities

The objective of the CDM programs is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") for the delivery of CDM programs over the 2015-2020 period. The IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, including a mid-term incentive based on a review of the 2015-2017 period.

The joint CDM plan provides combined funding of approximately $421.0 million, including participant incentives and program administration costs, with an energy savings target of approximately 1,648 GWh. The program for Oakville Hydro under the joint CDM plan started on January 1, 2016. LDC received $162.4 million from the IESO as at December 31, 2018 (2017 - $102.3 million) to deliver the CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. On September 26, 2018, $15.8 million was confirmed by the IESO as the joint mid-term incentive, of which $14.9 million representing LDC's portion was received in November 2018.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various legal actions and claims from customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under any applicable liability insurance policies which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions, subject to such claim not being disputed by the insurers. There have been no material changes in legal proceedings as disclosed in note 24 to the Consolidated Financial Statements.

Share Capital

Share capital consists of the following:

(in millions of Canadian dollars)	2018 $	2017 $
Authorized The authorized share capital of the Corporation consists of an unlimited number of common shares without par value.		
Issued and outstanding 1,200 common shares, of which all were fully paid.	817.8	817.8

Transactions with Related Parties

As the City is the sole shareholder of the Corporation, the Corporation and the City are considered related parties. The Corporation provides electricity, street lighting and ancillary services to the City. All transactions with the City are conducted on terms similar to those offered to unrelated parties.

Summary of Transactions with Related Parties
(in millions of Canadian dollars)

	Year ended December 31	
	2018 **$**	**2017** **$**
Revenues	276.7	283.3
Operating expenses and capital expenditures	18.3	22.2
Dividends declared and paid	93.9	75.0

Summary of Amounts Due to/from Related Parties
(in millions of Canadian dollars)

	As at December 31	
	2018 **$**	**2017** **$**
Accounts receivable	9.8	13.8
Unbilled revenue	23.9	26.3
Accounts payable and accrued liabilities	40.5	40.1
Customer deposits	17.3	15.7
Deferred revenue	2.5	1.9

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends are paid to the City.

Accounts receivable represent receivables from the City primarily for electricity, street lighting and ancillary services. Unbilled revenue represents receivables from the City mainly related to electricity provided and not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Customer deposits represent amounts received from the City for future expansion projects. Deferred revenue represents amounts received from the City primarily for the construction of electricity distribution assets.

Controls and Procedures

For purposes of certain Canadian securities regulations, the Corporation is a "Venture Issuer". As such, it is exempt from certain requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the Consolidated Financial Statements and the MD&A for the three months and year ended December 31, 2018 and 2017. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Corporation as at the date of and for the period presented.

Risk Management and Risk Factors

The Corporation faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, based on an overall enterprise risk philosophy, and achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. The Corporation's ERM framework utilizes industry best practices and international guidelines and focuses on identifying emerging trends in risks and related opportunities particular to the Corporation through a comprehensive evaluation of the Corporation's business and the industry generally. The Corporation views ERM as a management activity undertaken to add value and improve overall operations. It helps the Corporation by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Risk assessment is built into our decision-making process at all levels. Accordingly, ERM is an integral part of the strategic management of the Corporation and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification, risk trends and risk interdependencies.

While the Corporation's philosophy is that ERM is the responsibility of all business units at all levels, in strategic and functional matters, the ERM governance structure is comprised of three key levels.

At the first level is the Board, which maintains a general understanding of the Corporation's risk profile, the risk categories and the types of risks to which the Corporation may be exposed, and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that may impede the Corporation from achieving certain or all of its strategic objectives, and which are most material to its operational success.

The second level is the executive team, which ensures systems are in place to identify, manage, and monitor risks and trends. Through input from the business and other considerations, the executive team assesses the appropriateness and consistent application of systems to manage risks within the Corporation. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across the Corporation who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees the Corporation's risk profile and its performance against the defined risk philosophy. The senior leadership team understands changes in risk status and trends and determines appropriate risk responses and action plans. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

The Corporation is continually reviewing its ERM program to ensure the organization is focused upon and responsive to risks of the greatest significance, likelihood and impact. In 2018, the Corporation re-oriented its program to the key strategic and functional risk categories facing the organization, and the sub-component risks making up those categories. This allows the Corporation's executive leadership and responsible business units to concentrate on these risks and undertake deeper dives into root causes and risk trends in these areas on both a short-interval and long-term basis. By focusing in particular on the strategic risks to the organization, decision-making is strengthened and the Corporation has a greater ability to realize opportunities central to its interests.

The Corporation's business is subject to a variety of risks including those key risk areas and major component risks described in the following sections. There can be no assurance that any steps the Corporation may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Strategic Risks

Oversight Risk

Risk that provincial government or regulator activity (laws, frameworks or policies) impedes the Corporation's effective performance, and its ability to meet its objectives and serve its customers.

Regulatory and Energy Policy Risk

The Corporation is subject to the risk that its business activities may be impeded through the actions of regulatory authorities or by changes in regulation. There is a risk that future changes to Ontario's regulatory model, manner of regulation, and/or broader energy policy framework does not align with the Corporation's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory and other energy policy developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates at levels that will permit LDC to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;

- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in providing distribution services to customers, in a timely manner or at all;

- the OEB will adopt the other rate-setting principles, formulae, and inputs in a manner that result in rates that properly support LDC's activities;

- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates; and

- the OEB will not permit other parties to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on the Corporation.

LDC actively participates in industry engagement efforts in order to mitigate the above risks and realize potential opportunities in regulatory and energy policy development. Through these types of engagements, the Corporation monitors proposed regulatory and energy policy changes that may impede its business. LDC also employs a comprehensive organizational regulatory application program to ensure that all applications to the OEB achieve the highest utility standard of evidence gathering, preparation and presentation.

Emerging Government Policy Risk

The Corporation is subject to the risk that the policy priorities of provincial and federal governments and regulatory bodies beyond those specifically applicable to the energy space, including policies of more general application, and the implementation of policies by such bodies, may impact the Corporation's ability to deliver effective and efficient operations, meet business objectives, report on its activities and capitalize upon new opportunities. Developments and changes in any of the laws, rules, regulations and policies applicable to the businesses carried on by the Corporation, and the manner of implementation and application of the same, could materially adversely affect the Corporation. This may include developments with respect to labour and employment laws, changes to accounting standards and financial reporting requirements, environmental obligations and public safety rules, among others. The Corporation actively engages with government entities and participates in industry organizations to monitor emerging policies and where possible plays an advocacy role.

Franchise Risk

Risk that restrictions in LDC's business model and/or external conditions impede its ability to maintain and grow its right to be the sole provider of electricity distribution services in the City (its franchise) and serve its customers. The Corporation is subject to the risk that it is displaced from its strategic position or fails to gain a strategic advantage, which could materially adversely affect the Corporation's strategic goals and financial results.

The OEB has the authority to grant municipal distribution licences, has issued to LDC a licence stipulating a service area that reflects the territory within the City, and has not granted any other distribution licence that permits distribution within LDC's service area. In addition, there is a legal framework in place that establishes LDC, as the holder of the municipal distribution licence in the City, to be the sole provider of distribution activities across municipal rights of way. There is no assurance that these frameworks will continue to exist sufficiently or at all in order to provide LDC the opportunity to be the comprehensive distribution provider in the City.

While other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity, the pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation), technology development (e.g. energy storage), government-based incentives, regulatory frameworks, and compliance frameworks especially for non-utility entities.

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage.

Risks to the Corporation’s franchise interests may also result from impairment to the Corporation's image in the community, public confidence or brand. The Corporation is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Negative perceptions regarding this commitment could impact the public’s perception of the Corporation. In addition, events and/or external factors that draw negative media attention to the Corporation could cause reputational damages and impact the Corporation’s business and relationship with its stakeholders. These factors could lead customers, governments and regulators to look more favourably to alternative services and service providers to utility-based electricity distribution.

The Corporation has dedicated personnel focused on monitoring external competitive factors, including alternative service providers and technologies, and developing strategies for further enhancing the LDC’s interactive grid which support the reliability of its core infrastructure grid operations, promote greater value, and deliver solutions for its customers. Additionally, the Corporation maintains relationships with its customers to better understand the specific needs and expectations of each class of customer. The Corporation also conducts customer research and consultations in the ordinary course of its operations, and as part of the development of its rate application whereby it directly considered customer preferences and feedback, in addition to other inputs, as part of developing its business plan. The Corporation also has dedicated personnel focused on the utility’s key account customers, which respond to issues raised by large commercial and industrial customers and assists with their energy management needs. Through these types of engagements, the Corporation can monitor its customers’ specific needs and can work with them to develop energy solutions.

Governance Risk

Risk that municipal activity (laws, policies, or intervention) impedes the Corporation’s effective performance, and ability to meet its objectives and serve its customers.

The Corporation is a government-controlled enterprise whose sole shareholder is the City. The operations of the Corporation and its subsidiaries are influenced by the broad by-law enactment and enforcement powers of the City. Additionally, as the Corporation’s sole shareholder, the City has set out the governing objectives and principles, including financial objectives, for the Corporation through the Shareholder Direction, as described above. Under the Shareholder Direction, the City has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. Certain conflicts may arise where the City’s goals and objectives in implementing such rules, policies, directives or objectives differ from the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects.

The Corporation engages on a systematic basis with the City Mayor, City Councillors, the City Manager's office, and other departments and agencies to ensure a sharing of perspectives on the vital interests of the Corporation and its customers. Through such engagements the parties review and consider the challenges to the Corporation achieving the objectives and principles set out under the Shareholder Direction, and in particular the impact that proposed changes in city by-laws or municipal policies may create for the Corporation's ability to meet its business objectives and serve its customers.

Functional Risks

Human Capital Risk

Risk that the Corporation is unable to maintain necessary resource talent and skilled resources.

The Corporation is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support the Corporation's future talent requirements. All retirements pose risks for knowledge management and business continuity at the Corporation. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

The Corporation's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. The Corporation's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions, including negotiating collective bargaining agreements with the Society of United Professionals and PWU. There can be no assurance that the Corporation will be able to secure the support of its labour unions.

The Corporation's ability to develop its work processes to meet changing circumstances also depends on its ability to access adequate resources from its external contractor community. One way in which the Corporation seeks to mitigate this risk is through its use of business practices and internal procedures to identify a diverse group of reputable third party service providers and entering into contracts with, and monitoring the performance of, these third-party service providers.

Operations Risk

Risk that the Corporation is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the grid at acceptable levels.

Asset Management Risk

The Corporation is subject to the risk that it may be unable to maintain continuous supply due to failure of the distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements now and in the future.

LDC estimates that approximately 33% of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025. Asset condition assessment demographics also indicate substantial asset investment needs for a number of critical assets during this period. At the same time, Toronto is a growing city, and LDC must make upgrades to keep pace with urban intensification and electrification and ensure good stewardship of the distribution system. Further, extreme weather is no longer an infrequent experience, and has instead become a regular condition of operating a distribution system. For example, the Corporation experienced four extreme weather events in the first half of 2018, leaving nearly 160,000 customers without electricity. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change and adoption of electric vehicles and fuel-switching potentially increases, the pressures on the Corporation's system will only increase, and such factors may drive a need for incremental capital expenditures for system upgrades so that the grid can handle increased loads.

LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of the Corporation to fund additional infrastructure investments, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by the Corporation. The expected completion date for the Copeland Station is in the first half of 2019. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. The increase in costs and delay in completion date are attributable to a variety of factors, including contractor performance and construction delays. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2018, the Corporation was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies' Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom. Other contractors have taken on part of the remaining work to contribute to the completion of the project. All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials, equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and government approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. It uses a variety of asset and project management tools to implement its plans, measures progress on a recurring short interval basis, and regularly monitors and manages the health of its assets. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

The Corporation's ability to operate effectively is also in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and the Corporation's financial, billing and business systems to capture data and to produce timely and accurate information. Specifically, on October 1, 2018, the Corporation successfully completed the implementation of, and transitioned to, a new ERP system. The ERP system is being used to operate the Corporation's financial, and business systems to capture data and to produce timely and accurate information. Failure of the newly implemented ERP system could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The Corporation has mitigation strategies, access to consultants with ERP expertise and is developing an internal ERP centre of excellence to help assist in the implementation, and support of ERP for users. Additionally, in respect of the Corporation's operational technology systems in general, there is isolation from business systems and independent operation which mitigates against wider systemic risk to the business systems.

Security Risk

The Corporation is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets.

LDC's electricity distribution infrastructure and technology systems are potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. The Corporation has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework and the OEB's Ontario Cyber Security Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose the Corporation to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect the Corporation and also result in third-party claims against the Corporation.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that the Corporation can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, the Corporation may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

The Corporation is subject to the risk of external threats to its physical and perimeter security. This includes the security of the Corporation's facilities including office buildings and distribution stations. In order to safeguard its assets and staff, the Corporation has developed policies and guidelines around physical and perimeter security and facilities related emergency preparedness. The Corporation has also implemented electronic security technologies to ensure that only authorized personnel have access to the Corporation facilities.

Business Interruption Risk

The Corporation is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. The Corporation's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. The Corporation has implemented various initiatives aimed at improving the system's resiliency to increasingly frequent extreme weather events caused by climate change. These initiatives include updating major equipment specifications, revising planning guidelines, investigating the load forecast impact, revising design practices, and enhancing maintenance programs. The Corporation has also implemented a Grid Emergency Management (GEM) program to prepare for and respond to major power outage events and has incorporated recommendations from the independent review panel of experts formed to review the Corporation's response to the 2013 Ice Storm that affected Toronto. Although the Corporation's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to the Corporation's facilities or interruption of the Corporation's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although the Corporation has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Safety Risk

Risk to the Corporation employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon the Corporation activities.

Occupational Health and Safety Risk

The Corporation is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of the Corporation's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. The Corporation is subject to compliance with provincial Health and Safety legislation. The Corporation's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. The Corporation also uses an IRS (Internal Responsibility System) to clearly define responsibility and accountability for safety at each level within the organization. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Public Safety Risk

Due to the nature of the Corporation’s business of operating and maintaining its distribution system, the Corporation is subject to the risk of public injuries or fatalities. The Corporation mitigates risks to public safety through equipment inspection, replacement and maintenance, employee training, communications programs and reactive and emergency work. The Corporation also has developed specific construction standards and design practices and new products for use in the distribution system go through a thorough review and introduction process. The selection process for new products and the development of standards promotes customer health and safety.

Financial Risk

Risk that the Corporation is unable to maintain its financial health and performance at acceptable levels.

Market and Credit Risk

The Corporation is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC’s security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. The Corporation estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of the Corporation, as at December 31, 2018, by $41.3 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2018, by $53.1 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its Commercial Paper Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.1 million to annual finance costs.

The Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2018 was not material.

Capital Structure Risk

The Corporation is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation’s requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its medium term notes program, Commercial Paper Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's medium term notes program by credit rating agencies, the rating assigned to short-term borrowings under the Commercial Paper Program by a credit rating agency, and the availability of the commercial paper market. In the event the Corporation is unable to maintain an R-1 (low) credit rating for its Commercial Paper Program, the

Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due. The Corporation's only source of external equity financing is its existing shareholder, the City of Toronto.

The Corporation regularly reviews the external market environment and has regular engagements with its credit rating agencies, securities dealers and investor community to monitor capital structure risk.

Compliance Risk

Risk that the Corporation does not meet its material compliance obligations under legal and regulatory instruments.

The Corporation is committed to complying with applicable legal and regulatory requirements and other requirements to which the organization subscribes. The Corporation has a Corporate Compliance program that strengthens the organization's culture of compliance and provides reasonable assurance, to the Corporation's senior leadership and the Corporation's Board of Directors, of adherence with material compliance requirements. There can be no assurance that the Corporation will comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings that could have a material adverse effect on the Corporation. The OEB may not allow recovery in rates for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

Critical Accounting Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following notes to the Consolidated Financial Statements:

- Note 25(b) – Recognition and measurement of regulatory balances;
- Note 25(j) – Revenue recognition – measurement of unbilled revenue, determination of the CDM incentive;
- Notes 25(f) and 25(g) – Determination of useful lives of depreciable assets;
- Notes 25(m) and 13 – Measurement of post-employment benefits – key actuarial assumptions;
- Notes 25(o) and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used; and
- Note 24 – Recognition and measurement of provisions and contingencies.

Significant Accounting Policies

The Corporation's Consolidated Financial Statements have been prepared in accordance with IFRS with respect to the preparation of financial information. The Consolidated Financial Statements are presented in Canadian dollars, which is the Corporation's functional currency. The significant accounting policies of the Corporation are summarized in note 25 to the Consolidated Financial Statements.

Changes in Accounting Policies

Effective January 1, 2018, the Corporation has adopted new IFRS standards and applied the following new accounting policies in preparing the Consolidated Financial Statements:

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 effective for annual periods beginning on or after January 1, 2018, which replaced existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. IFRS 15 contains a five step model that applies to contracts with customers that specifies that revenue is recognized when or as an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. Depending on whether certain criteria are met, revenue is recognized at a point in time or over time.

The Corporation adopted IFRS 15 using the modified retrospective approach with the following practical expedients:

- The Corporation did not restate completed contracts that began and ended in the same annual reporting period or completed contracts at the beginning of the earliest period presented; and

- The Corporation did not disclose the amount of consideration allocated to the remaining performance obligations nor did it provide an explanation of when the Corporation expects to recognize that amount as revenue for comparative periods presented in the Consolidated Financial Statements.

The Corporation recognizes revenue in the amount that it has a right to invoice when the amount directly corresponds with the value of the Corporation's performance to date.

The adoption of IFRS 15 resulted in a $207.6 million income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017, and had no impact to opening retained earnings as at January 1, 2018. The Corporation updated the impact previously disclosed in the 2017 audited consolidated financial statements for the year ended December 31, 2017 to include the additional income statement reclassification between energy sales and energy purchases for the comparative year ended December 31, 2017. Refer to note 25(q) of the Consolidated Financial Statements for details on the transitional adjustment.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ("IFRS 9") effective for annual periods beginning on or after January 1, 2018, which replaced IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39"). IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for measuring impairment on financial assets, and new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The Corporation adopted IFRS 9 retrospectively on January 1, 2018. Despite the retrospective adoption of IFRS 9, the Corporation is not required, upon initial application, to restate comparatives.

i) Classification and measurement of financial instruments

IFRS 9 largely retains the existing requirements in IAS 39 for the classification and measurement of financial liabilities. However, it eliminates the previous IAS 39 categories for financial assets of held to maturity, loans and receivables and available for sale.

Under IFRS 9, on initial recognition, a financial asset is classified and measured at amortized cost, fair value through other comprehensive income, or fair value through profit or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics.

The adoption of IFRS 9 has not had a significant effect on the Corporation's accounting policies related to financial instruments. The impact of IFRS 9 on the classification and measurement of financial instruments is set out below.

Financial Instrument	IAS 39 Measurement basis	IFRS 9 Measurement basis
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Unbilled revenue	Loans and receivables	Amortized cost
Working capital facility	Financial liability – amortized cost	Amortized cost
Commercial paper	Financial liability – amortized cost	Amortized cost
Customer deposits	Financial liability – amortized cost	Amortized cost
Leases	Financial liability – amortized cost	Amortized cost
Debentures	Financial liability – amortized cost	Amortized cost
Accounts payable	Financial liability – amortized cost	Amortized cost

Financial Instrument	IAS 39 Carrying amount as at January 1, 2018 $	IFRS 9 Carrying amount as at January 1, 2018 $
Cash and cash equivalents	—	—
Accounts receivable	217.7	218.3
Unbilled revenue	278.3	277.4
Working capital facility	11.7	11.7
Commercial paper	159.0	159.0
Customer deposits	58.1	58.1
Leases [(1)]	3.1	3.1
Debentures	2,034.0	2,034.0
Accounts payable	325.1	325.1

[(1)] Includes transitional adjustment for the recognition of new leases upon adoption of IFRS 16 *Leases* ("IFRS 16") on January 1, 2018. Refer to note 25(q) of the Consolidated Financial Statements for details on the transitional adjustment

ii) Impairment of financial assets

Loss allowances for accounts receivable and unbilled revenue are always measured at an amount equal to life time expected credit losses ("ECL"). Lifetime ECL are the ECL that result from all possible default events over the expected life of a financial instrument.

When determining whether the credit risk of a financial asset has increased significantly since initial recognition and when estimating ECL, the Corporation considers reasonable and supportable information that is relevant and available without undue cost or effort. This includes both quantitative and qualitative information and analysis, based on the Corporation's historical experience, adjusted for forward-looking factors specific to the current credit environment.

The Corporation assumes that credit risk on a financial asset has increased if it is more than 30 days past due date.

The Corporation considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to the Corporation in full, without recourse by the Corporation, such as realising security (if any is held).

If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* ("IFRS 16"), which replaced IAS 17 *Leases* ("IAS 17") and related interpretations. IFRS 16 introduces a single lessee accounting model eliminating the previous distinction between finance and operating leases. IFRS 16 requires the recognition of lease-related assets and liabilities on the balance sheet, except for short-term leases and leases of low value underlying assets. Lessor accounting remained substantially unchanged.

Although IFRS 16 is effective for annual periods beginning on or after January 1, 2019, the Corporation early adopted IFRS 16 on January 1, 2018 using the modified retrospective approach, in accordance with the transitional provisions in IFRS 16. The comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4 *Determining whether an Arrangement contains a Lease*. In applying this approach, the Corporation elected to use practical expedients that allowed it to exclude the initial direct costs from the measurement of the right-of use assets at the date of the initial application, and to use hindsight in determining the lease term. As a practical expedient permitted by IFRS 16, the Corporation applied IFRS 16 to existing contracts that were previously identified as leases applying IAS 17 and IFRIC 4, and did not apply IFRS 16 to contracts that were not previously identified as containing a lease.

The adoption of IFRS 16 resulted in an increase of $1.6 million in total assets and total liabilities each for recognition of right-of-use assets and lease liabilities, respectively, and had no impact to opening retained earnings as at January 1, 2018. Refer to note 25(q) of the Consolidated Financial Statements for details on the transitional adjustment.

The adoption of IFRS 15, IFRS 9 and IFRS 16 resulted in no changes to the consolidated balance sheets as at December 31, 2017 or consolidated statements of cash flows for the year ended December 31, 2017.

Future Accounting Pronouncements

A number of new interpretations and amendments to existing standards have been issued but are not yet effective for the year ended December 31, 2018, and have not been applied in preparing the Consolidated Financial Statements.

IFRIC 23 Uncertainty over Income Tax Treatments

On June 7, 2017, the IASB issued IFRIC 23 *Uncertainty over Income Tax Treatments*. The interpretation provides guidance on the accounting for current and deferred tax assets and liabilities in situations in which there is uncertainty over income tax treatments. The interpretation is applicable for annual reporting periods beginning on or after January 1, 2019.

Annual Improvements to IFRS Standards 2015-2017 Cycle

On December 12, 2017, as part of its annual improvements process, the IASB issued narrow-scope amendments to the following standards:

IFRS 3 *Business Combinations* – the amendments clarify that when an entity obtains control of a business that is a joint operation, it re-measures previously held interests in that business.

IFRS 11 *Joint Arrangements* – the amendments clarify that when an entity obtains joint control of a business that is a joint operation, it does not re-measure previously held interests in that business.

IAS 12 *Income Taxes* – the amendments clarify that an entity recognizes income tax consequences of dividends in profit or loss, other comprehensive income or equity, depending on where the entity recognized the originating transaction or event that generated the distributable profits giving rise to the dividend.

IAS 23 *Borrowing Costs* – the amendments clarify that an entity treats as general borrowings any borrowings made specifically to obtain a qualifying asset that remain outstanding when the asset is ready for its intended use or sale.

The amendments are effective for annual reporting periods beginning on or after January 1, 2019.

Definition of Material (Amendments to IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors)

On October 31, 2018, the IASB issued amendments to IAS 1 and IAS 8 – the amendments clarify the definition of 'material' and align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

The Corporation anticipates that the adoption of these accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements, if any.

Forward-Looking Information

Certain information included in this MD&A constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "intends", "may", "might", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in the MD&A includes, but is not limited to, the statements regarding the settlement variance and other regulatory balance variances as described in the section entitled "Results of Operations"; the statements regarding the reduction in future electricity distribution rates for customers as described in the section entitled "Results of Operations"; the effect of changes in energy consumption on future revenue as described in the section entitled "Summary of Quarterly Results of Operations"; the Corporation's plans to lower overall financing costs and enhance borrowing flexibility as described in the section entitled "Liquidity and Capital Resources"; the Corporation's available sources of liquidity and capital resources and the sufficiency thereof to satisfy working capital requirements for the next twelve months as described in the section entitled "Liquidity and Capital Resources"; the planned and proposed capital initiatives and the expected results of such initiatives as described in the section entitled "Liquidity and Capital Resources"; the expected capital expenditures required to complete Copeland Station and the anticipated completion date for Copeland Station as described in the section entitled "Liquidity and Capital Resources" and the subsection entitled "Asset Management Risk"; the extension of the Revolving Credit Facility maturity date as referenced under the section entitled "Liquidity and Capital Resources"; the anticipated contractual obligations and other commitments of the Corporation over the next five years as set out in the section entitled "Liquidity and Capital Resources"; the payment of dividends as described in the section entitled "Liquidity and Capital Resources"; electricity distribution rates and rate applications as described in the section entitled "Corporate Developments"; approvals related to LDC's CIR application as described in the section entitled "Corporate Developments"; the plans to meet CDM targets and to receive reimbursement and/or cost efficiency incentives from the IESO as described in the section entitled "Corporate Developments"; the Corporation's reliance on debt financing through its medium term notes program, Commercial Paper Program or existing credit facilities to finance the Corporation's daily operations, repay existing indebtedness, and fund capital expenditures as described in the subsection entitled "Capital Structure Risk"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the subsection entitled "Market and Credit Risk"; the Corporation's plans to train and retain skilled employees, mitigate risks from retiring employees, maintain the support of its labour unions and enter into agreements with, and monitor the performance of, its third party providers as described in the subsection entitled "Human Capital Risk"; and the expectation that approximately 33% of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025 as described in the subsection entitled "Asset Management Risk".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, no unforeseen changes in the demand for energy consumption, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects (including Copeland Station), no unforeseen changes to project plans, no significant changes in weather compared to historical seasonal trends, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for cost efficiency CDM incentives, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation's ability to borrow and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC's capital and maintenance programs necessary to maintain the performance of aging distribution assets and make required infrastructure improvements; risks associated with capital projects, including Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes including factors relating to LDC's distribution activities; risks associated with increased competition from regulated and unregulated entities; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of the Corporation's information assets; risks associated with failure of the newly implemented ERP system; risk of external threats to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and LDC's limited insurance coverage for losses resulting from these events; risk to the Corporation's employees and the general public of serious/fatal injuries and illnesses relating to or impacting upon its activities; risks of municipal government activity, including the risk that the City could introduce rules, policies or directives that can potentially limit the Corporation's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic and its potential inability to train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; risk that the Corporation may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk that the Corporation is unable to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet the Corporation's requirements, objectives, or strategic opportunities; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk associated with the impairment to the Corporation's image in the community, public confidence or brand; risk associated with the Corporation failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of the LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under the section entitled "Risk Management and Risk Factors" in this MD&A. Please review the section "Risk Management and Risk Factors" in detail. All of the forward-looking information included in this MD&A is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Management and Risk Factors" section in this MD&A. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this MD&A or as of the date specified in this MD&A, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Selected Annual Information

The following table sets forth selected annual financial information for the three years ended December 31, 2018, 2017 and 2016. This information has been derived from the Corporation's consolidated financial statements.

Selected Annual Consolidated Financial Information
(in millions of Canadian dollars)

	2018 $	2017 $ *[Restated]*[6]	2016 $ *[Restated]*[6]
Year Ended December 31			
Total Revenues [1]	3,472.7	3,642.1	3,996.0
Net income after net movements in regulatory balances [1]	167.3	156.5	151.4
As at December 31			
Total assets and regulatory balances [2]	5,360.1	5,226.2	4,954.4
Total debentures [2,3]	2,034.9	2,034.0	2,084.6
Other non-current financial liabilities [4]	33.9	9.1	17.3
Total equity [2]	1,833.5	1,760.4	1,428.9
Dividends [5]	93.9	75.0	63.4

[1] See "Results of Operations" for further details on distribution revenue, other revenue, and net income after net movements in regulatory balances.

[2] See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.

[3] Total debentures include current and long-term debentures.

[4] Other non-current financial liabilities include primarily non-current obligations under capital lease and non-current customer deposits. Under IFRS, deposits that are due or will be due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.

[5] See "Liquidity and Capital Resources" for further details on dividends.

[6] These numbers have been restated to account for the impact of adopting IFRS 15. Additional details on IFRS 15 are discussed in the "Changes in Accounting Policies" section of this MD&A.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.
Toronto, Canada

March 6, 2019

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

March 21, 2019

TABLE OF CONTENTS

PART 1 - FORWARD-LOOKING INFORMATION

Certain information included in this AIF constitutes “forward-looking information” within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words “anticipates”, “believes”, “budgets”, “committed”, “can”, “could”, “estimates”, “expects”, “focus”, “forecasts”, “future”, “intends”, “may”, “might”, “plans”, “propose”, “projects”, “schedule”, “seek”, “should”, “trend”, “will”, “would”, “objective”, “outlook” or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in this AIF includes, but is not limited to, the statements regarding: anticipated capacity to be provided by Copeland Station, the expected completion date of Copeland Station and the expected capital expenditures required to complete Copeland Station as described in the sections entitled “LDC’s Electricity Distribution System” and “Asset Management Risk”; wage increases for employees as described in the section entitled “Employees”; the effect of changes in energy consumption on future revenue as described in the section entitled “Seasonal Effects”; electricity distribution rates and rate applications as described in the section entitled “Rate Applications”; the plans to meet CDM targets and to receive reimbursement and/or cost efficiency incentives from the IESO as described in the section entitled “Conservation and Demand Management”; the effects of the Corporation or a subsidiary ceasing to be exempt from tax under the ITA and the TA and the payment of transfer taxes and the prescribed transfer tax rate for any future transfer of interest by the Corporation and its subsidiaries, or any changes to tax rates, as described in the section entitled “Tax Regime”; the Corporation's reliance on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro’s daily operations, repay existing indebtedness, and fund capital expenditures as described in the section entitled “Capital Structure Risk”; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled “Market and Credit Risk”; the Corporation’s plans to attract, train and retain skilled employees, mitigate risks from retiring employees, maintain the support of its labour unions and enter into agreements with, and monitor the performance of, its third party providers as described in the section entitled “Human Capital Risk”; the expectation that approximately 33% of Toronto Hydro’s electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025 as described in the section entitled “Asset Management Risk”; the expectation that none of the legal actions and claims as described further in the section entitled “Legal Proceedings” would have a material adverse effect on the Corporation and the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled “Legal Proceedings”.

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation’s capital projects (including Copeland Station), no unforeseen changes to project plans, no significant changes in weather compared to historical seasonal trends, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals for cost efficiency CDM incentives, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation's ability to borrow and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC’s capital and maintenance programs necessary to maintain the performance of aging distribution assets and make required infrastructure improvements; risks associated with capital projects, including Copeland Station; risks associated with electricity industry regulatory developments and other governmental policy changes including factors relating to LDC's distribution activities**;** risks associated with increased competition from regulated and unregulated entities; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of Toronto Hydro's information assets; risks associated with failure of the newly implemented ERP system; risk of external threats to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors, terrorism and pandemics and LDC's limited insurance coverage for losses resulting from these events; risk to Toronto Hydro's employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro's activities; risks of municipal government activity, including the risk that the City could introduce rules, policies or directives that can potentially limit Toronto Hydro's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic and its potential inability to attract, train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; risk that Toronto Hydro may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk that the Corporation is unable to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet the Corporation's requirements, objectives, or strategic opportunities; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discounts rates and their effect on future revenue requirements and future post-employment benefit obligations; risk associated with the impairment to the Corporation's image in the community, public confidence or brand; risk associated with the Corporation failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of the LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders and other factors which are discussed in more detail under Part 8 "Risk Factors" in this AIF.

All of the forward-looking information included in this AIF is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Factors" section of this AIF. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this AIF or as of the date specified in this AIF, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

PART 2 - GLOSSARY OF DEFINED TERMS

In addition to terms defined elsewhere in this AIF, the below defined terms shall have the following meanings:

"Affiliate Relationships Code" refers to the Affiliate Relationships Code for Electricity Distributors and Transmitters that was published by the OEB and became effective on April 1, 1999, as amended.

"AIF" refers to the Corporation's Annual Information Form for the year ended December 31, 2018.

"Board" refers to the board of directors of the Corporation.

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Canadian Environmental Protection Act" refers to the *Canadian Environmental Protection Act, 1999* (Canada), as amended.

"Capital Assets" refers to the sum of property, plant and equipment and intangible assets, net of accumulated depreciation and amortization. See note 6 and note 7 to the Consolidated Financial Statements.

"CDM" refers to conservation and demand management.

"CDS" refers to CDS Clearing and Depository Services Inc.

"CEA" refers to the Canadian Electricity Association.

"CEO" refers to the President and Chief Executive Officer of the Corporation.

"CFO" refers to the Executive Vice-President and Chief Financial Officer.

"CIR" refers to Custom Incentive Rate-setting.

"City" refers to the city incorporated under the *City of Toronto Act, 1997* (Ontario), as amended.

"City Council" refers to Toronto City Council.

"City Councillor" refers to a councillor of Toronto City Council.

"Conservation and Demand Management Code" refers to the Conservation and Demand Management Code for Electricity Distributors that was published and became effective on September 16, 2010.

"Consolidated Financial Statements" refers to the comparative audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at and for the years ended December 31, 2018 and December 31, 2017, a copy of which is available on the SEDAR website at www.sedar.com.

"Consumer Price Index" refers to the index measuring price movements published by Statistics Canada.

"Consumer Protection Act" refers to the *Consumer Protection Act, 2002* (Ontario), as amended.

"Copeland Station" refers to the Clare R. Copeland transformer station, formerly called "Bremner Station".

"Corporation" refers to Toronto Hydro Corporation.

"CPAB" refers to Canadian Public Accountability Board.

"CP Program" refers to the commercial paper program established by the Corporation under which the Corporation issues commercial paper. See section 9.3 under the heading "Credit Facilities".

"CUPE One" refers to the Canadian Union of Public Employees, Local One.

"Dangerous Goods Transportation Act" refers to the *Dangerous Goods Transportation Act*, *1990* (Ontario), as amended.

"DBRS" refers to DBRS Limited.

"Debentures" has the meaning set forth under section 9.2 under the heading "Debentures".

"Distribution System Code" refers to the Distribution System Code that was published by the OEB on July 14, 2000, as amended.

"EHSMS" refers to the Environment, Health and Safety Management System.

"Electricity Act" refers to the *Electricity Act, 1998* (Ontario), as amended.

"Electricity Property" refers to a municipal corporation's or an MEU's interest in real or personal property used in connection with generating, transmitting, distributing or retailing electricity.

"Electricity Restructuring Act" refers to the *Electricity Restructuring Act, 2004* (Ontario), as amended.

"Energy Competition Act" refers to the *Energy Competition Act, 1998* (Ontario), as amended.

"Energy Consumer Protection Act" refers to the *Energy Consumer Protection Act, 2010* (Ontario), as amended.

"Environmental Protection Act" refers to the *Environmental Protection Act, 1990* (Ontario), as amended.

"ERM" refers to Enterprise Risk Management.

"ERP" refers to Enterprise Resource Planning.

"Fire Protection and Prevention Act" refers to the *Fire Protection and Prevention Act, 1997* (Ontario), as amended.

"GWh" refers to a gigawatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One GWh is equal to one million kWh.

"Hydro One" refers to Hydro One Limited, Hydro One Inc. or Hydro One Networks Inc. and their respective subsidiaries, as appropriate.

"ICD.D" refers to the designation granted by the Institute of Corporate Directors, through the Directors Education Program jointly developed by the Institute of Corporate Directors and the University of Toronto’s Rotman School of Management.

"ICM" refers to Incremental Capital Module. See section 4.3(e)(i) under the heading "Rate Setting Mechanism" for more information.

"IEEE" refers to the Institute of Electrical and Electronic Engineers.

"IESO" refers to the Independent Electricity System Operator. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"IRM" refers to Incentive Regulation Mechanism. See section 4.3(e)(i) under the heading "Rate Setting Mechanism" for more information.

"ISO" refers to the International Organization for Standardization.

"ITA" refers to the *Income Tax Act, 1985* (Canada), as amended.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LDC" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro-Electric System Limited.

"Management's Discussion and Analysis" or "MD&A" refers to Management's Discussion and Analysis of Financial Condition and Results of Operations of the Corporation for the year ended December 31, 2018, a copy of which is available on the SEDAR website at www.sedar.com.

"MED" refers to Major Event Days as defined by IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

"MEU" refers to a Municipal Electricity Utility in the Province of Ontario.

"Moody's" refers to Moody's Canada Inc.

"MTN Program" refers to the medium term note program established by the Corporation under which the Corporation issues debentures. See section 9.2 under the heading "Debentures" for the debentures currently outstanding.

"Named Executive Officer" or **"NEO"** means, collectively, the Corporation's CEO, the CFO, and/or a person serving in either of those capacities during the year and the three most highly compensated executive officers of Toronto Hydro who were serving as executive officers as at December 31, 2018, and each individual who would be amongst the three most highly compensated executive officers for Toronto Hydro, but for the fact that such individual was not an executive officer on December 31, 2018, if any.

"Oakville Hydro" refers to Oakville Hydro Electricity Distribution Inc.

"OBCA" refers to the *Business Corporations Act, 1990* (Ontario), as amended.

"OEB" refers to the Ontario Energy Board.

"OEB Act" refers to the *Ontario Energy Board Act, 1998* (Ontario), as amended.

"OEFC" refers to the Ontario Electricity Financial Corporation.

"OFHA" refers to the *Fair Hydro Act, 2017* (Ontario).

"OFHP" refers to Ontario's Fair Hydro Plan.

"OHSAS" refers to the Occupational Health and Safety Assessment Series.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OPA" refers to the Ontario Power Authority. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"Open Access" refers to the opening of the Province's wholesale and retail electricity markets to competition pursuant to the requirement under the Electricity Act that transmitters and distributors of electricity in the Province provide generators, retailers and consumers with non-discriminatory access to their transmission and electricity distribution systems. Open Access commenced on May 1, 2002.

"OPG" refers to Ontario Power Generation Inc.

"OREC" refers to *Ontario Rebate for Electricity Consumers Act*, 2016 (Ontario).

"OSC" refers to the Ontario Securities Commission.

"PCBs" refers to polychlorinated biphenyls, a synthetic chemical compound consisting of chlorine, carbon and hydrogen. PCBs are used primarily as insulating and cooling elements in electrical equipment. Secondary uses include hydraulic and heat transfer fluids, flame proofing adhesives, paints, sealants and cable insulating paper.

"PILs" refers to the Payments In Lieu of Corporate Taxes regime contained in the Electricity Act pursuant to which MEUs that are exempt from tax under the ITA and the TA are required to make, for each taxation year, payments in lieu of corporate taxes to the OEFC. See note 25(o) and note 20 to the Consolidated Financial Statements.

"PP&E" refers to property, plant and equipment.

"Province" refers to the Province of Ontario.

"Prudential Facility" refers to a $75.0 million demand facility that the Corporation entered into with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO. See section 9.3 under the heading "Credit Facilities".

"PWU" refers to the Power Workers' Union.

"Residential Tenancies Act" refers to the *Residential Tenancies Act*, *2006* (Ontario), as amended.

"Retail Settlement Code" refers to the Retail Settlement Code that was published by the OEB on December 13, 2000 and became effective on the commencement of Open Access (except with respect to "Service Agreements", as that term is defined in the Retail Settlement Code, which came into effect on March 1, 2001), as amended.

"**Revolving Credit Facility**" refers to the Corporation's credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility. See section 9.3 under the heading "Credit Facilities".

"S&P" refers to Standard & Poor's Financial Services LLC, a subsidiary of S&P Global Inc.

"SAIDI" means System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" means System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SEDAR" refers to the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval. SEDAR's website is www.sedar.com.

"Shareholder Direction" refers to the Shareholder Direction adopted by the Council of the City with respect to the Corporation, as amended and/or restated from time to time, pursuant to which the City has set out certain corporate governance principles with respect to the Corporation.

"Smart Meter" refers to a metering device capable of recording and transmitting hourly consumption information of a residential or general service customer.

"Standard Supply Customers" refers to persons connected to an electricity distributor's distribution system who are not served by retailers or whose retailer is unable to sell them electricity or who request the distributor to sell electricity to them.

"Standard Supply Service" refers to an electricity distributor's obligation to sell electricity to Standard Supply Customers, or to give effect to such rates as determined by the OEB under section 79.16 of the OEB Act.

"Standard Supply Service Code" refers to the Standard Supply Service Code for Electricity Distributors that was published by the OEB on December 8, 1999 and became effective on the commencement of Open Access, as amended.

"TA" refers to the *Taxation Act, 2007* (Ontario), as amended.

"Technical Standards and Safety Act" refers to the *Technical Standards and Safety Act, 2000* (Ontario), as amended.

"TH Energy" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro Energy Services Inc.

"Toronto Hydro" refers to Toronto Hydro Corporation and its subsidiaries.

"Total Recordable Injury Frequency" refers to the number of recordable injuries multiplied by 200,000 divided by exposure hours, as per CEA standards.

"Transfer By-law" refers to By-law No. 374-1999 of the City made under section 145 of the Electricity Act pursuant to which the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities and employees in respect of the electricity distribution system to LDC and in respect of electricity generation, co-generation and energy services to TH Energy. The Transfer By-law permits the Treasurer of the City to adjust the fair market value of the assets and the consideration paid in respect of the electricity distribution assets transferred to LDC as a consequence of OEB rate orders and permitted rates of return for 2000 or any subsequent year.

"Transportation of Dangerous Goods Act" refers to the *Transportation of Dangerous Goods Act, 1992* (Canada), as amended.

"Unit Smart Meter" refers to a unit Smart Meter installed by LDC in a unit of a multi-unit complex where the multi-unit complex is not connected solely to a bulk meter, and includes such other meters as may be prescribed by the Energy Consumer Protection Act.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

"Working Capital Facility" refers to a $20.0 million demand facility the Corporation entered into with a Canadian chartered bank for the purpose of working capital management. See section 9.3 under the heading "Credit Facilities".

Unless otherwise specified, all references to statutes are to statutes of the Province and all references to dollars are to Canadian dollars.

PART 3 - CORPORATE STRUCTURE

3.1 Name, Address, Incorporation

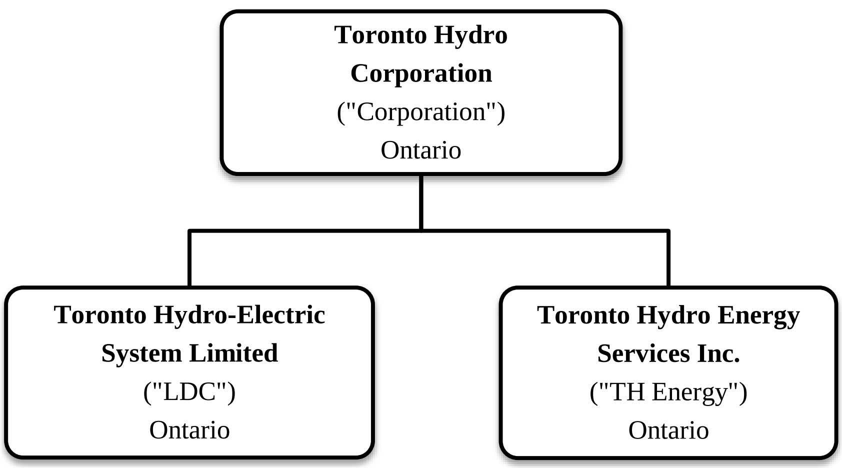
On January 1, 1998, the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York amalgamated to form the City. At the same time, the electric commissions of Toronto, East York, Etobicoke, North York, Scarborough and York were combined to form the Toronto Hydro-Electric Commission. Toronto Hydro is the successor to the Toronto Hydro-Electric Commission.

The Corporation, LDC and TH Energy were incorporated under the OBCA on June 23, 1999. Pursuant to the Transfer By-law, the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities in respect of the electricity distribution system to LDC and electricity generation, co-generation and energy services to TH Energy.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

3.2 Inter-corporate Relationships

The sole shareholder of the Corporation is the City. The Corporation, in turn, owns 100% of the shares of the subsidiaries listed below:



PART 4 - BUSINESS OF TORONTO HYDRO

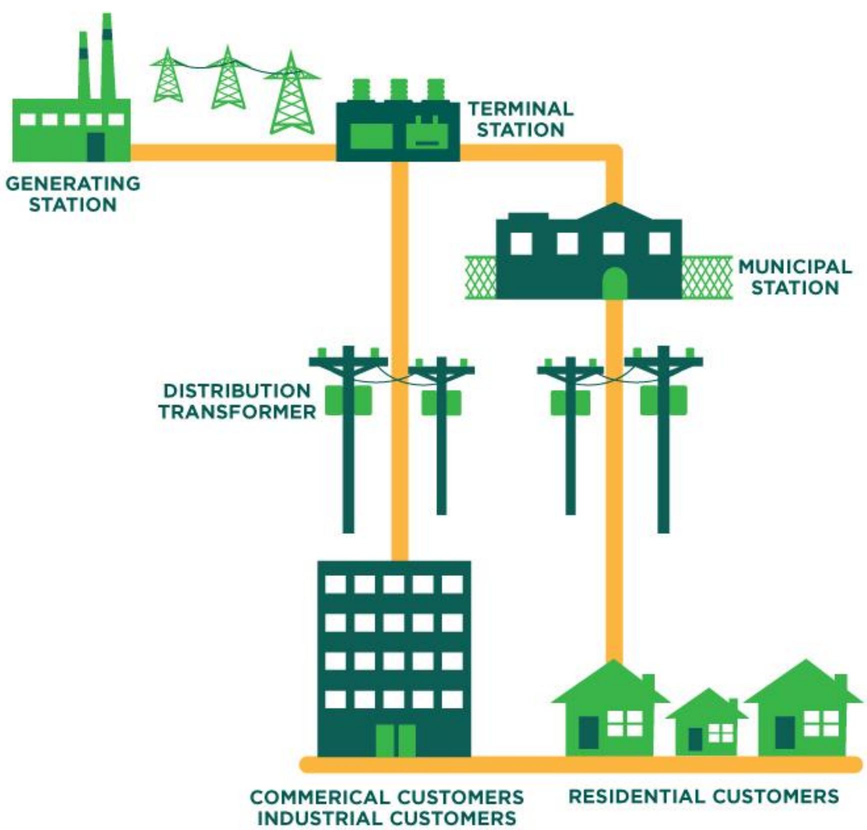
4.1 Industry Structure

The electricity industry in the Province is divided into four principal segments:

- Generation - the production of electricity at generating stations using nuclear, fossil, hydro, solar, wind or other sources of energy;
- Transmission - the transfer of electricity from generating stations to local areas using large, high-voltage power lines;
- Distribution - the delivery of electricity to homes and businesses within local areas using relatively low-voltage power lines; and
- Retailing - the purchase of electricity from generators and its sale to consumers together with a range of related services.

Electricity produced at generating stations is boosted to high voltages by nearby transformers so that the electricity can be transmitted long distances over transmission lines with limited power loss. The voltage is then reduced (stepped down) at terminal stations for supply to electricity distributors or large customers. Electricity distributors carry the electricity to distribution transformers that further reduce the voltage for supply to local customers. Electricity is distributed in the Province through a network of local electricity distributors that includes municipal electricity distributors, privately owned electricity distributors, and Hydro One.

The following diagram illustrates the basic structure of an electricity infrastructure system:



4.2 Toronto Hydro Corporation

Toronto Hydro Corporation is a holding company which wholly owns two subsidiaries:

- LDC – distributes electricity and engages in CDM activities; and
- TH Energy – provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries. The City is the sole shareholder of the Corporation.

4.3 Toronto Hydro-Electric System Limited ("LDC")

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates $4.7 billion of Capital Assets comprised primarily of an electricity distribution system that delivers electricity to approximately 772,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the Province.

(a) LDC's Electricity Distribution System

Electricity produced at generating stations is transmitted through transmission lines owned by Hydro One to terminal stations at which point the voltage is then reduced (or stepped down) to distribution-level voltages. Distribution-level voltages are then distributed across LDC's electricity distribution system to distribution class transformers at which point the voltage is further reduced (or stepped down) for supply to end use customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use circuits.

LDC's electricity distribution system is serviced from 1 control centre, 34 terminal stations and 1 transmission system terminal station, and is comprised of approximately 17,400 primary switches, approximately 60,560 distribution transformers, 146 in-service municipal substations, approximately 15,515 circuit kilometres of overhead wires supported by approximately 179,400 poles and approximately 13,207 circuit kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre. The control centre co-ordinates and monitors the distribution of electricity throughout LDC's electricity distribution assets, and provides isolation and work protection for LDC's construction and maintenance crews and external customers. LDC's control centre utilizes supervisory control and data acquisition (SCADA) systems to monitor, operate, sectionalize and restore the electricity distribution system.

(ii) *Terminal Stations*

LDC receives electricity at 34 terminal stations at which high voltage is stepped down to distribution-level voltages. These terminal stations contain power transformers and high-voltage switching equipment that are owned by Hydro One. These terminal stations also contain equipment such as circuit breakers, switches and station busses.

(iii) *Transmission System Terminal Stations*

LDC receives electricity at Cavanagh transmission system terminal station at which high voltage is stepped down to distribution-level voltages. The transmission system terminal station contains power transformers, high-voltage switching equipment, and low-voltage equipment such as circuit breakers, switches and station busses that are owned by LDC.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station in response to the developing need for distribution solutions in the downtown core of the City. Copeland Station will be considered a transmission system terminal station.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. It will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During 2018, the testing on high voltage cable, the protection and control equipment, and the supervisory control and data acquisition system were all completed. The Corporation received approval from HONI, the electricity transmission provider, and the IESO for energization of the project and successfully energized one of two Copeland Station power transformers with associated cables and switchgear. The second power transformer and associated switchgear is anticipated to be energized in the first half of 2019 following the HONI's completion of additional servicing to some of their equipment. As at December 31, 2018, the cumulative capital expenditures on the Copeland Station project amounted to $202.6 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See Part 8 under the heading "Risk Factors" below for further information on the Copeland Station project.

(iv) *Distribution Transformers and Municipal Substations*

Electricity at distribution voltages is distributed from the terminal stations to distribution transformers that are typically located in buildings or vaults or mounted on poles or surface pads that are used to reduce or step down voltages to utilization levels for supply to customers. The electricity distribution system includes approximately 60,560 distribution transformers. The electricity distribution system also includes 146 in-service municipal substations that are located in various parts of the City and are used to reduce or step down electricity voltage prior to delivery to distribution transformers. LDC also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

(v) *Wires*

LDC distributes electricity through a network comprised of an overhead circuit of approximately 15,515 kilometres supported by approximately 179,400 poles and an underground circuit of approximately 13,207 kilometres.

(vi) *Metering*

LDC provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. LDC owns the meters and is responsible for their maintenance and accuracy.

As part of its metering services, LDC also installs Unit Smart Meters in multi-unit complexes that fall within the Competitive Sector Multi-Unit Residential rate class. As at December 31, 2018, LDC had installed approximately 77,000 Unit Smart Meters in these types of multi-unit complexes.

(vii) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and the CEA for the twelve month periods ending December 31 in the years indicated below.

	LDC 2018	**LDC 2017**	**CEA 2017[(1)]**
SAIDI	0.98	0.99	7.15
SAIFI	1.48	1.43	2.53
CAIDI	0.66	0.69	2.82

Note:

(1) Data was extracted from the CEA's 2017 Service Continuity Report on Distribution System Performance in Electrical Utilities, excluding significant events. At the date of this AIF, such report for the year 2018 has not been published by the CEA.

(b) LDC's Service Area and Customers

LDC is the sole provider of electricity distribution services in the City, and serves approximately 772,000 customers. The City is the largest city in Canada with a population of approximately 2.9 million. The City is a financial centre with large and diversified service and industrial sectors.

The table below sets out LDC's customer classes and certain operating data with respect to each class for each of the years in the two-year period ended December 31, 2018:

	Year ended December 31	
	2018	**2017** (4)
Residential Service (1)		
Number of customers (as at December 31)......................	689,560	685,292
kWh..	5,418,189,931	4,933,060,853
Revenue	$815,401,037	$902,313,523
% of total service revenue	24.1%	25.5%
General Service (2)		
Number of customers (as at December 31)	82,292	82,233
kWh	17,806,672,372	17,276,676,523
Revenue	$2,337,309,219	$2,394,421,297
% of total service revenue	69.2%	67.8%
Large Users (3)		
Number of customers (as at December 31)	38	44
kWh	2,066,558,040	2,171,461,259
Revenue...	$225,602,981	$237,594,414
% of total service revenue	6.7%	6.7%
Total		
Number of customers (as at December 31)	771,890	767,569
kWh..	25,291,420,343	24,381,198,635
Revenue	$3,378,313,237	$3,534,329,234

Notes:

(1) "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

(2) "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.

(3) "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

(4) Effective January 1, 2018, the Corporation adopted IFRS 15 *Revenue from Contracts with Customers* (“IFRS 15”) and resulted in $207.6 million income statement reclassification between energy sales and energy purchases for the year ended December 31, 2017. The 2017 revenue has been restated in accordance with IFRS 15.

(c) LDC's Real Property

The following table sets forth summary information with respect to the principal real property owned, leased or otherwise used by LDC as at December 31, 2018:

Property	**Total**
Terminal stations	34 sites
Transmission system terminal stations	1 site
Municipal substations	146 sites
Decommissioned municipal substations	24 sites
Control centre(1)	1 site
Operation centres(2)	5 sites
Other(3)	32 sites

Notes:

(1) LDC's control centre is located within one of its operation centres.

(2) LDC's operation centres accommodate office, staff, crews, vehicles, equipment and material necessary to operate and monitor the electricity distribution system.

(3) Other properties include locations under construction (including Copeland Station), small work centres and surplus properties.

Under the OEB Act, electricity distributors are entitled to apply to the OEB for authority to expropriate land required in connection with new or expanded electricity distribution lines or interconnections. If, after a hearing, the OEB is of the opinion that the expropriation of land is in the public interest, the OEB may make an order authorizing expropriation upon payment of specified compensation. The Electricity Act grandfathered thousands of existing unregistered easements, principally for distribution over third-party lands. The Electricity Act also authorizes electricity distributors to locate assets on, over or under public streets and highways.

(d) Regulation of LDC

(i) *Legislative Framework*

The Electricity Act and the OEB Act provide the broad legislative framework for the Province's electricity market.

The Electricity Act restructured the Province's electricity industry. Under the Electricity Act, the former Ontario Hydro was reorganized into five separate corporations (listed below under their current names):

- OPG, the entity responsible for the former Ontario Hydro's generation business;
- Hydro One, the entity responsible for the former Ontario Hydro's electricity transmission, distribution and energy services businesses;
- OEFC, the entity responsible for managing and retiring the former Ontario Hydro's outstanding indebtedness and remaining liabilities;
- IESO, a non-profit corporation responsible for central market operations, long-term planning, procurement and conservation efforts; and
- Electrical Safety Authority, a non-profit corporation responsible for the electric installation inspection function.

Additionally, the Electricity Act requires electricity distributors in the Province to keep their distribution businesses separate from their other businesses.

The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, the regulation of electricity distribution rates charged by LDC and other electricity distributors and transmission rates charged by Hydro One and other transmitters. The OEB Act states that, subject to certain exceptions, LDC and other electricity distributors shall not carry on any business activity other than the distribution of electricity, except through affiliated companies. As an exception to the general restriction on its business activities, the OEB Act permits LDC to provide additional services related to the promotion of CDM activities and alternative, cleaner and renewable sources of energy and energy storage. As well, the OEB may authorize LDC to carry on a non-distribution business activity.

Through amendments to the Electricity Act, the operations and responsibilities of the IESO were amended on January 1, 2015 such that it was additionally authorized to implement an integrated power system supply plan and deliver CDM programs in the Province, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

The Energy Consumer Protection Act came into force on January 1, 2011. The Energy Consumer Protection Act amends several statutes, including the OEB Act, the Electricity Act, the Consumer Protection Act and the Residential Tenancies Act. The Energy Consumer Protection Act also enables and sets out the requirements relating to LDC's installation of Unit Smart Meters in multi-unit complexes and provides new rules regarding the manner in which energy consumers are to be billed for their electricity consumption.

On December 3, 2015, Bill 112 – Strengthening Consumer Protection and Electricity System Oversight Act, 2015 received Royal Assent and certain provisions thereunder were proclaimed into force effective as of March 4, 2016. The bill's measures as proclaimed into force amend the Energy Consumer Protection Act and the OEB Act by further enhancing consumer protection and increasing the OEB's powers with regard to utility regulation, including increases to potential administrative penalties for non-compliance. The bill also eliminates limitations on LDC affiliate lines of business and gives the OEB the discretion to authorize LDC and other electricity distributors to carry on a non-distribution business activity.

(ii) *Licences*

Distribution Licence

The OEB has granted LDC a distribution licence. The term of the current licence is until October 16, 2023. The licence allows LDC to own and operate an electricity distribution system in the City. Among other things, the licence provides that LDC must keep financial records associated with distributing electricity separate from its financial records associated with other activities, may not impose charges for the distribution of electricity except in accordance with distribution rate orders approved by the OEB and must comply with industry codes established by the OEB.

Electricity Generation Licence

On December 18, 2002, the OEB issued an electricity generation licence to TH Energy and TREC Windpower Co-operative (No.1) Incorporated (the co-venturers), in connection with a wind turbine located at Exhibition Place in the City. The licence allows the co-venturers to generate electricity or provide ancillary services for sale through the IESO-administered markets, or directly to another person, subject to certain terms and conditions. This licence terminates on December 17, 2022, although the term may be extended by the OEB.

(iii) *Industry Codes*

The OEB has established the Affiliate Relationships Code, the Distribution System Code, the Retail Settlement Code, the Standard Supply Service Code, and the Conservation and Demand Management Code. These codes prescribe minimum standards of conduct, as well as standards of service, for electricity distributors in the non-competitive electricity market, and have been assigned the following ranking in the event there is a conflict between them:

(1) Affiliate Relationships Code
(2) Distribution System Code
(3) Retail Settlement Code
(4) Standard Supply Service Code
(5) Conservation and Demand Management Code

These codes are summarized below.

Affiliate Relationships Code

The Affiliate Relationships Code establishes standards and conditions for the interaction between electricity distributors and their affiliated companies. It is intended to minimize the potential for an electricity distributor to cross-subsidize competitive or non-monopoly activities, protect the confidentiality of consumer information collected by an electricity distributor and ensure that there is no preferential access to regulated services. The Affiliate Relationships Code prescribes standards of conduct for an electricity distributor with respect to the following: the degree of separation from affiliates; sharing of services and resources; transfer pricing; financial transactions with affiliates; equal access to services; and confidentiality of customer information.

Distribution System Code

The Distribution System Code establishes the minimum conditions that an electricity distributor must meet in carrying out its obligations to distribute electricity under its licence and under the Energy Competition Act, and has been amended as the regulatory environment has evolved. Generally, the Distribution System Code prescribes the rights and responsibilities of electricity distributors and electricity distribution customers with respect to the following: connections; connection agreements and conditions of service; expansion projects; alternative bids (available to customers for work otherwise done by an electricity distributor); metering; operations; disconnection and security deposits; and other matters.

Retail Settlement Code

The Retail Settlement Code outlines the obligations of an electricity distributor with respect to its relationship with retail market participants and its role as a retail market settlements administrator. Under the terms of the Retail Settlement Code, an electricity distributor is required to do the following: unbundle the costs of competitive electricity services and non-competitive electricity services; record, in variance accounts, the difference between amounts billed by the IESO to the electricity distributor for competitive and non-competitive electricity services, and the aggregate amounts billed by the electricity distributor to consumers, retailers and others for the same services; and provide electricity billing and settlement services to retailers and customers.

Standard Supply Service Code

The Standard Supply Service Code requires an electricity distributor to act as a default supplier and provide Standard Supply Service to persons connected to the electricity distributor's distribution system. The Standard Supply Service Code also specifies the conditions and manner by which OEB approved Standard Supply Service rates are to be charged to customers. Under the Standard Supply Service Code, an electricity distributor's rates for Standard Supply Service must be approved by the OEB and must consist of the price of electricity and an administrative charge that will allow the electricity distributor to cover its costs of providing the service.

Conservation and Demand Management Code

CDM activities over the January 1, 2015 to December 31, 2020 timeframe are governed by the OEB's Conservation and Demand Management Requirement Guidelines for Electricity Distributors issued on December 19, 2014. See section 5.4 under the heading "Conservation and Demand Management" for more information on LDC's CDM activities.

(e) Distribution Rates

(i) *Rate Setting Mechanism*

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and IRM adjustments. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base (i.e. the aggregate of approved investment in PP&E and intangible assets excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital). IRM adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

Administratively, the OEB currently regulates the electricity rates for distributors through one of three specific rate-setting methods: Price Cap Incentive Rate-setting (suitable for most distributors), CIR (suitable for distributors with large or highly variable capital requirements), and Annual Incentive Rate-setting Index (suitable for distributors requiring limited rate adjustments). Under each of these methods, the OEB also allows recovery of costs arising from significant events satisfying certain criteria which are considered external to the regulatory regime and beyond the control of management.

Under the Price Cap Incentive Rate-setting method, rates are set on a single forward test-year cost of service basis for the first year and indexed for four subsequent years through an industry-standard IRM adjustment (using the 4^{th} generation price cap index formula). Under this method, the ICM is available to address any incremental capital investment needs that may arise during the term. In order to determine whether a distributor is eligible for the ICM, the OEB conducts a review of the distributor's ICM application by way of a detailed examination of evidence and consideration of a number of criteria, such as materiality, need and prudence.

Under the CIR method, rates are set for a minimum period of five years, typically on a forward test-year cost of service basis for the first year with subsequent annual adjustments based on a distributor-specific custom index. The particular mechanics through which rates are set and adjusted are determined by the OEB on a case-by-case basis.

The Annual Incentive Rate-setting Index method sets a distributor's rates through an industry-standard IRM adjustment (using a limited form of the 4^{th} generation price cap index formula) for one or more years.

Under each method, actual operating conditions may vary from forecasts such that actual returns achieved can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order.

On August 15, 2018, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC’s 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024.

See section 5.2 under the heading "Rate Applications" for more information on LDC's rate applications.

(ii) *Other Regulated Charges*

The OEB's 2006 Electricity Distribution Rate Handbook provides standard rates and guidelines to electricity distributors with respect to other regulated charges that are non-competitive in nature, required under OEB codes and guidelines, governed by the market rules or are under the direction of the Province, including transmission charges and retail service charges relating to services provided by electricity distributors to electricity retailers in accordance with the Retail Settlement Code. As part of its rate application filed on July 31, 2014, LDC sought the OEB's approval to update its other regulated charges commencing on May 1, 2015. In the CIR decision and rate order, the OEB approved updates to these other regulated charges.

(f) Competitive Conditions

The OEB distribution licence issued to LDC stipulates a service area that reflects the territory within the City. By law, only the OEB can grant such a licence for a service area and only an entity with such a licence can provide licenced services to the public-at-large within a service area. The OEB has not granted any other distribution licence that permits distribution within LDC's service area. In addition to this regulatory barrier to entry, there are other barriers to entry, including the cost of constructing an electricity distribution system, physical space limitations within and legal access to the right-of-way, the specialized skills associated with the distribution business, the level of expertise required to achieve operational and regulatory compliance, and LDC's relationships with its customers. Notwithstanding the existing barriers to entry, other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity. The pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation), government-based incentives, and technology advancements (e.g., multi-unit building sub-metering, micro-grids, electricity storage, virtual power).

4.4 Toronto Hydro Energy Services Inc.

TH Energy owns and operates $42.2 million of Capital Assets as of December 31, 2018. TH Energy owns certain street lighting assets located in the City, and has an agreement with the City to provide street lighting system maintenance and capital improvement services to the City. TH Energy sub-contracts street lighting services to LDC.

TH Energy also operates a wind turbine located at the Better Living Centre (Exhibition Place) in a joint venture with TREC Windpower Cooperative (No.1) Incorporated.

4.5 Environmental Matters

(a) Environmental Protection Requirements

Toronto Hydro is subject to extensive federal, provincial and local regulation relating to the protection of the environment. The principal federal legislation is the Canadian Environmental Protection Act which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances. Toronto Hydro is also subject to the federal Transportation of Dangerous Goods Act which prescribes safety standards and requirements for the handling and transportation of hazardous goods including PCBs and sets reporting, training and inspection requirements relating thereto.

The principal provincial legislation is the Environmental Protection Act which regulates releases and spills of contaminants, including PCBs, ozone-depleting substances and other halocarbons, contaminated sites, waste management, and the monitoring and reporting of airborne contaminant discharge. The provincial Technical Standards and Safety Act also applies to Toronto Hydro's operations with respect to the handling of and training related to compressed gas, propane and liquid fuels. The provincial Fire Protection and Prevention Act requires Toronto Hydro to incorporate procedures and training for dealing with any spills of flammable or combustible liquids. The provincial Dangerous Goods Transportation Act prescribes safety standards and requirements for the transportation of dangerous goods on provincial highways and sets out inspection requirements related thereto.

Municipal by-laws regulate discharges of industrial sewage and storm water run-off to the municipal sewer system and the reporting of the release of certain toxic substances into the environment.

(b) Financial and Operational Effects of Environmental Protection Requirements

In 2018, LDC spent approximately $3.1 million to meet environmental protection requirements. This includes costs for hazardous and non-hazardous waste disposal, testing, asbestos abatement, site remediation, wood and concrete pole removal, manifest and tonnage fees, Stewardship Ontario fees and the 2018 expenditure for the submersible transformer replacement program.

Toronto Hydro recognizes a liability for its best estimate of the future removal and handling costs for contamination in electricity distribution equipment in service. The liability is recognized when the decommissioning provision is incurred and when the fair value is determined. Actual future environmental costs may vary materially from the estimates used in the calculation of the decommissioning provision on Toronto Hydro's balance sheet.

(c) Environmental Policy and Oversight

Toronto Hydro has a strong commitment to the environment through the enforcement of a well-defined Environmental Policy. Conformance with the Environmental Policy is managed by Toronto Hydro's Environmental, Health and Safety department led by the Executive Vice-President and Chief Human Resources & Safety Officer. The content of the Environmental Policy is reviewed and approved annually by the Board.

Toronto Hydro's Environmental Policy identifies several core environmental principles, which include:

- Commitment from leadership to provide suitable and sufficient resources for the environmental management system;
- Compliance with all applicable laws, codes and standards;
- Continual improvement of environmental performance through the establishment of annual objectives, targets and programs;
- Employee engagement through education, training and providing general awareness of the Environmental Policy requirements and the environmental management system;
- Stakeholder engagement including consultation and engagement of environmental issues within the community and various stakeholders such as suppliers, customers, regulators, industry and the public;
- Pollution prevention through the implementation of policies, programs and procedures; and
- Integration of environmental considerations into our business processes.

LDC manages its environmental aspects in conformance with ISO 14001:2015 and was re-certified on January 18, 2019 as meeting the requirements of the ISO 14001:2015 standard by a third party auditor.

Legislative environmental reporting for federal, provincial and municipal governments is compiled and submitted annually. Third party environmental compliance audits are also conducted biennially in conformance with LDC's environment, health and safety audit plan.

Toronto Hydro's environmental policies, programs and procedures are reviewed and approved by management. Quarterly updates are presented to the Board's Human Resources and Environment Committee covering current environmental risks, environmental compliance audit findings, mitigation strategies and other material environmental matters.

4.6 Additional Information Regarding Toronto Hydro

(a) Employees

At December 31, 2018, Toronto Hydro had approximately 1,400 employees. Included in Toronto Hydro's employees are 723 members of bargaining units represented by the Power Workers' Union ("PWU"), 70 engineers represented by the Society of United Professionals, and an additional 75 Information Technology (IT) Professionals who will soon also be represented by the Society of United Professionals. Toronto Hydro employees currently represented by PWU were formerly represented by Canadian Union of Public Employees, Local One ("CUPE One"), which merged with PWU on October 6, 2016. The Society of United Professionals was certified as the bargaining agent for IT Professionals at Toronto Hydro on November 21, 2018. Toronto Hydro expects to receive notice to bargain by the end of March 2019, and to thereafter bargain with the Society of United Professionals for a first collective agreement to represent these employees.

On May 24, 2018, the PWU ratified collective agreements governing inside and outside employees for a four-year period beginning February 1, 2018 and expiring January 31, 2022. The collective agreements implemented wage increases of 2.3% effective on each of February 1, 2018, February 1, 2019, February 1, 2020, and February 1, 2021. The collective agreements also contain cost of living escalator clauses in the third and fourth years of the current agreements that provide for wage adjustments corresponding to the percentage change in the Consumer Price Index. The escalator clauses only become effective if certain prescribed thresholds are exceeded.

Full time employees of Toronto Hydro participate in the OMERS pension plan. Plan benefits are determined based on a formula that takes into account the highest 5-year average contributory earnings and the number of years of service and are indexed to increases in the Consumer Price Index, subject to an annual maximum of 6%. Any increase in the Consumer Price Index above 6% per year is carried forward for later years. Both participating employers and participating employees are required to make equal plan contributions based on participating employees' eligible contributory earnings. All obligations to make payments to retirees under the OMERS pension plan are the responsibility of OMERS.

In addition to OMERS, Toronto Hydro provides other employment and post-employment benefits to employees, including medical, dental and life insurance benefits. See note 25(m) and note 13 to the Consolidated Financial Statements.

(b) Specialized Skills and Knowledge

Trades and technical jobs play a critical role in the safe and reliable design, construction and maintenance of LDC's electricity distribution system. These jobs include overhead, underground, and stations trades as well as control room operators, designers and engineers. LDC hires experienced workers when available, along with apprentices for trades and technical positions. Trade apprentices require between 4 and 6 years to become fully competent and capable of performing all aspects of their job. LDC provides trades, legislative and compliance training through its apprenticeship program.

(c) Health and Safety

Toronto Hydro is committed to a safe and injury free work environment for all employees, contractors, visitors and the public. Through LDC's EHSMS, based on British Standards Institution OHSAS 18001:2007 Standard "*Occupational Health and Safety Management System - Requirements*", LDC maintains and reviews procedures, programs and the Occupational Health and Safety Policy which outlines several core principles including:

- Compliance
- Continual Improvement
- Engagement and Consultation
- Communication
- Accountability
- Risk Management
- Contractor Management
- Incident Investigation
- Performance Monitoring

The content of the Occupational Health and Safety Policy is reviewed and approved annually by the Board.

Toronto Hydro's health and safety performance is reviewed periodically by the Human Resources and Environment Committee of the Board. In 2018, the Total Recordable Injury Frequency was 0.83 recordable injuries per 200,000 hours worked compared to 1.06 in 2017.

LDC's legislated occupational health and safety requirements come under provincial jurisdiction exclusively and all legislated occupational health and safety reporting requirements are complied with. Management assurance that these requirements are met is accomplished by commissioning third party health and safety compliance audits conducted in conformance with LDC's environmental, health and safety audit plan.

Toronto Hydro's occupational health and safety policies, programs and procedures are reviewed and approved by management. Quarterly updates are presented to the Board covering current occupational health and safety risks, performance, compliance audit findings, mitigation strategies and other occupational health and safety matters.

(d) Code of Business Conduct and Whistleblower Procedure

All employees, officers and directors of Toronto Hydro are required to comply with the principles set out in the Code of Business Conduct and Whistleblower Procedure (the "Code"), which was originally implemented by Toronto Hydro in 2003, and is reviewed, revised and approved by the Board from time to time. The Code provides guidance to all employees in situations of potential perceived conflict of interest. All employees, officers and directors of Toronto Hydro are required to complete training in respect of the Code and sign an attestation in accordance with the Code upon commencement of employment and every three years thereafter.

The Code provides for the appointment of an Ethics Officer and establishes a direct hotline to the Ethics Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. Where the complaint involves the conduct of a director or officer of Toronto Hydro, the Ethics Officer is required to report it to the Chair of the Human Resources and Environment Committee of the Board, or, where such conduct relates to questionable auditing or accounting matters, to the Chair of the Audit Committee of the Board, who oversees the investigation of that complaint. In addition to the provisions of the Code, the Ethics Officer reports quarterly to the Human Resources and Environment Committee of the Board on the nature of complaints received and the Director, Internal Audit and Compliance reports quarterly to the Audit Committee on matters related to audit and accounting. A copy of Toronto Hydro's Code of Business Conduct and Whistleblower Procedure is available on the SEDAR website at www.sedar.com.

(e) Insurance

Toronto Hydro's current insurance policies provide coverage for a variety of losses and expenses which might arise from time to time, including:

- comprehensive general liability insurance;
- all risk property, property terrorism, boiler and machinery insurance;
- automobile liability insurance;
- directors and officers liability insurance;
- cyber insurance;
- crime insurance; and
- insurance covering loss or damage on certain physical assets.

Toronto Hydro believes that the coverage, amounts and terms of its insurance arrangements are consistent with industry practice.

(f) Intangible Property

The Corporation owns various intangible assets, such as computer software systems used in the course of business, and intellectual property, including the "Toronto Hydro" brand name and the trademark Toronto Hydro & Star Design. The Corporation also owns the trademarks peakSAVER®, POWERSHIFT® and PEAKSAVER PLUS®. The trademarks peakSAVER® and PEAKSAVER PLUS® have been licensed by the Corporation to the IESO and sub-licensed to various electricity distributors in the Province for the promotion of a province-wide demand response CDM program.

(g) Seasonal Effects

Toronto Hydro's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions. Revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. Toronto Hydro's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions and rate orders.

PART 5 - GENERAL DEVELOPMENT OF THE BUSINESS

5.1 Business Operations

(a) Three Year History

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2018, 2017 and 2016. This information has been derived from the Consolidated Financial Statements and is presented in millions of dollars.

	Year ended December 31		
	2018	**2017**	**2016**
Net income after net movements in regulatory balances	$167.3	$156.5	$151.4
Capital expenditures	$511.3	$552.9	$551.7
Total assets and regulatory balances	$5,360.1	$5,226.2	$4,954.4
Total equity	$1,833.5	$1,760.4	$1,428.9

(b) Business Operations

Over the past three years, Toronto Hydro continued to streamline its business operations to focus on LDC's core businesses of distributing electricity and engaging in CDM activities. See section 5.4 under the heading "Conservation and Demand Management" for more information on LDC's CDM activities.

5.2 Rate Applications

The following is an overview of LDC's rate applications from 2015 to date.

(a) 2015-2019 Rate Application

On July 31, 2014, LDC filed a rate application with the OEB under the CIR method which sought approval of LDC's 2015 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective May 1, 2015, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2016 and ending on December 31, 2019. The rate application included requests for approval of capital expenditures of approximately $2.5 billion over the 2015-2019 period. The rate application also sought approval to include in LDC's rate base capital amounts that were prudently incurred prior to 2015, subject to review by the OEB. In addition, LDC sought approval to recover the net book value of stranded meters.

On December 29, 2015, the OEB issued its CIR decision and on March 1, 2016, the OEB issued its CIR rate order, both in relation to the 2015-2019 rate application filed on July 31, 2014. The CIR decision and rate order approved a rate base of $3,232.0 million and revenue requirement of $633.1 million for 2015, and rates calculated on that basis. The CIR decision and rate order also approved, on an interim basis, subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2016 and ending on December 31, 2019. The OEB-approved revenue requirement generates an increase in funded capital expenditures over the CIR period.

The OEB approved new deferral and variance accounts including accounts to capture variances related to revenue requirement for ICM capital work undertaken from 2012 to 2014 and revenue requirement associated with capital work during the CIR term. The OEB approved recovery of the $15.8 million forecasted net book value relating to the stranded meters. The OEB also approved foregone revenue rate riders for the May 1, 2015 to February 29, 2016 period as well as other requested rate riders. In addition, the OEB approved the transfer of LDC's street lighting assets into rate base effective January 1, 2015 at a transfer price of $39.8 million, representing the opening net book value of the assets in 2015. The financial impact of the OEB's CIR decision and rate order has been reflected in 2015.

The rates for 2015 and 2016 were implemented on March 1, 2016, with effective dates of May 1, 2015 and January 1, 2016, respectively.

On August 22, 2016, LDC filed its 2017 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2017 and ending on December 31, 2017. On December 21, 2016, the OEB issued a decision finalizing LDC's 2017 rates and providing for other deferral and variance account dispositions.

On August 23, 2017, LDC filed its 2018 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2018 and ending on December 31, 2018. On December 14, 2017, the OEB issued a decision finalizing LDC's 2018 rates and providing for other deferral and variance account dispositions.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a decision and rate order approving LDC's 2019 rates and providing for other deferral and variance account dispositions.

(b) 2020-2024 Rate Application

On August 15, 2018, LDC filed a CIR application seeking approval of LDC's 2020 test-year revenue requirement on a cost of service basis and the corresponding electricity distribution rates effective January 1, 2020, and the subsequent annual rate adjustments based on a custom index specific to LDC for the period commencing on January 1, 2021 and ending on December 31, 2024. The rate application requests approvals to fund capital expenditures of approximately $2.8 billion over the 2020-2024 period. The rate application also seeks approval to include in LDC's rate base capital amounts that were incurred prior to 2020.

5.3 Ontario's Fair Hydro Plan

On March 2, 2017, the Government of Ontario announced the OFHP which includes a number of initiatives, some of which affect LDC or its customers.

OFHP includes the OREC, which came into effect on January 1, 2017. The OREC provides eligible customers with financial assistance in the form of an 8% rebate of the pre-tax cost of their electricity. The OREC rebates are administered by LDC and paid by the IESO in the month following customer billing. Current accounts receivable and unbilled revenue include the amount owing by the IESO to LDC. No effect on revenue or expense is recognized by LDC in respect of the OREC rebates.

OFHP also includes the OFHA, which enacted the Ontario Fair Hydro Plan Act, 2017 and amended the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. The OFHA came into effect on June 1, 2017 and its impact is reflected in the Consolidated Financial Statements. The OFHA provides eligible customers with financial assistance through various changes to commodity pricing, new or amended programs, and eliminating or reducing certain provincial charges on the electricity bill. The OFHP reduces electricity bills by 25% on average for eligible customers, which includes the 8% OREC rebate. The OFHA reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable, unbilled revenue, accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHA.

5.4 Conservation and Demand Management

The objective of the CDM programs is to reduce electricity consumption in the Province of Ontario by a total of 7 terawatt hours between January 1, 2015 and December 31, 2020, of which LDC's share is approximately 1,576 GWh of energy savings.

Under the energy conservation agreement with the IESO, LDC has a joint CDM plan with Oakville Hydro for the delivery of CDM programs over the 2015-2020 period. The IESO reimburses LDC for all adequately documented incurred costs, with an option to receive a portion of its funding in advance. Cost efficiency incentives may be awarded if LDC's electricity savings meet or exceed certain CDM plan targets for programs under the full cost recovery funding method, including a mid-term incentive based on a review of the 2015-2017 period.

The joint CDM plan provides combined funding of approximately $421.0 million, including participant incentives and program administration costs, with an energy savings target of approximately 1,648 GWh. The program for Oakville Hydro under the joint CDM plan started on January 1, 2016. LDC received $162.4 million from the IESO as at December 31, 2018 to deliver the CDM programs. Amounts received but not yet spent are presented on the consolidated balance sheets under current liabilities as deferred conservation credit. On September 26, 2018, $15.8 million was confirmed by the IESO as the joint mid-term incentive, of which $14.9 million representing LDC’s portion was received in November 2018.

PART 6 - RELATIONSHIP WITH THE CITY

6.1 Shareholder Direction

As sole shareholder of the Corporation, the City has adopted the Shareholder Direction that sets out the following corporate governance principles with respect to Toronto Hydro:

- the objectives and principles that govern the operations of Toronto Hydro;
- the matters in addition to those set out in the OBCA that require the approval of the City as the sole shareholder of the Corporation; and
- certain financial and administrative arrangements between the Corporation and the City.

The Shareholder Direction requires Toronto Hydro to conduct its affairs and govern its operations in accordance with such rules, policies, directives or objectives as directed by City Council from time to time.

(a) Shareholder Objectives and Principles

The Shareholder Direction provides that the following objectives and principles shall govern the operations of Toronto Hydro:

- to operate Toronto Hydro on an efficient and commercially prudent basis;
- to optimize the City's return on equity as the sole shareholder of the Corporation and operate Toronto Hydro with a view to meeting the financial performance objectives of the City as set out in the Shareholder Direction;
- to provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;
- to operate Toronto Hydro in an environmentally responsible manner consistent with the City's energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;
- to ensure that the business is managed in material compliance with all law; and
- to engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Shareholder Direction provides that the Board is responsible for determining and implementing the appropriate balance among these objectives and principles and for causing Toronto Hydro to conduct its affairs in accordance with the same.

(b) Shareholder Approval

In addition to those matters set out in the OBCA, the following matters, among others, require the approval of the City as the sole shareholder of the Corporation:

- subject to certain exceptions in the case of LDC, creating any security over the assets of the Corporation or LDC;
- in the case of LDC, providing any financial assistance to any person other than in accordance with the Shareholder Direction;
- in the case of the Corporation and LDC, making any investment in or providing any financial assistance to any subsidiary of the Corporation (other than LDC), other than trade payables incurred in the ordinary course of business on customary terms and an investment in or financial assistance to a subsidiary that originally was an investment in or financial assistance to LDC, in excess of 12% of the shareholder's equity of LDC as shown in its most recent financial statements; and
- acquiring any interest in the electricity distribution system, undertaking or securities of a distributor operating outside the City unless, among other things, the acquisition does not adversely affect the dividend payable to the City and there is no dilution of the City's shareholding in the Corporation.

The City has authorized the Corporation to provide financial assistance to its subsidiaries for the purpose of enabling them to carry on their respective businesses, including, in the case of LDC, for the purpose of satisfying the prudential requirements of the IESO. The Shareholder Direction limits the financial assistance that may be provided by the Corporation to its subsidiaries to an aggregate amount of $500.0 million, except in the case of LDC, which financial assistance is unlimited.

(c) Financial Performance

The Shareholder Direction provides that the Board will use its best efforts to ensure that Toronto Hydro meets certain financial performance standards, including those relating to the credit rating and dividends.

(d) Credit Rating

The Shareholder Direction provides that the Corporation will obtain and maintain a rating of A minus or higher (or its equivalent rating, depending on the credit rating agency) on its senior debt securities, as rated by two accredited credit rating agencies in Ontario (which include S&P, DBRS and Moody's). See section 9.4 under the heading "Credit Rating" for more information on the Corporation's credit ratings as at December 31, 2018.

(e) Equity Contribution

In December 2016, City Council approved making an equity contribution to the Corporation. On June 28, 2017, the Corporation issued 200 common shares to the City for total proceeds of $250.0 million, net of share issue costs and expenses.

(f) Dividends

In connection with receipt of the equity contribution of $250.0 million from the City on June 28, 2017, the Board declared dividends payable to the City and approved amendments to the Corporation's Dividend Policy, as follows:

- In respect of fiscal 2017, an aggregate amount of $75.0 million shall be paid to the City, consisting of two previously declared installments of $6.25 million each and a further $62.5 million. The $62.5 million was paid to the City on July 7, 2017.

- In respect of fiscal 2018 and subsequent fiscal years, 60% of the Corporation's consolidated net income after net movements in regulatory balances for the prior fiscal year shall be declared separately in four equal quarterly instalments, with each instalment payable to the City on the last business day of each fiscal quarter.

The revised Dividend Policy was set out in further detail, including that any dividends will be subject to restrictions imposed by law and the Shareholder Direction, in an amendment of the Shareholder Direction, which included the Corporation's former Dividend Policy. These changes also superseded the Board's previous decision announced in November 2016 that it would reduce dividend payments to the City to $25.0 million per year until further notice.

The Corporation declared and paid dividends to the City totalling $63.35 million in 2016, $75.0 million in 2017, and $93.9 million in 2018.

On March 6, 2019, the Board declared a quarterly dividend in the amount of $25.1 million, payable to the City by March 29, 2019.

LDC declared and paid $nil dividends to the Corporation in 2016, and declared and paid $2.1 million in 2017 and $42.7 million in 2018.

TH Energy declared and paid $nil dividends to the Corporation in 2016, 2017, and 2018.

6.2 Services Provided to the City

Toronto Hydro provides certain services to the City at commercial and regulated rates, including street lighting services. Ongoing street lighting services are provided by TH Energy and sub-contracted to LDC. See section 4.4 under the heading "Toronto Hydro Energy Services Inc." for more information. See note 22 to the Consolidated Financial Statements.

6.3 Shareholder Engagement

The Corporation believes that regular and constructive engagement with the City, its sole shareholder, is an important part of creating an open, candid and informed dialogue. In addition to the Corporation's annual shareholder meetings, representatives of the Corporation engage with the City through formal attendance at City of Toronto Council meetings and other engagements with Councillors throughout the year as required. Other means of communications with the City include the Corporation's annual and quarterly financial and management reports, and ward-specific updates.

PART 7- TAXATION

7.1 Tax Regime

The Corporation is exempt from tax under the ITA, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the OEFC in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

If the Corporation or a subsidiary ceases to be exempt from tax under the ITA and the TA, it will become subject to tax under those statutes, will no longer be required to make PILs payments to the OEFC, and will be deemed to have disposed of its assets for proceeds of disposition equal to their fair market value at that time and to have reacquired its assets at the same amount with the result that:

- such corporation would become liable to make a PILs payment in respect of any income or gains arising as a result of these deemed dispositions; and

- the amount of annual taxes payable by the corporation under the ITA, and the TA may be different from the PILs payment that would be payable without a loss of tax-exempt status to reflect, among other things, the consequences of these deemed dispositions and acquisitions.

The Electricity Act also provides that a municipal corporation or an MEU is required to pay a transfer tax when it transfers Electricity Property. An interest in Electricity Property includes any interest in a corporation, partnership or other entity that derives its value in whole or in part from Electricity Property. The transfer tax is the prescribed percentage (22% for transfers occurring between January 1, 2016 and December 31, 2018, and 33% for transfers occurring thereafter) of the fair market value of the interest transferred. The amount of transfer tax payable where the interest that is transferred is an interest in a corporation, partnership or other entity, is calculated in accordance with a special rule. The amount of transfer tax payable by an MEU on a transfer of Electricity Property may be reduced by:

- any PILs payment made by the MEU in respect of the part of the taxation year up to and including the date that the transfer takes place or a previous taxation year;

- any amount that the MEU has paid as tax under Part III of the TA in respect of the part of the taxation year up to and including the date of the transfer or a previous taxation year; and

- any amounts that the MEU would be liable to pay as tax under Part I of the ITA in respect of the taxation year if that tax were computed on the basis that the MEU had no income other than the capital gain realized on the transfer of its interest in the property.

Transfers of Electricity Property made to a MEU, Hydro One or OPG, or subsidiary of either of them and where the transferee is exempt from tax under the ITA at the time of transfer, the transfer will be an excluded transfer and thereby exempt from the transfer tax. Capital gains arising from a transfer of Electricity Property occurring between January 1, 2016 and December 31, 2018 are also exempt from the transfer tax.

In addition, a refund of transfer tax may be made where such tax had been paid on the sale or transfer of Electricity Property and where the proceeds of that transfer were reinvested in certain other capital or depreciable assets used in connection with generating, transmitting, distributing or retailing electricity in Ontario and, subject to certain deeming rules, before the end of the second taxation year following the taxation year in which the liability to pay the transfer tax arose.

PILs payments are deductible in computing the transfer tax only to the extent that they have not been previously applied to reduce transfer tax payable by a municipal corporation or a MEU.

7.2 PILs Recoveries through Rates

The OEB's Filing Requirements for Electricity Distribution Rate Applications provides for electricity distribution rate adjustments to permit recoveries relating to PILs payments. These recoveries are recalculated and submitted for recovery by LDC in each cost of service or rebasing distribution rate application. LDC is also generally at risk for variances between forecasted and actual PILs paid, excluding variances arising from changes in tax legislation not assumed in the setting of rates for the period in question, which variances are disposed of through deferral accounts under cost of service, IRM or CIR. See note 8(n) to the Consolidated Financial Statements.

PART 8 - RISK FACTORS

Risk Management

Toronto Hydro faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise wide approach to risk management, based on an overall enterprise risk philosophy, and achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure. Toronto Hydro's ERM framework utilizes industry best practices and international guidelines and focuses on identifying emerging trends in risks and related opportunities particular to Toronto Hydro through a comprehensive evaluation of Toronto Hydro's business and the industry generally. Toronto Hydro views ERM as a management activity undertaken to add value and improve overall operations. It helps Toronto Hydro by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Risk assessment is built into our decision-making process at all levels. Accordingly, ERM is an integral part of the strategic management of Toronto Hydro and is routinely considered in forecasting, planning and executing all aspects of the business.

The ERM framework is operationalized by a consistent, disciplined methodology that clearly defines the risk management process which incorporates subjective elements, risk quantification, risk trends and risk interdependencies.

While Toronto Hydro's philosophy is that ERM is the responsibility of all business units at all levels, in strategic and functional matters, the ERM governance structure is comprised of three key levels.

At the first level is the Board, which maintains a general understanding of Toronto Hydro's risk profile, the risk categories and the types of risks to which Toronto Hydro may be exposed, and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key risks that may impede the Corporation from achieving certain or all of its strategic objectives, and which are most material to its operational success.

The second level is the executive team, which ensures systems are in place to identify, manage, and monitor risks and trends. Through input from the business and other considerations, the executive team assesses the appropriateness and consistent application of systems to manage risks within Toronto Hydro. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across Toronto Hydro who actively engage in the day-to-day management of risks. Working with the executive team, this group oversees Toronto Hydro's risk profile and its performance against the defined risk philosophy. The senior leadership team understands changes in risk status and trends and determines appropriate risk responses and action plans. They also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

Toronto Hydro is continually reviewing its ERM program to ensure the organization is focused upon and responsive to risks of the greatest significance, likelihood and impact. In 2018, Toronto Hydro re-oriented its program to the key strategic and functional risk categories facing the organization, and the sub-component risks making up those categories. This allows Toronto Hydro's executive leadership and responsible business units to concentrate on these risks and undertake deeper dives into root causes and risk trends in these areas on both a short-interval and long-term basis. By focusing in particular on the strategic risks to the organization, decision-making is strengthened and Toronto Hydro has a greater ability to realise opportunities central to its interests.

Toronto Hydro's business is subject to a variety of risks including those key risk areas and major component risks described in the following sections. There can be no assurance that any steps Toronto Hydro may take to manage risks will avoid future loss resulting from the occurrence of such risks.

Strategic Risks

Oversight Risk

Risk that provincial government or regulator activity (laws, frameworks or policies) impedes the Corporation's effective performance, and its ability to meet its objectives and serve its customers.

Regulatory and Energy Policy Risk

Toronto Hydro is subject to the risk that its business activities may be impeded through the actions of regulatory authorities or by changes in regulation. There is a risk that future changes to Ontario's regulatory model, manner of regulation, and/or broader energy policy framework does not align with Toronto Hydro's business direction and could materially adversely affect the Corporation's strategic goals and financial results.

Ontario's electricity industry regulatory and other energy policy developments may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, and as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates at levels that will permit LDC to maintain safe and reliable service to its customers and earn the allowed rate of return on the investment in the business;
- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in providing distribution services to customers, in a timely manner or at all;
- the OEB will adopt the other rate-setting principles, formulae, and inputs in a manner that result in rates that properly support LDC's activities;
- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates; and
- the OEB will not permit other parties to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on Toronto Hydro.

LDC actively participates in industry engagement efforts in order to mitigate the above risks and realize potential opportunities in regulatory and energy policy development. Through these types of engagements, the Corporation monitors proposed regulatory and energy policy changes that may impede its business. LDC also employs a comprehensive organizational regulatory application program to ensure that all applications to the OEB achieve the highest utility standard of evidence gathering, preparation and presentation.

Emerging Government Policy Risk

Toronto Hydro is subject to the risk that the policy priorities of provincial and federal governments and regulatory bodies beyond those specifically applicable to the energy space, including policies of more general application, and the implementation of policies by such bodies, may impact Toronto Hydro's ability to deliver effective and efficient operations, meet business objectives, report on its activities and capitalize upon new opportunities. Developments and changes in any of the laws, rules, regulations and policies applicable to the businesses carried on by Toronto Hydro, and the manner of implementation and application of the same, could materially adversely affect Toronto Hydro. This may include developments with respect to labour and employment laws, changes to accounting standards and financial reporting requirements, environmental obligations and public safety rules, among others. The

Corporation actively engages with government entities and participates in industry organizations to monitor emerging policies and where possible plays an advocacy role.

Franchise Risk

Risk that restrictions in LDC’s business model and/or external conditions impede its ability to maintain and grow its right to be the sole provider of electricity distribution services in the City (its franchise) and serve its customers. Toronto Hydro is subject to the risk that it is displaced from its strategic position or fails to gain a strategic advantage, which could materially adversely affect the Corporation’s strategic goals and financial results.

The OEB has the authority to grant municipal distribution licences, has issued to LDC a licence stipulating a service area that reflects the territory within the City, and has not granted any other distribution licence that permits distribution within LDC's service area. In addition, there is a legal framework in place that establishes LDC, as the holder of the municipal distribution licence in the City, to be the sole provider of distribution activities across municipal rights of way. There is no assurance that these frameworks will continue to exist sufficiently or at all in order to provide LDC the opportunity to be the comprehensive distribution provider in the City.

While other regulated and unregulated entities have always competed with LDC and its predecessors to provide customers with other sources of energy, including electricity, the pervasiveness of this competition and its effects on LDC's distribution business have varied over time and continue to vary based on many factors, including the relative price of energy source (e.g., natural gas, grid-supplied electricity, behind-the-meter generation), technology development (e.g. energy storage), government-based incentives, regulatory frameworks, and compliance frameworks especially for non-utility entities.

There can be no assurance that the future nature, prevalence, or effects of these forms of competition will be comparable to current or historic experience. Failure to effectively scan our external and internal environment could lead to missed business opportunities and loss of competitive advantage.

Risks to Toronto Hydro’s franchise interests may also result from impairment to Toronto Hydro's image in the community, public confidence or brand. Toronto Hydro is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Negative perceptions regarding this commitment could impact the public’s perception of Toronto Hydro. In addition, events and/or external factors that draw negative media attention to Toronto Hydro could cause reputational damages and impact Toronto Hydro’s business and relationship with its stakeholders. These factors could lead customers, governments and regulators to look more favourably to alternative services and service providers to utility-based electricity distribution.

Toronto Hydro has dedicated personnel focused on monitoring external competitive factors, including alternative service providers and technologies, and developing strategies for further enhancing the LDC’s interactive grid which support the reliability of its core infrastructure grid operations, promote greater value, and deliver solutions for its customers. Additionally, Toronto Hydro maintains relationships with its customers to better understand the specific needs and expectations of each class of customer. The Corporation also conducts customer research and consultations in the ordinary course of its operations, and as part of the development of its rate application whereby it directly considered customer preferences and feedback, in addition to other inputs, as part of developing its business plan. Toronto Hydro also has dedicated personnel focused on the utility’s key account customers, which respond to issues raised by large commercial and industrial customers and assists with their energy management needs. Through these types of engagements, the Corporation can monitor its customers’ specific needs and can work with them to develop energy solutions.

Governance Risk

Risk that municipal activity (laws, policies, or intervention) impedes the Corporation’s effective performance, and ability to meet its objectives and serve its customers.

The Corporation is a government-controlled enterprise whose sole shareholder is the City. The operations of the Corporation and its subsidiaries are influenced by the broad by-law enactment and enforcement powers of the City. Additionally, as the Corporation’s sole shareholder, the City has set out the governing objectives and principles, including financial objectives, for the Corporation through the Shareholder Direction, as described above. Under the Shareholder Direction, the City has the power to direct the Corporation and its subsidiaries to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time. Certain conflicts may arise where the City’s goals and objectives in implementing such rules, policies, directives or objectives differ from the Shareholder Direction principles and could materially adversely affect the Corporation's business, operations, financial condition or prospects.

The Corporation engages on a systematic basis with the City Mayor, City Councillors, the City Manager’s office, and other departments and agencies to ensure a sharing of perspectives on the vital interests of Toronto Hydro and its customers. Through such engagements the parties review and consider the challenges to Toronto Hydro achieving the objectives and principles set out under the Shareholder Direction, and in particular the impact that proposed changes in city by-laws or municipal policies may create for Toronto Hydro’s ability to meet its business objectives and serve its customers.

Functional Risks

Human Capital Risk

Risk that the Corporation is unable to maintain necessary resource talent and skilled resources.

Toronto Hydro is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support Toronto Hydro’s future talent requirements. All retirements pose risks for knowledge management and business continuity at Toronto Hydro. Development and retention of talent to meet the evolving needs of the business requires LDC to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

Toronto Hydro's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances. Toronto Hydro's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions, including negotiating collective bargaining agreements with the Society of United Professionals and PWU. There can be no assurance that Toronto Hydro will be able to secure the support of its labour unions.

Toronto Hydro’s ability to develop its work processes to meet changing circumstances also depends on its ability to access adequate resources from its external contractor community. One way in which Toronto Hydro seeks to mitigate this risk is through its use of business practices and internal procedures to identify a diverse group of reputable third party service providers and entering into contracts with, and monitoring the performance of, these third-party service providers.

Operations Risk

Risk that the Corporation is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the grid at acceptable levels.

Asset Management Risk

Toronto Hydro is subject to the risk that it may be unable to maintain continuous supply due to failure of the distribution infrastructure and assets which could materially adversely affect the Corporation. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure (such as the Copeland Station project) to address safety, reliability and customer service requirements now and in the future.

LDC estimates that approximately 33% of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives by 2025. Asset condition assessment demographics also indicate substantial asset investment needs for a number of critical assets during this period. At the same time, Toronto is a growing city, and LDC must make upgrades to keep pace with urban intensification and electrification and ensure good stewardship of the distribution system. Further, extreme weather is no longer an infrequent experience, and has instead become a regular condition of operating a distribution system. For example, Toronto Hydro experienced four extreme weather events in the first half of 2018, leaving nearly 160,000 customers without electricity. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change, and adoption of electric vehicles and fuel-switching potentially increases, the pressures on Toronto Hydro’s system will only increase, and such factors may drive a need for incremental capital expenditures for system upgrades so that the grid can handle increased loads.

LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of Toronto Hydro to fund additional infrastructure investments, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

As described in section 4.3(a)(iii) under the heading "Transmission System Terminal Stations", one of LDC's largest capital initiatives currently in progress is the construction of Copeland Station, which is also one of the most complex projects ever undertaken by Toronto Hydro. The expected completion date for the Copeland Station is in the first half of 2019. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. The increase in costs and delay in completion date are attributable to a variety of factors, including contractor performance and construction delays. There may be additional unforeseen delays and expenditures prior to the completion of the project. On January 25, 2018, Toronto Hydro was informed that Carillion Construction Inc., the general contractor for the Copeland Station Project, filed for creditor protection under the Companies’ Creditors Arrangement Act after its affiliate, Carillion plc, went into compulsory liquidation in the United Kingdom. Other contractors have taken on part of the remaining work to contribute to the completion of the project. All capital projects for new and replacement infrastructure have risks related to delays or increased costs due to many factors, including: necessary modifications to project plans; the availability, scheduling and cost of materials, equipment and qualified personnel; LDC's ability to obtain necessary environmental and other regulatory and government approvals; and the impact of weather conditions, site conditions and contractor performance.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. It uses a variety of asset and project management tools to implement its plans, measures progress on a recurring short interval basis, and regularly monitors and manages the health of its assets. However, if LDC is unable to carry out these plans in a timely and optimal manner or becomes subject to significant unforeseen equipment failures, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, the ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets.

Toronto Hydro's ability to operate effectively is also in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, and Toronto Hydro's financial, billing and business systems to capture data and to produce timely and accurate information. Specifically, on October 1, 2018, the Corporation successfully completed the implementation of, and transitioned to, a new ERP system. The ERP system is being used to operate the Corporation’s financial, and business systems to capture data and to produce timely and accurate information. Failure of the newly implemented ERP system could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The Corporation has mitigation strategies, access to consultants with ERP expertise and is developing an internal ERP centre of excellence to help assist in the implementation, and support of ERP for users. Additionally, in respect of Toronto Hydro’s operational technology systems in general, there is isolation from business systems and independent operation which mitigates against wider systemic risk to the business systems.

Security Risk

Toronto Hydro is subject to the risk that it may be unable to preserve the confidentiality, integrity, authenticity, availability, accountability and non-repudiation of information assets.

LDC's electricity distribution infrastructure and technology systems are potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information (about customers, suppliers, counterparties and employees), additional regulatory scrutiny, litigation and reputational damage. Toronto Hydro has implemented security controls aligned with industry best practices and standards including the National Institute of Standards and Technology Cybersecurity Framework and the OEB’s Ontario Cyber Security Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, corruption or unavailability of critical data or confidential employee or customer information. A significant breach could materially adversely affect the financial performance of the Corporation or its reputation and standing with customers, regulators and in the financial markets. It could also expose Toronto Hydro to third-party claims.

LDC must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information (including the personal information of customers), as well as information provided by suppliers, contractors, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect Toronto Hydro and also result in third-party claims against Toronto Hydro.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Detective controls are employed to continuously monitor information systems so that Toronto Hydro can respond appropriately to minimize the damage in the event of a cyber-attack. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and often are not recognized until launched against a target, Toronto Hydro may be unable to anticipate these techniques or to implement adequate preventative measures. As such, there can be no assurance that such measures will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers, from a cyber-attack or the effects therefrom.

Toronto Hydro is subject to the risk of external threats to its physical and perimeter security. This includes the security of the Corporation’s facilities including office buildings and distribution stations. In order to safeguard its assets and staff, the Corporation has developed policies and guidelines around physical and perimeter security and facilities related emergency preparedness. The Corporation has also implemented electronic security technologies to ensure that only authorized personnel have access to Toronto Hydro facilities.

Business Interruption Risk

Toronto Hydro is subject to the risk that it may be unable to maintain continuing and sustainable business operations, or recover from business interruption, in an effective manner. Toronto Hydro's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions and natural disasters, as well as terrorism and pandemics. The Corporation has implemented various initiatives aimed at improving the system’s resiliency to increasingly frequent extreme weather events caused by climate change. These initiatives include updating major equipment specifications, revising planning guidelines, investigating the load forecast impact, revising design practices, and enhancing maintenance programs. The Corporation has also implemented a Grid Emergency Management (GEM) program to prepare for and respond to major power outage events and has incorporated recommendations from the independent review panel of experts formed to review Toronto Hydro’s response to the 2013 Ice Storm that affected Toronto. Although Toronto Hydro's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to Toronto Hydro's facilities or interruption of Toronto Hydro's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although Toronto Hydro has insurance which it considers to be consistent with industry practice, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Safety Risk

Risk to Toronto Hydro employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro activities.

Occupational Health and Safety Risk

Toronto Hydro is subject to the risk that employees may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate. Due to the nature of Toronto Hydro's business and business activities, occupational safety is an integral part of our corporate culture. Employees could be exposed to hazards when performing their work duties. This includes hazards such as electrical contact, working in confined spaces, fires and explosions, slips, trips and falls and motor vehicle accidents. Toronto Hydro is subject to compliance with provincial Health and Safety legislation. Toronto Hydro's management approach to occupational safety is to meet or excel on legal compliance and eliminate or safeguard known occupational hazards and risks. The Corporation also uses an IRS (Internal Responsibility System) to clearly define responsibility and accountability for safety at each level within the organization. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of our corporate values, including safety. LDC received OHSAS 18001 certification in 2013 and conducts annual third party audits to maintain certification, in addition occupational health and safety legal compliance audits are conducted every two years.

Public Safety Risk

Due to the nature of the Corporation's business of operating and maintaining its distribution system, Toronto Hydro is subject to the risk of public injuries or fatalities. Toronto Hydro mitigates risks to public safety through equipment inspection, replacement and maintenance, employee training, communications programs and reactive and emergency work. Toronto Hydro also has developed specific construction standards and design practices and new products for use in the distribution system go through a thorough review and introduction process. The selection process for new products and the development of standards promotes customer health and safety.

Financial Risk

Risk that the Corporation is unable to maintain its financial health and performance at acceptable levels.

Market and Credit Risk

Toronto Hydro is directly and indirectly subject to various market and credit fluctuations which could materially adversely affect the Corporation. For example, LDC is exposed to credit risk with respect to customer non-payment of electricity bills. LDC is permitted, at certain times of the year, to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (i.e. letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis. LDC's security interest or other measures, if any, may also not provide sufficient protection. Additionally, security interests and other measures taken by, or in favour of, LDC, if any, may not provide sufficient protection.

Toronto Hydro is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. Toronto Hydro estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation of Toronto Hydro, as at December 31, 2018, by $41.3 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2018, by $53.1 million.

The Corporation is exposed to short-term interest rate risk on the short-term borrowings under its CP Program and Working Capital Facility, and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. Toronto Hydro manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance. Toronto Hydro estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2.1 million to annual finance costs.

Toronto Hydro had limited exposure to the changing values of foreign currencies. While Toronto Hydro purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2018 was not material.

Capital Structure Risk

Toronto Hydro is subject to the risk that it may not be able to optimize its debt to equity ratio or access capital markets at effective rates. There can be no assurance that debt or equity financing will be available or sufficient to meet the Corporation's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to the Corporation.

The Corporation relies on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro's daily operations, repay existing indebtedness, and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the CP Program by a credit rating agency, and the availability of the commercial paper market. In the event the Corporation is unable to maintain an R-1 (low) credit rating for its CP Program, the Corporation has sufficient liquidity through its Revolving Credit Facility to repay its commercial paper obligations as they become due. The Corporation's only source of external equity financing is its existing shareholder, the City of Toronto.

The Corporation regularly reviews the external market environment and has regular engagements with its credit rating agencies, securities dealers and investor community to monitor capital structure risk.

Compliance Risk

Risk that the Corporation does not meet its material compliance obligations under legal and regulatory instruments.

Toronto Hydro is committed to complying with applicable legal and regulatory requirements and other requirements to which the organization subscribes. The Corporation has a Corporate Compliance program that strengthens the organization's culture of compliance and provides reasonable assurance, to Toronto Hydro's senior leadership and the Corporation's Board of Directors, of adherence with material compliance requirements. There can be no assurance that Toronto Hydro will comply with applicable future laws, rules, regulations and policies. Failure by Toronto Hydro to comply with applicable laws, rules, regulations and policies may subject Toronto Hydro to civil or regulatory proceedings that could have a material adverse effect on Toronto Hydro. The OEB may not allow recovery in rates for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

PART 9 - CAPITAL STRUCTURE

9.1 Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares without par value, of which 1,200 common shares are issued and outstanding as at the date of this AIF.

The City is the sole shareholder of the Corporation. See note 16 to the Consolidated Financial Statements.

9.2 Debentures

As at December 31, 2018, the Corporation had the following debentures (the "Debentures") outstanding, which have been issued pursuant to its MTN Program:

- $250.0 million of 4.49% Series 3 senior unsecured debentures, due November 12, 2019;
- $200.0 million of 5.54% Series 6 senior unsecured debentures due May 21, 2040;
- $300.0 million of 3.54% Series 7 senior unsecured debentures, due November 18, 2021;
- $250.0 million of 2.91% Series 8 senior unsecured debentures due April 10, 2023;
- $245.0 million of 3.96% Series 9 senior unsecured debentures due April 9, 2063;
- $200.0 million of 4.08% Series 10 senior unsecured debentures due September 16, 2044;
- $200.0 million of 3.55% Series 11 senior unsecured debentures due July 28, 2045;
- $200.0 million of 2.52% Series 12 senior unsecured debentures due August 25, 2026; and
- $200.0 million of 3.485% Series 13 senior unsecured debentures due February 28, 2048.

The Debentures are not listed, posted for trading or quoted on any stock exchange or quotation system.

The Debentures have been issued under the CDSX book entry system administered by CDS Clearing and Depository Services Inc. ("CDS") with BNY Trust Company of Canada as trustee. Accordingly, a nominee of CDS is the registered holder of the Debentures and beneficial ownership of the Debentures is evidenced through book entry credits to securities accounts of CDS participants (e.g., banks, trust companies and securities dealers), who act as agents on behalf of beneficial owners who are their customers, rather than by physical certificates representing the Debentures.

9.3 Credit Facilities

The Corporation has a Revolving Credit Facility, pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On July 30, 2015, the borrowing capacity under the Revolving Credit Facility was increased by $100.0 million from $700.0 million to $800.0 million and the maturity date extended by one year from October 10, 2019 to October 10, 2020. On August 19, 2016, the maturity date was extended by an additional year to October 10, 2021. On August 1, 2017, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2021 to October 10, 2022. On August 23, 2018, the maturity date of the Revolving Credit Facility was extended by one year from October 10, 2022 to October 10, 2023. Borrowings under the Revolving Credit Facility bear interest at fluctuating rates plus an applicable margin based on the Corporation's credit rating.

The Revolving Credit Facility contains certain covenants, the most significant of which is a requirement that the Corporation's debt to capitalization ratio not exceed 75%. As at December 31, 2018, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a CP Program allowing up to $600.0 million of unsecured short-term promissory notes to be issued in various maturities of no more than one year. On July 30, 2015, the amount the Corporation may issue under this program was increased by $100.0 million from $500.0 million to $600.0 million. The CP Program is backstopped by the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the CP Program are used for general corporate purposes. Borrowings under the CP Program bear interest based on the prevailing market conditions at the time of issuance.

Additionally, the Corporation has a Prudential Facility and a Working Capital Facility. The available amount under the Revolving Credit Facility as well as outstanding borrowings under the Revolving Credit Facility and CP Program are as follows:

	Revolving Credit Facility Limit	Revolving Credit Facility Borrowings	Commercial Paper Outstanding	Revolving Credit Facility Availability
December 31, 2018.	$800.0 million	-	$113.0 million	$687.0 million
December 31, 2017.	$800.0 million	-	$159.0 million	$641.0 million

For the year ended December 31, 2018, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and CP Program were $239.6 million with a weighted average interest rate of 1.68%.

As at December 31, 2018, $12.6 million had been drawn under the Working Capital Facility and $33.3 million of letters of credit had been issued against the Prudential Facility.

9.4 Credit Rating

As at December 31, 2018, the credit ratings of the Corporation were as follows:

	DBRS		S&P	
	Credit Rating	**Trend**	**Credit Rating**	**Outlook**
Issuer rating	A	Stable	A	Stable
Debentures................................	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain the subcategories "(high)" and "(low)" to indicate relative standing within the major rating categories. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

DBRS rates short-term debt instruments by rating categories ranging from a high of "R-1 (high)" to a low of "D". An R-1 (low) rating is the third highest of the ten rating categories. Short-term debt instruments which are rated in the "R-1 (low)" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "R-1 (low)" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

For the years ended December 31, 2018 and 2017, payments were made to both DBRS and S&P for credit rating services only.

PART 10 - DIRECTORS AND OFFICERS

10.1 Nomination of Directors

As at the date of this AIF, the Board consists of eleven directors, all of whom are appointed by the sole shareholder of the Corporation, the City.

Pursuant to the Shareholder Direction, in electing directors to the Board, the City gives due regard to the qualifications of a candidate, including: experience or knowledge; commercial sensitivity and acumen; independence of judgment; and personal integrity. The City seeks candidates with experience and knowledge in: public utility commissions or boards of major corporations or other commercial enterprises; corporate finance; corporate governance; market development; large system operation and management; urban energy industries; and public policy issues and laws relating to Toronto Hydro, the electricity industry, environmental matters, labour relations and occupational health and safety issues. Each citizen director is elected to serve for a term of up to two years or until his or her successor is appointed, and may be elected for a maximum of four consecutive terms for a maximum of eight consecutive years or such longer term until a successor is appointed. Each City Councillor director is elected to serve for two years or until his or her successor is elected. As at the date of this AIF, female directors constituted 36.4% (4 of 11) of the members of the Corporation's Board.

10.2 Committees of the Board of Directors

The Board had established three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee) as shown in the following chart.

Board of Directors

Audit Committee	**Corporate Governance and Nominating Committee**	**Human Resources and Environment Committee**
Michael Nobrega (Chair)	Tamara Kronis (Chair)	Brian Chu (Chair)
Heather Zordel	Brian Chu	Juliana Lam
Juliana Lam	Mary Ellen Richardson	Michael Nobrega
	Councillor Paul Ainslie	Deputy Mayor Stephen Holyday

(a) Audit Committee

The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. The Audit Committee reviews the Corporation's quarterly and annual financial statements as well as financial statements prepared in connection with the requirements of applicable regulatory authorities, reviews the audit plans of the external auditors, oversees the internal audit of the Corporation, reviews and makes recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation, and recommends the external auditor to the Board for appointment by the Corporation's sole shareholder. See Part 11 under the heading "Audit Committee" below for further information on the Audit Committee.

(b) Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committee is responsible for considering and making recommendations to the Board with respect to matters relating to the corporate governance of Toronto Hydro, including board and committee composition and mandates, and guidelines for assessing the effectiveness of the Board and its committees and procedures to ensure that the Board functions independently from management.

As part of its governance function, the Corporate Governance and Nominating Committee reviews a skills matrix for all potential director candidates, which is then forwarded to the Corporation's sole shareholder by the Board. The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the Board of Directors of LDC for approval by the Corporation's Board of Directors as required by the Affiliate Relationships Code. The Corporate Governance and Nominating Committee reviews and approves all orientation and education materials and programs for new and current directors undertaken by management.

The Corporate Governance and Nominating Committee is comprised of Tamara Kronis (Chair), Brian Chu, Mary Ellen Richardson and Councillor Paul Ainslie. Ms. Kronis, Mr. Chu and Ms. Richardson are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Councillor Ainslie is not independent within the meaning of applicable Canadian securities laws.

(c) Human Resources and Environment Committee

The Human Resources and Environment Committee is responsible for reviewing and assisting the Board in overseeing the recruitment and assessment of the CEO and the compensation of the CEO, reviewing and approving the compensation of the executive officers, reviewing and making recommendations to the Board concerning executive compensation disclosure under applicable securities laws, and reviewing and making recommendations to the Board regarding the compensation structure and benefit plans and programs of Toronto Hydro. The Human Resources and Environment Committee is also responsible for reviewing and approving the parameters of collective bargaining negotiations, the oversight of health and safety related matters and processes, and the oversight of environmental related matters and processes of Toronto Hydro. See section 12.1(a) under the heading "Human Resources and Environment Committee" for further information on the Human Resources and Environment Committee.

(d) Other Committees

In 2018, the Board of Directors established a Steering Committee, consisting of the Chair of the Board and the Chairs of the respective standing committees, to assist the Board and its standing committees in fulfilling their responsibilities by providing effective and timely guidance on emerging, time-sensitive, significant issues arising with respect to matters that overlap with the mandates of the standing Board committees. The Steering committee does not replace any of the functions of the Board or its standing committees unless otherwise expressly delegated by the Board from time to time. The role of the Steering Committee is to provide advice and recommendations to the respective Board committees(s) that will enable them to successfully carry out their responsibilities and ultimately properly advise and make recommendations to the Board.

Further, the Board of Directors may establish ad-hoc committees from time to time for a specific task or subject matter.

10.3 Directors

The following summaries set forth, for each of the directors of the Corporation, his or her name, province and country of residence, the date on which he or she became a director and the expiry date of his or her current term, his or her relevant education and experience, principal occupations within the five preceding years and board memberships with other reporting issuers. The following tables also summarize the attendance of individual directors at the Board and standing committee meetings held during 2018 and 2019 as of the date of this AIF.

David McFadden, Chair of the Board
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Mr. McFadden is a lawyer whose practice focused on the energy, infrastructure, financial services and aerospace industries. He was formerly Counsel at Gowling WLG, and a former member of the firm's Board of Trustees and Executive Committee. Mr. McFadden currently serves as Chair of the Board of Directors of 407 International Inc. and PCI Geomatics Inc. He also serves on the Board of Directors of Cricket Energy Holdings Inc. He is also a Vice-Chair of the Electricity Transformation Network of Ontario of the Independent Electricity System Operator and serves on the Advisory Board of the MaRS Advanced Energy Centre and on the Council for Clean & Reliable Electricity. Mr. McFadden was named the Energy Leader of the Year by the Ontario Energy Association in 2013. In the past, Mr. McFadden served as the Chair of the Board of Directors of the Ontario Energy Association. Mr. McFadden has also served as co-chair of the Electricity Transition Committee of the Ontario Government, and also served on the Ontario Government's Electricity Distribution Sector Review Panel and the Ontario Government's Electricity Conservation and Supply Task Force. Mr. McFadden has also been active in the higher education sector. He served as Chair of the Ontario Centres of Excellence from 2004-2010 and currently is a member of the Board of Governors of York University. Mr. McFadden holds a Bachelor of Laws at Osgoode Hall Law School and a Bachelor of Arts at the University of Toronto, and is a member of the Law Society of Ontario.

Mr. McFadden currently serves as Chair of the Board of Directors. He is also an *ex-officio* member of the Audit Committee, Human Resources and Environment Committee, and Corporate Governance and Nominating Committee.

Principal Occupation:
Corporate Director

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Other Committees(1)	1 of 1	100%
	2019 Attendance(2)	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
407 International Inc.

Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Brian Chu, Vice-Chair of the Board
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Mr. Chu is a founding partner of the law firm of Bogart Robertson & Chu LLP, whose practice focuses on corporate and commercial real estate law. Mr. Chu currently serves on the Board of Directors of the Technical Standards & Safety Authority and is a member of its Safety and Regulatory Affairs Committee. He also previously served as Trustee and Chair of the Centennial Centre of Science and Technology (Ontario Science Centre). He was formerly President of Laidlaw Foundation, Chair of the Board of Governors of Ontario College of Arts and Design, and Vice-Chair of Centennial College. Mr. Chu has been a member of the Canadian Tax Foundation since 1986. Mr. Chu holds a Juris Doctor from the University of Toronto and is a member of the Law Society of Ontario. Mr. Chu has extensive experience in compensation practices and policies, including determining executive compensation and setting, as well as communicating and reviewing, chief executive officer performance objectives. In his role at the Ontario Science Centre, he was accountable to the Minister of Tourism, Culture and Sport on all matters related to the hiring and termination of the chief executive officer. Mr. Chu is also responsible for human resources matters, salary and compensation relating to all staff at Bogart Robertson & Chu LLP.

Mr. Chu currently serves as Vice-Chair of the Board of Directors, is the Chair of the Human Resources and Environment Committee and a member of the Corporate Governance and Nominating Committee. Mr. Chu also served as a director of the Corporation from August 1, 2005 to April 14, 2013, during which time he served as a member of the Audit Committee and the Corporate Governance Committee, the Chair of the Corporate Governance Committee (from August 25, 2005 to November 30, 2008) and the Chair of the Audit Committee (from December 1, 2008 to April 14, 2013).

Principal Occupation:
Partner at Bogart Robertson & Chu LLP

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Corporate Governance and Nominating Committee	4 of 4	100%
Human Resources and Environment Committee	4 of 4	100%
Other Committees[1]	1 of 1	100%
	2019 Attendance[2]	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Heather Zordel
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Ms. Zordel is a lawyer with extensive experience in corporate finance, securities regulatory compliance and corporate governance. A partner in the Securities Group at Gardiner Roberts LLP, she is also a Commissioner of the Ontario Securities Commission, a Bencher of the Law Society of Ontario (LSO), a part-time adjudicator for the Law Society Tribunal, and a Board Member for the Lawyers' Professional Indemnity Company (LawPro) and the Condominium Authority of Ontario. Ms. Zordel is an audit committee member for the LSO and LawPro. Academically, she is the Co-Director and a Course Director for the Osgoode Part-time LL.M. program in securities law. Ms. Zordel has a Bachelor of Commerce from the University of Saskatchewan and a LL.B./J.D./LL.M. (Securities) from Osgoode Hall Law School.

Ms. Zordel currently serves as Chair of the Board of Directors of TH Energy.

Principal Occupation:
Partner and Securities Lawyer, Gardiner Roberts LLP
Former Partner at Cassels Brock and Blackwell LLP

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Audit Committee	5 of 5	100%
	2019 Attendance(1)	
Board	1 of 1	100%
Audit Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

The Honourable Howard Wetston, Senator
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

The Honourable Mr. Wetston, Senator was appointed to the Senate of Canada and assumed office on November 10, 2016. Mr. Wetston is a distinguished lawyer with a breadth of experience and expertise in competition law and policy, securities regulation, energy regulation and administrative law. In 2016, Mr. Wetston was awarded the Order of Canada for his significant contributions as a public servant, jurist and regulator. Mr. Wetston has served as Chair and Chief Executive Officer of the OSC, as Vice-Chair of the OSC, and as Chair and Chief Executive Officer of the OEB. During his time as Chair and Chief Executive Officer of the OSC, Mr. Wetston played a significant role in Canadian and international securities regulatory bodies by serving as a senior member of the Canadian Securities Administrators and as a Vice Chair of the International Organization of Securities Commissions. Mr. Wetston has served as a Judge of the Federal Court of Canada, Trial Division, an ex-officio member of the Federal Court's Appeal Division, and Director of Investigations and Research at the Bureau of Competition Policy. Mr. Wetston is a Senior Fellow of the C.D. Howe Institute and has served on several Advisory Boards, including the Program on Ethics in Law and Business at the University of Toronto, and the Shannon School of Business at Cape Breton University. He is a Board member of Spark Power Corp. Mr. Wetston is also a Trustee of the International Valuations Standards Council and a Member of the C.D. Howe Institute's Competition Policy Counsel. Mr. Wetston holds a Bachelor of Laws from Dalhousie University and a Bachelor of Science from Mount Allison University, and holds an ICD.D designation from the Institute of Corporate Directors and he has also received special recognition as a Board Diversity Champion from Catalyst Canada Honours. Mr. Wetston holds honorary doctorate degrees from Cape Breton University and Dalhousie University and he is a recipient of the Queen Elizabeth II Diamond Jubilee Medal.

Mr. Wetston currently serves as Chair of the Board of Directors of LDC.

Principal Occupation:
Senator

Board/Committee Membership	**2018 Attendance**	
Board	4 of 5	80%
	2019 Attendance(1)	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
Spark Power Group Inc., parent company to Spark Power Corp.

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Juliana Lam
Ontario, Canada

Director since:	April 26, 2017
Expiry of current term:	April 26, 2019, or effective date of appointment of a successor director

Ms. Lam has extensive executive level financial management experience in diverse industries including mining, manufacturing, services and distribution. She is currently serving as Executive Vice-President and Chief Operating Officer of Chartered Professional Accountants of Ontario. Prior to that, Ms. Lam was the Executive Vice-President and Chief Financial Officer of Uranium One Inc. Previously, Ms. Lam served as Senior Vice-President, Finance at Kinross Gold Corporation, Chief Financial Officer of Nexans Canada Inc., and has held senior finance roles within other publicly traded companies. She holds a Bachelor of Arts from the University of Toronto, an MBA from the Richard Ivey School of Business, University of Western Ontario, is a Chartered Professional Accountant (CPA, CA), and holds the ICD.D designation from the Institute of Corporate Directors. In addition to being a member of the board and the board committees of Toronto Hydro Corporation, Ms. Lam serves the community on the boards and board committees of two not-for-profit organizations in the Greater Toronto Area.

Ms. Lam currently serves as a member of the Board of Directors of TH Energy.

Principal Occupation:
Executive Vice-President & Chief Operating Officer, Chartered Professional Accountants of Ontario
Former Executive Vice-President & Chief Financial Officer, Uranium One Inc.

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Audit Committee	5 of 5	100%
Human Resources and Environment Committee	4 of 4	100%
	2019 Attendance(1)	
Board	1 of 1	100%
Audit Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:
(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Mary Ellen Richardson
Ontario, Canada

Director since:	December 11, 2016
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Ms. Richardson is an independent consultant to the energy sector, with extensive experience in the oil, natural gas and electricity industries. Ms. Richardson currently serves as a member of the Board of Directors, is a member of the Human Resources and Governance Committee and the Finance and Audit Committee of Markham District Energy Inc. In the past, Ms. Richardson has served as President of the Canadian District Energy Association, Vice-President, Corporate Affairs and Vice-President, Conversation Programs and External Relations at the OPA, President of the Association of Major Power Consumers in Ontario, and was a member of the Board of Directors and Human Resources Committee of Guelph Municipal Holdings Inc. Ms. Richardson has also served on the management board of the Ontario Centre of Excellence in Energy, on the Board of Directors of Environmental Careers Organization of Canada, on the Ontario Government's Electricity Conservation and Supply Task Force, on the Executive of the Stakeholders' Alliance for Competition and Customer Choice, and on Hydro One's Customer Advisory Board. Ms. Richardson holds an Honours degree in Economics from the University of Calgary, and the ICD.D designation.

Ms. Richardson currently serves as a member of the Board of Directors of the LDC.

Principal Occupation:
President, Mary Ellen Richardson Inc.

Board/Committee Membership	**2018 Attendance**	
Board	4 of 5	80%
Corporate Governance and Nominating Committee	3 of 4	75%
	2019 Attendance(1)	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

____

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Michael Nobrega
Ontario, Canada

Director since:	May 10, 2016
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Mr. Nobrega is a Chartered Accountant with extensive experience in finance and business. Mr. Nobrega has served as President & Chief Executive Officer of OMERS, Chief Investment Officer of OMERS, and as President & Chief Executive Officer of Borealis (OMERS) Infrastructure. Mr. Nobrega is currently interim President and Chief Executive Officer of Waterfront Toronto, and is the Chair of Ontario Centres of Excellence. Mr. Nobrega is also a member of the Board of Directors of IBI Group Inc. In the past, Mr. Nobrega was also president of a merchant bank, a tax partner at Arthur Anderson, Chartered Accountants, and a member of the Board of Directors of the Global Risk Institute. Mr. Nobrega earned an Honours Bachelor of Arts (Economics and Mathematics) from the University of Toronto, where, in 2002, he was honoured with the Arbor Award for outstanding community service. He holds a chartered accountancy designation from the Institutes of Chartered Accountants of Ontario and Canada, and was named a Fellow of the Institute of Chartered Accountants of Ontario in 2009. Mr. Nobrega has considerable experience in executive compensation matters from his years as the Chief Executive Officer of OMERS and Borealis (OMERS) Infrastructure. He is familiar with the structure of compensation systems and related benefit programs, and is experienced in executive performance evaluation.

Principal Occupation:
Interim President and CEO, Waterfront Toronto
Chair, Ontario Centres of Excellence
Former President & Chief Executive Officer of OMERS (from March 2007- March 2014)

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Audit Committee	5 of 5	100%
Human Resources and Environment Committee	4 of 4	100%
Other Committees[1]	1 of 1	100%
	2019 Attendance[2]	
Board	1 of 1	100%
Audit Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
IBI Group Inc.
CellCube Energy Storage Systems Inc.

Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Tamara Kronis
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	December 10, 2019, or effective date of appointment of a successor director

Ms. Kronis is a Toronto-based entrepreneur, goldsmith and lawyer. She is currently the Founder and CEO of Studio1098, a custom fine jewellery design studio, where she works as a goldsmith, gemmologist and jewellery designer. Prior to opening Studio1098, Ms. Kronis worked as a commercial lawyer whose practice included several transactions related to the Ontario energy market. Her past experience includes positions as Legal Counsel, Vertex Customer Management/Vertex Outsourcing, Associate Lawyer at Torys LLP, Director of Advocacy at EGALE Canada and Trial Assistant, United Nations (International Criminal Tribunal for the Former Yugoslavia). Ms. Kronis holds a Master of Arts in Political Science and a Bachelor of Laws from the University of Toronto, and a Bachelor of Arts in Politics and Economics from Brandeis University. She is a Fellow of the Canadian Gemmological Association and the Gemmological Association of Great Britain. Ms. Kronis is a member of the Law Society of Ontario.

Ms. Kronis currently serves as a member of the Board of Directors of TH Energy.

Principal Occupation:
Founder and CEO, Studio1098

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Corporate Governance and Nominating Committee	4 of 4	100%
Other Committees(1)	1 of 1	100%
	2019 Attendance(2)	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Committees other than the three standing committees (Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee).

(2) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Denzil Minnan-Wong
Ontario, Canada

Director since:	December 3, 2014
Expiry of current term:	December 31, 2020, or effective date of appointment of a successor director

Deputy Mayor Minnan-Wong is the City Councillor for Ward 16 – Don Valley East, and was previously City Councillor for Ward 34 – Don Valley East since 1997. Deputy Mayor Minnan-Wong is currently serving as Chair of City Council's Civic Appointments Committee, Chair of City Council's Striking Committee, and member of City Council's Executive Committee. He also sits on City Council's Committee of Revision, North York Community Council, City Council's Infrastructure and Environment Committee, and the Toronto Transit Commission Board. Deputy Mayor Minnan-Wong's past experience includes serving as Chair of City Council's Employee and Labour Relations Committee, Chair of City Council's Public Works and Infrastructure Committee, Chair of City Council's Economic Development Committee, Chair of North York Community Council, and a member of City Council's Planning and Transportation Committee, City Council's Works and Emergency Services Committee, City Council's Audit Committee, City Council's Corporations Nominating Panel and the Toronto Financial Service Advisory Committee. He was formerly on the Board of Directors for BUILD Toronto, and Invest Toronto. Deputy Mayor Minnan-Wong holds a Juris Doctor from Osgoode Hall Law School, and is a member of the Law Society of Ontario.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto

Board/Committee Membership	**2018 Attendance**	
Board	3 of 5	60%
	2019 Attendance[(1)]	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Paul Ainslie
Ontario, Canada

Director since:	February 10, 2015
Expiry of current term:	December 31, 2020, or effective date of appointment of a successor director

Councillor Ainslie is the City Councillor for Ward 24 – Scarborough Guildwood, and was previously City Councillor for Ward 43 – Scarborough East since December 2006. Councillor Ainslie is currently serving as Chair of the General Government and Licensing Committee and is the Mayor's designate on the Board of Directors for the Toronto Public Library. Councillor Ainslie also sits on the City Council's Executive Committee, Scarborough Community Council, and the Toronto Zoo Board of Management. Mr. Ainslie is a member of the Board of Directors of the Canadian National Exhibition Association, Municipal Section, the Ontario Good Roads Association, Toronto and Region Conservation Authority, and the Guild Renaissance Group. Councillor Ainslie's past experience includes serving as Co-Chair of the Rouge Valley Health System Centenary Buy A Bed fundraising campaign and Chair of the Board of Directors of Haliburton Club.

Principal Occupation:
Councillor, City of Toronto

Board/Committee Membership	**2018 Attendance**	
Board	4 of 5	80%
Corporate Governance and Nominating Committee	2 of 4	50%
	2019 Attendance(1)	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	0 of 1	0%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

Stephen Holyday
Ontario, Canada

Director since:	December 3, 2014
Expiry of current term:	December 31, 2020, or effective date of appointment of a successor director

Deputy Mayor Holyday is the Mayor's designate to the Board effective as of December 3, 2014. Deputy Mayor Holyday has been the City Councillor for Ward 2 - Etobicoke Centre, and was previously City Councillor for Ward 3 - Etobicoke Centre since December 2014. Deputy Mayor Holyday is currently serving as a Mayor’s Designate, Chair of City Council’s Special Committee on Governance, and Chair of City Council's Audit Committee. Deputy Mayor Holyday also sits on City Council's General Government and Licensing Committee, City Council’s Striking Committee, and Etobicoke York Community Council. Deputy Mayor Holyday is a member of the Board of Directors of the Hockey Hall of Fame, Exhibition Place Board of Governors and a member of the Canadian National Exhibition Association. Before being elected to public office, Stephen Holyday was Manager, Service Management at the Ontario Ministry of Energy. He holds a Bachelor of Technology in Architectural Science from Ryerson University. Through his previous experience as Vice-Chair of City Council's Employee and Labour Relations Committee, Mr. Holyday is familiar with compensation systems and related benefit programs at all levels.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto
Acting Manager and Manager, Service Management, Ontario Ministry of Energy (From May 2009 to November 2014)

Board/Committee Membership	**2018 Attendance**	
Board	5 of 5	100%
Human Resources and Environment Committee	3 of 4	75%
	2019 Attendance(1)	
Board	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2019 attendance is for the period of January 1, 2019 to the date of this AIF.

10.4 Executive Officers

The following table sets forth the name, province and country of residence, office, and principal occupation for each of the executive officers of the Corporation. 66.7% (2 out of 3) of the executive officers of the Corporation are female. 42.9% (3 out of 7) of the executive officers of LDC are female.

Name	**Residence**	**Office**	**Principal Occupation**
Anthony Haines(1)	Ontario, Canada	President and Chief Executive Officer	President and Chief Executive Officer, Toronto Hydro Corporation
Aida Cipolla(2)	Ontario, Canada	Executive Vice-President, Chief Financial Officer	Executive Vice-President, Chief Financial Officer, Toronto Hydro Corporation
Amanda Klein(3)	Ontario, Canada	Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer	Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro Corporation

Notes:

(1) Mr. Haines has been the President of LDC since September 2006. He was also appointed the CEO of the Corporation effective October 1, 2009.

(2) Ms. Cipolla was Manager, Corporate Accounting and External Reporting of LDC (from December 3, 2012 to December 20, 2015) and then Controller of LDC (from December 21, 2015 to August 26, 2018). Ms. Cipolla was appointed as the Corporation's Executive Vice-President and Chief Financial Officer effective as of August 27, 2018. She replaced Sean Bovingdon, the former CFO who left the Corporation.

(3) Ms. Klein was Director, Rates and Regulatory Affairs of LDC (from August 23, 2012 to December 31, 2014) until her appointment as Vice-President, Regulatory Affairs and General Counsel of the Corporation effective January 1, 2015. Ms. Klein was appointed Executive Vice-President, Regulatory Affairs and General Counsel of the Corporation effective September 1, 2016. There was a change in Ms. Klein's position and title as Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer effective as of October 1, 2018.

10.5 Cease Trade Orders, Bankruptcies, Penalties or Sanctions

1. No director or executive officer of the Corporation is, as at the date of this AIF, or has within ten (10) years prior to the date of this AIF:

   (a) been a director, chief executive officer or chief financial officer of any company (including the Corporation) that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer;

   (b) been a director, chief executive officer or chief financial officer of any company (including the Corporation) that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

2. No director, executive officer of the Corporation or, to the Corporation's knowledge, the City is, as at the date of this AIF, or has within ten (10) years prior to the date of this AIF:

   (a) been a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of such director or executive officer.

3. No director, executive officer of the Corporation or, to the Corporation's knowledge, the City, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

10.6 Independence

As at the date of this AIF, the Board consists of eleven directors, all of whom are appointed by the City in its capacity as sole shareholder of the Corporation. Three of the directors are Councillors of the City and are not considered independent because of their positions. None of the other directors have a direct or indirect material relationship with the Corporation and are independent within the meaning of applicable Canadian securities law.

No members of management sit on the Board. The Board meets regularly to discuss the management of the Corporation. A portion of each Board and Board committee meeting is reserved for Directors to meet without management present. Under its mandate, the Board is authorized to retain independent legal counsel and other advisors if it considers this appropriate. The mandate also provides that the Board shall have unrestricted access to the officers of the Corporation and is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate. The full text of the Board's written mandate is attached as Annex B.

The Corporation has developed a written position description for the Chair of the Board. The Chair is responsible for reporting to the Board, leading the directors and managing the day-to-day activities of the Board. The Chair is also responsible for engaging in discussions with the shareholder and its representatives as are necessary and desirable, maintaining an active and cooperative relationship with the CEO and other senior management of the Corporation, acting as the principal interface between the Board and the CEO of the Corporation, and providing advice and counsel to the CEO and other senior management of the Corporation.

The Board has also developed written position descriptions for the chair of each Board committee and the CEO.

10.7 Board Orientation and Continuing Education

Each new director, upon joining the Board, is given an orientation session with comprehensive set of materials designed to provide him/her with a summary of the key organizational, financial, regulatory, and operational aspects of Toronto Hydro. These materials also contain information on the various Toronto Hydro boards and their committees.

On an on-going basis, as part of regular and special board meetings, directors receive presentations, reports and training on topics related to Toronto Hydro's businesses and the obligations and responsibilities of directors. Topics covered are either suggested by management or requested by the directors. As well, directors receive information from management in response to any actions arising at a board meeting or otherwise. Educational programs through external service providers are also made available to the directors.

10.8 Board, Committee and Director Assessments

The Corporate Governance and Nominating Committee oversees a process used to evaluate the effectiveness of the Board as a whole, its committees and the individual directors. The process may be facilitated by an independent consultant with expertise in board assessments as selected by the Board. Alternatively, the Board may complete an internal assessment. The process may consist of an in-person interview and/or a written questionnaire evaluating the Board, its committees and the individual directors that are completed periodically by each director. The directors' responses to the questionnaire and/or interviews related to the operation of the Board and its committees are compiled into a summary report that is reviewed by the Chair of the Board. This report and recommended remedial actions are presented to the Board for review, consideration and implementation.

10.9 Board Oversight and Management of Risks

In accordance with its mandate, the Board is responsible for overseeing the identification of the principal risks of the business and implementation of appropriate systems to manage these risks. In 2009, Toronto Hydro adopted an ERM program to add value and improve the Corporation's operations through enabling the attainment of its strategic goals and objectives. The ERM program helps the Corporation achieve this by bringing a systematic and disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks applicable to Toronto Hydro. Accordingly, ERM is an integral part of the strategic management of the Corporation's business and is routinely considered in forecasting, planning and executing all aspects of Toronto Hydro’s operations. The ERM program follows industry best practices and international guidelines, adopting a rigorous top-down / bottom-up approach towards the management of risks.

See Part 8 under the heading "Risk Factors – Risk Management" above for further information on ERM.

10.10 Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of the Corporation or any of its subsidiaries had any outstanding indebtedness to the Corporation or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or any of its subsidiaries.

PART 11 - AUDIT COMMITTEE

11.1 Composition, Independence and Financial Literacy

The Audit Committee is comprised of Michael Nobrega (Chair), Juliana Lam and Heather Zordel, each of whom is independent and financially literate within the meaning of applicable Canadian securities laws.

11.2 Audit Committee Charter

Under the terms of its charter, the Audit Committee is responsible for: managing the relationship between Toronto Hydro and its external auditors; overseeing the external audit; overseeing the internal audit; reviewing and recommending to the Board for approval the financial statements, management's discussion and analysis and interim reports of the Corporation and its subsidiaries, the annual information form and other public disclosure of financial information extracted from the financial statements of the Corporation; overseeing internal financial control structure and financial risk management systems; establishing and reviewing certain procedures and policies; reviewing policy reporting; and reviewing and making recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation.

The full text of the Corporation's Audit Committee Charter is attached as Annex A.

11.3 Policy on the Provision of Services by the External Auditors

The Audit Committee has developed a Policy on the Provision of Services by the External Auditors. Under the terms of the Policy:

- the external auditors may not provide services to Toronto Hydro that impair or have the potential to impair the independence and objectivity of the external auditors in relation to the external audit function (generally, prohibited services include services where the external auditors participate in activities that are normally undertaken by management of Toronto Hydro, are remunerated through a "success fee" structure, act in an advocacy role for Toronto Hydro or may be required to audit their own work);

- the Audit Committee has pre-approved certain audit and permitted non-audit services as services that the auditors may provide to Toronto Hydro, including: services that constitute the agreed scope of the external audit or interim reviews of Toronto Hydro; services that are outside the agreed scope of, but are consistent with, the external audit or interim reviews of Toronto Hydro; tax services that do not compromise the independence and objectivity of the external auditors in relation to the external audit; and other services of an advisory nature that do not compromise the independence and objectivity of the external auditors in relation to the external audit work; and

- an authorization process has been established which provides, among other things: the Chief Financial Officer may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $25,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chief Financial Officer must report all such authorized engagements to the Audit Committee at its next meeting); the Chair of the Audit Committee may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $50,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chair must report all such authorized engagements to the Audit Committee at its next meeting); and the Audit Committee must authorize in advance all engagements of the external auditors to provide pre-approved services to Toronto Hydro above the prescribed thresholds and all engagements to provide services that are not pre-approved services regardless of the dollar value of the services.

Exceptions can be made to this Policy where the exceptions are in the interests of Toronto Hydro and appropriate arrangements are established to ensure the independence and objectivity of the external auditors in relation to the external audit. Any exception must be authorized by the Audit Committee and must be reported to the Board.

11.4 External Auditors Service Fees

The table below sets out the fees charged by Toronto Hydro's external auditor, KPMG LLP, on an accrual basis, for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,	
	2018	**2017**
Audit fees(1)	$659,830	$683,720
Audit-related fees(2)	$31,270	$32,000

Notes:

(1) Fees for audit services and interim reviews, excluding CPAB levy.

(2) Fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported under (1) above, specifically French translation.

PART 12 - EXECUTIVE COMPENSATION

12.1 Compensation Governance

(a) Human Resources and Environment Committee

(i) *Composition and Independence*

The Human Resources and Environment Committee, under the direction of the Board has oversight for Toronto Hydro’s senior executive compensation program. The Human Resources and Environment Committee is comprised of Brian Chu (Chair), Juliana Lam, Michael Nobrega, and Deputy Mayor Stephen Holyday. Mr. Chu, Ms. Lam, and Mr. Nobrega are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Deputy Mayor Holyday is not independent within the meaning of applicable Canadian securities laws. The appointment of one of the Corporation’s City Councillor directors to the Human Resources and Environment Committee is a requirement under the Shareholder Direction.

(ii) *Human Resources and Environment Committee Charter*

The Human Resources and Environment Committee operates under a written charter adopted by the Board. One of the primary functions of the Human Resources and Environment Committee is to advise and assist the Board in overseeing Toronto Hydro's compensation program and assessing the performance and compensation of the CEO and the other officers of Toronto Hydro. Specifically, under the terms of its charter, the Human Resources and Environment Committee is responsible for assisting the Board in fulfilling its responsibilities with respect to: the recruitment and assessment of the performance of the CEO; the review and approval of the compensation of the CEO and the other senior executive officers of Toronto Hydro; the review and approval of senior executive compensation policies; the review and approval of senior executive compensation disclosure; the review of the alignment of compensation programs with Toronto Hydro’s strategic plans and risk profile; and the general oversight of the compensation structure and benefit plans and programs for Toronto Hydro.

(b) Compensation Risk Oversight

Toronto Hydro has a rigorous risk management and governance structure in place to assist the Board with its oversight and management of all of Toronto Hydro's risks, including risks related to Toronto Hydro's compensation policies and practices. While the Board and the Human Resources and Environment Committee have not conducted a formal assessment of the implications of risks specifically associated with Toronto Hydro’s compensation policies and practices, the Human Resources and Environment Committee has and continues to consider the Corporation's strategic objectives, plans and risk strategy in its review and recommendations regarding Toronto Hydro's compensation program. In addition to Toronto Hydro’s ERM program, the practices, processes and systems in place to identify and mitigate compensation policies and practices that could encourage an executive officer to take inappropriate or excessive risks include: the periodic review and audit of Toronto Hydro’s senior executive compensation program by

Toronto Hydro’s internal auditor; the development and application of a management control reporting system providing transparency and control to compensation measures; the use of a balanced scorecard of corporate, divisional and individual performance objectives; the periodic benchmarking of Toronto Hydro’s compensation program; the review of Toronto Hydro’s compensation program by an independent compensation consultant and, from time to time, the OEB; and the application of maximum payout amounts for achievement of individual performance goals. See Part 8 under the heading “Risk Factors – Risk Management” and section 10.9 under the heading "Board Oversight and Management of Risks" for more information on Toronto Hydro’s ERM program, section 12.2(c)(ii) under the heading "Benchmarking" for more information on Toronto Hydro’s benchmarking of its compensation program, section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the Corporation's compensation consultant and section 12.2(d)(ii) under the heading "Performance-Based Incentive Compensation" for more information on Toronto Hydro’s performance-based incentive compensation program.

12.2 Compensation Discussion and Analysis

(a) Named Executive Officers

This Compensation Discussion and Analysis describes and explains all significant elements of compensation awarded to, earned by, paid to, or payable to the NEOs for the financial year ended December 31, 2018. The NEOs are:

(i) **Anthony Haines**
President and Chief Executive Officer, Toronto Hydro Corporation

(ii) **Sean Bovingdon**(1)
Former Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(iii) **Aida Cipolla**(2)
Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(iv) **Dino Priore**
Executive Vice-President and Chief Engineering and Construction Officer, Toronto Hydro-Electric System Limited

(v) **Ben La Pianta**(3)
Executive Vice-President and Chief Customer Care and Electric Operations Officer, Toronto Hydro-Electric System Limited

(vi) **Amanda Klein**
Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro-Electric System Limited

---

Notes:

(1) Effective, August 26, 2018, Mr. Bovingdon ceased his role as Executive Vice-President and Chief Financial Officer.

(2) Effective August 27, 2018, Ms. Cipolla began her role as Executive Vice-President and Chief Financial Officer.

(3) Effective January 1, 2018 Mr. La Pianta began his role as Executive Vice-President and Chief Customer Care and Electric Operations & Procurement Officer. Effective October 1, 2018, the position and title of Mr. La Pianta was changed to Executive Vice-President and Chief Customer Care and Electric Operations Officer.

(b) General Objectives of Compensation Program

Toronto Hydro’s senior executive compensation program is designed to attract and retain executives who have the skills and experience to help the Corporation achieve its strategic goals, to motivate executives to achieve such corporate goals and to reward senior executives for superior performance and achievement of corporate, divisional and individual objectives.

(c) Process for Establishing Compensation

(i) *Policies and Practices*

Toronto Hydro's overall senior executive compensation policy, structure and program is developed and supervised by the Human Resources and Environment Committee with the assistance of a compensation consultant, and approved by the Board. See section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the compensation consultant.

Pursuant to the terms of its charter, the Human Resources and Environment Committee has the responsibility to annually, and more frequently if appropriate, review and make recommendations to the Board with respect to the individual performance-based incentive compensation goals and objectives related to the compensation of the CEO and to assess the CEO's performance against those goals and objectives. The Human Resources and Environment Committee also makes recommendations to the Board with respect to the overall compensation and benefits of the CEO. The Board ultimately sets and approves the CEO's compensation.

The CEO has the responsibility to annually, and more frequently if appropriate, review and approve the individual performance-based incentive compensation goals and objectives related to the compensation of the other senior executive officers, including the NEOs, and assess the other senior executive officers' performance against those goals and objectives. The CEO proposes the other senior executive officers' performance-based incentive compensation and overall compensation, subject to the Human Resources and Environment Committee's review and approval.

(ii) *Benchmarking*

Toronto Hydro periodically benchmarks the compensation it provides to the NEOs to ensure reasonableness, competitiveness and effectiveness of Toronto Hydro's compensation program, including the level and type of compensation provided. The Human Resources and Environment Committee periodically engages a compensation consultant to conduct executive compensation benchmarking for the NEOs, to ensure that Toronto Hydro is able to attract, retain and motivate high-performing senior executives in the markets in which we compete for talent.

Toronto Hydro's objective is to pay competitively with other Canadian Utility and Energy Industry companies of comparable size and complexity. NEO compensation is generally benchmarked against:

- industry comparators in the public sector of like size: publicly owned utility / energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- publicly and privately owned (including publicly traded) utility / energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- industrial companies in the Greater Toronto Area ("GTA");
- industrial companies in Canada; and
- public sector organizations in Canada.

The benchmark data comes from proprietary compensation surveys, and publicly disclosed executive compensation information in Canada.

Toronto Hydro's flow-through revenue for electricity transmission and generation is excluded for purposes of identifying comparable general industry (i.e., non-local-distribution-company) peer companies, except in the case of the CFO, where the Toronto Hydro's full revenue is also considered because Toronto Hydro believes this role's accountability for cash management more closely matches organizations with similar total revenues. The senior executive compensation information derived from the benchmarking analysis is designed to assist the Human Resources and Environment Committee in establishing, over a reasonable period of time, total cash compensation for NEOs in the range of the median total cash compensation of the benchmark data. Total cash compensation to NEOs may exceed the median of the marketplace when corporate, divisional and individual performance significantly exceeds objectives.

(iii) *Compensation Consultants and Advisors*

The Human Resources and Environment Committee began engaging the services of Willis Towers Watson for senior executive compensation consulting services in 2016. The consulting services provided to the Human Resources and Environment Committee include providing advice on the competitiveness and appropriateness of Toronto Hydro's senior executive compensation program, compensation benchmarking services, and other compensation related matters that may arise from time to time. The Corporation also engages Willis Towers Watson for actuarial services. The Human Resources and Environment Committee or the Board is required to pre-approve the actuarial services Willis Towers Watson provides to Toronto Hydro in accordance with the Corporation's Policy on the Provision of Services by Compensation Advisors. The actuarial services provided by Willis Towers Watson do not present any conflicts with the services provided as compensation advisor to the Human Resources and Environment Committee.

The table below sets out the fees billed by Willis Towers Watson for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,	
	2018	**2017**
Executive Compensation – Related Fees [1].........................	$20,779	$94,906
All Other Fees [2]	$88,050	$42,427

Notes:

(1) Aggregate fees billed by Willis Towers Watson, or any of its affiliates, for services related to determining compensation for any of Toronto Hydro's directors and executive officers.

(2) Aggregate fees billed by Willis Towers Watson, or any of its affiliates, for services related to employee compensation and benefits management consultation or actuarial services that are not reported under (1) above.

(d) Elements of Compensation

The principal components of compensation for NEOs are:

- base salary;
- performance-based incentive compensation;
- personal benefits and perquisites;
- pension plan;
- post-employment benefits;
- retirement allowances; and
- termination payments.

As the Corporation has a single shareholder that is the registered and beneficial owner of all of its issued and outstanding shares, the Corporation is not able to offer an equity incentive plan or other stock-based compensation to its NEOs.

(i) *Base Salary*

In accordance with the general objectives and process for establishing compensation noted above, Toronto Hydro provides NEOs with a base salary to compensate them for services rendered during the fiscal year. Toronto Hydro provides reasonably competitive market-based base salaries to help attract, motivate, and retain NEOs who are critical to the Corporation's success.

Annually, adjustments to base salaries for NEOs are driven by market benchmarking data and the NEO's individual performance rating. The performance rating is determined, in the case of the CEO, by the Human Resources and Environment Committee and, in the case of the other NEOs, by the CEO, based on the achievement of performance-based incentive compensation objectives, knowledge, skills, and competencies related to day-to-day performance, as well as demonstration of desired corporate behaviours, subject to the Human Resources and Environment Committee's review and approval.

(ii) *Performance-Based Incentive Compensation*

All NEOs receive a portion of their annual compensation in the form of performance-based cash payments. The performance-based incentive compensation is designed to retain, motivate and reward NEOs for reaching corporate, divisional and individual performance objectives established at the beginning of each calendar year.

The annual performance-based incentive compensation is calculated as a percentage of the NEO's base salary for the year and, if earned, paid in one lump sum in the next fiscal year.

In order for a NEO to earn and receive the performance-based incentive compensation, the Corporation and the NEO must each achieve certain pre-determined performance objectives. Each NEO's performance-based incentive compensation is based on a weighting of corporate, divisional and individual performance objectives, whose weightings and objectives are determined at the start of each year and vary by role to reflect the performance focus of the role. The weighting and objectives are reviewed and set each year in order to reflect the Corporation's overall strategy and objectives.

Each year the board reviews and approves the Corporation's objectives. Each performance objective is weighted to reflect relative importance and includes threshold, target and outstanding expectations of performance. Specific performance targets are approved by the Board giving consideration to the Corporation's business plans and priorities for the upcoming year, the prior year's performance and a review of forecasted results based on a historical analysis of performance. Similarly divisional objectives are approved by the CEO and reviewed by the Human Resources and Environment Committee to recognize unique divisional priorities and ensure alignment with the Corporation's overall objectives.

The CEO's individual objectives are reviewed and approved by the Board. The individual objectives of the other NEOs are reviewed and approved by the CEO. Each NEO's individual objectives are based on areas of strategic and operational emphasis related to their respective responsibilities and portfolios.

The NEO's individual objectives are intended to be reasonably difficult to attain and to encourage success in the NEO's performance. Individual objectives are often but not always achieved by a NEO in any given year. NEOs review their objectives and measurements throughout the year, with one formal mid-year review with the Chair of the Board (in the case of the CEO), and with the CEO (in the case of the other NEOs), to track achievement to-date and revise performance goals as may be necessary to reflect any change in corporate strategy or priorities.

In the case of the CEO, an annual performance evaluation in respect of his individual performance goals is conducted by the Chair of the Board who provides a recommendation to the Human Resources and Environment Committee regarding the performance-based incentive compensation to be paid to the CEO. The amount paid to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee.

In the case of each of the other NEOs, an annual performance evaluation in respect of the individual objectives for each individual is conducted by the CEO, who proposes the amount of performance-based incentive compensation to be paid to each other NEO. The Human Resources and Environment Committee reviews and approves the amounts of performance-based incentive compensation to be paid to each of the other NEOs.

(iii) *Personal Benefits and Perquisites*

Toronto Hydro provides NEOs with other personal benefits and perquisites that Toronto Hydro believes are reasonable and consistent with its overall compensation program to better enable the Corporation to attract and retain superior employees for key positions. Benefits include group health, dental, group life insurance, short-term and long-term disability, accidental death & dismemberment, a gym subsidy, and educational reimbursements, all of which are generally available to all salaried employees.

(iv) *Pension Plan*

All full-time employees of Toronto Hydro, including the NEOs, are required to participate in the OMERS pension plan. Pursuant to the terms of the OMERS pension plan, NEOs are required to make equal plan contributions based on their eligible pensionable earnings. In 2018, Toronto Hydro and each NEO was required to contribute 9.0% equally of the first $55,900 of pensionable earnings and thereafter 14.6% equally on all earnings over $55,900 and up to $175,223. From $175,223 and up to a maximum of $391,300, contributions continue equally at 14.6% towards a Retirement Compensation Arrangement (RCA), which is governed separately under the Canadian Income Tax Act. The OMERS pension plan is generally available to all other salaried employees. See section 4.6 (a) under the heading "Employees" for more information on the OMERS pension plan.

(v) *Post-employment Benefits*

NEOs are eligible to receive post-employment health, dental and life insurance benefits after a minimum of five years of service with Toronto Hydro if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement. The post-employment benefits provided to eligible NEOs are the same as are generally available to all other salaried employees. Post-employment benefits aid in attracting and retaining key executives to ensure the long-term success of Toronto Hydro.

(vi) *Retirement Allowances*

From time to time, in certain circumstances, Toronto Hydro enters into retirement allowance agreements with its NEOs. The retirement allowance agreements are designed to recognize service, and to promote retention, stability and continuity, of the NEOs. These agreements are made on a case-by-case basis based on a NEO's years of service and position. Any retirement allowance provided to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any retirement allowance agreement is proposed by the CEO and reviewed and amended or approved by the Human Resources and Environment Committee. Retirement allowance payments are typically paid in one or two lump sum instalments following termination or retirement of the NEO.

(vii) *Termination Payments*

From time to time, Toronto Hydro enters into agreements with NEOs which provide for payments upon termination. These agreements are made on a case-by-case basis based on the NEO's age, years of service and position. Any such agreement for the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any such agreement is proposed by the CEO and reviewed and approved by the Human Resources and Environment Committee. Typically, termination payments are paid either as a lump sum or as salary continuation for an agreed period following termination.

12.3 Compensation of Named Executive Officers

(a) Summary Compensation Table

The following table provides a summary of the compensation earned during the years ended December 31, 2018, 2017 and 2016, by the NEOs:

Summary Compensation Table(1)

NEO Name and Principal Position	Year	Salary(2) ($)	Non-Equity Incentive Plan Compensation(3) ($)	All Other Compensation(4) ($)	Total Compensation ($)
Anthony Haines	2018	$583,999	$570,068	$16,053	$1,170,120
President and Chief Executive Officer,	2017	$548,490	$528,138	$10,452	$1,087,080
Toronto Hydro Corporation	2016	$522,286	$508,551	$10,301	$1,041,138
Sean Bovingdon(5)	2018	$262,632	$153,273	$1,727	$417,632
Former Executive Vice-President and	2017	$274,039	$166,500	$200,000	$640,539
Chief Financial Officer,					
Toronto Hydro Corporation					
Aida Cipolla(6)	2018	$215,668 (6)	$111,400	$1,560	$328,628
Executive Vice-President and Chief	2017	$185,478	$71,250	$1,560	$258,288
Financial Officer,	2016	$163,246	$61,750	$1,058	$226,054
Toronto Hydro Corporation					
Dino Priore	2018	$377,561	$224,808	$4,580	$606,949
Executive Vice-President and Chief	2017	$338,019	$211,371	$4,108	$553,498
Engineering and Construction Officer,	2016	$326,019	$192,889	$2,330	$521,238
Toronto Hydro –Electric System Limited					
Ben La Pianta	2018	$346,704	$207,482	$9,133	$563,319
Executive Vice-President and Chief	2017	$298,103	$195,137	$5,005	$498,245
Customer Care and Electric Operations	2016	$287,100	$169,295	$3,823	$460,218
Officer,					
Toronto Hydro –Electric System Limited					
Amanda Klein	2018	$283,000	$169,800	$2,863	$455,663
Executive Vice-President, Public and	2017	$237,767	$124,803	$0	$362,570
Regulatory Affairs and Chief Legal	2016	$209,154	$114,819	$178	$324,151
Officer,					
Toronto Hydro –Electric System Limited					

Notes:

(1) Amounts shown in this table are in Canadian dollars and have been rounded to the nearest dollar.

(2) Amounts shown reflect actual amounts paid during the year.

(3) Each NEO's annual performance-based incentive compensation for a fiscal year is determined and paid in the next fiscal year. Accordingly, amounts reflected in respect of a particular year (i.e. 2017) represent the annual performance-based incentive compensation earned by the NEO for the achievement of performance objectives in respect of that fiscal year (i.e. 2017) but which amounts are paid in the following fiscal year (i.e. 2018).

(4) Amounts shown in this column reflect all other compensation earned by the NEO during the year. The amounts shown include the aggregate value of perquisites and other personal benefits provided to the NEO, where such perquisites and personal benefits are not generally available to all employees and have been calculated by using the actual cost. In 2018, 2017 and 2016, perquisites and personal benefits were not worth $50,000 or more for any NEO, nor were they worth 10% or more of any NEO's total salary for the year, with the exception of Mr. Bovingdon. Mr. Bovingdon received a one-time $200,000 relocation allowance when he joined the Corporation in 2017.

(5) Effective August 26, 2018, Mr. Bovingdon ceased to be Executive Vice-President and Chief Financial Officer of the Corporation. See section 12.3(b)(vii) under the heading "Termination Payments" for a discussion regarding additional amounts respecting termination.

(6) Effective August 27, 2018, Ms. Cipolla is the Executive Vice-President and Chief Financial Officer and her annual base salary was $250,563. Prior to this role, Ms. Cipolla was the Corporation's Controller since December 2015. Her 2018 performance-based incentive compensation was in respect of her role as the Controller and Executive Vice-President and Chief Financial Officer.

(b) Compensation of NEOs in 2018 – Narrative Discussion

(i) *Base Salaries*

The NEOs' annual base salaries for 2018 were: $584,685 in the case of Mr. Haines, $388,359 in the case of Mr. Bovingdon, $250,563 in the case of Ms. Cipolla, $379,744 in the case of Mr. Priore, $350,476 in the case of Mr. La Pianta, and $283,000 in the case of Ms. Klein.

(ii) *Performance-Based Incentive Compensation*

The targets and component weightings for the 2018 performance-based incentive compensation were as follows:

Position	Target Performance-Based Incentive (% of salary)	Individual Performance (% weighting)	Divisional Performance (% weighting)	Corporate Performance (% weighting)
CEO	65%	20%	—	80%
CFO	40%	20%	20%	60%
Other NEOs	40%	20%	20%	60%

The performance-based incentive compensation amount payable to each NEO may exceed the respective target % of base salary indicated above when results exceed corporate, divisional and individual objectives and may be below the respective target % of base salary indicated above when the corporate, divisional and individual objectives are not achieved. The component weightings outlined above have been unchanged since 2011.

The performance objectives of the Corporation for 2018 were as follows:

Corporate Key Performance Indicators	Measure	Target	Weight (%)
Consolidated Net Income ($M)	Net Income after net movements in regulatory balances per the Corporation's Consolidated Financial Statements.	$148.0	40%
1-Year Distribution System Plan Investment ($M) (1)	TH Board approved cumulative regulated capital investments (not necessarily in service) as defined in the Distribution System Plan for the current year.	$435.0	5%
5-Year CIR Distribution System Plan Investment ($M) (1)	TH Board approved cumulative regulated capital investments (not necessarily in service) as defined in the Distribution System Plan for the five year rate period.	$1,942.6	5%
System Average Interruption Duration Index (SAIDI) (in minutes) (Defective equipment only)	Measure of the annual system average interruption duration per customer served, not including Major Event Days.	29.00	10%
System Average Interruption Frequency Index (SAIFI) (number of interruptions) (Defective equipment only)	Measure of the frequency of service interruptions per customer served, not including Major Event Days.	0.54	10%
First Contact Resolution	Percentage of telephone and email enquiries resolved in one contact, within a 21 day time period	86%	5%
Bill Accuracy	The percentage of issued bills that are considered accurate or inaccurate as defined by the Ontario Energy Board.	98.8%	5%
New Services Connected On Time	Percentage of connections for new low-voltage (<750 volts) service requests completed within five business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer	96.5%	5%
Employee Engagement	Average number of engagement sessions attended per employee per year	6.0	5%
Safety – Total Recordable Injury Frequency (TRIF)	Number of recordable injuries x 200,000 / exposure hours.	1.45	10%

Note:
(1) This is a non-GAAP measure as it includes all eligible capital expenditures, net of capital contributions related to regulated operations.

Corporate KPIs are cascaded down in the organization to create appropriate divisional performance objectives with strong line of sight.

Divisional KPIs support operational, financial, customer and employee targets. Weightings for these KPIs ranged from 5% to 25% of divisional performance. All divisional KPIs support achievement in the Corporation's four areas of focus: Customer, People, Operations, and Financial. These measures are aimed at increasing customer satisfaction, improving reliability, accomplishing LDC's work program safely and meeting regulatory requirements. Prioritization of these KPI's is determined based on divisional accountabilities. Some examples of Divisional measures are Customer Connection Index, Safety Inspections per Leader, Distribution System Health Index & Operating Expenses.

Performance-based incentives also include individual performance objectives which are set annually and are tied to business priorities and each individual's particular accountabilities. The number and weighting of individual objectives vary by individual and from year to year. Examples of the 2018 individual performance objectives for the NEOs include, but are not limited to, continuous improvement of operational processes to enhance performance and engagement.

In 2018, the Corporation exceeded all of its corporate targets represented by its KPIs. The NEOs exceeded the majority of their divisional and individual performance targets for 2018. Each of the corporate, divisional and individual performance targets were reasonably difficult to attain and served to encourage success in the NEOs performance and in the Corporation's overall results.

(iii) *Personal Benefits and Perquisites*

In 2018, the NEOs received personal benefits and perquisites as described in section 12.2(d)(iii) under the heading "Personal Benefits and Perquisites", and as quantified in the Summary Compensation Table in section 12.3(a) above.

(iv) *Pension Plan*

In 2018, each of the NEOs participated in the OMERS pension plan. The OMERS pension plan is a group pension plan that is generally available to all salaried employees. See section 4.6(a) under the heading "Employees" and section 12.2(d)(iv) under the heading "Pension Plan" for further information on the OMERS pension plan.

(v) *Post-employment Benefits*

As of December 31, 2018, Mr. Haines, Mr. Priore, Mr. La Pianta and Ms. Cipolla have each provided Toronto Hydro with more than five years of service and are eligible for post-employment medical, dental and life insurance benefits if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement.

(vi) *Retirement Allowance*

Mr. Haines is the only NEO entitled to retirement allowances, which allowances are calculated based on completed years of service and are payable in the form of lump-sum cash payments following Mr. Haines' termination (without cause) or retirement from the Corporation.

Under the terms of Mr. Haines' existing retirement allowance (the "Existing Allowance"), if Mr. Haines is terminated (without cause) or retires from the Corporation during 2019, he will receive a $750,000 retirement allowance. The amount of the Existing Allowance payable to Mr. Haines will thereafter be increased by an additional $125,000 per year (from 2019 to 2020) for each full calendar year of service completed. The maximum Existing Allowance payable to Mr. Haines is $1,000,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2020. In the event that Mr. Haines becomes permanently disabled while in active service for the Corporation, he will be deemed to remain in active service for the Corporation until December 31, 2020, at which point he will be considered to have retired and earned the maximum Existing Allowance of $1,000,000. In the event of the death of Mr. Haines while in active service for the Corporation, the Existing Allowance which Mr. Haines would have earned as of the date of his death will be paid to his designated beneficiary or to the legal representative of Mr. Haines' estate.

As part of his compensation package, Mr. Haines also participates in the OMERS defined benefit pension plan. See "Pension Plan" above in section 12.3(b)(iv). OMERS made significant unilateral changes to its defined benefit pension plan that significantly reduce the value of Mr. Haines' pension benefit under the OMERS pension plan. In order to mitigate the impact of these changes in a manner consistent with the terms of his existing employment relationship with the Corporation, the Corporation has awarded Mr. Haines a second retirement allowance (the "Second Allowance"). Under the terms of the Second Allowance, if Mr. Haines is terminated (without cause) or retires from the Corporation during 2019, he will receive a $975,000 retirement allowance. The amount of the Second Allowance payable to Mr. Haines will thereafter be increased by an additional $225,000 per year (from 2019 to 2021) for each full calendar year of service completed. The maximum Second Allowance payable to Mr. Haines is $1,650,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2021. In the event that Mr. Haines becomes permanently disabled while in active service for the Corporation, he will be deemed to remain in active service for the Corporation until December 31, 2021, at which point he will be considered to have retired and earned the maximum Second Allowance of $1,650,000. The provisions relating to entitlement on death are identical to those established for the Existing Allowance.

(vii) *Termination Payments*

Mr. Haines has entered into an agreement with the Corporation which provides for certain payments upon termination.

If the employment of Mr. Haines is terminated without cause by the Corporation, then Mr. Haines is entitled to a payment equal to 24 months of base salary and performance pay that would have been paid had he continued to work for 24 months (approximately $2,240,541 as at December 31, 2018), with the performance pay calculated based on the average annual performance pay earned by Mr. Haines during the 3 years preceding the date of termination. Mr. Haines would also be entitled to continued group health and dental benefit coverage for a period of 24 months from the date of termination.

Ms. Cipolla has entered into an agreement with the Corporation which provides for certain payments upon termination.

If the employment of Ms. Cipolla is terminated without cause by the Corporation, then Ms. Cipolla is entitled to one (1) month of severance pay for each completed year of employment, to a minimum of twelve (12) months and a maximum of eighteen (18) months, and would continue to be eligible for performance pay that would otherwise have been earned during the severance period. Ms. Cipolla would be entitled to benefits during the severance period.

In addition, and in connection with Mr. Bovingdon ceasing employment with the Corporation, Mr. Bovingdon was entitled to a termination payment in the aggregate amount of $580,569, representing 12 months of working notice of termination or pay in lieu thereof and performance pay that would otherwise have been earned and/or paid during the 12 month period of which $137,644 has been paid as of December 31, 2018, $341,019 is payable by December 31, 2019 and $101,906 will be payable by the end of 2020.

12.4 Compensation of Directors

(a) Director Compensation Table

Director Name	Total[(1)] ($)
David McFadden	$75,000
Brian Chu	$26,500
Heather Zordel	$26,500
Howard Wetston	$21,500
Juliana Lam	$26,500
Mary Ellen Richardson	$22,500
Michael Nobrega	$27,500
Tamara Kronis	$26,500
Deputy Mayor Denzil Minnan-Wong	$Nil
Councillor Paul Ainslie	$Nil
Deputy Mayor Stephen Holyday	$Nil

Note:

(1) There was no compensation paid to directors during 2018 other than in respect of director retainer fees and meeting attendance fees.

(b) Compensation of Directors – Narrative Discussion

Directors of the Corporation, other than Councillors of the City, are compensated for their services as directors through a combination of retainer fees and meeting attendance fees. These fees are set by the sole shareholder of the Corporation, the City. The annual retainer fees are as follows: chair of the Board – $75,000 and each of the other directors – $12,500. The meeting attendance fees are as follows: each meeting of the Board and the subsidiaries attended – $1,000 and each meeting of the Audit Committee, Corporate Governance and Nominating Committee, Human Resources and Environment Committee, or other Board committee attended – $1,000, subject to annual maximum fees per committee member of $5,000 for the Audit Committee, Corporate Governance Committee, Human Resources and Environment Committee or any other committee of the Board. The Board does, from time to time and in the normal course, strike ad hoc committees to streamline and expedite certain matters as they come before the Board. Any compensation Directors have earned from their attendance at these committees has been included in the table above. The Chair receives no meeting attendance fees. Councillors receive no remuneration for their services as directors of the Corporation. The other directors, other than the Chair, are subject to a maximum annual total retainer and attendance fees of $30,000.

PART 13 - LEGAL PROCEEDINGS

In the ordinary course of business, Toronto Hydro is subject to various legal actions and claims from customers, suppliers, former employees and other parties. As at the date hereof, the Corporation believes that none of these legal actions and claims from customers, suppliers, former employees and other parties in which it is currently involved or has been involved since the beginning of the most recently completed financial year, would be expected to have a material adverse effect on the Corporation. On an ongoing basis, Toronto Hydro assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy.

If damages were awarded under these actions, Toronto Hydro would make a claim under any applicable liability insurance policies which Toronto Hydro believes would cover any damages which may become payable by Toronto Hydro in connection with these actions, subject to such claim not being disputed by the insurers.

PART 14 - MATERIAL CONTRACTS

The following are material contracts (other than contracts entered into in the ordinary course of business) that the Corporation has entered into in the most recently completed financial year, or before the most recently completed financial year if such material contract is still in effect:

(a) trust indenture dated as of May 7, 2003 between Toronto Hydro Corporation and CIBC Mellon Trust Company (now BNY Trust Company of Canada) (the "**Trust Indenture**");

(b) a third supplemental trust indenture dated as of November 12, 2009 relating to the issuance of Series 3 senior unsecured debentures in the aggregate principal amount of $250,000,000;

(c) a sixth supplemental trust indenture dated as of May 20, 2010 relating to the issuance of Series 6 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(d) a seventh supplemental trust indenture made as of September 20, 2011 amending the definition of "GAAP" under the Trust Indenture;

(e) an eighth supplemental trust indenture dated as of November 18, 2011 relating to the issuance of Series 7 senior unsecured debentures in the aggregate principal amount of $300,000,000;

(f) a ninth supplemental trust indenture dated as of April 9, 2013 relating to the issuance of Series 8 senior unsecured debentures in the aggregate principal amount of $250,000,000;

(g) a tenth supplemental trust indenture dated as of April 9, 2013, as amended and restated as of September 2, 2015, relating to the issuance of Series 9 senior unsecured debentures in the aggregate principal amount of $245,000,000;

(h) an eleventh supplemental trust indenture dated as of September 16, 2014 relating to the issuance of Series 10 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(i) a twelfth supplemental trust indenture dated as of March 16, 2015 relating to the issuance of Series 11 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(j) a thirteenth supplemental trust indenture dated as of June 14, 2016 relating to the issuance of Series 12 senior unsecured debentures in the aggregate principal amount of $200,000,000; and

(k) a fourteenth supplemental trust indenture dated as of November 14, 2017 relating to the issuance of Series 13 senior unsecured debentures in the aggregate principal amount of $200,000,000.

Each of these supplemental trust indentures supplement the terms of the Trust Indenture, which contains customary covenants and representations by the Corporation for the public issuance of debt securities in the Canadian capital market.

Copies of these material contracts are available on the SEDAR website at www.sedar.com.

PART 15 - NAMED AND INTERESTS OF EXPERTS

The external auditor of the Corporation is KPMG LLP. KPMG LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

PART 16 - TRANSFER AGENTS AND REGISTRARS

The trustee and registrar for the outstanding Debentures of the Corporation is BNY Trust Company of Canada, located in Toronto, Ontario.

PART 17 - ADDITIONAL INFORMATION

Additional information relating to the Corporation, including additional financial information provided in the Consolidated Financial Statements and Management's Discussion and Analysis, is available on the SEDAR website at www.sedar.com.

ANNEX A - CHARTER – AUDIT COMMITTEE

1. General

(1) The board of directors ***(Board)*** of Toronto Hydro Corporation ***(Corporation)*** has established the Audit Committee ***(Committee)*** to assist the Board and the boards of directors of the Corporation's subsidiary entities in fulfilling their respective corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit and external audit functions.

(2) The composition, responsibilities and authority of the Committee are set out in this Charter.

(3) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least three persons who are directors of the Corporation ***(Members)***:

(a) all Members must be *independent*, (as determined by the Board in accordance with the meaning of "independence", as the context requires, given to it in the Canadian Securities Administrators' National Instrument 52-110 Audit Committees, as the same may be amended and/or replaced from time to time) ; and

(b) at least one of whom, including the chair of the Committee (***Chair***) is *financially literate* (ie, have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the accounting issues that can reasonably be expected to be raised by the financial statements of the Corporation).

(2) In addition to the Members, the Committee shall also include at least one director of Toronto Hydro-Electric System Limited who is not also a director of the Corporation (***THESL Members***). The THESL Members shall be invited to all the meetings of the Committee, shall be entitled to receive all Committee materials and to participate in all Committee discussions and deliberations, but shall have no voting rights.

(3) Members and THESL Members shall be appointed by the Board on the recommendation of the Chair of the Board and the Chair of the THESL Board, respectively, and shall serve until they resign, cease to be a director of the respective board, as applicable, or are removed or replaced by the Board.

(4) The Board shall designate one of the Members as Chair. The Committee shall periodically review the position description of the Chair and make recommendations to the Board.

(5) The Executive Vice-President and Chief Financial Officer (***Designated Representative)*** shall be appointed from time to time to act as the principal interface between the Committee and other senior management of the Corporation and its subsidiary entities.

(6) The Secretary of the Corporation shall be secretary of the Committee ***(Secretary)***.

(7) The Chair of the Corporation's Board of Directors shall be an *ex-officio* Member of the Committee with all of the responsibilities and privileges thereof, but shall only count towards meeting quorum if he or she is present at the meeting.

3. Responsibilities

The Committee shall assist the Board and the boards of directors of the Corporation's subsidiary entities in fulfilling their corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit functions, external audit functions, and the payment of dividends by the Corporation and its subsidiary entities.

The Committee has specifically recognized its responsibilities for overseeing the identification of the principal financial and audit risks of the Corporation and its subsidiary entities and overseeing the implementation of appropriate systems to manage these risks. In particular, the Committee shall have the responsibilities set out below.

(1) ***Managing the Relationship between the Corporation and its Subsidiaries and their External Auditors***

The Committee shall be responsible for managing the relationship between the Corporation and its subsidiary entities and their external auditors, including:

(a) appointing and replacing the external auditors, subject to the Boards of Directors and shareholder approval;

(b) setting the compensation of the external auditors subject to the approval of the board of directors or shareholder, as applicable;

(c) overseeing the work of the external auditors, including resolving disagreements between management and the external auditors with respect to financial reporting;

(d) pre-approving all audit services and permitted non-audit services to be provided to the Corporation and its subsidiary entities by the external auditors in accordance with the "Policy on the Provision of Services by the External Auditors";

(e) having the external auditors report to the Committee in a timely manner with respect to all required matters, including those set out in paragraph 3(2);

(f) ensuring the rotation of the audit partner having primary responsibility for the external audits of the Corporation and its subsidiary entities, the audit partner responsible for reviewing the external audit and the external auditors at such intervals as may be required; and

(g) reviewing and assessing the performance, independence and objectivity of the external auditors.

(2) ***Overseeing the External Audits***

The Committee shall be responsible for overseeing the external audits of the Corporation and its subsidiary entities, including:

(a) reviewing and approving the engagement letters and the audit plans, including financial risk areas identified by the external auditors and management;

(b) reviewing and assessing the accounting and reporting practices and principles used by the Corporation and its subsidiary entities in preparing their financial statements, including:

(1) all significant accounting policies and practices used, including changes from preceding years and any proposed changes for future years;

(2) all significant financial reporting issues, estimates and judgments made;

(3) all alternative treatments of financial information discussed by the external auditors and management, the results of such discussions and the treatments preferred by the external auditors;

(4) any major issues identified by the external auditors with respect to the adequacy of internal control systems and procedures and any special audit steps adopted in light of material deficiencies and weaknesses;

(5) the effect of regulatory and accounting initiatives and off-balance sheet transactions or structures on the financial statements;

(6) any errors or omissions in, and any required restatement of, the financial statements for preceding years;

(7) all significant tax issues;

(8) the reporting of all material contingent liabilities; and

(9) any material written communications between the external auditors and management;

(c) reviewing and assessing the results of the external audit and the external auditors' opinion on the financial statements;

(d) reviewing and discussing with the external auditors and management any management or internal control letters issued or proposed to be issued by the external auditors;

(e) reviewing and discussing with the external auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management); and

(f) reviewing and discussing with legal counsel any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies of the Corporation and its subsidiary entities and any material reports or enquiries received by the Corporation and its subsidiary entities from regulators or government agencies.

(3) ***Overseeing the Internal Audits***

The Committee shall be responsible for overseeing the internal audits of the Corporation and its subsidiary entities, including:

(a) periodically reviewing the Internal Audit Charter and making recommendations to the Board;

(b) reviewing and approving the audit plans, including significant risk exposures identified by the internal auditor and management;

(c) reviewing and discussing with the internal auditor and management the results of any internal audits;

(d) reviewing and discussing with the internal auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management);

(e) appointing and replacing the internal auditor;

(f) reviewing and assessing the performance of the internal auditor;

(g) ensuring the Committee is kept informed of emerging trends and successful practices in internal auditing; and

(h) confirming there is effective and efficient coordination of activities between internal and external auditors.

(4) ***Reviewing and Recommending to the Respective Boards for Approval the Financial Statements, MD&A and Interim Reports of the Corporation and its Subsidiaries***

The Committee shall review and recommend to each respective board of directors, as applicable, for approval, the financial statements, management's discussion and analysis of financial condition and results of operations ***(MD&A)*** and interim financial reports of the Corporation and its subsidiaries, annual information form ***(AIF)*** (other than executive compensation) of the Corporation and other public disclosure of financial information extracted from the financial statements of the Corporation and its subsidiaries with particular focus on:

(a) the quality and appropriateness of accounting and reporting practices and principles and any changes thereto;

(b) major estimates or judgments, including alternative treatments of financial information discussed by management and the external auditors, the results of such discussions and the treatment preferred by the external auditors;

(c) material financial risks;

(d) material transactions;

(e) material adjustments;

(f) compliance with loan agreements;

(g) material off-balance sheet transactions and structures;

(h) compliance with accounting standards;

(i) compliance with legal and regulatory requirements;

(j) controls; and

(k) disagreements with management.

(5) ***Overseeing Internal Financial Control Structure and Financial Risk Management Systems***

The Committee shall be responsible for overseeing the internal financial control structure and financial risk management systems of the Corporation and its subsidiary entities, including:

(a) reviewing and discussing with management and the external auditors the quality and adequacy of internal control over financial reporting structures of the Corporation and its subsidiary entities, including any major deficiencies or weakness and the steps taken by management to rectify these deficiencies or weaknesses;

(b) reviewing and discussing with management, the internal auditor and the external auditors the risk assessment and risk management policies of the Corporation and its subsidiary entities, the major financial risk exposures of the Corporation and its subsidiary entities, and the steps taken by management to monitor and control these exposures;

(c) reviewing and discussing with the Chief Executive Officer and the Chief Financial Officer of the Corporation the procedures undertaken by them in connection with the certifications required to be given by them in connection with annual and other filings required to be made by the Corporation under applicable securities laws; and

(d) periodically reviewing the Treasury Policy Register and making recommendations to the Board in respect of such policy and reviewing performance under this policy with Management.

(6) ***Establish and Review Certain Procedures and Policies***

The Committee shall establish adequate policies and procedures, or require that adequate policies and procedures are established, with respect to the following, and shall annually, or on such other schedule as stated herein, assess the adequacy of these procedures:

(a) the review of the public disclosure of financial information extracted from the financial statements of the Corporation;

(b) the receipt, retention and treatment of complaints received by the Corporation with respect to accounting, internal controls or auditing matters;

(c) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

(d) the approval by the Committee of the hiring policies for any present or former partner or employee of the current and former external auditor into a position of senior management with the Corporation or its subsidiaries; and

(e) the periodic review of the Policy on the Provision of Services by the External Auditors and Expense Reimbursement Policy, and provision of recommendations to the Board in respect of the same.

(7) ***Review of Policy Reporting***

(a) The Committee shall be responsible, on a quarterly basis, for reviewing and reporting to the Board in respect of the report of Internal Audit with respect to incidents regarding questionable accounting or auditing matters investigated under the Code of Business Conduct and Whistleblower Procedure during the previous quarter.

(b) The Committee shall be responsible for reviewing, on a quarterly basis, the report of Internal Audit concerning executive and Board expense reimbursements made in accordance with the Corporation's Expense Reimbursement Policy for the immediately preceding quarter.

(8) ***Review and Recommendations for Dividend Payment***

(a) The Committee shall be responsible for reviewing and making recommendations to each respective board of directors, as applicable, with respect to the declaration of dividends or distribution of capital by the Corporation or its subsidiary entities.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board and the boards of directors of the Corporation's subsidiaries arising therefrom.

(2) The Committee may delegate by written policy to the Chair and the Executive Vice-President and Chief Financial Officer of the Corporation ***(CFO)*** the authority, within specified limits, to authorize in advance all engagements of the external auditors to provide pre-approved services to the Corporation and its subsidiary entities. The Chair and the CFO shall report all engagements authorized by them to the Committee at its next meeting.

(3) The Committee shall have direct and unrestricted access to the external and internal auditors, officers and employees and information and records of the Corporation and its subsidiary entities.

(4) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(5) The Committee is authorized to invite officers and employees of the Corporation and its subsidiaries and outsiders with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(6) The external auditors shall have direct and unrestricted access to the Committee and shall report directly to the Committee.

(7) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities, in accordance with the Corporation's Expense Reimbursement Policy.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than four times each year.

(2) Any Member or THESL Member or the Secretary may call a meeting of the Committee. The external auditors or the CFO may ask a Member to call a meeting of the Committee. The Chair, along with the Designated Representative, is responsible for the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation and its subsidiary entities, external auditors, other Members and THESL Members, and other directors of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(3) Unless waived by all Members and THESL Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded, electronically or otherwise, to each Member and THESL Member at least three days before the date of the meeting.

(4) The quorum for each meeting of the Committee is at least 50% of the Members. In the absence of the Chair, the other Members may appoint one of their number as chair of a meeting. The Chair of a meeting shall not have a second or casting vote.

(5) The Chair or a delegate of the Chair shall report to the Board following each meeting of the Committee.

(6) The Secretary or a delegate of the Secretary shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of all meetings shall be distributed to the Members and THESL Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(7) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. A standing invitation to all meetings shall be given to the President and Chief Executive Officer of the Corporation and the CFO, except where the meeting, or part of the meeting, is for Members only or a private session with the internal auditor or the external auditors. A standing invitation should be given to the internal auditor and the engagement partners of the external auditors for all meetings where financial information is reviewed and approved.

(8) The Committee shall meet regularly alone and in private sessions with the Vice President, Audit and Corporate Compliance, the external auditors and management of the Corporation to facilitate full communication.

6. Review

(1) This Charter shall be reviewed by the Corporate Governance and Nominating Committee of the Corporation every three (3) years and any recommended changes shall be referred first to the Audit Committee for review and comment and second, after consideration of the input from the Audit Committee, to the Board of the Corporation for consideration and disposition.

(2) In addition to the triennial review, the Audit Committee may at any time review the Charter and make recommendations to the Corporate Governance and Nominating Committee for their review and recommendations to the Board with respect thereto.

ANNEX B - MANDATE – BOARD OF DIRECTORS

1. General

(1) The board of directors ***(Board)*** of *Toronto Hydro Corporation* ***(Corporation)*** is responsible for supervising the management of the business and affairs of the Corporation and its subsidiary entities ***(Group)***.

(2) The composition, responsibilities, and authority of the Board are set out in this Mandate.

(3) This Mandate, the Shareholder Direction issued by the City of Toronto ***(Shareholder)*** and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Board may adopt from time to time shall govern the meetings and procedures of the Board.

2. Composition

(1) The directors of the Corporation ***(Directors)*** should have a mix of competencies and skills necessary to enable the Board and Board committees to properly discharge their responsibilities.

(2) All of the Directors shall be residents of Canada.

(3) The Shareholder shall appoint Directors every two years.

(4) In appointing Directors the Shareholder shall give due regard to the qualifications of the candidates including:

(a) experience on a public utility commission or board of a major corporation or other commercial enterprise and/or the completion of formal training in directorship / governance;

(b) experience in regulated electricity utility sector at a senior management level;

(c) experience at an executive level in resource and performance management / compensation, including ability to appoint and evaluate the performance of the CEO and senior executives; oversee strategic human resource management, including workforce planning, compensation models, and labour relations; and oversee large scale organizational change;

(d) educational background, including university degrees and professional designations;

(e) experience or knowledge with respect to:

i) strategic planning, including ability to identify and critically assess strategic opportunities and threats to the organization;

ii) risk management, including ability to assess key risks to the organization on an enterprise basis and monitor the risk management framework systems;

iii) corporate finance / accounting / audit / securities, including ability to analyze financial statements, assess financial viability, contribute to financial planning, oversee budgets, and oversee funding arrangements;

iv) corporate governance;

v) market development, innovation and development of new strategic business lines;

vi) large system operation and management;

vii) urban energy industries;

viii) public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;

ix) environmental matters, including experience in environmental management;

x) labour relations;

xi) occupational health and safety issues;

xii) information technology governance, including privacy, data management and security;

xiii) legal and regulatory compliance, including ability to monitor compliance of legal and regulatory requirements;

xiv) stakeholder engagement / advocacy / communications, including ability to effectively engage and communicate to industry stakeholders and advocate on behalf of the organization;

(f) the following interpersonal skills and attributes:

i) leadership, including ability to make, and take responsibility for, decisions and take necessary actions in the best interest of the organization, set appropriate Board and organizational culture and represent the organization favourably;

ii) personal integrity / ethics, including understanding and fulfilling the duties and responsibilities of a director, being transparent and declaring any activities or conduct that might be a potential conflict, and maintaining Board confidentiality;

iii) communications skills, including ability to listen constructively and appropriately debate others' viewpoints, develop and deliver cogent arguments, and communicate effectively with a broad range of stakeholders;

iv) constructive questioning, including preparedness to ask questions and challenge management and peer directors in a constructive and appropriate manner;

v) critical and innovative thinking / decision making, including ability to critically analyze complex and detailed information, readily distill key issues, and develop innovative approaches and solutions to problems;

vi) influencing and negotiating, including ability to negotiate outcomes and influence others to agree with those outcomes and gain stakeholder support for the Board's decisions;

vii) crisis management, including ability to constructively manage crises, provide leadership around solutions and contribute to communications strategy with stakeholders;

viii) individual and team contribution, including ability to work as part of a team, and demonstrate the passion and time to make a genuine and active contribution to the Board and the organization;

ix) commercial sensitivity and acumen; and

x) independence of judgement

(g) at least three directors with financial management expertise.

(5) The Board shall appoint a Chair of the Board upon the nomination of the Shareholder from time to time.

(6) The Secretary of the Corporation shall be secretary of the Board ***(Secretary)***.

3. Responsibilities

(1) The Board is responsible for supervising the management of the business and affairs of the *Group*, including the following specific matters:

a) establishing sound financial principles and performance objectives;

b) approving any dividend payment or distribution of capital;

c) appointing the officers of the Corporation;

d) approving the overall business strategy and related business plan;

e) approving the financing strategy, including the selection of financial institutions and related banking authorities;

f) directing labour and employee relations matters; and

g) approving the financial statements in accordance with the requirements of the *Business Corporations Act* (Ontario).

(2) In discharging their responsibilities, the Directors owe the following duties to the Corporation:

a fiduciary duty: they must act honestly and in good faith with a view to the best interests of the Corporation; and

a duty of care: they must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

In discharging their responsibilities, the Directors are entitled to rely on the honesty and integrity of the senior officers of the Corporation and the auditors and other professional advisors of the Corporation.

In discharging their responsibilities, the Directors are also entitled to directors and officers liability insurance purchased by the Corporation and indemnification from the Corporation to the fullest extent permitted by law and the constating documents of the Corporation.

(3) The Board has specifically recognized its responsibilities for:

(a) to the extent feasible, satisfying itself as to the integrity of the President and Chief Executive Officer ***(CEO)*** and other senior officers of the Group and that the CEO and other senior officers of the Group create a culture of integrity throughout the Group;

(b) adopting a strategic planning process and approving annually (or more frequently if appropriate) a strategic plan which takes into account, among other things, the opportunities and risks of the business of the Group;

(c) considering and overseeing the strategic development of new business opportunities and innovation;

(d) overseeing the identification of the principal risks of the business of the Group and overseeing the implementation of appropriate systems to manage these risks;

(e) interaction of the Board with the Shareholder in accordance with the Shareholder Direction subject to the duties of the Directors at law;

(f) overseeing the integrity of the internal control and management information systems of the Group;

(g) succession planning (including appointing, training and monitoring the senior officers of the Corporation);

(h) recruiting and assessing the performance of the CEO, the compensation of the CEO and other officers of the Group, executive compensation disclosure and oversight of the compensation structure and benefit plans and programs of the Group;

(i) assessing the effectiveness of the Board;

(j) adopting a disclosure policy for the Group;

(k) developing and overseeing the orientation of new Directors, and the continuing education of existing Directors, of the Group; and

(l) developing the approach of the Corporation to corporate governance including a periodic review of the Code of Business Conduct and Whistleblower Procedure of the Group.

(4) In addition to those matters which must by law be approved by the Board, the Board oversees the development of, and reviews and approves, significant corporate plans and initiatives, including the annual business plan and budget, major acquisitions and dispositions and other significant matters of corporate strategy or policy, including the Environmental Policy, Occupational Health and Safety Policy, Code of Business Conduct and Whistleblower Procedure, Disclosure Policy, Signing Policy and Treasury Policy.

(5) In undertaking its responsibilities and overseeing and authorizing the activities of the Corporation, the Board shall consider the interests of its customers, as well as considering and balancing the interests of such other stakeholders as appropriate in the circumstances.

(6) The Board shall periodically review the Shareholder Direction and make recommendations to the Shareholder to facilitate and clarify interaction and communication between the Shareholder and the Board.

(7) The Board shall periodically review the performance of the Board and the Corporation's subsidiary entities against the Shareholder Direction.

(8) The Board shall periodically review the structure and mandate of each Board committee, the effectiveness of each committee, and the appointment and removal of committee members.

(9) The Board shall periodically review performance under the Environmental Policy with management.

(10) To assist the Directors in discharging their responsibilities, the Board expects management of the Corporation to:

(a) review and update annually (or more frequently if appropriate) the strategic plan and report regularly to the Board on the implementation of the strategic plan in light of evolving conditions;

(b) prepare and present to the Board annually (or more frequently if appropriate) a business plan and budget and report regularly to the Board on the Group's performance against the business plan and budget; and

(c) report regularly to the Board on the Corporation's business and affairs and on any matters of material consequence for the Corporation and its Shareholder.

Additional expectations are developed and communicated during the annual strategic planning and budgeting process and during regular Board and Board committee meetings.

(11) The Board considers that generally management should speak for the Corporation in its communications with securities holders and the public. The Board reviews the Corporation's continuous and timely material disclosure with securities holders and the public. All disclosures on behalf of the Corporation are to be made in compliance with the Corporation's disclosure policy.

(12) Directors are expected to attend Board meetings and meetings of Board committees of which they are members. Directors are also expected to spend the time needed, and to meet as frequently as necessary, to discharge their responsibilities.

(13) Directors are expected to undertake such activities as are required from them to remain current in their knowledge of issues relating to the business of the Group and matters relating to any Board committee of which they are members.

(14) Directors are expected to comply with the Code of Business Conduct and Whistleblower Procedure of the Group.

4. Authority

(1) The Board is authorized to carry out its responsibilities as set out in this Mandate.

(2) The Board is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Board is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Directors have unrestricted access to the officers of the Corporation. The Directors will use their judgment to ensure that any such contact is not disruptive to the operations of the Corporation and, except for the chair of any committee established by the Board, will advise the Chair and the CEO of the Corporation of any direct communications between them and the officers of the Corporation.

(5) The Board and the Directors have unrestricted access to the advice and services of the Secretary.

(6) The Board may delegate certain of its functions to Board committees, each of which will have its own charter.

5. Meetings and Proceedings

(1) The Board shall meet as frequently as is determined to be necessary but not less than four times each year.

(2) Any Director or the Secretary may call a meeting of the Board.

(3) The Chair is responsible for the agenda of each meeting of the Board, including input from other Directors and the officers and employees of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Directors, a notice of each meeting of the Board confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Director at least 48 hours before the date of the meeting.

(5) The quorum for each meeting of the Board is a majority of the number of Directors. In the absence of the Chair, the other Directors shall appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Secretary or his delegate shall keep minutes of all meetings of the Board, including all resolutions passed by the Board. Minutes of meetings shall be distributed to the Directors.

(7) An individual who is not a Director may be invited to attend a meeting of the Board for all or part of the meeting.

(8) The Directors shall meet alone regularly to facilitate full communication.

6. Review

(1) This Mandate shall be reviewed by the Corporate Governance Committee every 3 years and any recommended changes shall be brought to the Board of the Corporation for consideration and disposition.

RATE BASE VARIANCE ANALYSIS

1. RATE BASE UPDATE

Exhibit 2A provides information about Toronto Hydro's rate base and capital expenditures. This schedule provides a summary of the 2018 actuals for rate base, explains the material variances, and identifies material changes to the 2019 bridge and 2020 test year as a result of the 2018 actuals. This schedule also provides equivalent updates for capital in-service additions ("ISAs") and construction work in progress ("CWIP"). For updates to capital expenditures, please refer to Tab 2, Schedule 2 of this Exhibit.

Table 1 shows Toronto Hydro's updated asset net book values ("NBV"), working capital allowance ("WCA"), and rate base for 2018 actual results. Actual rate base for 2018 was $4,123.9 million. This is 2.0 percent lower than previously forecast, primarily due to project energization timing differences. (See Exhibit U, Tab 9, Schedule 1, section 3.4 for more information.) Toronto Hydro has updated the 2019 rate base forecast to $4,422.7 million, reflecting consequential changes from 2018 actuals. This is 1.3 percent lower than previously filed.

Table 1: Rate Base Summary ($ Millions) - Application Update

	OEB Approved[1]	**Actual**				**Bridge**	**Forecast**
	2015	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Opening PP&E NBV	2,849.0	2,843.2	3,085.4	3,462.0	3,744.7	4,038.8	4,270.4
Closing PP&E NBV	3,134.7	3,085.4	3,462.0	3,744.7	4,038.8	4,232.3	4,489.8
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,891.8**	**4,135.6**	**4,380.1**
Working Capital Allowance	240.2	247.9	275.8	247.4	232.1	287.2	235.2
Rate Base	**3,232.0**	**3,212.2**	**3,549.5**	**3,850.8**	**4,123.9**	**4,422.7**	**4,615.3**

Toronto Hydro's 2020 rate base forecast is unchanged. The utility estimates that the impact of rate base variances in 2018 and 2019 on the forecast Net Fixed Assets component of 2020 opening rate base will be less than one percent. As discussed in Section 3 below, Toronto Hydro proposes to update its 2020 working capital allowance ("WCA") during the rate order process in this proceeding.

1.1 In-Service Additions ("ISAs") and Construction Work in Progress ("CWIP") Update

Appendix A to this schedule provides an update to Toronto Hydro's response to 2B-Staff-75, part (a) (ii). The utility projects its net total five-year in-service additions to be about one percent greater than the forecast amount which formed the basis of Toronto Hydro's approved capital-related revenue requirement for the 2015-2019 period.

Table 2 provides an update to CWIP values for the 2015-2019 period.

Table 2: Historical, Bridge, and Forecasted Construction Work in Progress ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Opening CWIP	522.1	577.7	502.9	485.8	396.4	343.5
Additions (CAPEX)	490.6	508.4	496.6	434.9	425.3	514.0
Deductions (In Service Additions)	(435.3)	(584.3)	(520.3)	(524.4)	(440.6)	(489.8)
Other	0.3	1.1	6.5	0.0	-	-
Closing CWIP	577.7	502.9	485.8	396.4	381.1	367.7

1.2 Fixed Asset Continuity Statements

The continuity statements (OEB Appendix 2-BA) are filed at Exhibit U, Tab 1, Schedule 1, Appendix B.

1.3 Rate Base Variance Analysis[1]

1.3.1 2017 Historical versus 2018 Historical Year

Rate base increased by $273.1 million from 2017 to 2018. The increase in average PP&E NBV of $288.4 million was primarily due to assets coming into service. This was partially offset by WCA, which decreased by $15.3 million, primarily due to lower cost of power expenses related to declining commodity costs.

1.3.2 2018 Historical versus 2019 Bridge Year

Rate base is forecasted to increase by $298.9 million from 2018 to 2019. The increase in average PP&E NBV of $243.8 million is primarily due to assets coming into service. WCA is expected to increase by $55.1 million, primarily due to projected increases in commodity costs.

1.3.3 2019 Bridge versus 2020 Test Year

Rate base is forecasted to increase by $192.6 million from 2019 to 2020. The $244.5 million increase in average PP&E NBV is primarily due to assets coming into service. WCA is expected to decrease by $52.0 million primarily due to a lower WCA rate resulting from the utility's latest lead-lag study, which is partially offset by a projected increase in commodity costs. As discussed in Section 3 below, Toronto Hydro proposes to update its 2020 WCA as part of the rate order process in this proceeding.

[1] Rate base variance analysis for the 2015-2017 period can be found in Exhibit 2A, Tab 1, Schedule 1, at page 3.

1.4 Property, Plant and Equipment

1.4.1 Overview

Table 2 below presents an updated summary of Toronto Hydro's distribution asset balances before and after accumulated depreciation, and excluding CWIP, for the Historical (2015 to 2018), Bridge (2019), and Forecast (2020) years.

Table 3: Gross and Net PP&E – Years Ending December 31 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Land and Buildings	76.2	129.9	141.4	161.6	171.0	169.8
Other Distribution Assets	170.0	238.5	267.3	434.6	507.6	612.7
General Plant	127.7	185.2	247.5	240.1	241.4	243.0
TS Primary Above 50	5.8	6.0	36.9	37.9	38.9	39.1
Distribution System	149.9	156.8	184.5	213.5	233.9	277.9
Poles, Wires	2,172.2	2,430.6	2,663.8	2,876.9	3,132.8	3,426.9
Contributions and Grants	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(322.6)
Line Transformers	412.4	465.3	515.4	566.7	640.8	714.2
Services and Meters	262.0	290.0	321.8	344.7	385.3	451.0
Equipment	61.5	100.4	120.8	131.3	140.5	145.9
IT Assets	27.3	47.2	58.7	66.8	74.2	89.0
Gross Assets	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,846.8**
Accumulated Depreciation	(320.6)	(496.8)	(684.3)	(876.9)	(1,097.7)	(1,357.0)
Closing PP&E NBV (MIFRS)	**3,086.2**	**3,462.6**	**3,755.8**	**4,040.6**	**4,233.4**	**4,489.8**
Adjustments to Closing PP&E NBV						
Assets held for Sale	-	-	(8.7)	-	-	-
Monthly Billing	(0.7)	(0.6)	(2.3)	(1.7)	(1.1)	-
Closing PP&E NBV	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,232.3**	**4,489.8**

1.4.2 2017 Historical versus 2018 Historical[2]

Actual asset NBV for 2018 was $4,040.6 million compared to $3,755.8 million in 2017. The increase of $284.8 million to $4,040.6 million is primarily due to assets coming into service.

Table 4: 2017 Historical versus 2018 Historical ($ Millions)

	2017 Actual	2018 Actual	Variance ($)	Variance (%)
Land and Buildings	141.4	161.6	20.2	14.3%
Other Distribution Assets	267.3	434.6	167.3	62.6%
General Plant	247.5	240.1	(7.3)	-3.0%
TS Primary Above 50	36.9	37.9	0.9	2.6%
Distribution System	184.5	213.5	29.0	15.7%
Poles, Wires	2,663.8	2,876.9	213.1	8.0%
Contributions and Grants	(118.0)	(156.6)	(38.6)	32.7%
Line Transformers	515.4	566.7	51.3	10.0%
Services and Meters	321.8	344.7	22.9	7.1%
Equipment	120.8	131.3	10.6	8.7%
IT Assets	58.7	66.8	8.1	13.8%
Gross Assets	**4,440.1**	**4,917.5**	**477.4**	**10.8%**
Accumulated Depreciation	(684.3)	(876.9)	(192.6)	28.1%
Closing PP&E NBV (MIFRS)	**3,755.8**	**4,040.6**	**284.8**	**7.6%**

[2] PP&E variances for the 2015-2017 period can be found at Exhibit 2A, Tab 1, Schedule 1, pages 6-8.

1.4.3 2018 Historical versus 2019 Bridge

Forecasted asset NBV for 2019 is $4,233.4 million compared to $4,040.6 million in 2018. The increase of $192.8 million is primarily due to assets coming into service.

Table 5: 2018 Historical versus 2019 Bridge ($ Millions)

	2018 Actual	2019 Bridge	Variance ($)	Variance (%)
Land and Buildings	161.6	171.0	9.3	5.8%
Other Distribution Assets	434.6	507.6	73.0	16.8%
General Plant	240.1	241.4	1.3	0.5%
TS Primary Above 50	37.9	38.9	1.0	2.7%
Distribution System	213.5	233.9	20.4	9.5%
Poles, Wires	2,876.9	3,132.8	255.9	8.9%
Contributions and Grants	(156.6)	(235.2)	(78.7)	50.2%
Line Transformers	566.7	640.8	74.2	13.1%
Services and Meters	344.7	385.3	40.6	11.8%
Equipment	131.3	140.5	9.2	7.0%
IT Assets	66.8	74.2	7.4	11.1%
Gross Assets	**4,917.5**	**5,331.0**	**413.6**	**8.4%**
Accumulated Depreciation	(876.9)	(1,097.7)	(220.7)	25.2%
Closing PP&E NBV (MIFRS)	**4,040.6**	**4,233.4**	**192.8**	**4.8%**

1.4.4 2019 Bridge versus 2020 Forecast

Forecasted asset NBV in 2020 is $4,489.8 million compared to $4,233.4 million in 2019. The increase of $256.4 million is primarily due to assets coming into service. The 2020 NBV opening balance includes an adjustment of $1.1 million for the addition of the assets resulting from the monthly billing program.[3]

Table 6: 2019 Bridge versus 2020 Forecast ($ Millions)

	2019 Bridge	2020 Forecast	Variance ($)	Variance (%)
Land and Buildings	171.0	169.8	(1.2)	-0.7%
Other Distribution Assets	507.6	612.7	105.1	20.7%
General Plant	241.4	243.0	1.6	0.7%
TS Primary Above 50	38.9	39.1	0.2	0.5%
Distribution System	233.9	277.9	44.0	18.8%
Poles, Wires	3,132.8	3,426.9	294.1	9.4%
Contributions and Grants	(235.2)	(322.6)	(87.4)	37.1%
Line Transformers	640.8	714.2	73.4	11.5%
Services and Meters	385.3	451.0	65.7	17.0%
Equipment	140.5	145.9	5.4	3.9%
IT Assets	74.2	89.0	14.8	20.0%
Gross Assets	**5,331.0**	**5,846.8**	**515.8**	**9.7%**
Accumulated Depreciation	(1,097.7)	(1,357.0)	(259.3)	23.6%
Closing PP&E NBV (MIFRS)	**4,233.4**	**4,489.8**	**256.4**	**6.1%**

[3] See Exhibit 9.

2. GROSS ASSETS

2.1 Breakdown by Function

Table 7: Breakdown of Ending Balance of Gross Assets by Function ($ Millions)

Gross Assets	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.1
Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,996.0
General Plant	354.0	482.3	599.8	683.2	741.1	811.7
Gross Fixed Assets Before CWIP	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,846.8**
CWIP	577.7	502.9	485.8	396.4	381.1	367.7
Total Including CWIP	**3,984.5**	**4,462.3**	**4,925.9**	**5,313.9**	**5,716.6**	**6,214.5**

Note: Variances due to rounding may exist

2.2 Breakdown by Major Plant Account

Appendix C presents the gross assets breakdown by major plant account based on the uniform system of accounts for 2015-2020.

3. WORKING CAPITAL ALLOWANCE

The Working Capital Allowance filed at Exhibit 2A, Tab 3, Schedule 1 was based on the updated Lead/Lag study applied to forecast revenue, cost of power and eligible expenses.

The response to interrogatory 2A-Staff-53 included an estimate of the Working Capital Allowance reflecting the Cost of Power as calculated using the OEB's Appendix 2-Z. This resulted in a Working Capital Allowance of $202.9 million, compared with the pre-filed value of $235.2 million. The lower Working Capital Allowance would reduce 2020 revenue requirement by approximately $2.2 million. As noted in 2A-Staff-53, Toronto Hydro proposes to include the updated Cost of Power forecast, based on the OEB's Appendix 2-Z (with the most up-to-date forecasts of energy prices), during the Draft Rate Order process.

Toronto Hydro notes that the Ontario Energy Board's revised Customer Service Rules – specifically the extension of the bill payment dates – are expected to have an impact on the collection lag component of the Lead/Lag study. Toronto Hydro estimates the impact of these changes on 2020 revenue requirement to be an increase of $1.6 million. The utility requests that this change be approved by the OEB as part of the 2020 test year and in the calculation of the custom capital factor in the 2021-2024 rate years. However, as the net impact of this is expected to partially offset the change in WCA flowing from the updated Cost of Power, in the interest of efficiency, Toronto Hydro has not updated the 2020 revenue requirement and 2021-2024 custom capital factor at this time. If the change is approved by the OEB, the utility proposes to incorporate it during the Draft Rate Order process.

In-Service Additions for the 2015-2019 Period

	Historical												Bridge			Historical/Bridge		
	2015			2016			2017			2018			2019			2015-2019		
In-Service Additions	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Forecast**	**Var.**	**CIR Filing (-10%)**	**Actual / Forecast**	**Var.**
Gross	526.8	465.4	-12%	635.6	617.1	-3%	474.4	549.0	16%	413.2	563.6	36%	493.2	519.7	5%	2,543.1	2,714.8	7%
Customer Contributions	(14.3)	(30.1)	110%	(14.4)	(32.8)	127%	(14.9)	(28.7)	93%	(15.5)	(39.2)	153%	(16.0)	(79.1)	394%	(75.1)	(209.9)	180%
Net	**512.5**	**435.3**	**-15%**	**621.1**	**584.3**	**-6%**	**459.5**	**520.3**	**13%**	**397.7**	**524.4**	**32%**	**477.2**	**440.6**	**-8%**	**2,468.0**	**2,504.8**	**1%**

Rounding variances may exist

Notes:

In-Service Additions excludes Other Non Rate-Regulated Utility Assets

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2018

CCA Class	OEB Account	Description	Cost (Historical) Opening Balance	Cost (Historical) Additions	Cost (Historical) Disposals	Cost (Historical) Closing Balance	Accumulated Depreciation (Historical) Opening Balance	Accumulated Depreciation (Historical) Additions	Accumulated Depreciation (Historical) Disposals	Accumulated Depreciation (Historical) Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 136,960,666	$ 73,814,110	($ 2,863,680)	$ 207,911,095	($ 77,314,695)	($ 20,892,805)	$ 1,478,618	($ 96,728,883)	$ 111,182,213
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,433	$ -	($ 1)	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 116,632,610	$ 20,897,786	($ 269,609)	$ 137,260,787	($ 9,689,454)	($ 3,308,486)	$ 259,617	($ 12,738,324)	$ 124,522,463
47	1815	Transformer Station Equipment >50 kV	$ 36,917,966	$ 944,609	$ -	$ 37,862,575	($ 1,863,155)	($ 1,298,265)	$ -	($ 3,161,419)	$ 34,701,155
47	1820	Distribution Station Equipment <50 kV	$ 184,513,183	$ 30,319,716	($ 1,316,122)	$ 213,516,777	($ 28,844,525)	($ 8,622,713)	$ 531,283	($ 36,935,955)	$ 176,580,822
47	1830	Poles, Towers & Fixtures	$ 362,478,012	$ 21,287,951	($ 2,982,045)	$ 380,783,918	($ 36,669,123)	($ 10,921,669)	$ 452,096	($ 47,138,696)	$ 333,645,222
47	1835	Overhead Conductors & Devices	$ 390,547,495	$ 41,090,486	($ 3,322,079)	$ 428,315,901	($ 33,325,134)	($ 10,827,432)	$ 402,885	($ 43,749,681)	$ 384,566,221
47	1840	Underground Conduit	$ 1,127,938,656	$ 78,574,199	($ 923,662)	$ 1,205,589,193	($ 154,477,992)	($ 44,888,220)	$ 496,841	($ 198,869,371)	$ 1,006,719,822
47	1845	Underground Conductors & Devices	$ 782,844,420	$ 87,194,048	($ 7,833,777)	$ 862,204,692	($ 77,543,562)	($ 25,369,256)	$ 1,617,529	($ 101,295,289)	$ 760,909,403
47	1850	Line Transformers	$ 515,354,184	$ 62,025,718	($ 10,711,850)	$ 566,668,052	($ 77,429,407)	($ 23,997,546)	$ 3,384,391	($ 98,042,562)	$ 468,625,490
47	1855	Services (Overhead & Underground)	$ 122,134,425	$ 3,010,082	($ 519,052)	$ 124,625,454	($ 8,668,122)	($ 2,947,558)	$ 38,585	($ 11,577,095)	$ 113,048,359
47	1860	Meters	$ 79,895,152	$ 8,057,288	($ 834,542)	$ 87,117,898	($ 12,964,895)	($ 4,490,265)	$ 194,656	($ 17,260,504)	$ 69,857,394
47	1860	Meters (Smart Meters)	$ 119,808,247	$ 16,301,957	($ 3,155,319)	$ 132,954,885	($ 39,208,620)	($ 11,528,648)	$ 1,235,352	($ 49,501,916)	$ 83,452,969
N/A	1905	Land	$ 17,738,379	$ -	($ 379,722)	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 246,710,392	$ 4,456,339	($ 11,797,576)	$ 239,369,154	($ 29,323,031)	($ 11,318,351)	$ 3,060,414	($ 37,580,968)	$ 201,788,186
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 734,624)	($ 10,481)	$ -	($ 745,106)	$ 8,734
8	1915	Office Furniture & Equipment	$ 18,953,218	$ 673,247	$ 363,852	$ 19,990,318	($ 7,295,578)	($ 2,051,264)	$ 426	($ 9,346,416)	$ 10,643,902
50	1920	Computer Equipment - Hardware	$ 58,683,341	$ 8,077,721	$ -	$ 66,761,063	($ 28,967,065)	($ 10,714,855)	$ -	($ 39,681,921)	$ 27,079,142
10	1930	Transportation Equipment	$ 33,718,724	$ 2,912,073	($ 547,155)	$ 36,083,642	($ 21,592,028)	($ 3,636,383)	$ 547,155	($ 24,681,256)	$ 11,402,386
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 21,151,564	$ 2,199,041	$ -	$ 23,350,605	($ 9,064,186)	($ 2,257,857)	$ -	($ 11,322,044)	$ 12,028,562
8	1945	Measurement & Testing Equipment	$ 480,243	$ -	$ -	$ 480,243	($ 274,545)	($ 59,822)	$ -	($ 334,367)	$ 145,875
8	1950	Service Equipment	$ 845,773	$ 544,550	($ 125,129)	$ 1,265,194	($ 481,618)	($ 159,091)	$ 28,724	($ 611,984)	$ 653,210
8	1955	Communications Equipment	$ 45,358,046	$ 4,530,356	$ -	$ 49,888,402	($ 10,349,452)	($ 4,690,337)	$ -	($ 15,039,789)	$ 34,848,612
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 148,393)	($ 37,310)	$ -	($ 185,703)	$ 85,275
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 35,587,033	$ 6,524,511	($ 393,736)	$ 41,717,808	($ 8,735,164)	($ 2,802,429)	$ 85,125	($ 11,452,469)	$ 30,265,340
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 117,959,106)	($ 39,248,789)	$ 635,109	($ 156,572,786)	$ 11,205,218	$ 5,263,537	($ 112,504)	$ 16,356,251	($ 140,216,535)
N/A	1609	Capital Contributions Paid	$ 75,574,497	$ 88,593,906	$ -	$ 164,168,403	($ 7,221,863)	($ 3,538,390)	$ -	($ 10,760,252)	$ 153,408,151
N/A	2005	Property Under Capital Leases	$ 18,170,834	$ 1,576,880	$ -	$ 19,747,714	($ 10,349,973)	($ 1,320,504)	$ -	($ 11,670,476)	$ 8,077,238
		Sub-Total	**$ 4,442,099,105**	**$ 524,357,783**	**($ 46,976,096)**	**$ 4,919,480,793**	**($ 684,360,885)**	**($ 206,426,400)**	**$ 13,701,192**	**($ 877,086,094)**	**$ 4,042,394,698**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	($ 2,002,023)	$ -	$ -	($ 2,002,023)	$ 33,367	$ 133,468	$ -	$ 166,835	($ 1,835,187)
		Total PP&E	**$ 4,440,097,082**	**$ 524,357,783**	**($ 46,976,096)**	**$ 4,917,478,770**	**($ 684,327,518)**	**($ 206,292,932)**	**$ 13,701,192**	**($ 876,919,259)**	**$ 4,040,559,511**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 206,292,932)**			

10		Transportation	**Less:** *Fully Allocated Depreciation*	
			Transportation	($ 961,328)
		Stores Equipment	Stores Equipment	$ -
			Net Depreciation	($ 205,331,604)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2019

			Cost (Bridge)				Accumulated Depreciation (Bridge)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 207,911,095	$ 40,029,185	$ -	$ 247,940,281	($ 96,728,883)	($ 27,968,318)	$ -	($ 124,697,201)	$ 123,243,080
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 137,260,787	$ 9,342,754	$ -	$ 146,603,541	($ 12,738,324)	($ 3,576,986)	$ -	($ 16,315,310)	$ 130,288,231
47	1815	Transformer Station Equipment >50 kV	$ 37,862,575	$ 1,030,716	$ -	$ 38,893,291	($ 3,161,419)	($ 1,339,480)	$ -	($ 4,500,900)	$ 34,392,391
47	1820	Distribution Station Equipment <50 kV	$ 213,516,777	$ 20,600,010	($ 220,453)	$ 233,896,334	($ 36,935,955)	($ 9,828,871)	$ 64,678	($ 46,700,148)	$ 187,196,185
47	1830	Poles, Towers & Fixtures	$ 380,783,918	$ 28,474,609	($ 6,687,576)	$ 402,570,951	($ 47,138,696)	($ 11,163,183)	$ 1,605,971	($ 56,695,908)	$ 345,875,043
47	1835	Overhead Conductors & Devices	$ 428,315,901	$ 42,197,486	($ 2,275,088)	$ 468,238,300	($ 43,749,681)	($ 11,552,701)	$ 379,755	($ 54,922,627)	$ 413,315,673
47	1840	Underground Conduit	$ 1,205,589,193	$ 101,150,177	($ 620,190)	$ 1,306,119,180	($ 198,869,371)	($ 47,764,130)	$ 157,745	($ 246,475,756)	$ 1,059,643,424
47	1845	Underground Conductors & Devices	$ 862,204,692	$ 98,357,471	($ 4,710,197)	$ 955,851,966	($ 101,295,289)	($ 26,963,221)	$ 439,621	($ 127,818,888)	$ 828,033,077
47	1850	Line Transformers	$ 566,668,052	$ 82,017,280	($ 7,856,970)	$ 640,828,362	($ 98,042,562)	($ 25,545,270)	$ 1,089,782	($ 122,498,051)	$ 518,330,312
47	1855	Services (Overhead & Underground)	$ 124,625,454	$ 17,117,258	($ 330,315)	$ 141,412,397	($ 11,577,095)	($ 3,062,482)	$ 19,049	($ 14,620,528)	$ 126,791,869
47	1860	Meters	$ 87,117,898	$ 19,232,313	($ 1,296,379)	$ 105,053,832	($ 17,260,504)	($ 4,819,143)	$ 178,367	($ 21,901,280)	$ 83,152,552
47	1860	Meters (Smart Meters)	$ 132,954,885	$ 8,807,217	($ 2,919,112)	$ 138,842,990	($ 49,501,916)	($ 11,966,280)	$ 670,045	($ 60,798,152)	$ 78,044,838
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 239,369,154	$ 1,250,623	$ -	$ 240,619,777	($ 37,580,968)	($ 11,325,101)	$ -	($ 48,906,069)	$ 191,713,707
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 745,106)	($ 8,734)	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 19,990,318	$ 448,337	$ -	$ 20,438,655	($ 9,346,416)	($ 2,067,790)	$ -	($ 11,414,206)	$ 9,024,448
50	1920	Computer Equipment - Hardware	$ 66,761,063	$ 7,398,534	$ -	$ 74,159,596	($ 39,681,921)	($ 10,812,376)	$ -	($ 50,494,297)	$ 23,665,300
10	1930	Transportation Equipment	$ 36,083,642	$ 4,995,050	$ -	$ 41,078,692	($ 24,681,256)	($ 3,141,469)	$ -	($ 27,822,725)	$ 13,255,967
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 23,350,605	$ 5,530,796	$ -	$ 28,881,401	($ 11,322,044)	($ 2,443,955)	$ -	($ 13,765,998)	$ 15,115,403
8	1945	Measurement & Testing Equipment	$ 480,243	$ 19,437	$ -	$ 499,679	($ 334,367)	($ 61,540)	$ -	($ 395,908)	$ 103,772
8	1950	Service Equipment	$ 1,265,194	$ 122,762	$ -	$ 1,387,956	($ 611,984)	($ 131,053)	$ -	($ 743,037)	$ 644,919
8	1955	Communications Equipment	$ 49,888,402	$ 802,266	$ -	$ 50,690,668	($ 15,039,789)	($ 4,719,684)	$ -	($ 19,759,473)	$ 30,931,195
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 185,703)	($ 37,310)	$ -	($ 223,012)	$ 47,965
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 41,717,808	$ 10,865,041	($ 503,552)	$ 52,079,297	($ 11,452,469)	($ 3,134,194)	$ 54,408	($ 14,532,254)	$ 37,547,043
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 156,572,786)	($ 79,065,880)	$ 395,247	($ 235,243,420)	$ 16,356,251	$ 5,711,872	($ 20,148)	$ 22,047,976	($ 213,195,444)
N/A	1609	Capital Contributions Paid	$ 164,168,403	$ 26,301,319	$ -	$ 190,469,722	($ 10,760,252)	($ 7,235,447)	$ -	($ 17,995,699)	$ 172,474,023
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 11,670,476)	($ 652,639)	$ -	($ 12,323,115)	$ 7,424,599
		Sub-Total	**$ 4,919,480,793**	**$ 447,024,759**	**($ 27,024,585)**	**$ 5,339,480,967**	**($ 877,086,094)**	**($ 225,609,486)**	**$ 4,639,274**	**($ 1,098,056,306)**	**$ 4,241,424,660**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**	$ -	($ 2,730,141)	$ -	($ 2,730,141)	$ -	$ 34,127	$ -	$ 34,127	($ 2,696,014)
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	($ 2,002,023)	($ 3,702,262)	$ -	($ 5,704,285)	$ 166,835	$ 202,609	$ -	$ 369,444	($ 5,334,841)
		Total PP&E	**$ 4,917,478,770**	**$ 440,592,356**	**($ 27,024,585)**	**$ 5,331,046,541**	**($ 876,919,259)**	**($ 225,372,751)**	**$ 4,639,274**	**($ 1,097,652,736)**	**$ 4,233,393,805**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 225,372,751)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 223,613,230)

Notes:

Fixed Asset Continuity Schedule includes monthly billing

Socialized Renewable Energy Generation Investments include Energy Storage program

Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

Appendix A: Gross Assets Breakdown by Major Plant Account – Detailed by Uniform System of Account ($ Million)

	Description	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS	2019 Bridge MIFRS	2020 Forecast MIFRS
1815	Transformer Station Equipment	5.8	6.0	36.9	37.9	38.9	39.1
	Subtotal High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.1
1805	Land	7.1	7.1	7.0	7.0	7.0	7.0
1808	Buildings and Fixtures	51.4	105.1	116.6	137.3	146.6	145.4
1820	Distribution Station Equipment	149.9	156.8	184.5	213.5	233.9	277.9
1830	Poles, Towers and Fixtures	311.0	339.5	362.5	380.8	402.6	435.8
1835	O/H Conductors and Devices	299.4	349.5	390.5	428.3	468.2	515.0
1840	U/G Conduit	952.0	1,051.0	1,127.9	1,205.6	1,306.1	1,432.3
1845	U/G Conductors and Devices	609.9	690.6	782.8	862.2	955.9	1,043.7
1850	Line Transformers	412.4	465.3	515.4	566.7	640.8	714.2
1855	Services	93.3	109.1	122.1	124.6	141.4	175.3
1860	Meters (includes Smart Meters)	168.7	180.9	199.7	220.1	243.9	275.7
1970	Load Management-Customer	3.0	3.0	3.0	3.0	3.0	3.0
1980	System Supervisory Equipment	25.4	28.2	33.6	39.7	46.4	55.2
1609	Capital Contributions Paid	21.7	75.6	75.6	164.2	190.5	238.0
2440	Contributed Capital	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(322.6)
	Subtotal Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,996.0
1611	Computer Software	101.6	113.6	137.0	207.9	247.9	298.3
1905	Land	17.7	17.7	17.7	17.4	17.4	17.4
1612	Land Rights	-	-	-	1.6	1.6	
1908	Buildings and Fixtures	126.9	184.5	246.7	239.4	240.6	242.2
1910	Leasehold Improvements	0.8	0.8	0.8	0.8	0.8	0.8
1915	Office Furniture and Equipment	10.8	15.4	19.0	20.0	20.4	21.1
1920	Computer Equipment	27.3	47.2	58.7	66.8	74.2	89.0
1930	Transportation Equipment	26.6	29.9	33.7	36.1	41.1	46.2
1935	Stores Equipment	0.0	0.0	0.0	0.0	0.0	0.0
1940	Tools, Shop and Garage Equipment	14.7	17.8	21.2	23.4	26.2	28.4
1945	Measurement & Test Equipment	0.5	0.5	0.5	0.5	0.5	0.5
1950	Power Operated Equipment	0.6	0.7	0.8	1.3	1.4	1.2
1955	Communication Equipment	8.0	35.9	45.4	49.9	50.7	48.3
1960	Miscellaneous Equipment	0.3	0.3	0.3	0.3	0.3	0.3
2005	Property Under Capital Leases	18.2	18.2	18.2	18.2	18.2	18.2
	Subtotal General Plant	354.0	482.3	599.8	683.2	741.1	811.7
	GROSS FIXED ASSETS BEFORE CWIP	3,406.8	3,959.4	4,440.1	4,917.5	5,331.0	5,846.8
2055	Construction Work-in-Process	577.7	502.9	485.8	396.4	381.1	367.7
	TOTAL INCLUDING CWIP	3,984.5	4,462.3	4,925.9	5,313.9	5,712.2	6,214.5

CAPITAL EXPENDITURES VARIANCE ANALYSIS

1. CAPITAL EXPENDITURES

This schedule provides a summary of the capital expenditure variances resulting from the update of 2018 actuals. This information is supplemental to the comprehensive 2015-2019 Distribution System Plan ("DSP") variance analysis provided in Exhibit 2B, Section E4, and the detailed 2015-2019 capital program-level variance analyses provided in Exhibit 2B, Sections E5 to E8.

Updated OEB Appendices 2-AA and 2-AB (initially filed at Exhibit 2A, Tab 4, Schedules 2 and 3, and discussed further in Exhibit 2B, Section E4) can be found as Appendices A and B to this schedule. Toronto Hydro has updated these Appendices for 2018 actual expenditures and any consequential 2019 forecast adjustments.

Toronto Hydro is also providing, as Appendix C to this schedule, an updated OEB Appendix 2-AB in the format requested by OEB Staff in undertaking JTC1.2, wherein:

- the portfolio and Gross Total Expenditure lines reflect all capital expenditures made by the utility, including capital contributions made to Hydro One;
- the Capital Contributions Received line includes all capital contributions to the utility from its customers; and
- the Net Total Expenditures line represents the difference between the Gross Total Expenditures and the Capital Contributions Received.

1.1 Update to Plan versus Actual Variances for 2015-2019

As explained in Exhibit 2B, Section E4.1, the OEB approved the utility's custom rate setting mechanism and a resulting capital related revenue requirement ("CRRR") of $2,497.9 million for the 2015-2019 period. Toronto Hydro's forecast capital spending continues to be slightly less than approved for the period, resulting in a refund to customers through the CRRR Variance Account.[1] As a result primarily of variances in project energization timing in 2018 and 2019, this refund has been updated to $77.9 million from $59.4 million.[2] As discussed in Exhibit U, Tab 2, Schedule 1, Section 1, despite shifts in energization timing over the 2015-2019 period, Toronto Hydro's total in-service additions ("ISA") are forecast to be within one percent of the ISA amount that formed the basis of the OEB-approved CRRR for the period, indicating successful completion of the funded 2015-2019 Distribution System Plan.

Toronto Hydro's capital expenditures totalled $435.6 million in 2018. The utility is on pace for $443.0 million in capital expenditures in 2019. Overall, Toronto Hydro expects to spend $2,379.4 million during the 2015-2019 period, which is four percent less than the $2,489.3 million forecast in the utility's 2015-2019 DSP, and is virtually unchanged from the $2,383.5 previously forecast in this application. Table 1, below, presents the breakdown of plan[3] versus actuals by year and by category.

---

[1] See Exhibit 9, Tab 1, Schedule 1 for more information.
[2] See Exhibit U, Tab 9, Schedule 1, Section 4.5
[3] As noted in Exhibit 2B, Section E4, "plan" refers to the utility's 2015-2019 Distribution System Plan as originally filed.

Table 1: Historical Capital Expenditure Summary ($ Millions)

Category	Historical												Bridge		
	2015			2016			2017			2018			2019		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.
System Access	86.1	58.3	(32%)	95.3	79.0	(17%)	104.9	65.5	(38%)	95.8	88.0	(8%)	92.3	112.1	21%
System Renewal	251.7	304.1	21%	239.6	266.1	11%	256.2	250.3	(2%)	275.9	245.5	(11%)	287.3	244.2	(15%)
System Service	76.5	37.9	(50%)	70.7	53.3	(25%)	65.1	72.4	11%	52.6	31.0	(41%)	80.2	41.5	(48%)
General Plant	104.6	79.4	(24%)	101.5	109.5	8%	30.3	98.9	226%	34.2	58.4	71%	30.3	46.4	53%
Other	12.2	11.6	(5%)	11.6	3.7	(68%)	10.8	10.7	(1%)	11.5	12.7	10%	12.1	(1.3)	(111%)
Total CAPEX	**531.1**	**491.4**	**(7%)**	**518.8**	**511.6**	**(1%)**	**467.4**	**497.8**	**7%**	**470.0**	**435.6**	**(7%)**	**502.2**	**443.0**	**(12%)**
System O&M	128.8	116.1	(10%)	126.5			126.3			139.6			131.0		

1.2 System Access Update

In 2018, Toronto Hydro invested $88.0 million in the demand and compliance driven activities that constitute its System Access programs. The utility forecasts $112.1 million in additional investments in 2019. Overall, the utility is on pace to spend $402.9 million during the 2015-2019 period, which is about 15 percent less than the $474.5 million originally forecast in the utility's 2015-2019 DSP, and about 0.5 percent greater than initially forecast in this application.

As discussed in the following sections, variances over the 2018-2019 period are primarily driven by variances in the Externally Initiated Plant Relocations and Expansion program as a result of third party schedule delays. Variances in other programs are minor.

1.2.1 Customer Connections

Over the 2015-2019 period, Toronto Hydro's net capital expenditures for the Customer Connections program have not materially changed from the forecast expenditures provided in Exhibit 2B, Section E5.1. In 2018, Toronto Hydro's expenditures in this program were $44.0 million.

Table 2: Historical and Forecast Customer Connections Program Costs ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Customer Connection	32.6	39.6	22.1	43.5	39.8
Generation Connection	(0.9)	0.4	(0.2)	0.5	0.0
Total	**31.7**	**40.1**	**21.9**	**44.0**	**39.8**

Customer Connections

In 2018, Toronto Hydro's net capital expenditures under the Customer Connection segment were essentially on budget, coming in at $43.5 million versus the $44.8 million previously forecast in this application. Toronto Hydro is forecasting a slight increase in 2019 expenditures, from the $37.6 million previously filed to $39.8 million.

Table 3: Historical and Forecast Customer Connection Segment Costs ($ Millions)

		Actual				Bridge
		2015	**2016**	**2017**	**2018**	**2019**
Customer Connection	*Gross*	68.3	67.1	58.6	81.1	83.6
	Capital Contribution	(35.7)	(27.4)	(36.5)	(37.6)	(43.8)
	Net	**32.6**	**39.6**	**22.1**	**43.5**	**39.8**

Generation Connections

Toronto Hydro spent a gross amount of $1.1 million connecting 322 distributed generation facilities in 2018. The utility continues to forecast $2.8 million of additional expenditures in 2019. Overall, Toronto Hydro forecasts $6.3 million of fully recoverable expenditures in this program during the 2015-2019 period, which is $2.8 million lower than the $9.1 million previously filed in this application. Variances are generally caused by factors outside of the utility's control, including customer-driven connection delays.

Table 4: Historical & Forecast Generation Connection Segment Costs ($ Millions)

		Actual				Bridge
		2015	**2016**	**2017**	**2018**	**2019**
Generation Connection	*Gross*	0.9	0.6	0.8	1.1	2.8
	Customer Contribution†	(1.8)	(0.2)	(1.0)	(0.5)	(2.8)
	Net[4]	**(0.9)**	**0.4**	**(0.2)**	**0.5**	**0**

1.2.2 Externally Initiated Plant Relocations and Expansion

Toronto Hydro continues to execute Externally Initiated Plan Relocations projects in accordance with coordination requirements and third-party project specifications and timelines. The utility spent a gross amount of $23.4 million in 2018, with $18.4 million in associated capital contributions. Due to project delays outside of Toronto Hydro's control, amounts related to the Metrolinx ECLRT were shifted from 2018 to 2019. The utility anticipates $69.8 million in expenditures in 2019, offset by $57.9 million in capital contributions. Toronto Hydro is on pace to invest a net amount of $24.3 million in this program during 2015-2019, which is approximately 5 percent greater than the amount previously forecast in this application. As stated in Exhibit 2B, Section E5.2.3.2, the scope, timing, and pacing of externally initiated relocation projects are driven by operational and planning decisions of third parties, which are beyond Toronto Hydro's control.

[4] All DG connections are 100 percent funded by capital contributions from the customer, and consequently, there should be zero net expenditure for DG connections. However, due to the pacing and timing of a DG installation, capital contributions may be collected from the customer in one year whereas the gross expenditures may span several years. As a result, the 2015-2017 historical yearly total net expenditures do not equal zero.

Table 5: Historical and Forecast Externally Initiated Plant Relocations and Expansion Program Costs ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Total Project Cost	3.8	9.0	12.5	23.4	69.8
Capital Contributions	(1.6)	(6.4)	(9.9)	(18.4)	(57.9)
Net Cost	**2.2**	**2.6**	**2.6**	**5.0**	**11.9**

1.2.3 Load Demand

Toronto Hydro spent $16.4 million on Load Demand projects in 2018. The utility forecasts $23.5 million in expenditures in 2019. These amounts are aligned with the 2018-2019 forecasts previously filed in this application, with a minor variance of 2.6 percent. Variances in 2018 and 2019 are generally due to evolving localized capacity needs, resulting in the reprioritization of work.

Table 6: Historical and Forecast Load Demand Program Costs ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Load Demand	9.9	16.8	16.2	16.4	23.5

1.2.4 Metering

Toronto Hydro invested $22.0 million in the Metering program in 2018 and forecasts spending another $26.1 million in 2019. Overall, the utility’s 2015-2019 capital expenditures for this program are expected to be approximately $104.8 million, a decrease of one percent from the previous forecast in Exhibit 2B, Section E5.4.

Increased compliance spending on wholesale metering in 2018-2019 has largely been offset by a reduction in residential and small commercial and industrial metering expenditures. Despite this reduction, Toronto Hydro remains on track to complete the replacement of all 2G smart meters with 4G models by the end of 2019. Required suite metering investments over 2018-2019 are also lower than previously forecast due to lower than forecast need from new buildings. Although there has been some change in the timing of projects, overall spending on system upgrades has remained consistent with the forecast in Exhibit 2B, Section E5.4.

Table 7: Historical and Forecast Metering Program Costs ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Metering	14.5	17.4	24.8	22.0	26.1

1.2.5 GPMC

Toronto Hydro spent $0.6 million on Generation Protection, Monitoring, and Control work in 2018. The utility deferred expenditures of $7.5 million to 2019. As a result, Toronto Hydro forecasts $10.9 million in expenditures for 2019. Despite the variances in timing discussed below, Toronto Hydro's forecast spending for the 2015-2019 period is unchanged from the total amount previously forecast in this application.

Table 8: Historical and Forecast Generation Protection, Monitoring, and Control Program Costs ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Generation Protection, Monitoring, and Control	-	2.1	0.0	0.6	10.9

In section E5.5.4.1, Toronto Hydro stated that it would install bus-tie reactors at Leslie TS and Richview TS in 2019. However, as a result of the level of interest in renewable generation in the areas served by Leslie TS and Richview TS and higher than anticipated costs, Toronto Hydro determined that these projects should be deferred. The associated cost reduction of $2.0 million (including the $0.8 million previously deferred into 2018) has been absorbed by other necessary monitoring and control initiatives in this program.

Negotiations of contractual agreements with customers to purchase over 200 monitoring and control systems ("MCS") and the execution of these agreements has taken longer than anticipated. Toronto Hydro deferred costs from 2018 into 2019 to execute all planned MCS contracts by the end of 2019.

The adoption of new wireless SCADA infrastructure over the 2015-2019 period under the Information Technology and Operational Technology Systems program (see Exhibit 2B, Section E8.4), as well as changes in scope and further evaluation and assessment of two-way communication systems, has delayed Toronto Hydro's procurement process for the radio communication link for the MCSs. As a result, a portion of this work has been deferred to 2019. Toronto Hydro still expects radio communication infrastructure installment to be completed by end of 2019.

Lastly, over the 2018-2019 period, Toronto Hydro is proceeding with planned implementation of energy monitoring and control capabilities (DG SCADA Management) to monitor and control distributed generation connected to the grid. Through a lengthy competitive process, Toronto Hydro managed to achieve cost reductions. Rather than the budgeted $6.6 million, capital expenditures for this work are expected to be roughly $4.8 million.

1.3 System Renewal Update

In 2018, Toronto Hydro invested $245.5 million in System Renewal projects. The utility forecasts $244.2 million in additional investments in 2019. Overall, the utility expects to spend $1,310.2 million during the 2015-2019 period, which is essentially unchanged from the $1,310.8 million initially forecast in the 2015-2019 DSP, and the $1,303.3 million previously forecast in this application.

Table 9: System Renewal Expenditures: 2015-2019 ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
System Renewal	304.1	266.1	250.3	245.5	244.2

As discussed in the following sections, variances over the 2018-2019 period are primarily driven by variances in the Area Conversions program, Underground System Renewal – Horseshoe program, and Overhead System Renewal program. Variances in the remaining programs are minor.

1.3.1 Area Conversions

Toronto Hydro invested $34.4 million in the Area Conversions program in 2018. The utility forecasts an additional $36.0 million in 2019. Overall, Toronto Hydro is on pace to spend $171.6 million during the 2015-2019 period, which is about 6 percent more than the $162.2 million initially forecast in the 2015-2019 DSP, and about 8 percent less than the amount previously forecast in this application.

Table 10: Historical & Forecast Area Conversions Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Rear-Lot Conversion	26.7	14.5	8.2	5.0	5.5
Box Construction Conversion	19.6	13.6	18.7	29.4	30.5
Total	**46.3**	**28.1**	**26.9**	**34.4**	**36.0**

Rear-Lot Conversion

Toronto Hydro invested $5.0 million in Rear Lot Conversion projects in 2018 and is forecasting an additional $5.5 million in 2019. The utility anticipates completing conversion projects for 257 customers over the two-year period. Overall, Toronto Hydro is on pace to invest $59.9 million in Rear Lot Conversion projects during the 2015-2019 period, which is aligned with the original forecast in the 2015-2019 DSP and about 8 percent less than the amount previously forecast in this application.

Lower than forecast expenditures in 2018-2019 is the result of project reprioritization between years. Toronto Hydro advanced a portion of the Jamestown rear lot project (originally scheduled for 2021-2022 as noted in Exhibit 2B, Section E6.1.4.1) as the urgency of the work increased following a significant decline in reliability performance in the area. To resource this work and the continuation of the multi-phase Thorncrest rear lot project, Toronto Hydro deferred other rear lot work, including a large scope of work ($4.2 million) in the Forest Hill rear lot area. The net result of these project timing changes was a $5.2 million deferral of expenditures to the 2020-2024 period. This deferral also facilitated the allocation of resources to urgent, incremental work in the Overhead System Renewal program.

Box Construction Conversion

Toronto Hydro invested $29.4 million in Box Construction Conversion projects in 2018 and forecasts an additional $30.5 million in 2019. The utility anticipates the conversion of 1,646 poles over the two year period. Overall, Toronto Hydro is on pace to invest $111.7 million in Box Construction Conversion projects during the 2015-2019 period, which is about 9 percent more than the $102.9 million initially forecast in the utility's

2015-2019 DSP and about 7 percent less than the amount previously forecast in this application.

Lower than forecast expenditures and pole replacement units in 2018-2019 are due to project deferrals. In 2018, Toronto Hydro deferred a portion of its planned investments into 2019 due to project execution challenges. This in turn resulted in the deferral of some 2019 projects. As noted in the Box Construction segment (Exhibit 2B, Section E6.1), projects consist of multiple phases, and as a result, unit attainment may only be recorded once all phases of a project are complete. For projects carrying over into 2019, a significant portion of the work is already complete, and Toronto Hydro expects the poles replaced to be included as part of the 2020 units achieved.

1.3.2 Underground System Renewal - Horseshoe

In 2018, Toronto Hydro invested $69.1 million in the Underground System Renewal – Horseshoe program installing 156 circuit-kilometres of primary cables, 251 transformers, and 39 switches. The utility forecasts $55.8 million of additional investments in 2019 to install an incremental 131 circuit-kilometres of primary cable, 264 transformers, and 28 switches. Overall, Toronto Hydro is on pace to invest $404.2 million during the 2015-2019 period, which is about 12 percent less than the $459.3 million initially forecast in the utility's 2015-2019 DSP, and about 4 percent less than the amount previously forecast in this application.

Table 11: Historical & Forecast Underground System Renewal – Horseshoe Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Underground System Renewal Horseshoe	115.5	80.7	83.1	69.1	55.8

Lower than forecast expenditures are the result of the following factors:

- In 2018, work executed in this program was executed as planned. Minor variances in unit replacements are attributed to changes in detailed designs, which required fewer units to be replaced, and spill-over of unit achievements from 2019 to 2020 as a result of projects being partially completed in 2019.
- Toronto Hydro deferred some work from 2019 to allow incremental work in the Overhead System Renewal program to proceed on an urgent basis.

1.3.3 Underground System Renewal – Downtown

The Underground System Renewal – Downtown program is a new program starting in 2020.

1.3.4 Network System Renewal

Toronto Hydro invested $18.8 million in the Network System Renewal program in 2018 and is tracking to spend another $32.2 million in 2019. Overall, Toronto Hydro projects total 2015-2019 capital expenditures of $92.7 million, which is essentially aligned with both the original 2015-2019 DSP and the forecast previously provided in this application.

Table 12: Historical & Forecast Network System Renewal Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Legacy Network Equipment Renewal (ATS & RPB)	1.0	1.1	3.3	3.9	1.6
Network Unit Renewal	4.7	7.6	8.3	7.5	8.7
Network Vault Renewal	4.6	8.0	2.3	6.6	18.3
Network Circuit Reconfiguration	-	0.0	0.7	0.7	3.7
Total	**10.2**	**16.8**	**14.7**	**18.8**	**32.2**

Investments within each segment of the Network System Renewal program are adjusted for each year to prioritize execution based on evolving requirements throughout the program. Toronto Hydro forecasts a minor increase of $2.4 million over the previously forecasted 2018-2019 amounts in this application. Higher than expected costs in the Legacy Network Equipment Renewal, Network Vault Renewal, and Network Circuit Reconfiguration segments were partially offset by a decrease in the Network Unit Renewal segment. Generally, Toronto Hydro is on pace to complete the volume of work previously forecast, with minor reductions in the number of network unit replacements and minor adjustments to the projects completed under the Network Circuit Reconfiguration project.

1.3.5 Overhead System Renewal

In 2018, Toronto Hydro invested $30.4 million in the Overhead System Renewal program, installing 1,510 poles, 412 transformers, 90 switches, and 102 circuit-kilometres of primary conductor. The utility forecasts $24.8 million of additional investments in 2019 to install an incremental 1,330 poles, 310 transformers, 13 switches, and 50 circuit-kilometers of primary conductor. Overall, Toronto Hydro forecasts $202.9 million of expenditures during the 2015-2019 period, which is an additional 10 percent increase on the amount previously forecast in this application.

Table 13: Historical & Forecast Overhead System Renewal Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Overhead System Renewal	61.0	51.0	35.7	30.4	24.8

Variances in 2018-2019 are primarily the result of emerging needs on the overhead system in the Horseshoe area of the City. Incremental work has included:

- additional porcelain insulator replacements to mitigate the risk of pole fires;
- additional circuit renewal work to address poor reliability, including poor reliability on Bathurst TS feeders serving large industrial customers;
- accelerated conversion work on feeders from Leslie MS to allow for the urgent decommissioning of deteriorating Leslie MS stations equipment.

As noted above, additional investment in the Overhead System Renewal program was enabled in part by the reprioritization of work in the Underground System Renewal – Horseshoe and Rear Lot Conversion projects.

1.3.6 Stations Renewal

Toronto Hydro invested $21.9 million in the Stations Renewal program in 2018, which is $2.2 million greater than the initial 2018 bridge year forecast in this application. Overall, as shown in the table below, Toronto Hydro expects to spend a total of $85.6 million in this program during 2015-2019 period, which amounts to a 0.4 percent variance relative to the previous forecast filed in this application. Please refer to Exhibit 2B, Section E6.6.4, for a detailed discussion of Toronto Hydro's accomplishments in this program relative to the originally filed 2015-2019 DSP.

Table 14: Historical & Forecast Stations Renewal Program Expenditures ($ Millions)

Segment	Actual				Bridge
	2015	2016	2017	2018	2019
Transformer Stations	7.6	6.3	7.0	8.3	7.5
Municipal Stations	3.2	3.0	7.6	6.7	8.0
Control and Monitoring	0.3	1.3	2.9	3.0	4.1
Battery and Ancillary Systems	0.1	0.8	1.4	3.9	2.4
Total	**11.3**	**11.6**	**19.0**	**21.9**	**22.0**

Transformer Stations and Municipal Stations

Toronto Hydro has deferred $6.5 million of planned expenditures in the Transformer Stations segment from 2019 to the 2020-2024 period. Due to site-specific complexities, design coordination work between Toronto Hydro and Hydro One remains ongoing for projects at Duplex TS and Strachan TS; the utility has deferred capital contributions for these projects accordingly. Toronto Hydro expects to complete this work in the 2020-2024 period. There are no in-service addition implications, as these projects were not scheduled for energization in the 2015-2019 period.

The utility has also deferred two breaker replacements from the Transformer Stations segment in order to fund higher priority power transformer replacements in the Municipal Stations segment.

Control and Monitoring

Toronto Hydro is on track to complete all planned units of work in the Control and Monitoring segment in 2018-2019. Minor variances versus the initial bridge year forecasts are due to typical cost variances between high-level estimates and final costs.

Battery and Ancillary Systems

Toronto Hydro expects to incur higher than forecast costs for Battery and Ancillary Systems in the 2018-2019 bridge years. A one-off fire suppression system installation project at Cavanaugh TS has cost more than initially estimated due to project complexities encountered during the project lifecycle. Toronto Hydro also plans to complete a greater number of station battery replacements than planned to accommodate telecom system upgrades in certain areas of the City.

1.3.7 Reactive and Corrective Capital

An upward trend in reactive capital investment needs continued in 2018. Toronto Hydro invested $66.1 million in the Reactive and Corrective Capital program, $7.7 million more than previously forecast in this application. Overall for 2015-2019, Toronto Hydro forecasts $281.6 million of expenditures in this program, an additional increase of about 5 percent over the previous forecast in this application.

Table 15: Historical & Forecast Reactive and Corrective Capital Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Reactive Capital	39.0	50.2	52.5	62.2	59.5
Worst Performing Feeder	3.0	4.1	3.0	3.9	4.2
Total	**42.0**	**54.3**	**55.5**	**66.1**	**63.7**

The increase in spending is due to a higher than anticipated volume of reactive work requests. In 2018, there was a significant number of severe weather events leading to the reactive replacement of damaged assets. Overall, there was a 130 percent increase in the number of reactive work requests issued during the weeks in which major storms occurred.

Another driver of the increase in reactive work requests was a larger number of deficient assets such as transformers. In 2018, Toronto Hydro saw a 44 percent increase from the 2013-2018 average number of transformer-related reactive work requests to address deficiencies such as oil leaks and corrosion, which is consistent with the overall pattern of aging, deterioration, and PCB spill risks for these asset types. Toronto Hydro has revised its 2019 forecast expenditures upwards to reflect recent trends.

1.4 System Service Update

In 2018, Toronto Hydro invested $31 million in System Service projects. The utility forecasts $41.5 million in additional investments in 2019. Overall, the utility expects to spend $236.2 million during the 2015-2019 period, which is about 32 percent less than the $345 million initially forecast in the 2015-2019 DSP, and about 4 percent less than the amount previously forecast in this application.[5]

Table 16: System Service Expenditures: 2015-2024 ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
System Service	37.9	53.3	72.4	31.0	41.5

As discussed in the following sections, variances over the 2018-2019 period are primarily driven by variances in the Stations Expansion and System Enhancement programs.

[5] Refer to Exhibit 2B, Section E4.1.2 for discussion of lower than forecast spending in System Service during the 2015-2019 period.

1.4.1 System Enhancements

Toronto Hydro invested $9.4 million in the System Enhancements program in 2018 and forecasts an additional $4.0 million in 2019. Overall, Toronto Hydro is on pace to invest $48.2 million during the 2015-2019 period, which less than the amount initially forecast in the utility's 2015-2019 DSP, and about 6 percent more than the amount previously forecasted in this application.

Table 17: Historical & Forecast System Enhancement Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Contingency Enhancement	6.7	15.9	12.1	9.4	2.7
Customer-Owned Station Protection	-	-	-	-	1.3
Total	**6.7**	**15.9**	**12.1**	**9.4**	**4.0**

Contingency Enhancements

Toronto Hydro invested $9.4 million in Contingency Enhancement work in 2018 and forecasts $2.7 million in additional investments in 2019. Overall, this is approximately double the investment previously forecast for the 2018-2019 period in this application. This increase is related to (1) emerging reliability and contingency needs in certain areas due to load growth and other factors; and (2) the ongoing build-out of feeder automation networks. For example, Toronto Hydro has increased the number of forecasted SCADA-enabled inter-feeder tie-points for 2018-2019 from seven to 14 feeders, and the number of sectionalizing points from three to 12 feeders. The utility is also continuing projects during 2018-2019 to upgrade undersized conductors and undersized trunk egress cables at Fairchild TS and Bathurst TS, which will support long-term improvements in reliability and system operability in these growing areas.

Customer-Owned Station Protection ("COSP")

Toronto Hydro deferred COSP work planned for 2018 into 2019 due to delays in the initial inspection portion of the program. The utility expects this work to be completed in 2019.

1.4.2 Energy Storage

Renewable Enabling Energy Storage Systems

Toronto Hydro spent $0.1 million on renewable enabling Energy Storage System projects in 2018 and forecasts $7.9 million in investments in 2019. The utility has deferred $5.8 million in investments from 2018 to 2019 due the timing of an RFP process and vendor selection, as well as challenges associated with land acquisition. For a full discussion of the utility's 2015-2019 investments in this program compared to the original 2015-2019 DSP, please refer to Exhibit 2B, Section E7.2.3.3.

Table 18: Historical & Forecast Renewable Enabling ESS Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
REI Investments	-	-	-	**0.1**	**7.9**

Customer Specific Energy Storage Systems

In 2018, Toronto Hydro invested and recovered $8.4 million of investments associated with the Metrolinx Eglinton Cross Town Light Rail Transit (ECLRT) Energy Storage System. The utility forecasts $19.4 million in additional investments, which are also 100 percent recoverable, in 2019. Toronto Hydro continues to be on pace to complete this project by the end of 2019.

Table 19: Historical & Forecast Customer Specific ESS Expenditures ($ Millions)

	Actual	Bridge	Total
	2018	2019	
Metrolinx ECLRT	8.4	19.4	**27.8**

1.4.3 Network Condition Monitoring and Control

There are no historical or bridge expenditures associated with the Network Condition Monitoring and Control program over the 2015-2019 period as it is a new independent program starting in 2020. Similar work was completed on a smaller scale in the 2015-2019 period and was funded through the Network System Renewal program.

1.4.4 Stations Expansion

In 2018, Toronto Hydro invested $21.0 million in the Stations Expansion program and forecasts an additional $29.1 million in 2019. Overall, Toronto Hydro is on pace to invest $167.0 million in Station Expansion projects during the 2015-2019 period, which is about 11 percent less than the $188.6 million initially forecast in the utility's 2015-2019 DSP,[6] and about 7 percent less than the amount previously forecasted in this application.

Table 20: Historical & Forecast Station Expansion Program Expenditures ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
Copeland TS Expansion	20.5	19.1	22.0	8.7	9.1
Hydro One Contributions	2.5	15.3	37.4	12.3	16.4
Local Demand Response	--	--	0.1	0.1	3.6
Total	**23.0**	**34.4**	**59.4**	**21.0**	**29.1**

[6] EB-2014-0116, Exhibit 2B, Section E7.9 Stations Expansion and Exhibit 2B, Section E7.10 Local Demand Response

Copeland TS Expansion

Toronto Hydro invested $8.7 million in Copeland TS Expansion work in 2018, which includes expenditures on both Copeland TS Phase 1 and 2. The utility has budgeted another $9.1 million of investments in 2019. A substantial portion of the Copeland Phase 1 assets have been energized. Toronto Hydro expects all remaining work related to Copeland Phase 1 to be complete and the project fully energized in 2019. The increase of $2.5 million in Copeland TS Expansion expenditures over the previous forecast in this application is largely due to the cost of replacing the General Contractor for the completion of energization and delays experienced by Hydro One.

Hydro One Contribution

Toronto Hydro made $12.3 million in capital contributions to Hydro One in 2018 and forecasts $16.4 million 2019. Expenditures over the 2015-2019 period are forecast to be 16 percent lower than previously forecast in this application. The variance in 2018-2019 is attributed to delays in the execution of agreements with Hydro One. Toronto Hydro has deferred approximately $4.4 million of investments from 2018 to 2019 due to work delays at Basin TS, Horner TS, and Gerrard TS-Carlaw TS and has consequently deferred $9.4 million of capital contributions associated with Horner TS from 2019 into the 2020-2024 period.

In 2019, triggered by true up processes and timelines, Toronto Hydro expects to reconcile past Hydro One capital contributions by:

1. incurring $4.3 million in additional capital contributions for the Midtown Toronto Transmission Reinforcement project (Leaside TS x Bridgman TS), identified as the Leaside-Birch project in the utility’s 2015-2019 DSP; and

2. recovering $4.9 million in capital contributions made for the Bridgman PT project and the Runnymede TS J-Q bus installation project.

Local Demand Response

Toronto Hydro invested $0.1 million in Local DR work in 2018 and has deferred the remaining expenditures into 2019 to adjust to certain design challenges in the execution of this unique project. The utility expects to complete the planned work by end of 2019.

1.5 General Plant Update

In 2018, Toronto Hydro invested $58.4 million in General Plant activities. The utility forecasts $46.4 million in additional investments in 2019. Overall, the utility expects to spend $392.7 million during the 2015-2019 period, which is about 31 percent more than the $300.9 million initially forecast in the 2015-2019 DSP, and about one percent less than the amount previously forecast in this application.[7]

Table 21: General Plant Expenditures: 2015-2019 ($ Millions)

	Actual				Bridge
	2015	2016	2017	2018	2019
General Plant	79.4	109.5	98.9	58.4	46.4

1.5.1 Control Operations Reinforcement

The Control Operations Reinforcement program is a new one-time program during the 2020-2024 period.

[7] Refer to Exhibit 2B, Section E4.1.3 for discussion of higher than forecast spending in General Plant during the 2015-2019 period.

1.5.2 Facilities Management and Security

Toronto Hydro invested $1.7 million in the Facilities Management and Security program in 2018 and forecasts an additional $3.5 million in 2019. Overall, Toronto Hydro is on pace to invest $36.0 million in facilities projects during the 2015-2019 period, which is aligned with the amount previously filed in this application.

Table 22: Historical & Forecast Facilities Management and Security Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Work Centres	11.4	5.3	4.2	1.2	1.8
Stations	3.2	2.8	1.6	0.5	0.5
Security Improvements	0.7	0.9	0.5	0.1	1.3
Total	**15.3**	**9.0**	**6.3**	**1.7**	**3.5**

In 2018, Toronto Hydro shifted planned expenditures from the Stations and Security Improvements segments to the Work Centres segment to address several potential health and safety risks, such as slip, trip, fall, lighting, and space hazards. As noted in Exhibit 2B, Section E8.2, Toronto Hydro's Carlton, and Commissioners work centres are in need of several improvements to address potential safety hazards both reactively and proactively. In 2019, Toronto Hydro is focussed on investing in the Stations and Security Improvements segments while continuing to address health and safety concerns under the Work Centres segment.

1.5.3 Fleet and Equipment Services

Toronto Hydro invested $2.9 million in the Fleet and Equipment Services program in 2018 and plans to invest an additional $3.6 million in 2019. Toronto Hydro is on pace to spend $19.0 million on Fleet and Equipment Services work during the 2015-2019 period, which is aligned with the forecast expenditures previously provided in this application. For a discussion of the variance between the planned and actual expenditures in the 2015-2019 period, please refer to Exhibit 2B, Section E8.3.

Table 23: Historical & Forecast Fleet and Equipment Services Program Expenditures ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Heavy Duty Vehicles	2.2	2.9	3.3	1.5	2.7
Light Duty Vehicles	1.3	0.8	0.3	0.7	0.8
Equipment	0.6	0.1	1.1	0.8	0.1
Total	**4.1**	**3.7**	**4.7**	**2.9**	**3.6**

1.5.4 Information Technology and Operational Technology Systems (“IT/OT”)

Toronto Hydro invested $53.7 million in the IT/OT program in 2018, which is $10.9 million less than the 2018 bridge year forecast in this application. Overall, as shown in Table 24, below, Toronto Hydro is forecasting $225.3 million of expenditures in this program during the 2015-2019 period, which is 2.6 percent less than the forecast previously provided in this application. Please refer to Exhibit 2B, Section E8.4.4, for a discussion of Toronto Hydro’s accomplishments during the 2015-2019 period.

Table 24: Historical & Forecast IT/OT Program Expenditures ($ Millions)

Segments	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
IT Hardware	7.5	9.3	10.1	7.8	8.8
IT Software	14.8	21.7	40.3	40.1	23.0
Communication Infrastructure	6.1	17.6	4.9	5.8	7.5
Total	**28.4**	**48.6**	**55.4**	**53.7**	**39.3**

IT Hardware

In 2018, Toronto Hydro's spending was as forecasted in the application. In 2019, Toronto Hydro anticipates spending an additional $1.0 million above the amount originally forecasted in the application. The increase is attributable to additional hardware required to accommodate higher than anticipated IT storage and backup needs.

IT Software

In 2018, Toronto Hydro spent $40.1 million, which is $10.7 million less than forecast in the Application. The majority of the variance can be attributed to a re-assessment of business needs following implementation of the ERP. Some of the variance is also attributable to the extension of the lifecycle of a data warehousing solution given the lack of replacement options available at this time. In 2019, Toronto Hydro expects to complete some of the deferred work following an assessment of availability of adequate vendor solutions, and business needs and priorities.

Communication Infrastructure

In 2018, the variance for this segment was negligible. Similarly, the forecast for 2019 has increased by a negligible amount. Overall, this segment experienced a 1.2 percent increase compared to the forecast provided in the application.

1.6 Other Capital

For the 2015-2019 period, Toronto Hydro's Other Capital expenditures are forecast to be 36 percent lower than originally planned. Please refer to Exhibit 2B, Section E4.1.4 for a discussion of the 2015-2019 variances in this category.[8]

[8] Please note that the negative amount in 2019 is due to regular movements in pre-capitalized inventory balances over time.

Table 25: Other Capital Expenditures: 2015-2024 ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
Other Capital	11.6	3.7	10.7	12.7	(1.3)

2. SYSTEM O&M

In 2018, Toronto Hydro spent $139.6 million in System O&M expenditures and forecasts $131.0 million in investments in 2019. Expenditures in 2018 are $12.7 million more than the amount previously forecast in this application. This variance is primarily driven by increased maintenance work attributed to major storm events. Please see Exhibit U, Tab 4A, Schedule 1, for OM&A program variance analysis resulting from 2018 actuals.

Table 26: System O&M Expenditures 2015-2020 ($ Millions)

	Actual				Bridge
	2015	**2016**	**2017**	**2018**	**2019**
System O&M	116.1	126.5	126.3	139.6	131.0

OEB Appendix 2-AA
Capital Programs Table

Programs ($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	MIFRS	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Customer and Generation Connections	31.7	40.1	21.9	44.0	39.8	42.9	43.9	44.8	45.6	46.3
Externally Initiated Plant Relocations & Expansion	2.2	2.6	2.6	5.0	11.9	11.4	20.8	4.6	4.7	4.5
Generation Protection, Monitoring and Control	-	2.1	0.0	0.6	10.9	3.7	2.3	2.4	2.5	2.7
Load Demand	9.9	16.8	16.2	16.4	23.5	11.3	11.4	18.5	22.6	23.6
Metering	14.5	17.4	24.8	22.0	26.1	22.6	14.8	23.6	30.6	39.2
System Access Total	**58.3**	**79.0**	**65.5**	**88.0**	**112.1**	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**
Area Conversions	46.3	28.2	26.9	34.4	36.0	41.4	47.2	46.3	50.4	35.6
Network System Renewal	10.2	16.8	14.7	18.8	32.2	18.6	19.3	18.5	17.7	18.3
Reactive and Corrective Capital	42.0	54.3	55.5	66.1	63.7	61.2	62.4	63.5	64.4	65.8
Stations Renewal	11.3	11.6	19.0	21.9	22.0	27.5	35.3	29.4	27.0	22.4
Underground Renewal - Downtown	-	-	-	(0.0)	-	15.1	22.5	23.9	30.0	30.6
Underground Renewal - Horseshoe	115.5	80.7	83.1	69.1	55.8	93.0	88.7	90.3	93.1	95.2
Overhead Infrastructure Relocation	0.9	3.1	2.6	0.3	1.6	-	-	-	-	-
SCADAMATE R1 Renewal	3.5	4.9	2.1	1.1	1.9	-	-	-	-	-
PILC Piece Outs & Leakers	6.0	5.7	1.8	0.8	0.1	-	-	-	-	-
Underground Legacy Infrastructure	7.4	9.9	9.0	2.7	6.0	-	-	-	-	-
Overhead System Renewal	61.0	51.0	35.7	30.4	24.8	49.8	50.4	51.3	56.5	57.7
System Renewal Total	**304.1**	**266.1**	**250.3**	**245.5**	**244.2**	**306.6**	**325.7**	**323.1**	**339.0**	**325.5**
Energy Storage Systems	-	-	-	0.1	7.9	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4
Overhead Momentary Reduction	0.0	-	-	-	0.3	-	-	-	-	-
Stations Expansion	23.0	34.5	59.4	21.0	29.1	19.5	40.0	49.3	12.5	15.2
System Enhancements	7.1	17.2	12.2	9.4	4.0	6.2	6.2	5.6	4.8	4.9
Handwell Upgrades	4.7	0.8	0.8	0.0	-	-	-	-	-	-
Polymer SMD-20 Renewal	3.0	0.3	0.0	0.4	-	-	-	-	-	-
Design Enhancement	0.0	0.6	(0.0)	0.0	0.2	-	-	-	-	-
System Service Total	**37.9**	**53.3**	**72.4**	**31.0**	**41.5**	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**
Facilities Management and Security	15.4	9.0	6.3	1.7	3.5	11.6	11.8	12.1	12.3	12.6
Fleet and Equipment	4.1	3.7	4.7	2.9	3.6	8.6	8.9	8.5	8.7	7.8
IT/OT Systems	28.4	48.6	55.4	53.7	39.3	54.8	55.7	49.5	56.6	64.8
Control Operations Reinforcement	-	-	-	-	-	3.9	17.4	18.9	-	-
Operating Centers Consolidation Plan	31.6	48.3	32.2	-	-	-	-	-	-	-
Program Support	-	0.0	0.4	-	-	-	-	-	-	-
General Plant Total	**79.4**	**109.5**	**98.9**	**58.4**	**46.4**	**78.8**	**93.7**	**89.0**	**77.7**	**85.2**
AFUDC	10.8	12.5	9.8	8.9	4.0	6.0	8.2	8.7	8.9	7.7
Miscellaneous	0.8	(8.8)	0.9	3.8	(5.3)	1.0	0.8	1.2	0.6	1.0
Other Total	**11.6**	**3.7**	**10.7**	**12.7**	**(1.3)**	**7.0**	**9.0**	**9.8**	**9.5**	**8.7**
Subtotal	**491.4**	**511.6**	**497.8**	**435.6**	**443.0**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	(0.8)	(3.2)	(1.2)	(0.7)	(17.7)	(4.4)	(3.1)	(3.2)	(3.3)	(3.5)
Total	**490.6**	**508.4**	**496.6**	**434.9**	**425.3**	**514.0**	**578.8**	**583.9**	**562.4**	**570.9**

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

CATEGORY	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access	86.1	58.3	-32.3%	95.3	79.0	-17.2%	104.9	65.5	-37.6%	95.8	88.0	-8.1%	92.3	112.1	21.4%	91.8	93.3	93.9	106.0	116.4
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	306.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	34.2	60.1	71.3	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	78.8	93.7	89.0	77.7	85.2
Other	12.2	11.6	-4.8%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	12.7	10.5%	12.1	(1.3)	-111.1%	7.0	9.0	9.8	9.5	8.7
TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	518.4	581.8	587.1	565.7	574.4
Capital Contributions Paid	(6.6)	(4.0)	-40.0%	(29.1)	(16.6)	-42.9%	(48.2)	(37.4)	-22.5%	(32.1)	(12.4)	-61.2%	(30.5)	(18.5)	-39.4%	(12.8)	(16.1)	(15.2)	(16.8)	(14.6)
Net Capital Expenditures	524.5	487.5	-7.1%	489.7	495.0	1.1%	419.2	460.5	9.9%	438.0	423.2	-3.4%	471.6	424.5	-10.0%	505.6	565.7	571.9	548.9	559.8
System O&M	128.8	116.1	-9.9%		126.5	--		126.3	--		139.6	--		131.0	--	130.4				

Note: Variances due to rounding may exist

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Refer to respective category sections for discussion on historical vs forecast shifts: Section E5 for System Access, Section E6 for System Renewal, Section E7 for System Service and Section E8 for General Plant. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: 2020

CATEGORY	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access	103.3	97.4	-5.8%	112.8	113.0	0.2%	122.0	113.0	-7.4%	113.8	153.0	34.4%	111.9	236.0	110.9%	160.4	189.6	181.3	193.8	207.2
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	306.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	58.5	72.2	77.1	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	78.8	93.7	89.0	77.7	85.2
Other	12.2	13.5	10.9%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	13.0	13.2%	12.1	(1.3)	-111.1%	7.0	9.0	9.8	9.5	8.7
GROSS TOTAL EXPENDITURE	548.3	532.3	-2.9%	536.2	545.6	1.8%	484.5	545.3	12.5%	488.0	500.9	2.6%	521.7	566.9	8.7%	611.3	690.2	680.4	653.6	665.2
Capital Contributions Received	(17.2)	(40.9)	138.1%	(17.4)	(34.0)	95.3%	(17.1)	(47.5)	177.1%	(18.0)	(65.3)	262.7%	(19.6)	(123.9)	533.0%	(92.9)	(108.4)	(93.2)	(87.8)	(90.9)
NET TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	518.4	581.8	587.1	565.7	574.4
System O&M	128.8	116.1	-9.9%		126.5			126.3			139.6			131.0		130.4				

Note: Variances due to rounding may exist

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Refer to respective category sections for discussion on historical vs forecast shifts. Section E5 for System Access, Section E6 for System Renewal, Section E7 for System Service and Section E8 for General Plant. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Refer to Section E4 on Variance analysis for between Plan vs Actuals. For variance explanations as a result of updated financial information, refer to Exhibit U, Tab 2, Schedule 2.

OVERHEAD COSTS UPDATE

An updated OEB Appendix 2-D has been filed at Exhibit U, Tab 2, Schedule 3, Appendix A. As mentioned in Exhibit 2A, Tab 5, Schedule 2, there have been no changes in the utility's overhead expense capitalization policy since its last rebasing application.

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year
Operations	146.9	155.1	153.6	154.5	166.7	169.0
Maintenance	73.6	65.1	68.5	77.4	71.2	72.0
Billing and Collecting	36.8	34.0	35.9	34.7	41.5	45.8
Community Relations	3.5	2.5	2.4	3.0	2.7	2.8
Administrative and General	90.4	98.2	104.5	108.3	104.9	109.4
Taxes Other Than Income Taxes	5.2	4.6	5.3	4.9	5.4	5.5
Donations	1.0	1.0	1.0	0.8	0.9	1.0
Total OM&A Before Capitalization (B)	$ 357.4	$ 360.6	$ 371.1	$ 383.6	$ 393.4	$ 405.6

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

Capitalized OM&A	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Labour Capitalization	(99.1)	(95.6)	(101.1)	(101.4)	(109.8)	(112.5)	Yes	
Vehicle Capitalization	(4.2)	(4.3)	(4.5)	(4.2)	(3.9)	(4.1)	Yes	
Material Handling On-cost	(10.2)	(10.8)	(10.3)	(9.6)	(11.6)	(11.5)	Yes	
Total Capitalized OM&A (A)	(113.4)	(110.8)	(115.9)	(115.3)	(125.2)	(128.1)		

% of Capitalized OM&A (=A/B)	-32%	-31%	-31%	-30%	-32%	-32%		

OPERATING REVENUE VARIANCE ANALYSIS

1. LOAD, CUSTOMERS, AND REVENUES

Exhibit 3, Tab 1, includes information about Toronto Hydro's total load, customer, and distribution revenue forecast. This schedule provides an updated load and customer forecast for the period 2018 through 2024. Table 1 below summarizes the forecasted loads, distribution revenue and customers, and compares to the originally filed ("original") forecast.

Table 1: Total Load, Revenues, and Customers

Year		Total Normalized GWh		Total Normalized MVA		Total Distribution Revenue ($M)		Total Customers	
		Original	Update[1]	Original	Update[1]	Original	Update	Original	Update
2013	Actual	25,245.1	25,312.2	42,737.5	42,828.4	531.9	533.5	724,144	724,144
2014	Actual	25,132.0	25,200.9	41,866.4	41,960.8	536.6	537.7	735,262	735,262
2015	Actual	25,031.1	25,097.8	41,320.7	41,410.4	628.0	629.5	747,811	747,811
2016	Actual	24,909.3	24,964.8	41,335.6	41,414.0	661.4	657.6	759,031	759,031
2017	Actual	24,427.6	24,498.5	40,731.3	40,744.9	693.6	700.4	765,559	765,559
2018	Bridge / Actual	24,378.2	24,609.4	40,925.0	40,220.7	740.7	740.6	771,079	769,571
2019	Bridge	24,123.8	24,195.5	40,761.1	40,662.4	771.5	773.7	776,786	776,890
2020	Forecast	24,036.0	24,044.0	40,408.1	40,232.3	796.9	800.2	784,330	784,236
2021	Forecast	23,818.0	23,763.4	40,275.5	39,999.7	824.2	824.9	790,944	790,979
2022	Forecast	23,651.8	23,651.0	40,200.6	39,918.9	846.8	848.2	798,591	799,336
2023	Forecast	23,475.3	23,541.8	40,104.6	39,857.0	885.2	886.7	806,238	805,850
2024	Forecast	23,396.7	23,494.7	40,166.6	39,887.4	924.2	927.1	813,886	811,785

Note 1: Historical and forecast loads for Update reflect normalization based on average HDD and CDD over 2009-2018 period.

Toronto Hydro's detailed and updated load forecasts by rate class, customer forecast by rate class, and forecast of distribution revenues by rate class (OEB Appendix 2-IB) are shown in Appendix A to this schedule.

1.1 Load Forecast Update

Toronto Hydro's original load forecast was based on regression models using actual historical loads and input variables to the end of 2017, and forecasts of input variables for the 2018-2024 period. For the updated forecast, regression models were re-run using actual historical loads and input variables to the end of 2018. Specifically, the updated load forecasts include the following:

a) 2018 actual kWh and kVA billing determinants by class;
b) updated 10 year historical average HDD and CDD: 2009-2018 period, compared to 2008-2017 period in the original forecast;
c) updated forecasts of model input variables: updated forecasts of GDP and Unemployment rates based on the latest (January 2019) Conference Board of Canada forecast; and
d) re-estimated model co-efficients: models were tested for goodness of fit and reasonableness of independent variable co-efficients. Model specifications remained unchanged for all classes except for GS 1,000-4,999 kW class. The unemployment rate variable was found to be statistically insignificant for the specific rate class and was removed from the model in this update.

The updated load forecast models also incorporate the latest information related to actual IESO verified CDM savings to the end of 2017, and non-verified 2018 results. For the 2019-2024 forecast period, the CDM savings included in the forecast are based on the latest CDM plan submitted to the IESO.

Toronto Hydro notes the very recent Provincial directives on conservation programs in the province. However, at time of preparation of the load forecast for the update, the potential impacts are unknown, and therefore Toronto Hydro has included the latest forecast for CDM savings through the forecast period. Details of the CDM forecast are provided in Appendix B to this schedule. Updated tables originally provided in response to 3-VECC-25 and 3-VECC-26 are also provided in Appendix C and D.

The underlying CDM savings forecast for the purpose of LRAMVA calculations over the 2020-2024 period are also filed as Appendix E. As discussed during the Technical Conference, these savings include persistence of 2019 forecast CDM savings. Persistence of 2018 savings is not included, as the actual results of these programs are known and included (even if they are not yet verified by the IESO).

Board Staff's interrogatory 3-Staff-106 inquired about the impacts on the load forecast due to the TTC Spadina extension, and the proposed Eglinton Crosstown project. The updated historical loads now contain the full impact of the Spadina extension and therefore are reflected in the load forecast. As noted in Toronto Hydro's interrogatory response, the load impacts of the Eglinton Crosstown project are uncertain in both level and timing, and would not have a material impact on rate setting for the CIR period. They have not been reflected in the updated load forecast.

Similarly, no consideration of EV loads or DER for purpose of customer load shedding has been included in the updated load forecast, for the reasons indicated in the original evidence.

A summary of the billing unit load forecasts, by class, is provided in Table 2.

Table 2: Billing Unit Load Forecast by Class

Rate Class		2018	2019	2020	2021	2022	2023	2024
Residential (GWh)	Original	4,580.0	4,532.0	4,510.6	4,458.7	4,422.7	4,386.7	4,366.4
	Updated	4,770.3	4,543.9	4,531.2	4,488.5	4,462.0	4,435.6	4,425.2
CSMUR (GWh)	Original	256.2	263.9	277.1	286.9	300.3	313.8	328.4
	Updated	266.8	278.1	297.8	314.7	336.4	352.4	367.6
GS <50 kW (GWh)	Original	2,307.4	2,281.5	2,267.6	2,238.8	2,214.3	2,187.5	2,169.9
	Updated	2,361.2	2,308.4	2,299.0	2,276.4	2,263.7	2,251.3	2,242.4
GS 50-999 kW (MVA)	Original	25,259.1	25,224.7	24,899.2	24,849.5	24,840.9	24,813.6	24,875.7
	Updated	24,863.0	25,304.9	24,899.0	24,780.6	24,747.8	24,722.8	24,752.9
GS 1000-4999 kW (MVA)	Original	10,443.0	10,383.8	10,392.9	10,334.3	10,283.8	10,232.6	10,228.5
	Updated	10,219.7	10,393.7	10,406.7	10,362.1	10,352.3	10,350.5	10,370.6
Large User (MVA)	Original	4,897.2	4,826.4	4,789.3	4,764.6	4,748.4	4,730.2	4,733.9
	Updated	4,812.6	4,637.9	4,600.4	4,530.2	4,491.6	4,455.9	4,435.7
Street lighting (MVA)	Original	325.7	326.1	326.6	327.1	327.6	328.1	328.6
	Updated	325.5	325.8	326.3	326.8	327.3	327.7	328.2
USL (GWh)	Original	41.2	41.2	41.3	41.2	41.2	41.2	41.3
	Updated	40.5	40.5	40.6	40.5	40.5	40.5	40.6

1.2 Customer Forecast

Similar to the load forecast, the forecast of customers by rate class has also been updated to reflect the latest actuals (to end of 2018). As noted in Exhibit 3, Tab 1, Schedule 1, section 6, most of the customer forecasts are based on extrapolation models. Details of the models used for each rate class are provided in the following table.

Table 3: Customer Forecast Models

Rate Class	Type of model (e.g. linear trend)	Period used for model	Model Explanation
Residential	Linear Trend	2002-2018	Full historical data set used for trend
CSMUR	Based on estimated projections	N/A	Based on CMHC's forecast of housing starts for multi-unit developments in Toronto. Toronto Hydro uses its professional judgment to estimate the market share of the units from this forecast that will be serviced by Toronto Hydro.
GS <50 kW	Linear Trend	2014-2018	Shorter period than full data set to reflect latest trend in the class.
GS 50-999 kW	Linear Trend	2002-2018	Full historical data set used for trend
GS 1000-4999 kW	Latest actual	N/A	Customer numbers for this group relatively stable
Large User	Latest actual	N/A	Customer numbers for this group relatively stable
Street lighting	Linear Trend	2007-2018	Full historical data set used for trend
USL	Latest actual	N/A	Customer numbers for this group relatively stable

A summary of the customer forecasts, by class, is provided in Table 2.

Table 4: Customer Forecast by Class

Rate Class		2018	2019	2020	2021	2022	2023	2024
Residential	Original	612,675	614,320	615,965	617,609	619,254	620,899	622,544
	Updated	612,169	613,542	615,118	616,694	618,269	619,845	621,421
CSMUR	Original	75,371	79,347	85,161	90,045	95,962	101,879	107,796
	Updated	74,523	80,204	85,852	90,897	97,558	102,374	106,611
GS <50 kW	Original	71,306	71,403	71,499	71,596	71,692	71,788	71,885
	Updated	71,170	71,466	71,599	71,732	71,864	71,997	72,130
GS 50-999 kW	Original	10,396	10,385	10,374	10,363	10,352	10,341	10,330
	Updated	10,515	10,447	10,417	10,387	10,357	10,327	10,297
GS 1000-4999 kW	Original	430	430	430	430	430	430	430
	Updated	432	430	430	430	430	430	430
Large User	Original	44	44	44	44	44	44	44
	Updated	44	38	38	38	38	38	38

Rate Class		2018	2019	2020	2021	2022	2023	2024
Street lighting (devices)	Original	164,756	165,024	165,292	165,560	165,828	166,096	166,364
	Updated	164,662	164,828	165,274	165,535	165,796	166,057	166,318
USL (connections)	Original	12,272	12,272	12,272	12,272	12,272	12,272	12,272
	Updated	12,245	12,180	12,180	12,180	12,180	12,180	12,180
USL (customers)	Original	857	857	857	857	857	857	857
	Updated	837	825	825	825	825	825	825

An update to Exhibit 3, Tab 1, Schedule 1, Appendix A1 and Appendix A2 are provided as Appendix F and Appendix G, showing details of the historical and forecast model inputs and model statistical results.

OEB 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 2020 Cost of Service			Consumption (kWh) [3]			
				Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2013*		Actual	24,602,483,277	24,614,578,389		
Historical	*2014*		Actual	24,558,531,773	24,505,064,297		
Historical	*2015*		Actual	24,428,042,829	24,404,398,486	Board-approved	
Historical	*2016*		Actual	24,567,033,429	24,275,284,295		
Historical	*2017*		Actual	23,598,572,231	23,822,039,462		
Historical	*2018*		Actual	24,371,454,893	23,928,196,254		
Bridge Year	*2019*		Forecast		23,525,784,369		
Test Year	*2020*		Forecast		23,377,600,153		
Test Year	*2021*		Forecast		23,103,887,065		
Test Year	*2022*		Forecast		22,994,400,874		
Test Year	*2023*		Forecast		22,888,042,435		
Test Year	*2024*		Forecast		22,842,029,746		

Variance Analysis	Year	Year-over-year			Versus Board-approved
	2013				
	2014	-0.2%	-0.4%		
	2015	-0.5%	-0.4%		
	2016	0.6%	-0.5%		
	2017	-3.9%	-1.9%		
	2018	3.3%	0.4%		
	2019		-1.7%		
	2020		-0.6%		
	2021		-1.2%		
	2022		-0.5%		
	2023		-0.5%		
	2024		-0.2%		
	Geometric Mean	-0.2%	-0.7%		

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

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

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

	Calendar Year (for 2020 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	*2013*	Actual	606,350			Actual	4,988,814,396	5,003,113,071			Actual	8,228	8,251		
Historical	*2014*	Actual	609,928			Actual	4,879,959,207	4,889,931,927			Actual	8,001	8,017		
Historical	*2015*	Actual	610,961	Board-approved	612,985	Actual	4,807,191,038	4,808,717,399	Board-approved	4,909,898,145	Actual	7,868	7,871	Board-approved	8,010
Historical	*2016*	Actual	611,021			Actual	4,903,931,991	4,782,426,081			Actual	8,026	7,827		
Historical	*2017*	Actual	611,660			Actual	4,545,714,645	4,621,607,673			Actual	7,432	7,556		
Historical	*2018*	Actual	612,169			Actual	4,927,526,992	4,770,271,625			Actual	8,049	7,792		
Bridge Year	*2019*	Forecast	613,542			Forecast		4,543,879,091			Forecast		7,406		
Test Year	*2020*	Forecast	615,118			Forecast		4,531,218,421			Forecast		7,366		
Test Year	*2021*	Forecast	616,694			Forecast		4,488,479,794			Forecast		7,278		
Test Year	*2022*	Forecast	618,269			Forecast		4,462,016,247			Forecast		7,217		
Test Year	*2023*	Forecast	619,845			Forecast		4,435,552,699			Forecast		7,156		
Test Year	*2024*	Forecast	621,421			Forecast		4,425,206,261			Forecast		7,121		

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
	2013			*2013*				*2013*			
	2014	0.6%		*2014*	-2.2%	-2.3%		*2014*	-2.8%	-2.8%	
	2015	0.2%		*2015*	-1.5%	-1.7%		*2015*	-1.7%	-1.8%	
	2016	0.0%		*2016*	2.0%	-0.5%		*2016*	2.0%	-0.6%	
	2017	0.1%		*2017*	-7.3%	-3.4%		*2017*	-7.4%	-3.5%	
	2018	0.1%		*2018*	8.4%	3.2%		*2018*	8.3%	3.1%	
	2019	0.2%		*2019*		-4.7%		*2019*		-5.0%	
	2020	0.3%		*2020*		-0.3%		*2020*		-0.5%	
	2021	0.3%		*2021*		-0.9%		*2021*		-1.2%	
	2022	0.3%		*2022*		-0.6%		*2022*		-0.8%	
	2023	0.3%		*2023*		-0.6%		*2023*		-0.8%	
	2024	0.3%	0.3%	*2024*		-0.2%	-7.7%	*2024*		-0.5%	-8.0%
	Geometric Mean	0.2%		Geometric Mean	-0.3%	-1.2%		Geometric Mean	-0.5%	-1.5%	

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	*2013*	Actual	$ 212,060,221		
Historical	*2014*	Actual	$ 213,456,483		
Historical	*2015*	Actual	$ 250,173,765	Board-approved	$ 252,506,394
Historical	*2016*	Actual	$ 259,722,123		
Historical	*2017*	Actual	$ 275,943,904		
Historical	*2018*	Actual	$ 293,738,060		
Bridge Year	*2019*	Forecast	$ 304,906,894		
Test Year	*2020*	Forecast	$ 316,462,218		
Test Year	*2021*	Forecast	$ 326,685,424		
Test Year	*2022*	Forecast	$ 335,568,591		
Test Year	*2023*	Forecast	$ 350,677,309		
Test Year	*2024*	Forecast	$ 366,405,979		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	0.7%	
Note 2	*2015*	17.2%	
	2016	3.8%	
	2017	6.2%	
	2018	6.4%	
	2019	3.8%	
	2020	3.8%	
	2021	3.2%	
	2022	2.7%	
	2023	4.5%	
	2024	4.5%	25.3%
	Geometric Mean	5.6%	

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

2 Customer Class: CSMUR

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

	Calendar Year (for 2020 Cost of Service	Customers			
Historical	2013	Actual	36,156		
Historical	2014	Actual	43,022		
Historical	2015	Actual	54,516	Board-approved	54,122
Historical	2016	Actual	65,685		
Historical	2017	Actual	71,041		
Historical	2018	Actual	74,523		
Bridge Year	2019	Forecast	80,204		
Test Year	2020	Forecast	85,852		
Test Year	2021	Forecast	90,897		
Test Year	2022	Forecast	97,558		
Test Year	2023	Forecast	102,374		
Test Year	2024	Forecast	106,611		

	Consumption (kWh) (3)			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	133,317,285	130,096,054		
Actual	158,440,481	153,947,355		
Actual	203,724,686	202,136,385	Board-approved	213,116,822
Actual	231,489,091	231,291,163		
Actual	245,275,381	247,801,250		
Actual	270,836,212	266,754,658		
Forecast		278,114,515		
Forecast		297,763,685		
Forecast		314,675,582		
Forecast		336,411,558		
Forecast		352,414,588		
Forecast		367,617,638		

	Consumption (kWh) per Customer			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	3,687	3,598		
Actual	3,683	3,578		
Actual	3,737	3,708	Board-approved	3,938
Actual	3,524	3,521		
Actual	3,453	3,488		
Actual	3,634	3,579		
Forecast		3,468		
Forecast		3,468		
Forecast		3,462		
Forecast		3,448		
Forecast		3,442		
Forecast		3,448		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
Note 3	2014	19.0%	
Note 3	2015	26.7%	
Note 3	2016	20.5%	
	2017	8.2%	
	2018	4.9%	
	2019	7.6%	
	2020	7.0%	
	2021	5.9%	
	2022	7.3%	
	2023	4.9%	
	2024	4.1%	58.6%
	Geometric Mean	11.4%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	18.8%	18.3%	
2015	28.6%	31.3%	
2016	13.6%	14.4%	
2017	6.0%	7.1%	
2018	10.4%	7.6%	
2019		4.3%	
2020		7.1%	
2021		5.7%	
2022		6.9%	
2023		4.8%	
2024		4.3%	39.7%
Geometric Mean	19.4%	10.9%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	-0.1%	-0.6%	
2015	1.5%	3.6%	
2016	-5.7%	-5.0%	
2017	-2.0%	-0.9%	
2018	5.3%	2.6%	
2019		-3.1%	
2020		0.0%	
2021		-0.2%	
2022		-0.4%	
2023		-0.2%	
2024		0.2%	-11.9%
Geometric Mean	-0.4%	-0.4%	

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	2013	Actual	$ 10,916,837		
Historical	2014	Actual	$ 13,110,388		
Historical	2015	Actual	$ 17,785,616	Board-approved	$ 18,002,535
Historical	2016	Actual	$ 21,936,125		
Historical	2017	Actual	$ 25,564,379		
Historical	2018	Actual	$ 28,639,564		
Bridge Year	2019	Forecast	$ 32,193,282		
Test Year	2020	Forecast	$ 34,899,181		
Test Year	2021	Forecast	$ 38,054,484		
Test Year	2022	Forecast	$ 41,852,057		
Test Year	2023	Forecast	$ 45,786,430		
Test Year	2024	Forecast	$ 49,684,990		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
Note 3	2014	20.1%	
Note 3	2015	35.7%	
Note 3	2016	23.3%	
Note 3	2017	16.5%	
Note 3	2018	12.0%	
Note 3	2019	12.4%	
	2020	8.4%	176.0%
	2021	9.0%	
	2022	10.0%	
Note 3	2023	9.4%	
Note 3	2024	8.5%	
	Geometric Mean	16.4%	

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

3 Customer Class: GS < 50 kW

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

	Calendar Year (for 2020 Cost of Service	Customers			
Historical	2013	Actual	68,312		
Historical	2014	Actual	69,078		
Historical	2015	Actual	70,628	Board-approved	69,131
Historical	2016	Actual	70,499		
Historical	2017	Actual	71,116		
Historical	2018	Actual	71,170		
Bridge Year	2019	Forecast	71,466		
Test Year	2020	Forecast	71,599		
Test Year	2021	Forecast	71,732		
Test Year	2022	Forecast	71,864		
Test Year	2023	Forecast	71,997		
Test Year	2024	Forecast	72,130		

	Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	2,171,642,035	2,175,762,283		
Historical	2014	Actual	2,253,840,657	2,257,190,348		
Historical	2015	Actual	2,366,876,161	2,367,505,018	Board Approved	2,118,402,162
Historical	2016	Actual	2,371,216,399	2,337,491,516		
Historical	2017	Actual	2,311,840,421	2,332,595,227		
Historical	2018	Actual	2,404,335,418	2,361,181,460		
Bridge Year	2019	Forecast		2,308,351,146		
Test Year	2020	Forecast		2,299,006,608		
Test Year	2021	Forecast		2,276,427,231		
Test Year	2022	Forecast		2,263,652,846		
Test Year	2023	Forecast		2,251,299,520		
Test Year	2024	Forecast		2,242,389,081		

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	31790.1	31,850		
Historical	2014	Actual	32627.5	32,676		
Historical	2015	Actual	33511.9	33,521	Board Approved	
Historical	2016	Actual	33634.8	33,156		
Historical	2017	Actual	32508.0	32,800		
Historical	2018	Actual	33783.0	33,177		
Bridge Year	2019	Forecast		32,300		
Test Year	2020	Forecast		32,109		
Test Year	2021	Forecast		31,735		
Test Year	2022	Forecast		31,499		
Test Year	2023	Forecast		31,269		
Test Year	2024	Forecast		31,088		

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
	2013			2013				2013			
	2014	1.1%		2014	3.8%	3.7%		2014	2.6%	2.6%	
	2015	2.2%		2015	5.0%	4.9%		2015	2.7%	2.6%	
	2016	-0.2%		2016	0.2%	-1.3%		2016	0.4%	-1.1%	
	2017	0.9%		2017	-2.5%	-0.2%		2017	-3.3%	-1.1%	
	2018	0.1%		2018	4.0%	1.2%		2018	3.9%	1.1%	
	2019	0.4%		2019		-2.2%		2019		-2.6%	
	2020	0.2%		2020		-0.4%		2020		-0.6%	
	2021	0.2%		2021		-1.0%		2021		-1.2%	
	2022	0.2%		2022		-0.6%		2022		-0.7%	
	2023	0.2%		2023		-0.5%		2023		-0.7%	
	2024	0.2%	3.6%	2024		-0.4%	8.5%	2024		-3.8%	
	Geometric Mean	0.5%		Geometric Mean	2.6%	0.3%		Geometric Mean	1.5%	-0.2%	

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	2013	Actual	$ 69,733,891		
Historical	2014	Actual	$ 72,600,510		
Historical	2015	Actual	$ 89,474,756	Board-approved	$ 82,174,475
Historical	2016	Actual	$ 92,077,386		
Historical	2017	Actual	$ 98,790,549		
Historical	2018	Actual	$ 105,081,166		
Bridge Year	2019	Forecast	$ 107,580,797		
Test Year	2020	Forecast	$ 111,698,483		
Test Year	2021	Forecast	$ 114,497,852		
Test Year	2022	Forecast	$ 116,905,336		
Test Year	2023	Forecast	$ 121,448,904		
Test Year	2024	Forecast	$ 126,033,676		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	4.1%	
Note 2	2015	23.2%	
	2016	2.9%	
	2017	7.3%	
	2018	6.4%	
	2019	2.4%	
	2020	3.8%	
	2021	2.5%	
	2022	2.1%	
	2023	3.9%	
	2024	3.8%	35.9%
	Geometric Mean	6.1%	

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

4 Customer Class: GS 50-999 kW

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

	Calendar Year (for 2020 Cost of Service		Customers		
Historical	2013	Actual	11,885		
Historical	2014	Actual	11,852		
Historical	2015	Actual	10,364	Board-approved	12,054
Historical	2016	Actual	10,475		
Historical	2017	Actual	10,407		
Historical	2018	Actual	10,515		
Bridge Year	2019	Forecast	10,447		
Test Year	2020	Forecast	10,417		
Test Year	2021	Forecast	10,387		
Test Year	2022	Forecast	10,357		
Test Year	2023	Forecast	10,327		
Test Year	2024	Forecast	10,297		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	9,901,798,273	9,902,973,517		
Actual	10,026,512,948	9,994,682,007		
Actual	9,931,112,876	9,918,272,056	Board-approved	9,848,614,894
Actual	9,975,508,523	9,877,187,647		
Actual	9,622,771,103	9,705,438,682		
Actual	9,921,831,647	9,760,734,208		
Forecast		9,648,026,310		
Forecast		9,608,309,249		
Forecast		9,523,712,332		
Forecast		9,486,718,400		
Forecast		9,453,024,513		
Forecast		9,443,587,171		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	833,134	833,233		
Actual	845,976	843,291		
Actual	958,232	956,993	Board-approved	817,041
Actual	952,316	942,930		
Actual	924,644	932,588		
Actual	943,588	928,268		
Forecast		923,521		
Forecast		922,368		
Forecast		916,888		
Forecast		915,972		
Forecast		915,370		
Forecast		917,120		

Variance Analysis — Note 2

Year	Customers Year-over-year	Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2013								
2014	-0.3%		1.3%	0.9%		1.5%	1.2%	
2015	-12.6%		-1.0%	-0.8%		13.3%	13.5%	
2016	1.1%		0.4%	-0.4%		-0.6%	-1.5%	
2017	-0.6%		-3.5%	-1.7%		-2.9%	-1.1%	
2018	1.0%		3.1%	0.6%		2.0%	-0.5%	
2019	-0.6%			-1.2%			-0.5%	
2020	-0.3%			-0.4%			-0.1%	
2021	-0.3%			-0.9%			-0.6%	
2022	-0.3%			-0.4%			-0.1%	
2023	-0.3%			-0.4%			-0.1%	
2024	-0.3%	-13.6%		-0.1%	-2.4%		0.2%	12.9%
Geometric Mean	-1.4%		0.1%	-0.5%		3.2%	1.0%	

	Calendar Year (for 2020 Cost of Service		Transformer Allowance kVa
Historical	2013	Actual	5,677,788
Historical	2014	Actual	6,043,033
Historical	2015	Actual	6,255,491
Historical	2016	Actual	6,426,851
Historical	2017	Actual	6,355,256
Historical	2018	Actual	6,627,879
Bridge Year	2019	Forecast	6,478,563
Test Year	2020	Forecast	6,373,898
Test Year	2021	Forecast	6,344,371
Test Year	2022	Forecast	6,336,176
Test Year	2023	Forecast	6,329,840
Test Year	2024	Forecast	6,336,814

	Calendar Year (for 2020 Cost of Service		Revenues		
Historical	2013	Actual	$ 148,321,289		
Historical	2014	Actual	$ 148,888,895		
Historical	2015	Actual	$ 170,879,886	Board-approved	$ 180,346,188
Historical	2016	Actual	$ 178,409,499		
Historical	2017	Actual	$ 188,518,928		
Historical	2018	Actual	$ 197,548,326		
Bridge Year	2019	Forecast	$ 209,109,363		
Test Year	2020	Forecast	$ 213,178,385		
Test Year	2021	Forecast	$ 218,651,192		
Test Year	2022	Forecast	$ 223,853,389		
Test Year	2023	Forecast	$ 233,318,593		
Test Year	2024	Forecast	$ 243,640,524		

Demand (kVA)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	25,938,018	25,947,963		
Actual	25,788,227	25,748,810		
Actual	25,388,280	25,388,672	Board-approved	26,395,826
Actual	25,684,305	25,423,741		
Actual	24,835,921	25,046,941		
Actual	25,282,327	24,862,996		
Forecast		25,304,929		
Forecast		24,899,004		
Forecast		24,780,594		
Forecast		24,747,778		
Forecast		24,722,788		
Forecast		24,752,904		

Demand (kVA) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	2182	2183		
Actual	2176	2173		
Actual	2450	2450	Board-approved	2,190
Actual	2452	2427		
Actual	2386	2407		
Actual	2404	2365		
Forecast		2422		
Forecast		2390		
Forecast		2386		
Forecast		2389		
Forecast		2394		
Forecast		2404		

Variance Analysis — Note 2

Year	Revenues Year-over-year	Test Year Versus Board-approved	Demand Year-over-year (Actual)	Demand Year-over-year (Weather-normalized)	Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2013								
2014	0.4%		-0.6%	-0.8%		-0.3%	-0.5%	
2015	14.8%		-1.6%	-1.4%		12.6%	12.8%	
2016	4.4%		1.2%	0.1%		0.1%	-0.9%	
2017	5.7%		-3.3%	-1.5%		-2.7%	-0.8%	
2018	4.8%		1.8%	-0.7%		0.8%	-1.8%	
2019	5.9%			1.8%			2.4%	
2020	1.9%			-1.6%			-1.3%	
2021	2.6%			-0.5%			-0.2%	
2022	2.4%			-0.1%			0.2%	
2023	4.2%			-0.1%			0.2%	
2024	4.4%	18.2%		0.1%	-5.7%		0.4%	9.2%
Geometric Mean	5.1%		-0.6%	-0.5%		2.5%	1.0%	

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

5 Customer Class: GS 1000-4999 kW

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

	Calendar Year (for 2020 Cost of Service	Customers			
Historical	2013	Actual	516		
Historical	2014	Actual	447		
Historical	2015	Actual	432	Board-approved	440
Historical	2016	Actual	443		
Historical	2017	Actual	431		
Historical	2018	Actual	432		
Bridge Year	2019	Forecast	430		
Test Year	2020	Forecast	430		
Test Year	2021	Forecast	430		
Test Year	2022	Forecast	430		
Test Year	2023	Forecast	430		
Test Year	2024	Forecast	430		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	4,933,804,363	4,929,739,251		
Actual	4,882,286,646	4,858,037,398		
Actual	4,807,842,082	4,798,904,169	Board-approved	4,654,535,571
Actual	4,753,125,810	4,729,735,833		
Actual	4,589,196,040	4,617,746,316		
Actual	4,656,922,361	4,604,450,883		
Forecast		4,617,393,040		
Forecast		4,595,015,405		
Forecast		4,547,794,726		
Forecast		4,521,102,881		
Forecast		4,498,196,256		
Forecast		4,485,496,354		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	9,561,636	9,553,758		
Actual	10,922,341	10,868,093		
Actual	11,129,264	11,108,574	Board-approved	10,578,490
Actual	10,729,404	10,676,605		
Actual	10,647,787	10,714,029		
Actual	10,779,913	10,658,451		
Forecast		10,738,123		
Forecast		10,686,082		
Forecast		10,576,267		
Forecast		10,514,193		
Forecast		10,460,922		
Forecast		10,431,387		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
Note 4	2014	-13.4%	
	2015	-3.4%	
	2016	2.5%	
	2017	-2.7%	
	2018	0.2%	
	2019	-0.5%	
	2020	0.0%	
	2021	0.0%	
	2022	0.0%	
	2023	0.0%	
	2024	0.0%	-2.3%
	Geometric Mean	-1.8%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	-1.0%	-1.5%	
2015	-1.5%	-1.2%	
2016	-1.1%	-1.4%	
2017	-3.4%	-2.4%	
2018	1.5%	-0.3%	
2019		0.3%	
2020		-0.5%	
2021		-1.0%	
2022		-0.6%	
2023		-0.5%	
2024		-0.3%	-1.3%
Geometric Mean	-1.4%	-0.9%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	14.2%	13.8%	
2015	1.9%	2.2%	
2016	-3.6%	-3.9%	
2017	-0.8%	0.4%	
2018	1.2%	-0.5%	
2019		0.7%	
2020		-0.5%	
2021		-1.0%	
2022		-0.6%	
2023		-0.5%	
2024		-0.3%	1.0%
Geometric Mean	3.0%	0.9%	

	Calendar Year (for 2020 Cost of Service	Transformer Allowance kVa	
Historical	2013	Actual	8,869,214
Historical	2014	Actual	8,796,124
Historical	2015	Actual	8,758,785
Historical	2016	Actual	8,807,222
Historical	2017	Actual	8,540,919
Historical	2018	Actual	8,681,971
Bridge Year	2019	Forecast	8,688,218
Test Year	2020	Forecast	8,698,598
Test Year	2021	Forecast	8,661,828
Test Year	2022	Forecast	8,653,831
Test Year	2023	Forecast	8,652,323
Test Year	2024	Forecast	8,668,603

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	2013	Actual	$ 49,244,312		
Historical	2014	Actual	$ 47,728,955		
Historical	2015	Actual	$ 55,018,607	Board-approved	$ 55,588,622
Historical	2016	Actual	$ 57,159,426		
Historical	2017	Actual	$ 60,058,849		
Historical	2018	Actual	$ 63,165,673		
Bridge Year	2019	Forecast	$ 66,957,040		
Test Year	2020	Forecast	$ 69,800,867		
Test Year	2021	Forecast	$ 71,752,739		
Test Year	2022	Forecast	$ 73,584,709		
Test Year	2023	Forecast	$ 76,919,599		
Test Year	2024	Forecast	$ 80,532,751		

Demand (kVA)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	11,071,372	11,063,303		
Actual	10,765,500	10,721,411		
Actual	10,620,705	10,608,801	Board-approved	10,671,871
Actual	10,586,541	10,531,012		
Actual	10,215,013	10,277,353		
Actual	10,337,416	10,219,659		
Forecast		10,393,741		
Forecast		10,406,674		
Forecast		10,362,104		
Forecast		10,352,308		
Forecast		10,350,511		
Forecast		10,370,633		

Demand (kVA) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	21,456	21,441		
Actual	24,084	23,985		
Actual	24,585	24,557	Board-approved	24,254
Actual	23,897	23,772		
Actual	23,701	23,845		
Actual	23,929	23,657		
Forecast		24,171		
Forecast		24,202		
Forecast		24,098		
Forecast		24,075		
Forecast		24,071		
Forecast		24,118		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	-3.1%	
Note 2	2015	15.3%	
	2016	3.9%	
	2017	5.1%	
	2018	5.2%	
	2019	6.0%	
	2020	4.2%	
	2021	2.8%	
	2022	2.6%	
	2023	4.5%	
	2024	4.7%	25.6%
	Geometric Mean	5.0%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	-2.8%	-3.1%	
2015	-1.3%	-1.1%	
2016	-0.3%	-0.7%	
2017	-3.5%	-2.4%	
2018	1.2%	-0.6%	
2019		1.7%	
2020		0.1%	
2021		-0.4%	
2022		-0.1%	
2023		0.0%	
2024		0.2%	-2.5%
Geometric Mean	-1.7%	-0.6%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	12.2%	11.9%	
2015	2.1%	2.4%	
2016	-2.8%	-3.2%	
2017	-0.8%	0.3%	
2018	1.0%	-0.8%	
2019		2.2%	
2020		0.1%	
2021		-0.4%	
2022		-0.1%	
2023		0.0%	
2024		0.2%	-0.2%
Geometric Mean	2.8%	1.2%	

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

6 Customer Class: Large Use

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

	Calendar Year (for 2020 Cost of Service	Customers			
Historical	2013	Actual	52		
Historical	2014	Actual	47		
Historical	2015	Actual	44	Board-approved	49
Historical	2016	Actual	42		
Historical	2017	Actual	44		
Historical	2018	Actual	44		
Bridge Year	2019	Forecast	38		
Test Year	2020	Forecast	38		
Test Year	2021	Forecast	38		
Test Year	2022	Forecast	38		
Test Year	2023	Forecast	38		
Test Year	2024	Forecast	38		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	2,317,813,992	2,317,601,280		
Actual	2,202,455,832	2,196,239,262		
Actual	2,156,018,802	2,153,586,276	Board-approved	2,228,386,374
Actual	2,175,392,445	2,160,782,885		
Actual	2,127,297,946	2,140,373,619		
Actual	2,034,120,651	2,008,921,808		
Forecast		1,973,960,059		
Forecast		1,889,478,427		
Forecast		1,796,298,178		
Forecast		1,767,816,828		
Forecast		1,740,689,851		
Forecast		1,720,190,903		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	44,573,346	44,569,255		
Actual	46,860,762	46,728,495		
Actual	49,000,427	48,945,143	Board-approved	45,477,273
Actual	51,795,058	51,447,212		
Actual	48,347,681	48,644,855		
Actual	46,230,015	45,657,314		
Forecast		51,946,317		
Forecast		49,723,117		
Forecast		47,271,005		
Forecast		46,521,495		
Forecast		45,807,628		
Forecast		45,268,182		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	-9.6%	
	2015	-6.4%	
	2016	-4.5%	
	2017	4.8%	
	2018	0.0%	
	2019	-13.6%	
	2020	0.0%	
	2021	0.0%	
	2022	0.0%	
	2023	0.0%	
	2024	0.0%	-22.4%
	Geometric Mean	-3.1%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	-5.0%	-5.2%	
2015	-2.1%	-1.9%	
2016	0.9%	0.3%	
2017	-2.2%	-0.9%	
2018	-4.4%	-6.1%	
2019		-1.7%	
2020		-4.3%	
2021		-4.9%	
2022		-1.6%	
2023		-1.5%	
2024		-1.2%	-15.2%
Geometric Mean	-3.2%	-2.9%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	5.1%	4.8%	
2015	4.6%	4.7%	
2016	5.7%	5.1%	
2017	-6.7%	-5.4%	
2018	-4.4%	-6.1%	
2019		13.8%	
2020		-4.3%	
2021		-4.9%	
2022		-1.6%	
2023		-1.5%	
2024		-1.2%	9.3%
Geometric Mean	0.9%	0.2%	

	Calendar Year (for 2020 Cost of Service	Transformer Allowance kVa	
Historical	2013	Actual	5,297,783
Historical	2014	Actual	5,037,228
Historical	2015	Actual	4,961,605
Historical	2016	Actual	5,040,441
Historical	2017	Actual	4,944,707
Historical	2018	Actual	4,814,758
Bridge Year	2019	Forecast	4,544,019
Test Year	2020	Forecast	4,507,133
Test Year	2021	Forecast	4,438,539
Test Year	2022	Forecast	4,400,675
Test Year	2023	Forecast	4,365,743
Test Year	2024	Forecast	4,345,829

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	2013	Actual	$ 28,480,997		
Historical	2014	Actual	$ 27,002,470		
Historical	2015	Actual	$ 30,728,825	Board-approved	$ 29,054,341
Historical	2016	Actual	$ 32,178,414		
Historical	2017	Actual	$ 34,275,778		
Historical	2018	Actual	$ 34,250,928		
Bridge Year	2019	Forecast	$ 34,072,361		
Test Year	2020	Forecast	$ 35,147,422		
Test Year	2021	Forecast	$ 35,673,516		
Test Year	2022	Forecast	$ 36,257,882		
Test Year	2023	Forecast	$ 37,515,423		
Test Year	2024	Forecast	$ 38,932,355		

Demand (kVA)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	5,493,794	5,493,928		
Actual	5,177,346	5,166,660		
Actual	5,090,547	5,088,775	Board-approved	5,305,030
Actual	5,170,992	5,134,655		
Actual	5,065,201	5,095,503		
Actual	4,873,591	4,812,584		
Forecast		4,637,881		
Forecast		4,600,360		
Forecast		4,530,224		
Forecast		4,491,580		
Forecast		4,455,940		
Forecast		4,435,652		

Demand (kVA) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	105,650	105,652		
Actual	110,156	109,929		
Actual	115,694	115,654	Board-approved	108,266
Actual	123,119	122,254		
Actual	115,118	115,807		
Actual	110,763	109,377		
Forecast		122,050		
Forecast		121,062		
Forecast		119,216		
Forecast		118,199		
Forecast		117,262		
Forecast		116,728		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	-5.2%	
Note 2	2015	13.8%	
	2016	4.7%	
	2017	6.5%	
	2018	-0.1%	
	2019	-0.5%	
	2020	3.2%	
	2021	1.5%	
	2022	1.6%	
	2023	3.5%	
	2024	3.8%	21.0%
	Geometric Mean	3.2%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	-5.8%	-6.0%	
2015	-1.7%	-1.5%	
2016	1.6%	0.9%	
2017	-2.0%	-0.8%	
2018	-3.8%	-5.6%	
2019		-3.6%	
2020		-0.8%	
2021		-1.5%	
2022		-0.9%	
2023		-0.8%	
2024		-0.5%	-13.3%
Geometric Mean	-3.0%	-2.1%	

Year	Year-over-year		Test Year Versus Board-approved
2013			
2014	4.3%	4.0%	
2015	5.0%	5.2%	
2016	6.4%	5.7%	
2017	-6.5%	-5.3%	
2018	-3.8%	-5.6%	
2019		11.6%	
2020		-0.8%	
2021		-1.5%	
2022		-0.9%	
2023		-0.8%	
2024		-0.5%	11.8%
Geometric Mean	1.2%	1.0%	

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

7 Customer Class: Street Lighting

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

	Calendar Year (for 2020 Cost of Service	Connections			
Historical	2013	Actual	163,426		
Historical	2014	Actual	163,810		
Historical	2015	Actual	164,008	Board-approved	164,098
Historical	2016	Actual	164,296		
Historical	2017	Actual	164,537		
Historical	2018	Actual	164,662		
Bridge Year	2019	Forecast	164,828		
Test Year	2020	Forecast	165,274		
Test Year	2021	Forecast	165,535		
Test Year	2022	Forecast	165,796		
Test Year	2023	Forecast	166,057		
Test Year	2024	Forecast	166,318		

Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
2013	Actual	114,205,296	114,205,296		
2014	Actual	114,087,684	114,087,684		
2015	Actual	114,178,674	114,178,674	Board-approved	114,092,929
2016	Actual	114,988,504	114,988,504		
2017	Actual	115,072,181	115,072,181		
2018	Actual	115,403,897	115,403,897		
2019	Forecast		115,582,493		
2020	Forecast		116,219,746		
2021	Forecast		116,021,507		
2022	Forecast		116,204,400		
2023	Forecast		116,387,293		
2024	Forecast		116,953,726		

Calendar Year	Consumption (kWh) per Connection	Actual (Weather actual)	Weather-normalized		Weather-normalized
2013	Actual	699	699		
2014	Actual	696	696		
2015	Actual	696	696	Board-approved	695
2016	Actual	700	700		
2017	Actual	699	699		
2018	Actual	701	701		
2019	Forecast		701		
2020	Forecast		703		
2021	Forecast		701		
2022	Forecast		701		
2023	Forecast		701		
2024	Forecast		703		

Variance Analysis

Year	Connections Year-over-year	Connections Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Connection Year-over-year (Actual)	Per Connection Year-over-year (Weather-normalized)	Per Connection Test Year Versus Board-approved
2013								
2014	0.2%		-0.1%	-0.1%		-0.3%	-0.3%	
2015	0.1%		0.1%	0.1%		0.0%	0.0%	
2016	0.2%		0.7%	0.7%		0.5%	0.5%	
2017	0.1%		0.1%	0.1%		-0.1%	-0.1%	
2018	0.1%		0.3%	0.3%		0.2%	0.2%	
2019	0.1%			0.2%			0.1%	
2020	0.3%			0.6%			0.3%	
2021	0.2%			-0.2%			-0.3%	
2022	0.2%			0.2%			0.0%	
2023	0.2%			0.2%			0.0%	
2024	0.2%	0.7%		0.5%	1.9%		0.3%	1.1%
Geometric Mean	0.2%		0.3%	0.2%		0.1%	0.1%	

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	2013	Actual	$ 12,108,215		
Historical	2014	Actual	$ 12,259,078		
Historical	2015	Actual	$ 12,269,663	Board-approved	$ 12,281,306
Historical	2016	Actual	$ 12,793,477		
Historical	2017	Actual	$ 13,706,308		
Historical	2018	Actual	$ 14,465,487		
Bridge Year	2019	Forecast	$ 15,047,142		
Test Year	2020	Forecast	$ 15,606,851		
Test Year	2021	Forecast	$ 16,087,184		
Test Year	2022	Forecast	$ 16,503,368		
Test Year	2023	Forecast	$ 17,220,081		
Test Year	2024	Forecast	$ 17,969,471		

Calendar Year	Demand (kVA)	Actual (Weather actual)	Weather-normalized		Weather-normalized
2013	Actual	323,205	323,205		
2014	Actual	323,887	323,887		
2015	Actual	324,136	324,136	Board-approved	324,479
2016	Actual	324,629	324,629		
2017	Actual	325,116	325,116		
2018	Actual	325,497	325,497		
2019	Forecast		325,821		
2020	Forecast		326,300		
2021	Forecast		326,776		
2022	Forecast		327,256		
2023	Forecast		327,732		
2024	Forecast		328,212		

Calendar Year	Demand (kVA) per Connection	Actual (Weather actual)	Weather-normalized		Weather-normalized
2013	Actual	2.0	2.0		
2014	Actual	2.0	2.0		
2015	Actual	2.0	2.0	Board-approved	2.0
2016	Actual	2.0	2.0		
2017	Actual	2.0	2.0		
2018	Actual	2.0	2.0		
2019	Forecast		2.0		
2020	Forecast		2.0		
2021	Forecast		2.0		
2022	Forecast		2.0		
2023	Forecast		2.0		
2024	Forecast		2.0		

Variance Analysis

Year	Revenues Year-over-year	Revenues Test Year Versus Board-approved	Demand Year-over-year (Actual)	Demand Year-over-year (Weather-normalized)	Demand Test Year Versus Board-approved	Per Connection Year-over-year (Actual)	Per Connection Year-over-year (Weather-normalized)	Per Connection Test Year Versus Board-approved
2013								
2014	1.2%		0.2%	0.2%		0.0%	0.0%	
2015	0.1%		0.1%	0.1%		0.0%	0.0%	
2016	4.3%		0.2%	0.2%		0.0%	0.0%	
2017	7.1%		0.1%	0.1%		0.0%	0.0%	
2018	5.5%		0.1%	0.1%		0.0%	0.0%	
2019	4.0%			0.1%			0.0%	
2020	3.7%			0.1%			-0.1%	
2021	3.1%			0.1%			0.0%	
2022	2.6%			0.1%			0.0%	
2023	4.3%			0.1%			0.0%	
2024	4.4%	27.1%		0.1%	0.6%		0.0%	-0.2%
Geometric Mean	4.0%		0.2%	0.2%		0.0%	0.0%	

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

8 Customer Class: Unmetered Scattered Load

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

	Calendar Year (for 2020 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	2013	Actual	873			Actual	41,087,638	41,087,638			Actual	47,065	47,065		
Historical	2014	Actual	888			Actual	40,948,317	40,948,317			Actual	46,113	46,113		
Historical	2015	Actual	866	Board-approved	898	Actual	41,098,509	41,098,509	Board-approved	41,132,354	Actual	47,458	47,458	Board-approved	45,804
Historical	2016	Actual	866			Actual	41,380,666	41,380,666			Actual	47,784	47,784		
Historical	2017	Actual	860			Actual	41,404,515	41,404,515			Actual	48,145	48,145		
Historical	2018	Actual	837			Actual	40,477,714	40,477,714			Actual	48,360	48,360		
Bridge Year	2019	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2020	Forecast	825			Forecast		40,588,612			Forecast		49,198		
Test Year	2021	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2022	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2023	Forecast	825			Forecast		40,477,714			Forecast		49,064		
Test Year	2024	Forecast	825			Forecast		40,588,612			Forecast		49,198		

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
	2013			2013				2013			
	2014	1.7%		2014	-0.3%	-0.3%		2014	-2.0%	-2.0%	
	2015	-2.5%		2015	0.4%	0.4%		2015	2.9%	2.9%	
	2016	0.0%		2016	0.7%	0.7%		2016	0.7%	0.7%	
	2017	-0.7%		2017	0.1%	0.1%		2017	0.8%	0.8%	
	2018	-2.7%		2018	-2.2%	-2.2%		2018	0.4%	0.4%	
	2019	-1.4%		2019		0.0%		2019		1.5%	
	2020	0.0%		2020		0.3%		2020		0.3%	
	2021	0.0%		2021		-0.3%		2021		-0.3%	
	2022	0.0%		2022		0.0%		2022		0.0%	
	2023	0.0%		2023		0.0%		2023		0.0%	
	2024	0.0%	-8.1%	2024		0.3%	-1.3%	2024		0.3%	7.4%
	Geometric Mean	-0.6%		Geometric Mean	-0.4%	-0.1%		Geometric Mean	0.7%	0.4%	

	Calendar Year (for 2020 Cost of Service	Connections				Consumption (kWh) per Connection	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2013	Actual	11,784			Actual	3,487	3,487		
Historical	2014	Actual	11,754			Actual	3,484	3,484		
Historical	2015	Actual	11,942	Board-approved	11,720	Actual	3,442	3,442	Board-approved	3,510
Historical	2016	Actual	12,056			Actual	3,432	3,432		
Historical	2017	Actual	12,196			Actual	3,395	3,395		
Historical	2018	Actual	12,245			Actual	3,306	3,306		
Bridge Year	2019	Forecast	12,180			Forecast		3,323		
Test Year	2020	Forecast	12,180			Forecast		3,332		
Test Year	2021	Forecast	12,180			Forecast		3,323		
Test Year	2022	Forecast	12,180			Forecast		3,323		
Test Year	2023	Forecast	12,180			Forecast		3,323		
Test Year	2024	Forecast	12,180			Forecast		3,332		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2013			2013			
	2014	-0.3%		2014	-0.1%	-0.1%	
	2015	1.6%		2015	-1.2%	-1.2%	
	2016	1.0%		2016	-0.3%	-0.3%	
	2017	1.2%		2017	-1.1%	-1.1%	
	2018	0.4%		2018	-2.6%	-2.6%	
	2019	-0.5%		2019		0.5%	
	2020	0.0%		2020		0.3%	
	2021	0.0%		2021		-0.3%	
	2022	0.0%		2022		0.0%	
	2023	0.0%		2023		0.0%	
	2024	0.0%	3.9%	2024		0.3%	-5.0%
	Geometric Mean	0.3%		0	-1.8%	-0.5%	

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

	Calendar Year (for 2020 Cost of Service		Revenues			
Historical	2013	Actual	$ 2,616,211		
Historical	2014	Actual	$ 2,661,624		
Historical	2015	Actual	$ 3,170,482	Board-approved	$ 3,173,355
Historical	2016	Actual	$ 3,314,179		
Historical	2017	Actual	$ 3,557,840		
Historical	2018	Actual	$ 3,669,773		
Bridge Year	2019	Forecast	$ 3,812,584		
Test Year	2020	Forecast	$ 3,440,724		
Test Year	2021	Forecast	$ 3,543,122		
Test Year	2022	Actual	$ 3,630,671		
Test Year	2023	Forecast	$ 3,784,557		
Test Year	2024	Forecast	$ 3,943,950		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2013		
	2014	1.7%	
Note 2	2015	19.1%	
	2016	4.5%	
	2017	7.4%	
	2018	3.1%	
	2019	3.9%	
	2020	-9.8%	
	2021	3.0%	
	2022	2.5%	
	2023	4.2%	
	2024	4.2%	8.4%
	Geometric Mean	4.2%	

Notes:

1 2015 Revenues are calculated on the rates that would have been applied if test year rate implementation was January 1, 2015.
2 Variances due to 2015 test year rate increases
3 CSMUR variances driven mainly strong rate of growth in number of customer and resulting electricity sales to the class.
4 Variance driven mainly by customer rate-class reclassification

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit U
Tab 3
Schedule 1
Appendix B
FILED: April 30, 2019
(2 pages)

CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	CDM-000409

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (including N	Agriculture	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	SAVE ON ENERGY AUDIT FUNDING PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$87,099	78	$589,927	806	$490,689	3,089	$843,810	10,627	$807,212	10,000	$515,146	5,000	$3,333,884	29,599
	SAVE ON ENERGY BUSINESS REFRIGERATION INCENTIVE PROGRAM			01-Sep-2016			Yes	Yes		Yes		$0	0	$0	0	$974,845	3,471	$2,002,425	8,695	$1,333,283	4,986	$1,325,886	4,945	$5,636,438	18,846
	SAVE ON ENERGY COUPON PROGRAM			01-Jul-2015	Yes	Yes						$2,198,646	15,586	$6,325,639	75,466	$28,833,518	154,796	$11,246,773	57,485	$2,319,530	10,000	$1,211,169	4,104	$52,135,275	317,309
	SAVE ON ENERGY ENERGY MANAGER PROGRAM			01-Jul-2015						Yes	Yes	$11,681	0	$710,398	10,277	$4,916,985	8,704	$2,366,450	3,941	$2,409,850	4,022	$2,164,050	3,561	$12,579,414	30,159
	SAVE ON ENERGY ENERGY PERFORMANCE PROGRAM			01-Jan-2015				Yes		Yes	Yes	$0	0	$0	0	$20,000	0	$194,000	0	$194,000	0	$194,000	0	$602,000	0
	SAVE ON ENERGY EXISTING BUILDING COMMISSIONING PROGRAM			01-Feb-2016				Yes		Yes	Yes	$0	0	$539,587	0	$705,212	1,199	$239,661	382	$106,086	0	$109,269	0	$1,699,815	1,581
	SAVE ON ENERGY HEATING & COOLING PROGRAM			01-Jul-2015	Yes	Yes						$2,535,506	4,022	$4,444,112	9,237	$3,527,141	3,349	$3,901,906	4,067	$2,720,318	3,000	$2,043,949	2,163	$19,172,932	25,838
	SAVE ON ENERGY HIGH PERFORMANCE NEW CONSTRUCTION PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$104,736	77	$1,604,652	3,677	$3,735,641	6,259	$2,029,841	3,111	$2,436,056	4,000	$1,962,732	2,964	$11,873,658	20,088
	SAVE ON ENERGY HOME ASSISTANCE PROGRAM			01-Sep-2015		Yes						$1,947	283	$1,119,803	1,171	$3,229,399	1,952	$196,222	302	$3,249,977	5,000	$3,314,981	5,100	$11,112,329	13,784
	SAVE ON ENERGY MONITORING & TARGETING PROGRAM			01-May-2016						Yes	Yes	$0	0	$0	0	$20,000	0	$20,000	1	$20,000	1	$20,000	1	$80,000	1
	SAVE ON ENERGY NEW CONSTRUCTION PROGRAM			01-Jul-2015	Yes							$400	39	$54,294	238	$442,175	1,007	$441,084	491	$443,689	500	$529,859	787	$1,911,501	3,063
	SAVE ON ENERGY PROCESS & SYSTEMS UPGRADES PROGRAM			01-Jul-2015				Yes		Yes	Yes	$27,425	0	$426,596	339	$5,197,067	31,448	$4,571,778	18,090	$5,136,078	21,060	$30,748,416	155,790	$46,107,360	226,727
	SAVE ON ENERGY RETROFIT PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$3,285,077	32,024	$26,503,158	160,024	$34,141,413	197,868	$31,465,524	182,017	$31,217,416	180,000	$30,579,363	175,000	$157,191,951	926,762
	SAVE ON ENERGY SMALL BUSINESS LIGHTING PROGRAM			01-Jul-2015			Yes					$0	0	$166,782	56	$1,519,280	3,991	$2,465,191	8,305	$1,910,606	6,000	$1,447,998	4,077	$7,509,857	22,420
	SAVE ON ENERGY SMART THERMOSTAT PROGRAM			01-Jan-2015	Yes	Yes						$0	0	$0	0	$0	0	$441,789	741	$0	0	$0	0	$441,789	741
		ADAPTIVE THERMOSTAT LOCAL PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$26,672	0	$501,323	1,054	$380,388	755	$379,099	750	$384,984	750	$1,672,465	3,308
		DATA CENTRE PILOT		14-Jul-2016								$0	0	$0	0	$0	0	$0	0	$0	0	$0	0	$0	0
		DIRECT INSTALL - HYDRONIC PILOT		01-Jul-2015								$0	668	$0	0	$0	0	$0	0	$0	0	$0	0	$0	668
		DIRECT INSTALL - RTU CONTROLS PILOT		01-Jul-2015		Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	372	$0	0	$0	0	$0	0	$0	0	$0	372
		ELECTRONICS TAKEBACK PILOT PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	1,145	$0	0	$0	0	$0	0	$0	0	$0	1,145
		HOME DEPOT HOME APPLIANCE MARKET UPLIFT CONSERVATION FUND PILOT PROGRAM		01-Jan-2015	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	10	$0	0	$0	0	$0	0	$0	0	$0	10
		MURB In-Suite Direct Install Lighting Program		01-Jan-2015								$0	0	$0	0	$0	0	$1,142,587	430	$2,711,299	6,000	$2,722,220	6,000	$6,576,106	12,430
		OPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$0	0	$159,764	0	$502,285	1,459	$662,347	8,000	$633,130	13,422	$1,957,525	13,422
		PUMPSAVER 2.0		01-Sep-2016								$0	0	$0	0	$0	0	$1,846,013	6,762	$1,273,427	4,000	$871,519	2,000	$3,990,959	12,762
		PUMPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$100,075	834	$3,254,578	13,914	$0	0	$0	0	$0	0	$3,354,653	14,748
		RTUSAVER		01-Jan-2017		Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$16,272	0	$2,068,149	3,297	$1,903,332	3,000	$1,903,332	3,000	$5,891,085	9,297
		SOCIAL BENCHMARKING LOCAL PROGRAM		01-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$4,078,842	14,211	$2,586,817	14,211	$2,586,817	14,211	$2,586,817	14,211	$11,839,293	14,211
		SWIMMING POOL EFFICIENCY LOCAL PROGRAM		01-Apr-2017	Yes							$0	0	$0	0	$376,548	1,029	$419,626	778	$411,598	750	$411,598	750	$1,619,370	3,307
		TRUCKLOAD EVENT PILOT PROGRAM		01-Sep-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	3,305	$0	0	$0	0	$0	0	$0	0	$0	3,305
		WHOLE HOME PILOT		30-Jan-2017	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$50,000	0	$51,600	0	$51,600	0	$51,600	0	$204,800	0
												$0	0	$0	0	$0	0	$0	0	$0	0	$0	0	$0	0
																								$0	
																								$0	
FCR TOTAL												8,252,517	52,777	42,611,695	266,957	96,190,691	447,339	71,423,919	325,947	64,283,619	285,280	85,732,016	403,627	368,494,456	1,725,903
Pay for Performance Programs																								$0	
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0

CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	CDM-000409

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (including N	Agriculture	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) ***(Not funded through 2015-2020 CDM Framework)***	LEGACY - BI-ANNUAL RETAILER EVENT INITIATIVE												6,775												**6,609**
	LEGACY - DIRECT INSTALL LIGHTING AND WATER HEATING INITIATIVE												9,596												**6,445**
	LEGACY - EFFICIENCY: EQUIPMENT REPLACEMENT INCENTIVE INITIATIVE												160,780												**159,686**
	LEGACY - ENERGY AUDIT INITIATIVE												7,008												**7,008**
	LEGACY - ENERGY MANAGER PROGRAM												8,403												**5,013**
	LEGACY - EXISTING BUILDING COMMISSIONING INCENTIVE INITIATIVE												522												**243**
	LEGACY - HVAC INCENTIVES INITIATIVE												3,399												**3,399**
	LEGACY - LOW INCOME INITIATIVE												1,740												**1,248**
	LEGACY - NEW CONSTRUCTION AND MAJOR RENOVATION INITIATIVE												25,577												**25,566**
	LEGACY - P4P FOR CLASS B OFFICE PILOT PROGRAM												2,469												**2,469**
	LEGACY - PROCESS AND SYSTEMS UPGRADES INITIATIVES - PROJECT INCENTIVE INITIATIVE												5,327												**5,327**
	LEGACY - PROGRAM ENABLED SAVINGS												311												**311**
2011-2014 CDM Framework (and 2015 extension) TOTAL												**$0**	**231,907.9**											**0.0**	**223,324**
TARGET GAP TOTAL																								**$0**	
CDM PLAN TOTAL												**$8,252,517**	**284,684.5**	**$42,611,695**	**266,956.8**	**$96,190,691**	**447,339.1**	**$71,423,919**	**325,946.8**	**$64,283,619**	**285,280.3**	**$85,732,016**	**403,626.7**	**$368,494,456**	**1,949,227**
MINIMUM ANNUAL SAVINGS CHECK													**True**		**True**		**True**		**True**		**True**		**True**		

Option
Yes
No

Program Types
Regional
Local
Provincial

2011-2014 Province Wide Programs
Aboriginal Program
Audit Funding
Bi-Annual Retailer Event
Conservation Instant Coupon Booklet
Direct Install Lighting
Energy Manager (PSUI)
Existing Building Commissioning
Heating and Cooling Initiative
High Performance New Construction
Low Income Home Assistance Program
Monitoring and Targeting (PSUI)
Other
peaksaverPLUS
Process and Systems Upgrades Program
Program Enabled Savings
Residential New Construction
Retrofit Initiative

2015-2020 CDM Programs
Audit Funding Program
Energy Manager Program
Existing Building Commissioning
High Performance New Construction
Home Assistance Program
Process and Systems Upgrades Program
Monitoring and Targeting Program
Coupon Program
New Construction Program
Heating and Cooling Program
Retrofit
Small Business Lighting
Whole Home Pilot Program

UPDATE TO 3-VECC-25

Table 1: Verified Gross CDM Savings per IESO/OPA Reports

Program Year	Verified Gross CDM Savings per IESO/OPA Reports (MWh)																			
	Calendar Year																			
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
2006	56,010	56,010	56,010	56,010	9,964	9,964	9,138	9,138	8,604	8,604	8,145	8,145	8,145	8,145	7,400	6,206	6,206	6,206	3,341	341,389
2007	-	325,918	237,877	226,833	226,833	226,824	40,551	40,551	40,551	18,405	15,514	12,062	12,062	12,062	12,062	5,774	1,403	1,256	1,256	1,457,795
2008	-	-	198,427	196,101	195,318	195,318	189,358	182,963	161,114	132,580	118,377	89,579	87,072	87,072	85,420	85,153	85,032	82,365	16,808	2,188,058
2009	-	-	-	207,499	183,543	183,543	183,487	182,023	177,457	170,241	157,083	106,015	74,958	58,123	36,220	26,986	26,976	26,616	23,866	1,824,635
2010	-	-	-	-	412,648	376,505	376,497	376,461	374,876	319,471	253,239	236,281	209,686	99,652	24,345	24,345	24,176	24,160	24,160	3,156,503
2011	-	-	-	-	-	290,029	289,158	287,288	280,372	278,421	274,558	263,083	262,934	243,971	238,509	208,193	207,404	206,173	35,115	3,365,210
2012	-	-	-	-	-	-	148,470	146,814	144,960	139,327	134,919	123,593	117,465	117,404	114,059	77,560	67,968	62,334	49,951	1,444,823
2013	-	-	-	-	-	-	-	185,316	182,084	175,009	169,472	155,245	147,549	147,471	143,269	138,920	120,027	93,232	88,365	1,745,959
2014	-	-	-	-	-	-	-	-	301,636	289,914	280,742	257,174	244,424	244,296	237,336	237,336	231,486	198,351	161,708	2,684,402
2015	-	-	-	-	-	-	-	-	-	404,267	389,832	385,053	384,740	384,278	383,152	375,930	375,834	372,162	291,543	3,746,792
2016	-	-	-	-	-	-	-	-	-	-	390,281	390,281	390,281	390,281	286,325	283,121	283,121	283,121	269,273	2,966,084
	56,010	381,928	492,314	686,443	1,028,306	1,282,183	1,236,660	1,410,555	1,671,655	1,936,239	2,192,161	2,026,510	1,939,315	1,792,756	1,568,098	1,469,524	1,429,631	1,355,975	965,386	24,921,649

Table 2: Cumulative Annual Gross CDM Savings (MWh)

Year	CUMULATIVE ANNUAL GROSS CDM SAVINGS (MWh)						
	Residential	CSMUR	GS<50 kW	GS50 -999 kW	GS1,000 – 4,999 kW	LU	Total
2006	23,311	-	-	-	-	-	23,311
2007	103,758	-	15,342	16,418	15,360	15,176	166,054
2008	235,152	-	68,853	72,194	70,403	69,562	516,164
2009	278,982	82	99,383	103,820	108,691	118,935	709,892
2010	337,794	339	172,007	177,242	187,203	205,179	1,079,763
2011	374,635	599	222,968	240,000	225,696	221,152	1,285,051
2012	412,941	913	279,602	329,834	262,093	250,368	1,535,750
2013	431,024	967	324,436	407,657	280,159	261,249	1,705,493
2014	457,816	1,225	369,622	502,026	324,608	283,352	1,938,649
2015	497,648	1,931	412,922	653,204	425,570	353,433	2,344,707
2016	555,301	4,081	435,450	811,045	525,668	420,890	2,752,435

Table 3: Reconciliation of CDM Verified Results and Cumulative CDM Savings Used in Load Forecast

Year	CDM Verified Results	Persistence Variance	Realization Rates Variance	Line Loss Variance	CDM in Load Forecast Appendix A-1
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2006	56,009.98	-	-33,366.83	667.97	23,311.13
2007	381,927.82	-	-220,454.10	4,579.96	166,053.68
2008	492,314.24	88,040.36	-78,163.74	13,973.49	516,164.35
2009	686,443.43	101,199.36	-96,695.23	18,944.79	709,892.35
2010	1,028,306.14	151,343.44	-128,416.61	28,530.35	1,079,763.33
2011	1,282,182.89	151,350.22	-182,706.82	34,225.20	1,285,051.49
2012	1,236,660.45	344,676.81	-86,652.76	41,065.74	1,535,750.24
2013	1,410,554.91	355,617.64	-106,481.63	45,801.85	1,705,492.77
2014	1,671,655.17	395,250.49	-180,480.16	52,223.25	1,938,648.76
2015	1,936,238.54	534,933.22	-189,500.30	63,035.59	2,344,707.05
2016	2,192,161.23	669,291.64	-182,944.27	73,926.59	2,752,435.20

Update to IR 3-VECC-26

Table 1: Residential Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	149,145	149,145	149,145	149,145	149,145	149,145	149,145	149,145
2018		52,794	52,794	52,794	52,794	52,794	52,794	52,794
2019			17,323	17,323	17,323	17,323	17,323	17,323
2020				12,049	12,049	12,049	12,049	12,049
2021					12,049	12,049	12,049	12,049
2022						12,049	12,049	12,049
2023							12,049	12,049
2024								12,049
Total	149,145	201,939	219,262	231,311	243,359	255,408	267,457	279,506

Table 2: CSMUR Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	6,410	6,410	6,410	6,410	6,410	6,410	6,410	6,410
2018		2,488	2,488	2,488	2,488	2,488	2,488	2,488
2019			1,914	1,914	1,914	1,914	1,914	1,914
2020				1,670	1,670	1,670	1,670	1,670
2021					1,670	1,670	1,670	1,670
2022						1,670	1,670	1,670
2023							1,670	1,670
2024								1,670
Total	6,410	8,898	10,812	12,482	14,152	15,821	17,491	19,161

Table 3: GS <50 kW Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	17,945	17,945	17,945	17,945	17,945	17,945	17,945	17,945
2018		38,252	38,252	38,252	38,252	38,252	38,252	38,252
2019			27,966	27,966	27,966	27,966	27,966	27,966
2020				25,679	25,679	25,679	25,679	25,679
2021					25,165	25,165	25,165	25,165
2022						25,165	25,165	25,165
2023							25,165	25,165
2024								25,165
Total	17,945	56,196	84,162	109,841	135,006	160,170	185,335	210,500

Table 4: GS 50 -999 kW Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	146,150	146,150	146,150	146,150	146,150	146,150	146,150	146,150
2018		156,457	156,457	156,457	156,457	156,457	156,457	156,457
2019			160,578	160,578	160,578	160,578	160,578	160,578
2020				161,578	161,578	161,578	161,578	161,578
2021					131,156	131,156	131,156	131,156
2022						131,156	131,156	131,156
2023							131,156	131,156
2024								131,156
Total	146,150	302,606	463,184	624,762	755,918	887,073	1,018,229	1,149,385

Update to IR 3-VECC-26

Table 5: GS 1,000 – 4,999 kW Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	39,247	39,247	39,247	39,247	39,247	39,247	39,247	39,247
2018		61,159	61,159	61,159	61,159	61,159	61,159	61,159
2019			61,404	73,831	73,831	73,831	73,831	73,831
2020				67,888	67,888	67,888	67,888	67,888
2021					56,235	56,235	56,235	56,235
2022						56,235	56,235	56,235
2023							56,235	56,235
2024								56,235
Total	39,247	100,405	161,810	242,125	298,359	354,594	410,829	467,064

Table 6: Large Use Gross Annualized CDM Savings (MWh)

Program Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	23,554	23,554	23,554	23,554	23,554	23,554	23,554	23,554
2018		32,633	32,633	32,633	32,633	32,633	32,633	32,633
2019			38,606	38,606	38,606	38,606	38,606	38,606
2020				168,390	168,390	168,390	168,390	168,390
2021					44,425	44,425	44,425	44,425
2022						44,425	44,425	44,425
2023							44,425	44,425
2024								44,425
Total	23,554	56,187	94,794	263,184	307,608	352,033	396,458	440,883

Table 7: Total Gross Annualized CDM Savings (MWh)

Prog.Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2017	382,450	382,450	382,450	382,450	382,450	382,450	382,450	382,450
2018	-	343,782	343,782	343,782	343,782	343,782	343,782	343,782
2019	-	-	307,791	320,218	320,218	320,218	320,218	320,218
2020	-	-	-	437,253	437,253	437,253	437,253	437,253
2021	-	-	-	-	270,699	270,699	270,699	270,699
2022	-	-	-	-	-	270,699	270,699	270,699
2023	-	-	-	-	-	-	270,699	270,699
2024	-	-	-	-	-	-	-	270,699
Total	382,450	726,232	1,034,023	1,483,703	1,754,402	2,025,101	2,295,800	2,566,498

Table 8: Cumulative Gross CDM Savings (MWh)

Year	CUMULATIVE GROSS CDM SAVINGS (MWh)						
	Residential	CSMUR	GS<50 kW	GS50 -999 kW	GS1,000 – 4,999 kW	LU	Total
2017	674,883,556	9,187,997	452,975,585	961,316,571	594,400,720	456,748,516	**3,149,512,945**
2018	775,731,922	13,641,844	482,555,931	1,117,414,607	646,789,310	485,614,048	**3,521,747,663**
2019	810,683,363	15,889,275	516,310,319	1,280,740,887	709,886,468	522,036,360	**3,855,546,672**
2020	825,632,666	17,726,295	543,850,402	1,446,602,804	776,648,270	631,440,077	**4,241,900,514**
2021	838,036,838	19,445,512	570,005,687	1,596,308,583	840,165,544	735,737,120	**4,599,699,283**
2022	850,441,009	21,164,728	595,912,691	1,731,333,441	898,059,207	780,926,170	**4,877,837,246**
2023	862,845,180	22,883,944	621,819,695	1,866,358,299	955,952,870	826,115,220	**5,155,975,208**
2024	875,249,351	24,603,160	647,726,699	2,001,383,157	1,013,846,533	871,304,269	**5,434,113,170**

Update to IR 3-VECC-26

Table 9: Residential – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	593,370	593,370	593,370	593,370	593,370	593,370	593,370	593,370
2017	81,579	153,560	153,560	153,560	153,560	153,560	153,560	153,560
2018		28,877	54,357	54,357	54,357	54,357	54,357	54,357
2019			9,475	17,836	17,836	17,836	17,836	17,836
2020				6,590	12,405	12,405	12,405	12,405
2021					6,590	12,405	12,405	12,405
2022						6,590	12,405	12,405
2023							6,590	12,405
2024								6,590
Total	674,949	775,807	810,762	825,713	838,118	850,524	862,929	875,334

Table 10: CSMUR – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006 - 2016	5,683	5,683	5,683	5,683	5,683	5,683	5,683	5,683
2017	3,506	6,599	6,599	6,599	6,599	6,599	6,599	6,599
2018		1,361	2,561	2,561	2,561	2,561	2,561	2,561
2019			1,047	1,971	1,971	1,971	1,971	1,971
2020				913	1,719	1,719	1,719	1,719
2021					913	1,719	1,719	1,719
2022						913	1,719	1,719
2023							913	1,719
2024								913
Total	9,189	13,643	15,891	17,728	19,447	21,167	22,886	24,606

Table 11: GS < 50kW – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006 - 2016	443,204	443,204	443,204	443,204	443,204	443,204	443,204	443,204
2017	9,815	18,476	18,476	18,476	18,476	18,476	18,476	18,476
2018		20,923	39,384	39,384	39,384	39,384	39,384	39,384
2019			15,297	28,793	28,793	28,793	28,793	28,793
2020				14,046	26,439	26,439	26,439	26,439
2021					14,046	26,439	26,439	26,439
2022						14,046	26,439	26,439
2023							14,046	26,439
2024								14,046
Total	453,020	482,603	516,360	543,903	570,342	596,782	623,221	649,660

Table 12: GS 50-999 kW – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006 - 2016	881,470	881,470	881,470	881,470	881,470	881,470	881,470	881,470
2017	79,940	150,476	150,476	150,476	150,476	150,476	150,476	150,476
2018		85,578	161,088	161,088	161,088	161,088	161,088	161,088
2019			87,832	165,331	165,331	165,331	165,331	165,331
2020				88,379	166,360	166,360	166,360	166,360
2021					88,379	166,360	166,360	166,360
2022						88,379	166,360	166,360
2023							88,379	166,360
2024								88,379
Total	961,410	1,117,523	1,280,865	1,446,743	1,613,104	1,779,464	1,945,824	2,112,185

Update to IR 3-VECC-26

Table 13: GS 1,000 – 4,999 kW – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	572,991	572,991	572,991	572,991	572,991	572,991	572,991	572,991
2017	21,467	40,408	40,408	40,408	40,408	40,408	40,408	40,408
2018		33,452	62,969	62,969	62,969	62,969	62,969	62,969
2019			33,587	63,222	63,222	63,222	63,222	63,222
2020				37,133	69,897	69,897	69,897	69,897
2021					37,133	69,897	69,897	69,897
2022						37,133	69,897	69,897
2023							37,133	69,897
2024								37,133
Total	594,458	646,852	709,955	776,724	846,621	916,519	986,416	1,056,314

Table 14: Large Use – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	444,020	444,020	444,020	444,020	444,020	444,020	444,020	444,020
2017	12,728	23,959	23,959	23,959	23,959	23,959	23,959	23,959
2018		17,635	33,195	33,195	33,195	33,195	33,195	33,195
2019			20,862	39,270	39,270	39,270	39,270	39,270
2020				90,996	171,286	171,286	171,286	171,286
2021					90,996	171,286	171,286	171,286
2022						90,996	171,286	171,286
2023							90,996	171,286
2024								90,996
Total	456,749	485,614	522,036	631,440	802,726	974,012	1,145,298	1,316,584

Table 15: Total – Gross Annual CDM Savings (MWh)

Prog. Year	Calendar Year							
	2017	2018	2019	2020	2021	2022	2023	2024
2006-2016	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739	2,940,739
2017	209,035	393,478	393,478	393,478	393,478	393,478	393,478	393,478
2018	-	187,825	353,553	353,553	353,553	353,553	353,553	353,553
2019	-	-	168,100	316,423	316,423	316,423	316,423	316,423
2020	-	-	-	238,057	448,108	448,108	448,108	448,108
2021	-	-	-	-	238,057	448,108	448,108	448,108
2022	-	-	-	-	-	238,057	448,108	448,108
2023	-	-	-	-	-	-	238,057	448,108
2024	-	-	-	-	-	-	-	238,057
Total	3,149,775	3,522,043	3,855,870	4,242,251	4,690,359	5,138,467	5,586,575	6,034,683

Load Forecast Energy Impacts (columns A–H) | LRAM Energy Impact Breakdown (columns I–P)

D=B+C; F=D+E; H=FxG

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	RES		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
1	2020 CDM Forecast	801,974	(778,251)	23,723.65	3,857.28	27,581	101.6%	28,027	2020 CDM Forecast	16,124.48	11,902.91					**28,027.39**
2	2021 CDM Forecast	814,023	(778,251)	35,772.39	3,084.97	38,857	100.8%	39,167	2021 CDM Forecast	16,124.48	11,139.95	11,902.91				**39,167.34**
3	2022 CDM Forecast	826,072	(778,251)	47,821.12	2,312.67	50,134	100.3%	50,307	2022 CDM Forecast	16,124.48	11,139.95	11,139.95	11,902.91			**50,307.29**
4	2023 CDM Forecast	838,121	(778,251)	59,869.85	1,540.37	61,410	100.1%	61,447	2023 CDM Forecast	16,124.48	11,139.95	11,139.95	11,139.95	11,902.91		**61,447.24**
5	2024 CDM Forecast	850,169	(778,251)	71,918.59	768.06	72,687	99.9%	72,587	2024 CDM Forecast	16,124.48	11,139.95	11,139.95	11,139.95	11,139.95	11,902.91	**72,587.19**
6									**Total**	**80,622.40**	**56,462.71**	**45,322.76**	**34,182.81**	**23,042.86**	**11,902.91**	**251,536.43**

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	CSMUR		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
7	2020 CDM Forecast	17,218	(14,417)	2,801	689.16	3,490	103.4%	3,607	2020 CDM Forecast	1,902.17	1,705.22					**3,607.39**
8	2021 CDM Forecast	18,888	(14,417)	4,471	649.83	5,121	103.0%	5,272	2021 CDM Forecast	1,902.17	1,665.07	1,705.22				**5,272.46**
9	2022 CDM Forecast	20,558	(14,417)	6,141	610.51	6,752	102.8%	6,938	2022 CDM Forecast	1,902.17	1,665.07	1,665.07	1,705.22			**6,937.52**
10	2023 CDM Forecast	22,228	(14,417)	7,811	571.18	8,382	102.6%	8,603	2023 CDM Forecast	1,902.17	1,665.07	1,665.07	1,665.07	1,705.22		**8,602.59**
11	2024 CDM Forecast	23,898	(14,417)	9,481	531.86	10,013	102.5%	10,268	2024 CDM Forecast	1,902.17	1,665.07	1,665.07	1,665.07	1,665.07	1,705.22	**10,267.66**
12									**Total**	**9,510.83**	**8,365.49**	**6,700.42**	**5,035.36**	**3,370.29**	**1,705.22**	**34,687.61**

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	GS<50		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
13	2020 CDM Forecast	528,267	(486,659)	41,608	12,031.48	53,639	91.04%	48,831	2020 CDM Forecast	25,510.01	23,320.56					**48,830.57**
14	2021 CDM Forecast	553,672	(486,659)	67,013	11,552.84	78,566	90.99%	71,485	2021 CDM Forecast	25,297.89	23,316.03	22,870.66				**71,484.58**
15	2022 CDM Forecast	578,837	(486,659)	92,178	10,878.44	103,057	90.96%	93,741	2022 CDM Forecast	24,832.18	23,171.66	22,866.13	22,870.66			**93,740.63**
16	2023 CDM Forecast	604,002	(486,659)	117,343	9,168.00	126,511	90.94%	115,053	2023 CDM Forecast	23,869.37	22,725.46	22,721.76	22,866.13	22,870.66		**115,053.37**
17	2024 CDM Forecast	629,166	(486,659)	142,507	5,925.19	148,433	90.93%	134,971	2024 CDM Forecast	22,277.45	21,959.70	22,275.56	22,721.76	22,866.13	22,870.66	**134,971.25**
18									**Total**	**121,786.90**	**114,493.42**	**90,734.10**	**68,458.54**	**45,736.78**	**22,870.66**	**464,080.41**

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	GS 50-1000kW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
19	2020 CDM Forecast	1,405,151	(1,158,734)	246,416	75,548.50	321,965	81.8%	263,251	2020 CDM Forecast	123,574.57	139,676.61					**263,251.18**
20	2021 CDM Forecast	1,550,567	(1,158,734)	391,832	61,072.88	452,905	83.1%	376,145	2021 CDM Forecast	123,524.77	139,546.31	113,073.61				**376,144.68**
21	2022 CDM Forecast	1,681,723	(1,158,734)	522,988	60,591.48	583,580	83.8%	488,829	2022 CDM Forecast	123,306.51	139,505.70	112,943.30	113,073.61			**488,829.12**
22	2023 CDM Forecast	1,812,878	(1,158,734)	654,144	59,977.68	714,122	84.2%	601,390	2023 CDM Forecast	123,167.73	139,302.17	112,902.70	112,943.30	113,073.61		**601,389.51**
23	2024 CDM Forecast	1,944,034	(1,158,734)	785,300	52,270.07	837,570	84.6%	708,471	2024 CDM Forecast	117,672.97	139,179.73	112,699.17	112,902.70	112,943.30	113,073.61	**708,471.48**
24									**Total**	**611,246.55**	**697,210.51**	**451,618.78**	**338,919.61**	**226,016.91**	**113,073.61**	**2,438,085.97**

Cumulative Net Breakdown

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	GS1-5MW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
25	2020 CDM Forecast	754,394	(656,924)	97,470	31,711.48	129,181	86.3%	111,523	2020 CDM Forecast	52,651.63	58,871.66					**111,523.30**
26	2021 CDM Forecast	816,091	(656,924)	159,167	26,125.77	185,293	86.4%	160,098	2021 CDM Forecast	52,629.42	58,787.22	48,681.23				**160,097.87**
27	2022 CDM Forecast	872,326	(656,924)	215,402	25,898.94	241,301	86.4%	208,583	2022 CDM Forecast	52,537.65	58,767.74	48,596.79	48,681.23			**208,583.42**
28	2023 CDM Forecast	928,560	(656,924)	271,636	25,659.37	297,296	86.5%	257,057	2023 CDM Forecast	52,517.55	58,684.39	48,577.31	48,596.79	48,681.23		**257,057.26**
29	2024 CDM Forecast	984,795	(656,924)	327,871	22,674.29	350,546	86.5%	303,173	2024 CDM Forecast	50,158.10	58,665.27	48,493.96	48,577.31	48,596.79	48,681.23	**303,172.66**
30									**Total**	**260,494.35**	**293,776.29**	**194,349.29**	**145,855.33**	**97,278.02**	**48,681.23**	**1,040,434.51**

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	LU		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
31	2020 CDM Forecast	620,763	(492,700)	128,063	78,627.05	206,690	93.5%	193,202	2020 CDM Forecast	47,264.88	145,937.49					**193,202.37**
32	2021 CDM Forecast	723,296	(492,700)	230,597	20,064.37	250,661	91.9%	230,317	2021 CDM Forecast	47,179.99	145,603.50	37,533.93				**230,317.42**
33	2022 CDM Forecast	767,721	(492,700)	275,022	19,349.74	294,372	90.8%	267,155	2022 CDM Forecast	46,892.76	145,528.48	37,199.94	37,533.93			**267,155.11**
34	2023 CDM Forecast	812,146	(492,700)	319,447	18,566.71	338,013	89.9%	304,019	2023 CDM Forecast	46,886.68	145,273.68	37,124.92	37,199.94	37,533.93		**304,019.14**
35	2024 CDM Forecast	856,571	(492,700)	363,872	15,668.07	379,540	89.1%	338,284	2024 CDM Forecast	44,286.93	145,268.24	36,870.11	37,124.92	37,199.94	37,533.93	**338,284.07**
36									**Total**	**232,511.24**	**727,611.38**	**148,728.90**	**111,858.79**	**74,733.87**	**37,533.93**	**1,332,978.11**

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Total Company		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MWh	2019	2020	2021	2022	2023	2024	Total
37	2020 CDM Forecast	4,127,767	(3,587,685)	540,082	202,464.95	742,547	87.3%	648,442	2020 CDM Forecast	267,027.75	381,414.46					**648,442.20**
38	2021 CDM Forecast	4,476,538	(3,587,685)	888,853	122,550.66	1,011,404	87.3%	882,484	2021 CDM Forecast	266,658.72	380,058.08	235,767.55				**882,484.35**
39	2022 CDM Forecast	4,747,237	(3,587,685)	1,159,552	119,641.78	1,279,194	87.2%	1,115,553	2022 CDM Forecast	265,595.74	379,778.60	234,411.18	235,767.55			**1,115,553.07**
40	2023 CDM Forecast	5,017,936	(3,587,685)	1,430,251	115,483.30	1,545,734	87.2%	1,347,569	2023 CDM Forecast	264,467.97	378,790.71	234,131.70	234,411.18	235,767.55		**1,347,569.11**
41	2024 CDM Forecast	5,288,634	(3,587,685)	1,700,950	97,837.54	1,798,787	87.2%	1,567,754	2024 CDM Forecast	252,422.10	377,877.96	233,143.81	234,131.70	234,411.18	235,767.55	**1,567,754.30**

MWh

Load Forecast Demand Impacts

LRAM Demand Impact Breakdown

Line No.	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
				D=(B+C)		F=D+E		H=FxG								
	GS 50-1000MW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MW	2019	2020	2021	2022	2023	2024	Total
1	2020 CDM Forecast	2,703	(2,291)	412	118	531	86.23%	458	2020 CDM Forecast	232.32	225.18					457.50
2	2021 CDM Forecast	2,957	(2,291)	666	115	781	86.58%	676	2021 CDM Forecast	232.30	225.14	218.91				676.35
3	2022 CDM Forecast	3,208	(2,291)	917	114	1,032	86.75%	895	2022 CDM Forecast	232.07	225.13	218.87	218.91			894.98
4	2023 CDM Forecast	3,459	(2,291)	1,168	114	1,282	86.86%	1,113	2023 CDM Forecast	231.80	224.91	218.86	218.87	218.91		1,113.34
5	2024 CDM Forecast	3,710	(2,291)	1,419	100	1,519	86.95%	1,320	2024 CDM Forecast	220.43	224.66	218.63	218.86	218.87	218.91	1,320.35
6									Total	1,148.93	1,125.02	875.26	656.63	437.77	218.91	4,462.52
	GS1-5MW		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MW	2019	2020	2021	2022	2023	2024	Total
7	2020 CDM Forecast	1,379	(1,265)	114	33	148	86.61%	128	2020 CDM Forecast	64.74	63.21					127.95
8	2021 CDM Forecast	1,451	(1,265)	186	32	218	86.64%	189	2021 CDM Forecast	64.74	63.20	61.15				189.08
9	2022 CDM Forecast	1,521	(1,265)	257	32	289	86.65%	250	2022 CDM Forecast	64.69	63.20	61.13	61.15			250.17
10	2023 CDM Forecast	1,592	(1,265)	327	32	359	86.65%	311	2023 CDM Forecast	64.65	63.15	61.13	61.13	61.15		311.22
11	2024 CDM Forecast	1,662	(1,265)	398	28	426	86.66%	369	2024 CDM Forecast	61.39	63.11	61.09	61.13	61.13	61.15	369.00
12								1,247	Total	320.21	315.87	244.50	183.41	122.28	61.15	1,247.43
	LU		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MW	2019	2020	2021	2022	2023	2024	Total
13	2020 CDM Forecast	1,287	(1,167)	120	47	167	86.09%	144	2020 CDM Forecast	56.71	87.08	-	-	-	-	143.79
14	2021 CDM Forecast	1,373	(1,167)	206	32	238	85.40%	203	2021 CDM Forecast	56.71	86.91	59.83	-	-	-	203.45
15	2022 CDM Forecast	1,444	(1,167)	277	32	309	85.02%	263	2022 CDM Forecast	56.69	86.91	59.67	59.83	-	-	263.11
16	2023 CDM Forecast	1,516	(1,167)	349	32	381	84.79%	323	2023 CDM Forecast	56.68	86.90	59.67	59.67	59.83	-	322.75
17	2024 CDM Forecast	1,587	(1,167)	420	28	448	84.59%	379	2024 CDM Forecast	53.14	86.89	59.66	59.67	59.67	59.83	378.86
18									Total	279.93	434.70	238.83	179.17	119.50	59.83	1,311.96
	Total Company		Cumulative 2018 Persistence	Cumulative Incremental Gross (For Load Forecast)	2020-2024 Load Forecast/LRAM Methodology Variance	Cumulative Incremental Gross (For LRAM)	Gross to Net Ratio	Net Cumulative	MW	2019	2020	2021	2022	2023	2024	Total
19	2020 CDM Forecast	5,369	(4,723)	646	199	845	86.27%	729	2020 CDM Forecast	353.77	375.47					729.24
20	2021 CDM Forecast	5,781	(4,723)	1,058	179	1,238	86.36%	1,069	2021 CDM Forecast	353.75	375.26	339.89				1,068.89
21	2022 CDM Forecast	6,174	(4,723)	1,451	179	1,630	86.41%	1,408	2022 CDM Forecast	353.46	375.24	339.67	339.89			1,408.26
22	2023 CDM Forecast	6,567	(4,723)	1,844	178	2,022	86.44%	1,747	2023 CDM Forecast	353.14	374.96	339.65	339.67	339.89		1,747.31
23	2024 CDM Forecast	6,959	(4,723)	2,236	156	2,392	86.46%	2,068	2024 CDM Forecast	334.96	374.66	339.38	339.65	339.67	339.89	2,068.21
24									Total	1,749.07	1,875.60	1,358.59	1,019.21	679.56	339.89	7,021.91

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use					CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jul 2002	19,204,876		8,649,128	31,276,255	16,527,279	8,820,370	256,949	166,002							0.00	6.21	243,228	0	1	1	0	15.57	71.0	1		66,908	10,576	46
Aug 2002	18,511,523		8,183,954	29,604,261	15,721,190	8,346,209	246,772	159,547							0.00	4.60	243,960	0	2	2	0	22.06	67.7	1		66,827	10,586	46
Sep 2002	16,114,720		7,687,179	28,298,565	14,984,372	7,895,845	269,652	158,251							0.00	2.92	244,692	0	3	3	0	13.55	66.7	1		66,826	10,619	46
Oct 2002	14,513,865		6,947,084	25,956,564	13,645,056	7,127,650	306,016	155,740							2.96	0.32	245,223	0	4	4	0	4.79	71.0	0		66,859	10,669	46
Nov 2002	15,395,003		7,232,335	27,256,662	13,902,998	7,204,315	363,235	158,333							7.14	0.00	245,755	0	5	5	0	-0.53	70.0	0		66,838	10,680	46
Dec 2002	17,264,325		7,335,346	28,296,964	13,783,673	7,157,154	373,118	162,451							11.98	0.00	246,286	0	6	6	0	-5.56	64.5	1		66,934	10,708	46
Jan 2003	18,311,915		7,916,178	30,509,950	14,995,396	7,598,243	403,495	163,775							18.27	0.00	246,791	0	7	7	0	-11.63	71.0	1		66,987	10,732	46
Feb 2003	17,946,872		8,123,903	30,717,592	14,953,503	7,633,376	371,971	162,553							16.96	0.00	247,295	0	8	8	0	-11.31	71.4	1		67,139	10,786	46
Mar 2003	16,306,690		7,612,193	28,018,838	14,110,408	7,296,898	339,070	159,786							10.79	0.00	247,800	0	9	9	0	-5.52	67.7	1		67,113	10,794	46
Apr 2003	14,622,587		7,121,777	26,707,917	13,805,589	7,149,673	288,109	160,638							5.34	0.08	247,644	0	10	10	0	-1.84	66.7	0		67,040	10,809	46
May 2003	13,572,543		6,652,815	24,857,765	13,226,484	7,017,781	236,326	153,861							0.17	0.00	247,488	0	11	11	0	6.50	67.7	0		67,126	10,828	46
Jun 2003	14,771,959		7,206,195	27,040,865	14,519,362	7,638,136	232,369	158,462							0.00	1.76	247,333	0	12	12	0	11.94	70.0	1		66,958	10,845	46
Jul 2003	16,298,890		7,827,787	29,154,832	15,538,655	7,771,092	252,559	163,533							0.00	3.82	247,015	0	13	13	0	14.71	71.0	1		67,046	10,848	46
Aug 2003	15,735,506		7,524,161	27,792,398	14,449,168	7,483,754	238,901	159,766							0.00	4.13	246,698	0	14	14	1	16.04	64.5	1		67,040	10,850	46
Sep 2003	14,015,178		6,905,035	26,228,274	14,274,728	7,348,513	279,868	157,630							0.04	0.80	246,381	0	15	15	0	11.65	70.0	1		66,964	10,851	46
Oct 2003	13,928,118		6,717,373	25,744,347	13,778,426	6,912,996	326,382	159,766							2.26	0.00	247,421	0	16	16	0	4.73	71.0	0		67,018	10,892	46
Nov 2003	15,092,616		6,999,278	26,923,503	13,922,169	7,029,585	383,778	161,194							5.35	0.00	248,462	0	17	17	0	1.60	66.7	0		66,892	10,874	46
Dec 2003	16,844,234		7,272,589	27,677,189	13,794,288	6,932,811	400,325	161,702							10.11	0.00	249,502	0	18	18	0	-3.98	67.7	1		67,064	10,908	47
Jan 2004	17,978,692		7,904,747	30,816,801	15,143,333	8,177,818	405,204	167,312							19.39	0.00	249,936	0	19	19	0	-13.06	67.7	1		66,973	10,939	47
Feb 2004	17,170,190		7,700,344	29,663,529	14,662,859	7,211,845	356,252	163,516							13.78	0.00	250,369	0	20	20	0	-8.28	69.0	1		67,046	10,971	47
Mar 2004	15,629,667		7,263,222	27,958,514	14,414,022	7,168,856	341,915	162,663							7.90	0.00	250,803	0	21	21	0	-2.07	74.2	1		67,001	10,986	47
Apr 2004	14,026,791		6,860,879	26,007,834	13,599,975	7,142,223	284,717	160,004							3.88	0.00	251,911	0	22	22	0	0.57	66.7	0		66,920	11,007	47
May 2004	13,190,260		6,697,193	25,467,554	13,536,594	6,883,795	236,779	158,600							0.61	0.28	253,019	0	23	23	0	7.92	64.5	0		66,875	11,018	47
Jun 2004	13,682,848		6,996,090	26,877,869	14,725,457	7,501,466	230,928	161,946							0.00	1.05	254,127	0	24	24	0	11.15	73.3	1		66,789	11,038	47
Jul 2004	14,728,572		7,410,303	28,203,152	15,020,716	7,789,243	247,688	164,679							0.00	2.79	254,823	0	25	25	0	15.50	67.7	1		66,753	11,045	47
Aug 2004	14,329,725		7,313,804	27,825,836	14,779,013	7,491,884	232,359	160,171							0.00	1.92	255,520	0	26	26	0	14.06	67.7	1		66,715	11,076	47
Sep 2004	13,952,065		7,074,372	27,537,276	15,242,637	7,559,001	287,188	163,732							0.00	1.37	256,216	0	27	27	0	12.85	70.0	1		66,658	11,104	47
Oct 2004	13,466,693		6,596,275	25,678,284	13,594,246	6,960,710	322,754	159,158							0.83	0.05	256,741	0	28	28	0	6.00	64.5	0		66,496	11,097	47
Nov 2004	14,734,158		6,925,586	26,942,928	14,049,875	7,104,274	380,877	161,489							4.67	0.00	257,266	0	29	29	0	0.48	73.3	0		66,585	11,119	47
Dec 2004	16,962,969		7,498,072	29,200,693	14,274,620	7,287,318	393,686	167,781							12.75	0.00	257,792	0	30	30	0	-6.05	67.7	1		66,505	11,146	47
Jan 2005	17,644,488		7,884,202	31,067,950	14,884,092	7,502,345	415,029	163,047							16.84	0.00	258,499	0	31	31	0	-10.68	64.5	1		66,464	11,167	47
Feb 2005	16,986,994		7,790,034	29,965,306	14,769,846	7,412,682	380,503	159,982							14.01	0.00	259,205	0	32	32	0	-7.08	71.4	1		66,628	11,184	47
Mar 2005	15,704,996		7,441,105	28,955,758	14,554,549	7,319,912	357,292	157,327							11.65	0.00	259,912	0	33	33	0	-6.16	67.7	1		66,630	11,198	47
Apr 2005	13,765,854		6,766,118	26,139,356	13,762,751	6,903,337	296,587	153,933							2.77	0.00	260,253	0	34	34	0	-0.56	70.0	0		66,556	11,426	48
May 2005	13,739,592		6,518,052	25,117,342	13,271,845	6,822,412	231,600	149,054							0.92	0.03	260,593	0	35	35	0	4.06	67.7	0		66,482	11,185	47
Jun 2005	17,351,693		7,803,803	30,831,062	16,622,447	8,214,883	239,904	151,947							0.00	4.88	260,933	0	36	36	0	15.35	73.3	1		66,471	11,214	47
Jul 2005	18,839,649		8,166,152	31,728,614	16,122,802	7,757,701	249,964	158,882							0.00	6.09	261,772	0	37	37	0	15.96	64.5	1		66,459	11,233	47
Aug 2005	17,458,775		7,764,782	30,249,616	16,074,354	7,558,624	245,451	155,642							0.00	4.54	262,611	0	38	38	0	15.82	71.0	1		66,448	11,242	47
Sep 2005	14,755,814		7,084,612	28,045,770	15,354,144	7,374,681	280,008	153,375							0.00	1.74	263,451	0	39	39	0	12.99	70.0	1		66,437	11,255	47
Oct 2005	13,612,493		6,553,620	26,087,500	14,169,462	6,868,355	320,937	152,229							1.33	0.25	264,067	0	40	40	0	7.19	64.5	0		66,426	11,267	47
Nov 2005	14,817,652		6,910,069	27,534,293	14,466,500	7,025,394	380,230	149,728							5.37	0.00	264,683	0	41	41	0	1.10	73.3	0		66,414	11,286	47
Dec 2005	16,564,476		7,437,910	29,721,095	14,596,020	7,011,795	390,672	156,298							13.46	0.00	265,299	0	42	42	0	-6.47	64.5	1		66,403	11,498	47
Jan 2006	16,528,280		7,352,899	28,878,874	14,408,784	6,987,662	407,562	155,071	919						9.80	0.00	266,390	0	43	43	0	-2.82	67.7	1		66,392	11,349	47
Feb 2006	16,386,367		7,542,777	29,982,830	15,093,663	7,321,461	384,419	156,294	1,742						13.58	0.00	267,482	0	44	44	0	-7.75	71.4	1		66,380	11,358	46
Mar 2006	15,149,542		7,166,823	28,307,388	14,682,471	7,162,165	354,233	153,057	2,657						8.67	0.00	268,573	0	45	45	0	-5.33	74.2	1		66,369	11,358	47
Apr 2006	13,403,677		6,457,396	25,422,610	13,533,302	6,820,677	292,933	150,215	11,561						2.58	0.00	268,728	0	46	46	0	0.65	60.0	0		66,358	11,375	47
May 2006	13,406,037		6,470,721	25,888,725	14,286,344	7,184,146	237,248	150,833	11,606						0.31	0.84	268,883	0	47	47	0	7.88	71.0	0		66,346	11,377	46
Jun 2006	15,451,886		7,089,496	28,261,902	15,667,781	7,630,593	229,557	164,514	31,912						0.00	2.45	269,038	0	48	48	0	12.56	73.3	1		66,335	11,397	48
Jul 2006	17,364,153		7,820,058	31,081,220	16,376,255	8,226,171	250,990	173,228	34,832						0.00	5.40	268,784	0	49	49	0	17.38	64.5	1		66,324	11,389	48
Aug 2006	16,091,548		7,335,937	29,427,040	15,969,371	7,769,925	246,501	167,021	158,772						0.00	3.28	268,529	0	50	50	0	14.60	71.0	1		66,313	11,417	49
Sep 2006	13,630,359		6,438,984	25,986,422	14,337,632	7,055,393	275,432	158,610	172,366						0.05	0.43	268,274	0	51	51	0	11.65	66.7	1		66,301	11,430	49
Oct 2006	13,539,041		6,406,677	26,187,123	14,215,738	6,993,313	327,134	162,871	77,332						2.42	0.04	269,122	0	52	52	0	4.76	67.7	0		66,290	11,441	49
Nov 2006	14,672,047		6,757,402	27,548,591	14,482,704	7,137,127	385,452	162,055	83,723						4.78	0.00	269,971	0	53	53	0	2.07	73.3	0		66,279	11,426	49
Dec 2006	15,905,028		6,862,288	27,901,327	13,823,127	6,798,357	386,505	161,258	174,382						8.15	0.00	270,819	0	54	54	0	-2.39	61.3	1		66,267	11,444	49
Jan 2007	16,860,542		7,271,758	29,655,760	14,728,039	6,827,632	411,032	163,099	176,241		619	662	620	612	12.87	0.00	271,104	0	55	55	0	-6.55	71.0	1		66,256	11,426	49
Feb 2007	17,559,780		7,779,608	31,920,692	15,448,530	7,368,713	389,657	166,716	200,631		2,518	2,695	2,521	2,491	18.43	0.00	271,390	0	56	56	0	-12.36	71.4	1		66,245	11,452	49
Mar 2007	15,835,869		7,080,109	28,724,775	14,455,093	7,075,744	353,562	161,555	188,933		4,843	5,183	4,849	4,791	9.77	0.00	271,675	0	57	57	0	-5.63	71.0	1		66,233	11,502	48
Apr 2007	14,015,785		6,614,987	26,882,008	13,826,904	6,949,028	299,516	161,255	95,034		2,683	2,871	2,686	2,654	4.86	0.00	272,337	0	58	58	0	0.02	63.3	0		66,222	11,476	49
May 2007	13,193,760		6,358,708	26,056,580	14,129,655	6,799,020	234,356	156,695	95,619		3,811	4,078	3,816	3,770	0.19	0.72	273,000	0	59	59	0	5.76	71.0	0		66,211	11,469	48
Jun 2007	15,356,609		7,195,124	29,659,945	15,737,684	7,646,739	236,262	164,442	254,239		13,609	14,563	13,625	13,462	0.00	3.31	273,662	0	60	60	0	12.19	70.0	1		66,199	11,440	49
Jul 2007	15,996,547		7,165,384	29,130,162	15,095,626	6,920,126	242,518	159,383	257,728		17,060	18,257	17,081	16,876	0.00	3.42	274,654	0	61	61	0	14.04	67.7	1		66,188	11,497	49
Aug 2007	16,310,715		7,397,331	30,383,781	16,092,600	7,888,869	250,774	164,834	304,904		32,761	35,059	32,800	32,408	0.00	4.55	275,647	0	62	62	0	14.51	71.0	1		66,177	11,537	49
Sep 2007	14,648,382		6,773,712	27,726,358	14,881,500	7,365,566	279,044	159,347	673,950		153,296	164,047	153,478	151,644	0.01	1.58	276,639	0	63	63	0	11.56	63.3	1		66,166	11,556	49
Oct 2007	13,669,526		6,417,300	26,458,047	14,461,050	6,811,240	323,853	159,820	268,175		61,241	65,536	61,313	60,581	0.49	0.64	276,870	0	64	64	0	9.24	71.0	0		66,154	11,550	49
Nov 2007	14,885,949		6,793,419	27,999,974	14,498,864	7,138,206	383,672	162,357	288,120		66,945	71,640	67,024	66,224	7.43	0.00	277,101	0	65	65	0	-1.40	73.3	0		66,143	11,586	49
Dec 2007	16,952,833		7,162,959	29,656,718	14,288,014	7,134,747	389,185	164,376	605,185		143,379	153,435	143,549	141,834	12.35	0.00	277,333	0	66	66	0	-5.84	61.3	1		66,245	11,590	49
Jan 2008	17,303,818		7,255,552	30,117,101	14,544,566	7,290,645	411,876	163,183	633,075		160,535	170,615	161,912	159,978	12.25	0.00	276,668	1	67	67	0	-6.16	71.0	1		66,054	11,754	49
Feb 2008	17,133,103		7,467,755	31,053,267	14,825,158	7,423,436	384,450	164,250	678,400		172,630	183,407	174,175	172,094	15.27	0.00	276,004	2	68	68	0	-9.12	69.0	1		66,150	11,863	48
Mar 2008	15,932,193		7,025,196	29,231,975	14,423,537	7,278,631	358,313	163,413	639,565		164,527	174,613	166,185	164,200	11.68	0.00	275,339	3	69	69	0	-7.00	61.3	1		66,093	11,929	48
Apr 2008	13,569,546		6,232,609	26,561,753	13,834,754	7,030,859	295,774	159,698	324,877		85,681	90,717	86,764	85,727	2.60	0.00	275,487	4	70	70	0	0.71	73.3	0		66,152	11,977	48
May 2008	12,997,434		6,008,329	25,595,496	13,402,249	6,551,008	234,952	157,052	317,418		84,776	89,652	85,954	84,927	0.45	0.08	275,634	5	71	71	0	3.87	67.7	0		66,094	12,016	49
Jun 2008	15,225,020		6,815,659	28,778,409	15,179,659	7,389,078	232,922	161,925	813,699		220,491	232,859	223,872	221,197	0.00	2.38	275,782	6	72	72	0	13.65	70.0	1		66,311	12,066	49
Jul 2008	16,372,699		7,450,961	30,676,404	15,600,553	7,729,728	248,421	162,898	908,690		286,193	298,022	294,329	290,812	0.00	3.58	275,861	7	73	73	0	14.83	71.0	1		66,286	12,063	49
Aug 2008	14,993,967		6,974,647	29,212,143	14,708,046	7,223,683	239,612	156,724	909,611		286,760	298,589	294,935	291,411	0.00	2.06	275,941	8	74	74	0	13.64	64.5	1		66,226	12,077	49
Sep 2008	14,475,078		6,546,717	27,751,922	14,836,846	7,147,376	286,630	161,934	943,468		300,311	312,794	309,311	305,616	0.00	0.89	276,020	9	75	75	0	12.06	70.0	1		66,293	12,105	48
Oct 2008	13,520,757		5,978,097	26,183,872	13,787,454	6,468,382	329,428	161,317	373,284		119,139	124,064	122,736	121,270	2.00	0.00	274,048	10	76	76	0	3.37	71.0	0		65,867	12,095	48
Nov 2008	15,034,445		6,371,446	27,954,146	13,933,956	6,742,182	386,520	162,065	387,786		124,376	129,468	128,183	126,651	7.31	0.00	272,076	11	77	77	0	-1.22	66.7	0		66,084	12,128	47
Dec 2008	16,999,025		6,907,975	29,515,669	13,697,323	6,569,481	380,803	159,641	779,128		250,370	260,581	258,072	254,989	13.12	0.00	270,104	12	78	78	0	-7.49	67.7	1		65,917	12,156	47
Jan 2009	18,085,109		7,449,513	31,830,043	14,394,700	6,916,937	417,231	166,009	781,026		251,847	262,057	259,773	256,669	18.78	0.00	268,103	13	79	79	0	-12.88	67.7	1		65,700	12,147	47
Feb 2009	17,161,604		7,141,763	30,274,237	14,137,158	7,032,492	382,752	169,699	872,363		284,782	296,087	294,459	290,941	13.66	0.00	266,102	14	80	80	0	-8.48	67.9	1		66,133	12,181	47
Mar 2009	15,537,555		6,762,583	28,734,498	13,852,975	6,706,802	356,765	163,022	790,830		259,470	269,680	268,551	265,342	9.22	0.00	264,101	15	81	81	0	-6.38	71.0	1		66,140	12,189	47
Apr 2009	13,566,450		6,184,035	26,569,246	13,069,618	6,464,118	303,012	163,555	397,057		131,454	136,547	136,293	134,664	3.20	0.04	264,115	16	82	82	0	-1.44	66.7	0		65,846	12,163	47
May 2009	12,630,429		5,839,729	25,359,397	12,918,802	6,198,502	236,904	158,517	387,097		129,428	134,356	134,446	132,840	0.41	0.22	264,129	17	83	83	0	4.55	64.5	0		65,798	12,208	47
Jun 2009	13,893,651		6,355,937	27,601,014	14,186,089	7,154,419	235,165	164,224	985,346		331,286	343,778	344,492	340,377	0.00	1.14	264,143	18	84	84	0	11.08	73.3	1		66,074	12,231	47
Jul 2009	14,421,448		6,433,015	27,746,325	14,098,821	7,580,400	242,648	158,771	1,037,777		385,965	415,173	477,154	657,619	0.00	1.41	265,544	19	85	85	0	13.43	67.7	1		65,854	12,287	47
Aug 2009	15,905,175		6,889,426	30,110,630	15,188,061	7,600,951	251,837	163,149	1,048,237		394,099	423,306	486,520	666,873	0.00	2.94	266,946	20	86	86	0	15.53	64.5	1		66,047	12,295	47
Sep 2009	14,229,262		6,247,175	27,597,597	14,339,504	7,169,548	285,097	152,004	1,087,394		410,633	423,124	435,862	430,655	0.04	0.70	268,348	21	87	87	0	11.96	70.0	1		66,100	12,337	47
Oct 2009	13,259,165		5,848,076	26,632,712	13,429,012	6,599,010	333,095	154,586	431,034		163,591	168,519	173,786	171,709	1.96	0.00	269,334	22	88	88	0	4.55	67.7	0		65,873	12,316	47
Nov 2009	14,141,334		5,944,580	27,039,895	13,455,164	6,448,557	388,982	155,243	446,880		170,193	175,285	180,902	178,740	4.15	0.00	270,320	23	89	89	0	2.75	70.0	0		65,835	12,384	47
Dec 2009	17,105,538		6,581,648	29,804,130	13,785,482	6,547,808	391,443	156,359	912,877		354,366	364,577	377,827	373,313	12.36	0.00	271,306	24	90	90	0	-5.94	67.7	1		65,883	12,444	47

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use					CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jan 2010	17,924,992		6,976,445	31,213,806	14,241,881	6,887,447	418,962	161,385	977,385		452,832	463,043	476,293	470,602	15.23	0.00	271,953	25	91	90	0	-8.41	64.5	1		65,607	12,597	47
Feb 2010	17,226,261		7,008,354	31,219,988	14,309,939	6,940,328	386,994	160,271	1,087,680		509,859	521,163	535,833	529,431	13.37	0.00	272,599	26	92	90	0	-7.22	67.9	1		66,056	12,574	47
Mar 2010	14,736,357		6,346,826	28,434,459	13,753,127	6,649,951	357,966	157,363	989,507		471,335	481,545	494,795	488,883	5.73	0.00	273,246	27	93	90	0	-3.39	74.2	1		66,156	12,703	47
Apr 2010	12,477,897		5,668,790	26,385,054	12,962,111	6,020,159	301,056	151,092	496,279		239,289	244,381	250,990	247,991	1.01	0.00	273,933	28	94	90	0	0.83	66.7	0		65,995	12,826	47
May 2010	13,534,058		5,880,416	27,651,502	13,731,068	6,523,040	245,168	148,588	481,284		233,117	238,046	244,441	241,520	0.58	1.47	274,619	29	95	90	0	8.64	64.5	0		65,681	12,829	47
Jun 2010	15,798,830		6,509,809	29,271,497	14,797,216	7,140,037	236,789	146,396	1,242,974		626,035	638,527	654,738	646,915	0.00	1.96	275,306	30	96	90	0	13.92	73.3	1		65,799	12,873	47
Jul 2010	19,201,876		7,334,276	33,142,955	16,003,442	7,951,562	251,509	146,894	1,210,379		616,917	658,986	764,661	1,081,536	0.00	5.32	275,972	31	97	90	0	17.44	67.7	1		66,029	12,906	46
Aug 2010	17,547,175		6,982,545	32,038,022	15,859,052	7,873,418	250,633	145,629	1,221,641		634,107	676,176	781,851	1,098,521	0.00	4.48	276,637	32	98	90	0	17.11	67.7	1		65,895	12,916	46
Sep 2010	14,247,209		6,223,643	28,280,435	14,471,534	6,895,759	287,534	139,740	1,287,982		694,736	707,228	723,439	714,796	0.00	1.05	277,303	33	99	90	0	12.14	70.0	1		65,794	12,978	46
Oct 2010	12,717,913		5,531,390	26,621,990	13,346,576	6,100,189	333,276	141,068	510,156		277,188	282,116	288,511	285,064	1.15	0.00	278,027	34	100	90	0	5.44	64.5	0		66,041	12,980	46
Nov 2010	14,323,060		5,940,255	28,209,107	13,648,636	6,455,800	388,390	140,793	533,706		296,418	301,511	308,119	304,438	5.58	0.00	278,751	35	101	90	0	0.43	73.3	0		65,976	13,021	46
Dec 2010	17,371,279		6,756,652	30,994,726	13,745,366	7,095,603	392,178	139,025	1,077,737		606,009	616,220	629,470	621,949	13.81	0.00	279,474	36	102	90	0	-7.07	67.7	1		66,167	13,168	50
Jan 2011	17,965,617		6,927,647	32,102,264	14,127,431	7,206,767	418,421	129,836	1,080,094		608,925	620,888	631,727	623,882	17.01	0.00	280,433	37	103	90	0	-10.16	64.5	1		65,996	13,266	50
Feb 2011	17,529,602		7,001,158	32,127,156	14,366,063	7,338,692	388,767	127,365	1,198,046		676,921	691,822	701,543	692,552	15.36	0.00	281,392	38	104	90	0	-9.13	67.9	1		65,942	13,314	50
Mar 2011	15,874,592		6,666,235	30,212,577	14,021,973	7,223,723	360,148	125,860	1,091,123		622,562	642,726	642,283	632,921	10.48	0.00	282,351	39	105	90	0	-5.22	74.2	1		65,945	13,246	50
Apr 2011	13,373,937		5,903,347	27,529,036	12,896,350	6,751,637	303,774	125,469	548,501		315,821	329,073	324,456	319,195	3.56	0.00	282,199	40	106	90	0	0.87	63.3	0		65,856	12,938	50
May 2011	12,445,752		5,576,188	26,949,664	12,907,764	6,939,061	242,522	118,094	536,015		312,072	328,768	318,973	313,167	0.23	0.42	282,047	41	107	90	0	9.25	67.7	0		66,224	12,795	50
Jun 2011	15,136,619		6,572,629	29,598,238	14,434,050	7,817,235	234,769	117,692	1,379,371		816,610	874,307	828,328	810,765	0.00	1.74	281,895	42	108	90	0	12.47	73.3	1		66,681	12,845	50
Jul 2011	19,602,554		7,463,855	33,339,840	15,288,401	8,098,236	253,286	127,864	1,351,322		810,567	879,855	818,486	806,564	0.00	6.41	283,481	43	109	90	0	15.75	64.5	1		66,723	12,824	50
Aug 2011	16,685,431		7,202,543	32,002,545	14,932,286	7,864,672	246,519	118,097	1,355,817		816,125	888,755	822,788	810,248	0.00	3.94	285,068	44	110	90	0	15.21	71.0	1		66,900	12,824	50
Sep 2011	14,050,791		6,525,174	29,338,870	14,168,564	7,607,759	285,201	115,240	1,407,871		851,851	930,740	855,607	834,124	0.00	1.32	286,655	45	111	90	0	13.04	70.0	1		67,017	12,791	51
Oct 2011	12,942,861		5,749,023	27,141,971	12,995,566	6,701,139	334,303	116,146	560,076		341,825	376,412	342,004	332,888	1.61	0.08	287,409	46	112	90	0	6.66	64.5	0		67,039	12,701	51
Nov 2011	14,150,147		6,135,800	28,148,892	13,177,961	6,001,090	390,581	117,427	591,831		369,400	414,870	365,929	354,710	3.86	0.00	288,163	47	113	90	0	2.40	73.3	0		67,161	12,562	51
Dec 2011	16,454,135		6,760,958	30,000,241	13,449,851	6,123,030	402,229	119,781	1,227,567		791,282	912,900	772,883	744,755	9.23	0.00	288,917	48	114	90	0	-2.70	64.5	1		67,244	12,587	52
Jan 2012	17,189,290		7,144,766	30,695,585	13,908,310	7,139,900	423,256	121,978	1,318,263		836,029	965,231	720,161	684,942	11.71	0.00	289,160	49	115	90	0	-5.43	67.7	1		67,442	12,357	52
Feb 2012	16,056,605		6,947,844	30,511,792	13,901,887	7,211,780	391,701	115,971	1,239,429		812,547	944,672	712,471	679,535	10.33	0.00	289,403	50	116	90	0	-4.71	69.0	1		67,517	12,195	51
Mar 2012	14,125,525		6,610,789	28,422,488	13,508,455	7,082,771	360,155	117,866	1,140,005		785,940	907,987	709,942	679,960	4.68	0.01	289,645	51	117	90	0	0.49	71.0	1		67,517	12,125	51
Apr 2012	13,415,652		6,349,242	27,018,421	12,782,948	6,973,939	315,028	117,376	995,241		710,347	835,934	683,939	658,279	3.36	0.00	290,210	52	118	90	0	-1.32	63.3	0		67,507	12,037	52
May 2012	13,133,097		6,298,435	27,692,283	14,562,308	7,173,183	238,309	113,581	955,594		703,197	830,050	695,244	665,093	0.00	1.18	290,775	53	119	90	0	8.69	71.0	0		67,473	12,116	52
Jun 2012	16,449,199		6,920,052	29,902,107	15,260,262	7,435,603	236,599	112,514	1,111,035		755,304	894,814	732,899	695,829	0.00	3.39	291,340	54	120	90	0	13.08	70.0	1		67,360	12,129	52
Jul 2012	19,456,208		7,859,012	33,204,579	15,803,145	7,859,647	251,219	120,795	1,303,638		822,921	963,891	753,720	706,725	0.00	6.35	291,612	55	121	90	0	15.46	67.7	1		67,365	12,159	52
Aug 2012	16,963,481		7,106,370	30,946,391	15,510,339	7,844,744	250,899	115,291	1,251,040		796,229	953,581	754,493	715,161	0.00	3.62	291,885	56	122	90	0	15.18	71.0	1		67,464	12,175	52
Sep 2012	14,046,286		6,506,846	28,041,323	14,413,342	7,400,942	287,762	116,419	1,054,138		736,653	892,776	728,372	689,919	0.02	1.19	292,157	57	123	90	0	10.73	63.3	1		67,607	12,183	52
Oct 2012	13,242,942		6,120,297	26,747,664	14,156,783	7,215,165	334,221	113,648	931,032		687,406	831,252	697,308	669,654	1.58	0.04	291,762	58	124	90	0	6.55	71.0	0		67,845	12,184	52
Nov 2012	14,790,898		6,720,938	28,210,819	14,268,656	7,099,906	387,559	118,414	1,053,014		739,475	873,854	712,837	688,378	6.59	0.00	291,366	59	125	90	0	-1.36	73.3	0		67,924	12,205	52
Dec 2012	16,106,072		6,849,155	28,845,345	13,587,636	6,820,259	390,271	115,694	1,184,117		780,674	919,514	691,393	674,899	8.36	0.00	290,971	60	126	90	0	-2.73	61.3	1		67,904	12,225	52
Jan 2013	17,123,333		7,418,873	30,634,027	14,654,298	6,999,070	416,577	117,661	1,375,993		970,087	1,192,975	769,801	714,709	12.14	0.00	291,445	61	127	90	0	-6.04	67.7	1		67,921	12,259	53
Feb 2013	17,019,837		7,505,055	31,515,122	14,769,489	7,151,307	388,030	116,401	1,339,910		976,513	1,209,265	788,781	734,391	14.55	0.00	291,919	62	128	90	0	-7.66	67.9	1		67,944	12,262	53
Mar 2013	15,441,826		6,950,492	28,834,513	14,484,635	7,204,748	365,740	118,337	1,189,928		911,966	1,122,225	758,877	709,511	9.90	0.00	292,393	63	129	90	0	-5.16	67.7	1		68,017	12,206	53
Apr 2013	13,781,403		6,522,474	27,541,564	14,314,860	6,964,997	307,864	115,232	1,038,826		824,253	1,033,171	731,082	686,888	4.51	0.00	293,714	64	130	90	0	0.13	66.7	0		68,028	12,199	53
May 2013	12,978,737	344,698	6,668,144	26,598,851	13,945,408	7,219,587	253,838	119,480	997,442	2,332	815,956	1,025,899	743,166	693,998	0.46	0.75	295,035	65	131	90	0	7.63	71.0	0	35,811	68,025	12,074	53
Jun 2013	14,654,454	357,299	6,725,030	28,830,537	15,242,003	7,057,222	227,370	110,637	1,159,690	2,556	876,418	1,105,944	783,417	726,069	0.00	2.04	296,356	66	132	90	0	12.91	70.0	1	36,156	68,220	11,885	52
Jul 2013	17,596,372	416,733	7,756,647	31,685,353	15,690,464	7,582,708	251,581	122,290	1,360,727	2,849	954,877	1,191,320	805,673	737,439	0.00	4.45	296,993	67	133	90	0	16.14	67.7	1	36,777	68,313	11,924	51
Aug 2013	15,770,492	395,981	7,236,606	29,939,127	15,420,606	7,467,653	250,283	113,167	1,305,826	2,832	923,906	1,178,577	806,500	746,241	0.00	3.03	297,631	68	134	90	0	14.20	71.0	1	37,407	68,386	11,913	51
Sep 2013	13,613,479	375,178	6,616,791	27,712,222	14,725,640	7,303,337	289,793	114,468	1,100,302	2,736	854,777	1,103,425	778,578	719,903	0.00	0.91	298,268	69	135	90	0	11.10	63.3	1	37,871	68,468	11,923	51
Oct 2013	13,018,661	370,361	6,324,666	26,756,876	14,431,160	7,172,470	333,570	112,883	971,804	2,529	797,633	1,027,385	745,373	698,757	1.60	0.01	299,160	70	136	90	0	6.51	71.0	0	38,174	68,558	11,890	51
Nov 2013	15,053,411	401,648	7,027,355	28,607,720	14,514,980	7,034,713	392,104	116,709	1,099,128	2,664	858,051	1,080,038	761,973	718,295	8.12	0.00	300,051	71	137	90	0	-2.60	73.3	0	38,253	68,586	11,904	51
Dec 2013	17,018,027	447,865	7,426,848	30,014,923	14,019,894	6,930,691	392,785	113,251	1,235,973	2,898	905,857	1,136,471	739,050	704,230	14.20	0.00	300,942	72	138	90	0	-7.70	61.3	1	38,602	68,595	11,914	51
Jan 2014	18,837,350	504,749	8,361,525	32,856,560	15,384,595	7,305,563	414,695	119,065	1,461,521	3,604	1,105,198	1,469,137	891,933	775,178	18.64	0.00	300,719	73	139	90	0	-12.65	71.0	1	39,542	68,617	11,904	51
Feb 2014	17,625,995	463,676	7,942,566	32,326,644	15,725,347	7,343,277	392,326	114,207	1,423,195	3,507	1,112,518	1,489,197	913,924	796,525	18.33	0.00	300,496	74	140	90	0	-12.29	67.9	1	40,438	68,570	11,913	52
Mar 2014	16,365,607	448,348	7,755,734	30,888,681	15,109,271	7,265,256	359,544	117,291	1,263,891	3,198	1,038,982	1,382,009	879,277	769,540	14.28	0.00	300,273	75	141	90	0	-9.74	67.7	1	41,224	68,638	11,970	50
Apr 2014	14,008,764	383,650	6,757,314	27,748,285	13,512,418	6,922,565	317,075	116,254	1,103,396	2,868	939,052	1,272,339	847,072	745,003	4.22	0.00	302,104	76	142	90	0	-1.06	66.7	0	42,022	68,723	11,931	45
May 2014	12,193,265	377,883	6,455,952	27,615,215	14,267,396	6,635,439	237,737	110,813	1,059,440	2,954	929,600	1,263,384	861,073	752,714	0.23	0.38	303,936	77	143	90	0	6.75	67.7	0	42,409	68,856	11,886	48
Jun 2014	14,362,245	432,326	7,148,962	29,879,616	14,951,950	7,224,040	236,512	114,787	1,231,773	3,238	998,483	1,361,959	907,710	787,499	0.00	2.27	305,768	78	144	90	0	12.44	70.0	1	43,022	68,952	11,852	47
Jul 2014	14,952,825	447,715	7,370,235	30,444,149	14,971,801	7,039,103	250,699	117,902	1,445,306	3,609	1,087,869	1,467,098	933,497	799,830	0.00	2.29	307,010	79	145	90	0	13.11	71.0	1	43,554	69,058	11,767	46
Aug 2014	14,641,040	452,321	7,244,285	29,857,964	14,917,763	6,974,514	250,712	113,340	1,386,992	3,588	1,052,584	1,451,406	934,455	809,378	0.00	2.64	308,252	80	146	90	0	14.34	64.5	1	44,190	69,002	11,779	46
Sep 2014	13,488,940	452,371	7,212,176	28,770,119	14,765,092	6,735,694	291,310	118,367	1,168,693	3,466	973,827	1,358,856	902,103	780,811	0.03	1.00	309,494	81	147	90	0	16.91	70.0	1	44,785	69,896	10,845	45
Oct 2014	12,737,878	438,137	6,822,741	26,973,512	14,096,396	6,612,482	334,641	112,446	1,032,208	3,203	908,724	1,265,214	863,630	757,876	1.16	0.04	310,295	82	148	90	0	6.71	71.0	0	45,725	70,194	10,622	46
Nov 2014	15,038,105	491,299	7,624,423	29,138,642	14,300,641	6,565,942	389,010	116,863	1,167,447	3,375	977,558	1,330,056	882,863	779,067	8.14	0.00	311,095	83	149	90	0	-2.38	66.7	0	46,681	70,190	10,632	43
Dec 2014	16,119,263	510,443	7,772,535	29,527,625	13,985,324	6,381,557	392,326	114,542	1,312,797	3,671	1,032,021	1,399,553	856,304	763,812	9.98	0.00	311,895	84	150	90	0	-3.56	67.7	1	47,754	70,354	10,537	43
Jan 2015	17,860,289	614,310	8,751,184	32,591,873	14,903,205	6,923,063	415,927	117,177	1,588,681	5,680	1,234,666	1,911,548	1,169,349	966,900	17.56	0.00	312,446	85	151	90	0	-12.09	67.7	1	48,980	70,387	10,502	44
Feb 2015	18,485,093	630,879	9,030,270	34,209,360	15,582,841	7,390,728	393,044	118,223	1,547,021	5,527	1,242,844	1,937,649	1,198,180	993,526	22.60	0.00	312,996	86	152	90	0	-16.85	67.9	1	49,914	70,351	10,492	44
Mar 2015	15,528,943	552,995	8,146,278	30,449,220	14,735,852	7,057,208	362,171	116,102	1,373,856	5,041	1,160,693	1,798,182	1,152,756	959,868	11.85	0.00	313,547	87	153	90	0	-8.04	71.0	1	50,816	70,390	10,478	44
Apr 2015	13,191,273	482,393	7,171,596	27,632,038	14,107,586	6,752,261	308,340	113,366	1,199,397	4,520	1,049,057	1,655,487	1,110,535	929,261	3.15	0.00	314,460	88	154	90	0	-0.29	66.7	0	51,933	70,376	10,435	44
May 2015	12,537,416	521,710	7,320,727	27,528,762	14,269,832	6,717,759	244,319	116,240	1,151,617	4,655	1,038,498	1,643,835	1,128,891	938,880	0.05	1.10	315,374	89	155	90	0	7.72	64.5	0	53,094	70,421	10,380	44
Jun 2015	13,594,466	537,734	7,392,320	28,702,264	14,942,227	6,995,292	236,354	113,937	1,338,944	5,104	1,115,450	1,772,094	1,190,033	982,268	0.00	1.08	316,288	90	156	90	0	12.16	73.3	1	54,516	70,436	10,364	44
Jul 2015	16,611,532	638,808	8,438,995	31,734,954	15,496,789	7,050,227	251,098	119,626	1,571,056	5,688	1,215,308	1,908,895	1,223,840	997,650	0.00	3.69	317,577	91	157	90	0	13.78	71.0	1	57,061	70,393	10,368	44
Aug 2015	15,780,681	605,648	7,808,045	30,467,452	15,293,390	7,286,293	252,434	110,850	1,507,668	5,655	1,175,889	1,888,478	1,225,097	1,009,558	0.00	2.86	318,866	92	158	90	0	14.46	64.5	1	58,994	70,324	10,376	44
Sep 2015	15,037,926	643,506	7,909,572	30,809,706	15,361,895	7,288,661	289,680	121,494	1,270,376	5,462	1,087,906	1,768,058	1,182,682	973,926	0.00	2.73	320,154	93	159	90	0	13.76	70.0	1	60,600	70,329	10,388	44
Oct 2015	12,561,658	566,054	6,880,856	27,165,796	14,149,749	6,781,108	334,582	112,578	1,122,016	5,048	1,015,177	1,646,217	1,132,243	945,318	1.55	0.00	320,725	94	160	90	0	4.21	67.7	0	61,353	70,308	10,425	44
Nov 2015	13,507,088	576,072	7,367,611	27,985,179	14,251,053	6,886,279	391,355	115,988	1,269,021	5,319	1,092,074	1,730,584	1,157,458	971,750	4.06	0.00	321,296	95	161	90	0	1.95	70.0	0	62,050	70,331	10,446	44
Dec 2015	14,575,804	591,114	7,542,310	28,627,975	13,700,879	6,633,371	390,109	115,720	1,427,017	5,785	1,152,917	1,821,010	1,122,639	952,723	5.87	0.00	321,867	96	162	90	0	0.61	67.7	1	62,647	70,300	10,475	44
Jan 2016	16,905,232	702,951	8,296,922	31,303,890	14,589,555	7,077,736	424,021	117,777	1,772,732	12,004	1,302,026	2,373,457	1,444,393	1,151,445	13.63	0.00	323,625	97	163	90	0	-7.88	64.5	1	63,370	70,280	10,496	44
Feb 2016	16,036,882	684,766	8,260,157	31,358,669	14,817,878	7,136,726	391,053	115,831	1,666,720	11,277	1,265,456	2,322,905	1,428,971	1,142,355	12.29	0.00	325,382	98	164	90	0	-7.42	69.0	1	63,732	70,271	10,510	44
Mar 2016	14,386,913	610,747	7,791,991	29,550,266	14,442,395	7,004,562	362,703	115,865	1,533,020	10,652	1,224,018	2,232,698	1,423,897	1,143,071	7.51	0.00	327,139	99	165	90	0	-2.61	67.7	1	64,294	70,233	10,510	44
Apr 2016	13,316,857	583,931	7,362,729	28,341,950	14,282,348	6,999,358	306,864	117,208	1,338,350	9,553	1,106,291	2,055,522	1,371,744	1,106,623	5.59	0.00	326,960	100	166	90	0	-4.20	70.0	0	64,680	70,214	10,508	44
May 2016	13,129,784	584,064	7,200,135	28,032,831	14,392,114	7,108,040	246,533	113,804	1,285,034	9,838	1,095,155	2,041,053	1,394,419	1,118,078	0.41	1.19	326,780	101	167	90	0	5.65	67.7	0	64,917	70,165	10,502	44
Jun 2016	15,660,600	650,589	7,860,446	30,101,670	15,135,778	7,329,068	235,732	115,825	1,494,063	10,786	1,176,306	2,200,306	1,469,942	1,169,747	0.00	2.79	326,600	102	168	90	0	8.94	73.3	1	65,685	70,122	10,475	42
Jul 2016	18,559,188	718,708	8,625,104	33,007,906	15,718,295	7,601,116	252,779	117,703	1,753,065	12,020	1,281,612	2,370,164	1,511,700	1,188,064	0.00	5.71	327,168	103	169	90	0	14.33	64.5	1	65,758	70,175	10,359	44
Aug 2016	19,400,047	768,645	8,903,033	34,570,269	16,279,283	7,755,391	251,938	120,594	1,682,334	11,950	1,240,043	2,344,812	1,513,253	1,202,246	0.00	6.30	327,737	104	170	90	0	16.42	71.0	1	66,456	70,149	10,310	44
Sep 2016	14,844,846	676,823	7,668,790	30,522,551	15,299,229	7,309,325	291,217	114,998	1,417,551	11,542	1,147,260	2,195,294	1,460,861	1,159,813	0.00	2.31	328,305	105	171	90	0	12.53	70.0	1	66,796	70,128	10,318	44
Oct 2016	12,177,966	615,120	7,016,560	27,550,296	14,294,548	6,974,029	335,878	113,952	1,252,003	10,669	1,070,562	2,044,011	1,398,559	1,125,745	1.46	0.13	328,965	106	172	90	0	7.36	64.5	0	67,351	70,106	10,333	44
Nov 2016	13,478,836	630,733	7,356,201	28,324,064	14,328,205	7,039,077	390,978	115,363	1,416,039	11,242	1,151,655	2,148,765	1,429,705	1,157,222	3.62	0.00	329,625	107	173	90	0	2.35	73.3	0	67,985	70,068	10,343	44
Dec 2016	15,756,855	718,420	7,960,693	30,588,500	14,087,872	7,009,103	393,775	117,739	1,592,340	12,226	1,215,818	2,261,041	1,386,696	1,134,563	11.61	0.00	330,285	108	174	90	0	-5.55	64.5	1	68,472	70,109	10,352	44
Jan 2017	16,480,695	754,884	8,290,299	31,356,469	14,497,397	7,246,213	420,963	116,559	2,154,484	27,027	1,354,430	2,813,214	1,633,251	1,249,545	11.64	0.00	331,991	109	175	90	0	-5.38	67.7	1	69,066	70,064	10,364	44
Feb 2017	15,648,066	717,350	8,157,446	31,031,301	14,616,437	7,239,837	392,596	115,453	2,097,987	26,297	1,363,401	2,851,627	1,673,520	1,283,955	10.26	0.00	333,696	110	176	90	0	-5.22	67.9	1	69,376	70,097	10,386	44
Mar 2017	15,154,920	712,713	8,100,646	30,678,174	14,631,711	7,210,048	362,401	118,682	1,863,150	23,984	1,273,282	2,646,375	1,610,076	1,240,457	10.55	0.00	335,402	111	177	90	0	-6.63	74.2	1	69,954	70,467	10,370	44
Apr 2017	12,748,785	611,881	7,164,591	27,367,757	13,752,407	6,815,849	305,235	114,265	1,626,559	21,508	1,150,816	2,436,371	1,551,104	1,200,904	1.92	0.00	336,181	112	178	90	0	2.48	60.0	0	70,312	70,659	10,399	44
May 2017	12,300,434	621,833	7,039,866	27,390,899	14,212,213	6,986,874	248,809	116,324	1,561,762	22,150	1,139,233	2,419,222	1,576,743	1,213,334	0.72	0.29	336,960	113	179	90	0	6.31	71.0	0	70,637	70,602	10,448	44
Jun 2017	14,184,753	692,294	7,713,934	29,957,774	14,914,799	7,343,685	236,747	116,430	1,815,804	24,284	1,223,649	2,607,981	1,662,141	1,269,406	0.00	2.27	337,739	114	180	90	0	12.09	73.3	1	71,041	70,610	10,407	44
Jul 2017	16,246,996	746,338	8,084,204	31,292,836	15,182,237	7,423,654	251,532	114,721	2,130,581	27,063	1,333,193	2,809,311	1,709,360	1,289,283	0.00	3.76	337,985	115	181	90	0	14.95	64.5	2	71,093	70,601	10,413	44
Aug 2017	15,153,113	735,232	7,908,049	30,932,533	15,165,085	7,453,959	251,239	120,423	2,044,619	26,905	1,289,951	2,779,262	1,711,115	1,304,673	0.00	2.43	338,231	116	182	90	0	14.01	71.0	3	71,591	70,621	10,418	44
Sep 2017	14,398,577	748,487	7,711,142	30,231,629	14,969,940	7,379,629	292,182	116,421	1,722,816	25,988	1,193,434	2,602,041	1,651,873	1,258,626	0.00	2.38	338,477	117	183	90	0	12.32	66.7	4	71,834	70,645	10,424	43
Oct 2017	12,533,838	677,231	6,940,374	27,549,310	14,245,297	6,957,227	336,969	113,111	1,521,618	24,021	1,113,650	2,422,728	1,581,424	1,221,655	0.78	0.26	339,538	118	184	90	0	8.09	67.7	5	72,231	70,664	10,430	44
Nov 2017	14,385,819	739,868	7,727,492	29,086,849	14,231,845	6,894,773	391,260	117,864	1,720,978	25,310	1,198,006	2,546,891	1,616,643	1,255,813	6.47	0.00	340,598	119	185	90	0	-1.48	73.3	6	72,683	70,682	10,436	44
Dec 2017	16,807,840	843,294	8,316,949	30,469,544	14,441,803	7,202,749	409,100	120,951	1,935,245	27,527	1,264,751	2,679,970	1,568,010	1,231,224	15.18	0.00	341,658	120	186	90	0	-9.51	61.3	7	73,031	70,701	10,441	44

Model Input Data

Month	Purchased Energy per day, kWh (by customer class)								Cumulative CDM impacts per day, kWh						HDD10 per day	CDD18 per day	GDP	Time Trend			Blackout Dummy	DewPoint Temperature	Business Days Percent	Shoulder Flag	Customer Numbers			
	Residential	Competitive Sector Multi-Unit Residential (CSMUR)	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street lighting	Unmetered Scattered Load	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use				Residential	GS<50 kW & GS 1,000-4,999 kW	Large Use					CSMUR	GS<50 kW (excluding FIT)	GS 50-999 kW	Large Use
Jan 2018	18,005,194	883,304	8,809,537	33,215,018	14,962,879	7,298,499	422,522	115,054	2,476,431	40,128	1,442,877	3,270,022	1,777,201	1,328,513	15.62	0.00	342,710	121	187	90	0	-9.97	71.0	1	73,455	70,711	10,447	44
Feb 2018	16,560,149	802,626	8,537,724	31,888,468	14,685,369	7,139,581	391,074	115,453	2,411,491	39,045	1,452,434	3,314,673	1,821,019	1,365,098	11.82	0.00	343,763	122	188	90	0	-6.19	67.9	1	73,465	70,713	10,463	44
Mar 2018	15,175,018	748,767	8,034,963	30,268,340	14,274,981	6,961,427	363,128	113,942	2,141,562	35,610	1,356,430	3,076,092	1,751,983	1,318,852	9.87	0.00	344,816	123	189	90	0	-7.39	67.7	1	73,919	70,708	10,489	44
Apr 2018	14,248,720	725,951	7,750,941	29,354,457	14,086,517	6,857,805	307,536	115,419	1,869,616	31,933	1,225,967	2,831,988	1,687,813	1,276,799	6.67	0.00	345,469	124	190	90	0	-3.82	66.7	0	74,037	70,704	10,486	44
May 2018	13,322,593	711,128	7,447,894	28,486,123	14,450,080	6,973,326	246,135	112,418	1,795,137	32,888	1,213,627	2,812,054	1,715,712	1,290,015	0.06	1.40	346,121	125	191	90	0	8.04	71.0	0	74,081	70,714	10,463	44
Jun 2018	15,637,085	751,312	7,736,604	30,294,664	15,076,104	7,425,837	237,671	108,819	2,087,141	36,055	1,303,556	3,031,463	1,808,637	1,349,630	0.00	2.02	346,774	126	192	90	0	11.72	70.0	1	74,523	70,599	10,515	44
Jul 2018	19,817,641	879,507	8,838,210	34,426,020	16,032,434	7,164,055	252,218	118,485	2,448,956	40,182	1,420,254	3,265,485	1,860,017	1,370,763	0.00	5.41	347,368	127	193	90	0	15.37	67.7	1	75,000	70,645	10,530	44
Aug 2018	19,205,209	889,526	8,756,998	34,450,013	16,150,116	7,331,758	252,219	115,279	2,350,148	39,947	1,374,188	3,230,557	1,861,927	1,387,126	0.00	5.24	347,961	128	194	90	0	17.42	71.0	1	75,635	70,605	10,506	38
Sep 2018	15,716,276	823,780	7,924,686	31,466,330	15,337,200	7,017,087	292,261	116,652	1,980,257	38,585	1,271,368	3,024,558	1,797,464	1,338,168	0.00	2.55	348,554	129	195	90	0	13.94	63.3	1	76,188	70,652	10,422	38
Oct 2018	13,062,503	740,383	7,233,223	28,581,640	14,581,606	6,716,338	338,543	113,552	1,748,995	35,665	1,186,374	2,816,129	1,720,806	1,298,860	2.64	0.26	348,790	130	196	90	0	4.44	71.0	0	76,449	70,679	10,419	38
Nov 2018	15,251,327	810,750	7,987,746	30,394,748	14,647,124	6,617,801	391,974	110,009	1,978,145	37,580	1,276,238	2,960,453	1,759,129	1,335,178	8.55	0.00	349,025	131	197	90	0	-2.71	73.3	0	76,776	70,777	10,439	38
Dec 2018	16,229,086	845,463	8,194,131	29,726,304	14,563,781	6,498,382	414,751	114,887	2,224,430	40,871	1,347,342	3,115,142	1,706,209	1,309,035	10.18	0.00	349,260	132	198	90	0	-3.74	61.3	1	76,806	70,829	10,462	38
Jan 2019									2,588,009	46,739	1,543,805	3,747,983	1,950,575	1,428,155	15.20	0.00	350,233	133	199	90	0	-9.09	71.0	1	77,382	70,840	10,460	38
Feb 2019									2,520,143	45,477	1,554,031	3,799,160	1,998,668	1,467,484	14.26	0.00	351,206	134	200	90	0	-8.52	67.9	1	77,884	70,851	10,457	38
Mar 2019									2,238,053	41,476	1,451,311	3,525,707	1,922,896	1,417,769	9.41	0.00	352,180	135	201	90	0	-5.41	67.7	1	78,481	70,862	10,455	38
Apr 2019									1,953,854	37,194	1,311,723	3,245,924	1,852,467	1,372,562	3.72	0.00	352,856	136	202	90	0	-0.78	66.7	0	79,103	70,873	10,452	38
May 2019									1,876,019	38,306	1,298,519	3,223,076	1,883,087	1,386,769	0.31	0.84	353,533	137	203	90	0	7.32	71.0	0	79,699	70,884	10,450	38
Jun 2019									2,181,179	41,995	1,394,739	3,474,556	1,985,077	1,450,855	0.00	2.07	354,209	138	204	90	0	12.08	66.7	1	80,204	70,895	10,447	38
Jul 2019									2,559,296	46,801	1,519,600	3,742,783	2,041,470	1,473,574	0.00	4.48	354,894	139	205	90	0	14.97	71.0	1	80,703	70,906	10,445	38
Aug 2019									2,456,036	46,528	1,470,311	3,702,749	2,043,566	1,491,164	0.00	3.75	355,580	140	206	90	0	15.39	67.7	1	81,201	70,917	10,442	38
Sep 2019									2,069,480	44,942	1,360,299	3,466,641	1,972,814	1,438,534	0.01	1.61	356,265	141	207	90	0	12.84	66.7	1	81,699	70,929	10,440	38
Oct 2019									1,827,797	41,540	1,269,360	3,227,747	1,888,678	1,396,278	1.55	0.08	356,962	142	208	90	0	6.05	71.0	0	82,197	70,940	10,437	38
Nov 2019									2,067,273	43,771	1,365,510	3,393,166	1,930,740	1,435,320	5.91	0.00	357,660	143	209	90	0	-0.07	70.0	0	82,695	70,951	10,435	38
Dec 2019									2,324,654	47,604	1,441,588	3,570,465	1,872,658	1,407,216	11.08	0.00	358,357	144	210	90	0	-4.79	64.5	1	83,193	70,962	10,432	38
Jan 2020									2,635,733	52,142	1,626,152	4,233,364	2,134,018	1,727,455	15.20	0.00	359,068	145	211	90	0	-9.09	71.0	1	83,692	70,973	10,430	38
Feb 2020									2,478,111	48,986	1,580,477	4,143,198	2,111,233	1,713,818	14.26	0.00	359,779	146	212	90	0	-8.52	65.5	1	84,170	70,984	10,427	38
Mar 2020									2,279,323	46,272	1,528,724	3,982,303	2,103,736	1,714,892	9.41	0.00	360,489	147	213	90	0	-5.41	71.0	1	84,620	70,995	10,425	38
Apr 2020									1,989,884	41,494	1,381,690	3,666,286	2,026,684	1,660,211	3.72	0.00	361,220	148	214	90	0	-0.78	66.7	0	85,050	71,006	10,422	38
May 2020									1,910,613	42,735	1,367,783	3,640,480	2,060,184	1,677,396	0.31	0.84	361,951	149	215	90	0	7.32	64.5	0	85,460	71,017	10,420	38
Jun 2020									2,221,401	46,850	1,469,135	3,924,527	2,171,765	1,754,913	0.00	2.07	362,682	150	216	90	0	12.08	73.3	1	85,852	71,028	10,417	38
Jul 2020									2,606,491	52,212	1,600,655	4,227,491	2,233,462	1,782,393	0.00	4.48	363,415	151	217	90	0	14.97	71.0	1	86,224	71,039	10,415	38
Aug 2020									2,501,326	51,907	1,548,738	4,182,272	2,235,755	1,803,669	0.00	3.75	364,149	152	218	90	0	15.39	64.5	1	86,596	71,050	10,412	38
Sep 2020									2,107,642	50,138	1,432,858	3,915,588	2,158,349	1,740,009	0.01	1.61	364,882	153	219	90	0	12.84	70.0	1	86,968	71,061	10,410	38
Oct 2020									1,861,503	46,343	1,337,067	3,645,755	2,066,300	1,688,898	1.55	0.08	365,628	154	220	90	0	6.05	67.7	0	87,340	71,072	10,407	38
Nov 2020									2,105,394	48,831	1,438,347	3,832,597	2,112,318	1,736,121	5.91	0.00	366,374	155	221	90	0	-0.07	70.0	0	87,712	71,083	10,405	38
Dec 2020									2,367,521	53,108	1,518,482	4,032,857	2,048,773	1,702,128	11.08	0.00	367,120	156	222	90	0	-4.79	67.7	1	88,084	71,094	10,402	38
Jan 2021									2,675,332	57,199	1,704,358	4,671,466	2,308,546	2,012,784	15.20	0.00	367,888	157	223	90	0	-9.09	64.5	1	88,456	71,105	10,400	38
Feb 2021									2,605,176	55,656	1,715,647	4,735,253	2,365,465	2,068,213	14.26	0.00	368,657	158	224	90	0	-8.52	67.9	1	88,862	71,117	10,397	38
Mar 2021									2,313,567	50,759	1,602,245	4,394,422	2,275,788	1,998,147	9.41	0.00	369,425	159	225	90	0	-5.41	74.2	1	89,320	71,128	10,395	38
Apr 2021									2,019,780	45,519	1,448,140	4,045,702	2,192,434	1,934,434	3.72	0.00	370,202	160	226	90	0	-0.78	66.7	0	89,811	71,139	10,392	38
May 2021									1,939,318	46,879	1,433,563	4,017,225	2,228,673	1,954,457	0.31	0.84	370,980	161	227	90	0	7.32	64.5	0	90,337	71,150	10,390	38
Jun 2021									2,254,775	51,394	1,539,790	4,330,667	2,349,380	2,044,777	0.00	2.07	371,757	162	228	90	0	12.08	73.3	1	90,897	71,161	10,387	38
Jul 2021									2,645,650	57,276	1,677,635	4,664,984	2,416,123	2,076,796	0.00	4.48	372,533	163	229	90	0	14.97	67.7	1	91,491	71,172	10,385	38
Aug 2021									2,538,906	56,942	1,623,221	4,615,087	2,418,603	2,101,586	0.00	3.75	373,309	164	230	90	0	15.39	67.7	1	92,084	71,183	10,382	38
Sep 2021									2,139,307	55,001	1,501,768	4,320,803	2,334,867	2,027,412	0.01	1.61	374,084	165	231	90	0	12.84	70.0	1	92,678	71,194	10,380	38
Oct 2021									1,889,470	50,838	1,401,371	4,023,046	2,235,290	1,967,859	1.55	0.08	374,869	166	232	90	0	6.05	64.5	0	93,272	71,205	10,377	38
Nov 2021									2,137,025	53,567	1,507,521	4,229,224	2,285,071	2,022,882	5.91	0.00	375,653	167	233	90	0	-0.07	73.3	0	93,866	71,216	10,375	38
Dec 2021									2,403,091	58,258	1,591,511	4,450,208	2,216,330	1,983,274	11.08	0.00	376,438	168	234	90	0	-4.79	67.7	1	94,459	71,227	10,372	38
Jan 2022									2,714,930	62,257	1,781,822	5,066,605	2,467,622	2,136,410	15.20	0.00	377,258	169	235	90	0	-9.09	64.5	1	95,053	71,238	10,370	38
Feb 2022									2,643,736	60,577	1,793,624	5,135,788	2,528,463	2,195,243	14.26	0.00	378,078	170	236	90	0	-8.52	67.9	1	95,620	71,249	10,367	38
Mar 2022									2,347,812	55,247	1,675,068	4,766,128	2,432,607	2,120,873	9.41	0.00	378,898	171	237	90	0	-5.41	74.2	1	96,145	71,260	10,365	38
Apr 2022									2,049,675	49,543	1,513,958	4,387,911	2,343,509	2,053,247	3.72	0.00	379,699	172	238	90	0	-0.78	63.3	0	96,643	71,271	10,362	38
May 2022									1,968,023	51,024	1,498,719	4,357,025	2,382,246	2,074,500	0.31	0.84	380,499	173	239	90	0	7.32	67.7	0	97,114	71,282	10,360	38
Jun 2022									2,288,149	55,938	1,609,774	4,696,980	2,511,270	2,170,368	0.00	2.07	381,300	174	240	90	0	12.08	73.3	1	97,558	71,293	10,357	38
Jul 2022									2,684,810	62,340	1,753,885	5,059,575	2,582,611	2,204,354	0.00	4.48	382,088	175	241	90	0	14.97	64.5	1	97,975	71,305	10,355	38
Aug 2022									2,576,485	61,976	1,696,997	5,005,457	2,585,263	2,230,666	0.00	3.75	382,876	176	242	90	0	15.39	71.0	1	98,392	71,316	10,352	38
Sep 2022									2,170,972	59,864	1,570,024	4,686,281	2,495,757	2,151,936	0.01	1.61	383,663	177	243	90	0	12.84	70.0	1	98,809	71,327	10,350	38
Oct 2022									1,917,437	55,332	1,465,064	4,363,338	2,389,318	2,088,725	1.55	0.08	384,449	178	244	90	0	6.05	64.5	0	99,226	71,338	10,347	38
Nov 2022									2,168,656	58,303	1,576,038	4,586,956	2,442,529	2,147,128	5.91	0.00	385,234	179	245	90	0	-0.07	73.3	0	99,643	71,349	10,345	38
Dec 2022									2,438,660	63,409	1,663,845	4,826,632	2,369,051	2,105,086	11.08	0.00	386,020	180	246	90	0	-4.79	64.5	1	100,060	71,360	10,342	38
Jan 2023									2,754,529	67,314	1,859,286	5,461,744	2,626,698	2,260,035	15.20	0.00	386,801	181	247	90	0	-9.09	67.7	1	100,477	71,371	10,340	38
Feb 2023									2,682,296	65,497	1,871,601	5,536,322	2,691,461	2,322,273	14.26	0.00	387,583	182	248	90	0	-8.52	67.9	1	100,883	71,382	10,337	38
Mar 2023									2,382,056	59,735	1,747,890	5,137,833	2,589,426	2,243,599	9.41	0.00	388,364	183	249	90	0	-5.41	74.2	1	101,272	71,393	10,335	38
Apr 2023									2,079,571	53,568	1,579,777	4,730,119	2,494,584	2,172,060	3.72	0.00	389,145	184	250	90	0	-0.78	60.0	0	101,650	71,404	10,332	38
May 2023									1,996,728	55,169	1,563,875	4,696,825	2,535,818	2,194,543	0.31	0.84	389,925	185	251	90	0	7.32	71.0	0	102,017	71,415	10,330	38
Jun 2023									2,321,523	60,482	1,679,758	5,063,292	2,673,160	2,295,958	0.00	2.07	390,706	186	252	90	0	12.08	73.3	1	102,374	71,426	10,327	38
Jul 2023									2,723,969	67,404	1,830,134	5,454,166	2,749,100	2,331,911	0.00	4.48	391,485	187	253	90	0	14.97	64.5	1	102,719	71,437	10,325	38
Aug 2023									2,614,065	67,010	1,770,773	5,395,827	2,751,923	2,359,746	0.00	3.75	392,263	188	254	90	0	15.39	71.0	1	103,064	71,448	10,322	38
Sep 2023									2,202,636	64,726	1,638,280	5,051,759	2,656,647	2,276,460	0.01	1.61	393,042	189	255	90	0	12.84	66.7	1	103,409	71,459	10,320	38
Oct 2023									1,945,403	59,827	1,528,757	4,703,630	2,543,346	2,209,591	1.55	0.08	393,818	190	256	90	0	6.05	67.7	0	103,755	71,470	10,317	38
Nov 2023									2,200,287	63,039	1,644,556	4,944,688	2,599,988	2,271,374	5.91	0.00	394,594	191	257	90	0	-0.07	73.3	0	104,100	71,482	10,315	38
Dec 2023									2,474,229	68,560	1,736,180	5,203,056	2,521,773	2,226,899	11.08	0.00	395,371	192	258	90	0	-4.79	61.3	1	104,445	71,493	10,312	38
Jan 2024									2,794,128	72,371	1,936,750	5,856,883	2,785,774	2,383,661	15.20	0.00	395,958	193	259	90	0	-9.09	71.0	1	104,790	71,504	10,310	38
Feb 2024									2,627,034	67,990	1,882,351	5,732,138	2,756,030	2,364,844	14.26	0.00	396,545	194	260	90	0	-8.52	69.0	1	105,141	71,515	10,307	38
Mar 2024									2,416,300	64,222	1,820,713	5,509,538	2,746,244	2,366,326	9.41	0.00	397,133	195	261	90	0	-5.41	64.5	1	105,500	71,526	10,305	38
Apr 2024									2,109,467	57,592	1,645,595	5,072,328	2,645,659	2,290,873	3.72	0.00	397,720	196	262	90	0	-0.78	70.0	0	105,865	71,537	10,302	38
May 2024									2,025,432	59,313	1,629,031	5,036,625	2,689,390	2,314,586	0.31	0.84	398,307	197	263	90	0	7.32	71.0	0	106,235	71,548	10,300	38
Jun 2024									2,354,897	65,026	1,749,742	5,429,605	2,835,050	2,421,549	0.00	2.07	398,895	198	264	90	0	12.08	66.7	1	106,611	71,559	10,297	38
Jul 2024									2,763,129	72,468	1,906,383	5,848,757	2,915,589	2,459,468	0.00	4.48	399,482	199	265	90	0	14.97	71.0	1	106,992	71,570	10,295	38
Aug 2024									2,651,644	72,045	1,844,549	5,786,198	2,918,583	2,488,825	0.00	3.75	400,069	200	266	90	0	15.39	67.7	1	107,373	71,581	10,293	38
Sep 2024									2,234,301	69,589	1,706,536	5,417,238	2,817,536	2,400,984	0.01	1.61	400,657	201	267	90	0	12.84	66.7	1	107,754	71,592	10,290	38
Oct 2024									1,973,370	64,321	1,592,449	5,043,922	2,697,374	2,330,457	1.55	0.08	401,244	202	268	90	0	6.05	71.0	0	108,135	71,603	10,288	38
Nov 2024									2,231,918	67,775	1,713,073	5,302,420	2,757,446	2,395,619	5.91	0.00	401,831	203	269	90	0	-0.07	70.0	0	108,516	71,614	10,285	38
Dec 2024									2,509,798	73,711	1,808,515	5,579,480	2,674,494	2,348,712	11.08	0.00	402,419	204	270	90	0	-4.79	64.5	1	108,897	71,625	10,283	38

Residential Model

Dependent Variable: RES_DAY
Method: Least Squares
Date: 03/19/19 Time: 13:42
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(1,429,603)**	104,160	-13.73	0.000
CDD18_DAY	**1,003,361**	40,988	24.48	0.000
HDD10_DAY	**296,592**	9,160	32.38	0.000
SHOULDER_FLAG	**309,843**	90,705	3.42	0.001
TREND_2008	**(3,388)**	903	-3.75	0.000
C	**12,711,385**	74,509	170.60	0.000

R-squared	**92.8%**	Mean dependent var	15367630.88
Adjusted R-squared	**92.6%**	S.D. dependent var	1800000.11
S.E. of regression	488,231.0	Akaike info criterion	29.06
Sum squared resid	45,766,944,664,847.0	Schwarz criterion	29.16
Log likelihood	(2,871.4)	Hannan-Quinn criter.	29.11
F-statistic	497.1	Durbin-Watson stat	1.28
Prob(F-statistic)	0.0		

CSMUR Model

Dependent Variable: CSMUR_PERDAY
Method: Least Squares
Date: 03/06/19 Time: 03:01
Sample: 2013M05 2018M12
Included observations: 68
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
CUST_NUM	**10**	0	46.21	0.000
DEW	**6,695**	1,236	5.42	0.000
CDD18_DAY	**16,881**	3,250	5.19	0.000
HDD10_DAY	**16,827**	1,703	9.88	0.000
C	**(128,948)**	19,874	(6.49)	0.000

R-squared	**97.8%**	Mean dependent var	612254.46
Adjusted R-squared	**97.7%**	S.D. dependent var	149460.03
S.E. of regression	22,750.7	Akaike info criterion	22.97
Sum squared resid	32,608,405,765.3	Schwarz criterion	23.14
Log likelihood	(776.1)	Hannan-Quinn criter.	23.04
F-statistic	707.1	Durbin-Watson stat	1.03
Prob(F-statistic)	0.0		

GS <50 kW Model

Dependent Variable: LESS50_DAY
Method: Least Squares
Date: 03/06/19 Time: 03:28
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(242,885)**	40,510	(6.00)	0.000
CDD18_DAY	**276,524**	10,328	26.77	0.000
BUS_DAYS_PERCENT	**9,195**	3,257	2.82	0.005
HDD10_DAY	**80,213**	2,999	26.74	0.000
NUMCUSTNETFIT	**329**	14	22.97	0.000
GDP	**13**	2	5.99	0.000
SHOULDER_FLAG	**165,990**	30,104	5.51	0.000
TREND_JUL2002	**(10,720)**	897	(11.96)	0.000
C	**(19,195,769)**	743,924	(25.80)	0.000

R-squared	**95.4%**	Mean dependent var	7186339.68
Adjusted R-squared	**95.2%**	S.D. dependent var	713059.28
S.E. of regression	156,782.0	Akaike info criterion	26.81
Sum squared resid	4,645,731,102,010.8	Schwarz criterion	26.96
Log likelihood	(2,644.9)	Hannan-Quinn criter.	26.86798814
F-statistic	485.7	Durbin-Watson stat	1.155036629
Prob(F-statistic)	0.0		

GS 50-999kW model

Dependent Variable: GS350_DAY
Method: Least Squares
Date: 03/19/19 Time: 15:00
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(1,636,149)**	92,191	(17.75)	0.000
BUS_DAYS_PERCENT	**45,438**	9,638	4.71	0.000
CDD18_DAY	**946,816**	31,103	30.44	0.000
CUST_NUMBERS	**363**	35	10.29	0.000
DEW	**74,836**	14,627	5.12	0.000
GDP	**30**	1	26.73	0.000
HDD10_DAY	**384,616**	19,957	19.27	0.000
SHOULDER_FLAG	**389,153**	83,381	4.67	0.000
C	**9,574,381**	872,957	10.97	0.000

R-squared	**96.4%**	Mean dependent var	29084310.74
Adjusted R-squared	**96.3%**	S.D. dependent var	2063120.60
S.E. of regression	399,314.0	Akaike info criterion	28.68
Sum squared resid	30,136,368,679,837.6	Schwarz criterion	28.83
Log likelihood	(2,830.1)	Hannan-Quinn criter.	28.73777209
F-statistic	633.7	Durbin-Watson stat	1.439752354
Prob(F-statistic)	0.0		

GS 1000-4999kW Model

Dependent Variable: GS450_DAY
Method: Least Squares
Date: 03/06/19 Time: 03:25
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(955,498)**	67,690	(14.12)	0.000
BUS_DAYS_PERCENT	**47,724**	6,435	7.42	0.000
DEW	**84,159**	10,570	7.96	0.000
GDP	**23**	3	7.79	0.000
HDD10_DAY	**151,943**	12,558	12.10	0.000
TREND_JUL2002	**(10,352)**	1,616	(6.41)	0.000
CDD18_DAY	**281,629**	28,298	9.95	0.000
C	**4,241,721**	866,858	4.89	0.000

R-squared	83.79%	Mean dependent var	14522469.65
Adjusted R-squared	**83.2%**	S.D. dependent var	771953.67
S.E. of regression	**31649028.9%**	Akaike info criterion	28.21
Sum squared resid	19,031,559,621,186.8	Schwarz criterion	28.34
Log likelihood	(2,784.5)	Hannan-Quinn criter.	28.26
F-statistic	140.3	Durbin-Watson stat	1.05449678
Prob(F-statistic)	0.0		

Large Use Model

Dependent Variable: LU_DAY
Method: Least Squares
Date: 03/06/19 Time: 03:38
Sample: 2002M07 2018M12
Included observations: 198
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BLACKOUT	**(368,060)**	60,337	(6.10)	0.000
BUS_DAYS_PERCENT	**15,711**	5,078	3.09	0.002
CDD18_DAY	**143,974**	25,215	5.71	0.000
CUST	**42,463**	8,550	4.97	0.000
DEW	**33,809**	9,129	3.70	0.000
GDP	**5**	1	4.10	0.000
HDD10_DAY	**61,792**	10,303	6.00	0.000
TREND_SPLINE_2010	**(8,450)**	1,154	(7.32)	0.000
C	**2,603,674**	744,157	3.50	0.001

R-squared	**70.4%**	Mean dependent var	7149049.95
Adjusted R-squared	**69.2%**	S.D. dependent var	425163.92
S.E. of regression	236,020.6	Akaike info criterion	27.63
Sum squared resid	10,528,384,295,470.9	Schwarz criterion	27.78
Log likelihood	(2,725.9)	Hannan-Quinn criter.	27.68611426
F-statistic	56.3	Durbin-Watson stat	1.261604392
Prob(F-statistic)	0.0		

OPERATING REVENUE: REVENUE OFFSETS VARIANCE ANALYSIS

1. OTHER REVENUE

Exhibit 3, Tab 2 includes information about the other revenue that Toronto Hydro received from non-distribution related services. This schedule provides a summary of the 2018 actuals, explains the material variances, and identifies material changes to the 2019 bridge and 2020 test year as a result of the 2018 actuals.

Table 1 below provides an updated summary of 2015-2019 Other Revenues. A more detailed breakdown of Other Revenue by Uniform System of Accounts is provided in the updated OEB Appendix 2-H, which is filed as Appendix A to this schedule.

Table 1: Other Revenue Summary

Description	Actual Year 2015	Actual Year 2016	Actual Year 2017	Actual Year 2018	Bridge Year 2019	Test Year 2020
Specific Service Charges	6.8	9.5	7.2	6.0	5.1	3.7
Late Payment Charges	4.1	4.5	3.7	3.3	3.7	3.8
Other Operating Revenues	10.8	12	13.4	11.8	12.4	12.0
Other Income or Deductions	16.1	18.7	21.4	26.1	27.6	27.4
Total Revenue Offset	**37.8**	**44.7**	**45.7**	**47.2**	**48.8**	**46.8**

Note 1: See Table 2 below for expected changes to the 2020 Test Year Forecast.

In 2018, Revenue Offsets were $3.3 million higher than originally forecasted in Exhibit 3, Tab 2, Schedule 1, page 1. The difference was primarily due to higher revenues from the pole attachments and accident claims, which are accounted for in the Other Income or Deductions category.

In 2019, Revenue Offsets are expected to be approximately $2.1 million higher than the original forecast as follows:

- Specific Service Charges are expected to decrease by $1.5 million as a result of the removal of the Collection of Account and Install/Remove Load Control Devices charges as of July 1 in accordance with the OEB rate order dated March 14, 2019, made under Phase 1 of the Customer Service Rules review (EB-2017-0183).
- Other Income and Deductions is expected to increase by $3.6 million due to lower merchandising and jobbing costs of $2 million as a result of capitalization of major assets related to accident claims, and a $1.6 million gain on disposition of a property which is expected to be sold in the second or third quarter of this year.

The 2019 changes to specific service charges revenues and merchandising and jobbing cost changes are expected to affect the 2020 forecast, as summarized in Table 2 below.

Table 2: Identified Changes in Other Revenues for 2020 Test Years ($ Millions)

	2020 Test Year Original Forecast	Identified Changes	Revised 2020 Test Year
Specific Service Charges	6.6	(3.0)	3.6
Late Payment Charges	3.8	-	3.8
Other Operating Revenues	12.0	-	12.0
Other Income or Deductions	25.4	2.0	27.4
Total	47.7	(1.0)	46.8

Toronto Hydro requests that these changes be approved by the OEB as part of the 2020 test year. However, as the net impact of these changes is only $1 million, in the interest efficiency, Toronto Hydro has decided not updated the 2020 revenue requirement. If the changes are approved by the OEB, the utility proposes to incorporate them in the 2020 revenue requirement as part of the Draft Rate Order process.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
		2015	2016	2017	2018	2019	2020
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
4225	Late Payment Charges	$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
4082	Retailers' Fixed charge	$5,320	$5,280	$5,520	$5,280	$5,420	$5,420
4082	Retailers' Variable Charge	$257,269	$225,343	$178,662	$146,005	$171,386	$162,420
4082	Distributor Consolidated Billing (DCB) Charges	$143,718	$125,603	$106,118	$87,079	$99,207	$94,067
4082	Retail Consolidated Billing (RCB) Credit	-$9,072	-$8,351	-$635	$0	$0	$0
4084	Retailer Service Transaction Request	$13,764	$12,656	$10,350	$8,302	$9,282	$8,816
4084	Retailer Service Transaction Processing	$6,344	$5,722	$4,485	$3,190	$4,271	$4,081
4090/4086	SSS Admin Charge	$2,196,126	$2,317,539	$2,269,960	$2,313,558	$2,389,560	$2,407,409
4210	Parking Rental	$3,790	$1,200	$1,200	$4,408	$0	$0
4210	Property Rental	$41,516	$46,854	$53,414	$47,228	$0	$0
4215	TTC Rectification	$253,250	$303,900	$303,900	$303,900	$303,900	$303,900
4215	Settlement Discounts Taken	$404,384	$381,359	$523,847	$340,755	$389,382	$389,382
4215	Stale Dated Cheques	$453,706	$417,078	$736,416	$462,171	$533,368	$533,368
4220	Street Lighting	$7,055,723	$8,200,259	$9,229,601	$8,035,739	$8,536,375	$8,076,074
4325	Merchandise and Jobbing Revenue	$23,108,588	$32,769,384	$45,929,144	$47,400,242	$36,014,502	$37,732,615
4330	Merchandise and Jobbing Costs	-$14,047,565	-$19,805,704	-$29,913,621	-$27,406,949	-$15,651,688	-$15,991,089
4335	Gain/Loss on disposals	$211,338	$0	$0	$0	$0	$0
4375	Shared Services Recovery[1]	$2,927,027	$3,212,613	$4,829,010	$5,670,327	$5,494,615	$5,507,706
4355	Gain on Disposition of Utility and Other Property	$4,062,681	$2,132,160	$515,158	$576,205	$1,630,000	$0
4398	Foreign Exchange Gain/(Loss)	-$1,500,430	$162,383	$54,784	-$128,336	$0	$0
4405	Investment Interest Income	$1,298,537	$186,388	$9	$0	$120,000	$120,000
Specific Service Charges		$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
Late Payment Charges		$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
Other Operating Revenues		$10,825,837	$12,034,443	$13,422,839	$11,757,613	$12,442,150	$11,984,936
Other Income or Deductions		$16,060,177	$18,657,224	$21,414,483	$26,111,488	$27,607,430	$27,369,233
Total		**$37,799,149**	**$44,729,912**	**$45,720,340**	**$47,158,636**	**$48,889,769**	**$46,795,749**

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Appendix 2-H
Other Operating Revenue

Account Breakdown Details

Account 4235 -Specific Service Charges

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account Set Up Charge	$3,163,196	$3,315,852	$3,132,490	$2,686,465	$3,010,922	$3,027,508
NSF Collection Charges	$59,445	$111,704	$106,825	$116,209	$107,980	$108,541
Collection Service Charges	$2,986,342	$5,165,058	$3,130,010	$2,495,315	$1,437,643	$0
Connection-Reconnection Charge	$554,565	$873,835	$644,708	$516,900	$550,698	$553,890
Easement Letter	$24,978	$29,773	$39,955	$37,168	$0	$0
Misc Revenue	-$1,700	$1,625	$132,834	$114,046	$0	$0
Total	**$6,786,826**	**$9,497,848**	**$7,186,822**	**$5,966,102**	**$5,107,243**	**$3,689,939**

Account 4325 -Merchandise and Jobbing Revenue

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Inventory Sales	$88,900	$1,722,500	$5,447,129	$2,899,790	$2,200,000	$2,200,000
Isolation	$779,822	$1,110,436	$3,245,726	$3,559,037	$3,205,922	$3,184,384
Customer and Temp Services	$4,433,778	$5,325,404	$4,771,188	$6,251,865	$4,465,678	$4,681,016
MicroFIT	$93,500	$71,060	$157,066	$69,000	$50,000	$62,500
Scrap Sales	$2,351,600	$3,264,400	$3,198,906	$2,955,541	$2,988,600	$3,048,400
Accident Claims	$2,422,022	$1,683,500	$3,281,539	$3,648,653	$2,502,500	$2,562,600
Pole & Duct Rental	$11,145,300	$18,051,800	$23,106,399	$26,147,228	$19,236,165	$20,624,017
Streetlighting[1]	$520,678	$459,415	$332,279	$377,304	$669,103	$669,103
Other[2]	$1,272,988	$1,080,869	$2,388,913	$1,491,825	$696,534	$700,595
Total	**$23,108,588**	**$32,769,384**	**$45,929,144**	**$47,400,242**	**$36,014,502**	**$37,732,615**

Account 4330 -Merchandise and Jobbing Costs

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Inventory Sales	-$110,700	-$1,661,500	-$5,240,465	-$2,954,604	-$2,000,000	-$2,000,000
Isolation	-$663,612	-$915,208	-$3,681,121	-$4,968,289	-$3,672,322	-$3,654,584
Customer and Temp Services	-$3,638,181	-$4,372,001	-$3,751,142	-$4,683,780	-$4,051,478	-$4,260,816
MicroFIT	-$47,007	-$78,191	-$25,354	-$3,061	-$50,000	-$62,500
Scrap Sales	-$1,131,000	-$863,200	-$1,048,740	-$1,557,885	-$1,300,500	-$1,326,500
Accident Claims	-$2,267,530	-$2,321,000	-$3,026,630	-$761,183	-$265,600	-$320,800
Pole & Duct Rental	-$4,771,400	-$8,416,600	-$10,670,064	-$11,047,712	-$3,502,950	-$3,553,027
Streetlighting[1]	-$476,270	-$380,939	-$302,663	-$336,850	-$569,180	-$569,180
Other[2]	-$941,865	-$797,065	-$2,167,442	-$1,093,585	-$239,658	-$243,681
Total	**-$14,047,565**	**-$19,805,704**	**-$29,913,621**	**-$27,406,949**	**-$15,651,688**	**-$15,991,088**

Account 4405 - Investment Interest Income

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Investment Interest Income	$1,298,537	$0	$9	$0	$120,000	$120,000
Regulated Assets Charges-Revenue	$0	$186,388	$0	$0	$0	$0
Total	**$1,298,537**	**$186,388**	**$9**	**$0**	**$120,000**	**$120,000**

Notes

1 The amounts reported as shared services recovery in account 4375 do not include the cost recovery associated with fleet, occupancy and IT services provided by THESL to THESI, THESU and THC presented as part of Appenix 2N. The recovery of these costs is included in the OM&A evidence as part of the Allocation and Recoveries program for an average annual value of $1.1M for the period 2015-2020.
Streetlighighting recoveries and costs related to emergency response, engineering and planning included in Appendix 2N are shown under the merchandising and jobbing section (4325 & 4330).

2 The "Other" category is composed of IT services related to Hydro One Telecom and other various adhoc services.

OPERATING COSTS: OM&A VARIANCE ANALYSIS

1. OM&A OVERVIEW

Toronto Hydro's total OM&A expenditures in 2018 were $268.3 million, which is $7.1 million, or 2.7 percent, higher than the original forecast in Exhibit 4A, Tab 1, Schedule 1.

The Emergency Response program had the largest variance in 2018. Expenditures in this program were $10.9 million higher than forecasted as a result of the utility having to respond to four weather related major event days throughout the year. The increase in Emergency Response was offset by decreases in several programs, including Supply Chain and Customer Care.

Toronto Hydro has identified a number of changes to its 2019 bridge and 2020 test year forecasts. These changes are presented in Table 2 and discussed below. The net impact of these changes to the 2020 revenue requirement is $0.5 million. In the interest of efficiency, Toronto Hydro has decided not to flow these changes through the OM&A appendices, the revenue requirement work form and cost allocation models. The utility requests that the OEB approve these changes as part of the 2020 test year, and proposes to make the updates as part of the rate order process.

Table 1: Identified Changes in OM&A for 2019 Bridge and 2020 Test Years

	CIR Application		Identified Changes		Updated Figures	
OM&A Programs ($millions)	2019 Bridge	2020 Test	2019 Bridge	2020 Test	2019 Bridge	2020 Test
Customer Driven Work	9.6	9.6	1.0	1.0	10.6	10.6
Asset and Program Management	15.3	13.1	-	0.8	15.3	13.9
Charitable Donations and LEAP	0.8	0.9	0.2	0.2	1.0	1.0
Common Costs and Adjustments	(1.3)	0.8	(1.4)	(1.5)	(2.7)	(0.7)
Total OM&A	**268.2**	**277.5**	**(0.2)**	**0.5**	**267.9**	**278.0**

In Common Cost and Adjustments, Toronto Hydro identified a reduction in post-employment benefits of $1.4 million in 2019 and $1.5 million in 2020 as a result of the most recent actuarial valuation (Exhibit U, Tab 4A, Schedule 3, Appendix C). In the Customer-Driven Work program, Toronto Hydro expects an increase of $1.0 million in 2019 and 2020 due to a higher demand for Toronto Hydro to facilitate safe entry into customer-owned vaults. The $0.8 million change to Asset Program Management in the 2020 test year relates to Local Demand Response costs that were inadvertently omitted from the original OM&A budget in Exhibit 4A. Similarly, the $0.2 million in LEAP costs relates to an omission in the original evidence.

2. OM&A PROGRAMS AND EXPENDITURES

This section explains the material changes to the program expenditures resulting from the 2018 update. For detailed information about the programs, including year over year variance analyses, please refer to the evidence in Exhibit 4A, Tab 2.

2.1 Preventative and Predictive Overhead Line Maintenance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 1 for information about this program, including detailed variance analyses.

2.2 Preventative and Predictive Underground Line Maintenance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 2 for information about this program, including detailed variance analyses.

2.3 Preventative and Predictive Station Maintenance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 3 for information about this program, including detailed variance analyses.

2.4 Corrective Maintenance

Table 2 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Corrective Maintenance program by segment.

Table 2: Corrective Maintenance Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Corrective Maintenance	16.1	16.8	20.3	19.6	17.0	17.2

The decrease of $1.2 million from 2017 to 2018 is due to the utility performing less corrective maintenance work in 2018 than in 2017, as illustrated by the number of Work Requests in Figure 1 below. A decrease of $2.6 million from 2018 to 2019 is expected due to aligning the 2019 work volumes with 2016 levels.

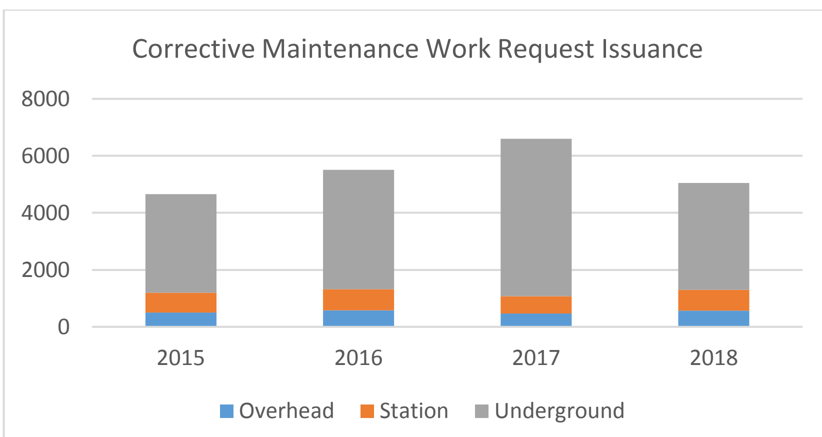


Figure 1: Historical Corrective Work Requests

2.5 Emergency Response

Table 3 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Emergency Response program by segment.

Table 3: Emergency Response Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Emergency Response	16.5	15.2	15.9	27.3	16.5	16.6

In 2018, the cost of this program was $10.9 million higher than forecasted in Exhibit 4A, Tab 2, Schedule 5, and $11.4 million higher than in 2017. The variances are attributable to four weather related major event days that Toronto Hydro experienced in 2018. As shown in Table 4, the number of weather events in 2018 far-exceeded historical levels. In responding to these events, Toronto Hydro had to mobilize significant resources to restore power, mitigate safety and reliability issues, and address environmental risks. The utility also had to perform residual clean-up work to restore the system to normal conditions, such as performing feeder patrols, emergency inspections, and reconnections mandated by the Electrical Safety Authority.

Table 4: Major Event Days due to Extreme Weather (2015-2018)

Date	Cause
Mar 3, 2015	Freezing Rain
Oct 15, 2017	Wind Storm
Apr 4, 2018	Wind Storm
Apr 15, 2018	Freezing Rain
May 4, 2018	Wind Storm
Jun 13, 2018	Wind Storm

2.6 Disaster Preparedness Management

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 6 for information about this program, including detailed variance analyses.

2.7 Control Centre Operations

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 7 for information about this program, including detailed variance analyses.

2.8 Customer Driven Work

Table 5 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Customer-Driven Work program by segment.

Table 5: Customer-Driven Work Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Customer Connections	2.1	2.4	2.3	3.2	3.1	3.2
Public Safety and Damage Prevention	4.0	4.2	5.9	4.1	4.7	4.5
Customer-Owned Equipment Services	4.1	3.4	3.5	3.5	2.8	2.9
Total	**10.2**	**10.0**	**11.6**	**10.9**	**10.6**	**10.6**

In 2018, the Public Safety and Damage Prevention decreased by $1.8 million as a result of Toronto Hydro having to suspend one of its contractors due to performance issues. This decrease was offset by an increase of $0.9 million in the Customer Connections segment for having to design and execute higher complexity projects.

In the Customer-Owned Equipment Services segment, 2018 costs were in line with 2017, but $1.6 million higher than forecasted in Exhibit 4A, Tab 2, Schedule 8 due to increases in volume of customer requests for Toronto Hydro to facilitate safe entry into customer-owned vaults.

2.9 Asset and Program Management

Table 6 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Asset and Program Management program by segment.

Table 6: Asset and Program Management Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
System Planning	6.6	10.1	6.6	8.1	7.7	7.7
Local Demand Response	0.0	0.0	0.0	0.9	2.3	0.8
Standards & Policies	2.5	2.6	2.9	2.7	2.7	2.8
Program Management & Support	2.0	5.3	2.0	2.9	2.6	2.6
Total	**11.2**	**18.1**	**11.5**	**14.7**	**15.3**	**13.9**

The expenditures in this program in 2018 were overall in line with the forecast in Exhibit 4A, Tab 2, Schedule 9. The only material variance was the Local Demand Response segment, where the expenditures in 2018 were $0.8 million lower than forecasted due to lower than anticipated costs associated with contractual demand response capacity. These costs are expected to carry over into 2019 to continue the activities undertaken in 2018 and deliver the full scope of the local demand response initiative.

2.10 Work Program Execution

Table 7 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Work Program Execution program by segment.

Table 7: Work Program Execution Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
External Work Execution	3.6	3.5	3.2	5.0	1.5	1.6
Internal Work Execution	15.9	16.0	17.4	14.4	18.7	20.2
Total	**19.5**	**15.9**	**20.5**	**19.4**	**20.3**	**21.8**

The expenditures in this program in 2018 were overall in line with the forecast in Exhibit 4A, Tab 2, Schedule 10. However, there were material variances at the segment level due to an increase in the amount and percentage of reactive work that Toronto Hydro had to complete in 2018. To manage the additional workload, Toronto Hydro relied more heavily on external resources. This led higher costs than forecasted in the External Work Execution segment. The increase was mitigated at the program level by commensurate reductions to the Internal Work Execution segment.

2.11 Fleet and Equipment Services

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 11 for information about this program, including detailed variance analyses.

2.12 Facilities Management

Table 8 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Facilities Management program by segment.

Table 8: Facilities Management Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Facilities Maintenance Services	14.6	15.4	15.3	15.3	14.7	15.1
Rentals & Leases	5.2	5.3	1.7	0.3	0.4	0.4
Utilities & Communications	2.4	2.4	2.6	2.6	3.0	3.1
Property Taxes	5.2	4.6	5.6	4.9	5.4	5.5
Total	**27.4**	**27.8**	**25.3**	**23.1**	**23.4**	**24.0**

The expenditures in this program in 2018 were overall in line with the forecast in Exhibit 4A, Tab 2, Schedule 12. However, there was an increase of $1.2 million in the Facilities Maintenance Services segment because of higher than anticipated costs in 2018 for maintenance work at Toronto Hydro’s Milner, Carlton, and Commissioners facilities, as well as the utility’s substations. This increase was offset by lower expenses for property taxes and utilities and communications.

2.13 Supply Chain Services

Table 9 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Supply Chain Services program by segment.

Table 9: Supply Chain Services Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Supply Chain Services	**10.4**	**13.4**	**11.4**	**10.4**	**12.3**	**12.6**

In 2018, the costs of the Supply Chain program were approximately $1.3 million lower than forecasted in Exhibit 4A, Tab 2, Schedule 13, and $1 million lower than in 2017. The difference is due to changes in the accounting treatment for open bin equipment whereby the cost of this equipment has been allocated to OM&A and capital programs, and various credits to the Supply Chain program budget due to cable equipment returns and other operational adjustments. These changes are not expected to carry into 2019 budget, and that is the main reason why the increase from 2018 to 2019 is expected to be higher than what is presented in the evidence at Exhibit 4A, Tab 2, Schedule 13, page 14.

2.14 Customer Care

Table 10 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Customer Care program by segment.

Table 10: Customer Care Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Billing, Remittance & Meter Data Management	15.7	13.4	15.5	15.0	16.2	20.7
Collections	10.8	10.3	9.2	8.0	12.4	12.6
Customer Relationship Management	11.4	11.6	11.5	10.5	10.6	11.3
Communications & Public Affairs	3.1	2.9	3.3	4.2	4.7	4.9
Total	**41.0**	**38.1**	**39.6**	**37.7**	**44.0**	**49.4**

In 2018, Customer Care program costs were $5.3 million lower than the forecast provided in Exhibit 4A, Tab 2, Schedule 14, and $1.9 million lower than 2017 actuals. The variance is attributable to lower labour costs due to various drivers including the effect of the winter disconnection moratorium, and lower than forecasted bad debt expenses in 2018.

As explained in the response to undertaking JTC3.10, Toronto Hydro applies professional judgement to assess a number of quantitative and qualitative factors when forecasting bad debt expense. With regard to these considerations, Toronto Hydro anticipated bad debt to climb in 2018. Although this expectation did not materialize in 2018, Toronto Hydro continues to believe that it is reasonable, based on the trends and indicators discussed in the undertaking response to JTC3.10, to expect an increase in bad debt over the forecast period. Therefore, Toronto Hydro has provisioned for an increase of $2.6M in bad debt expenses in 2019 relative to 2018 actuals.

In addition to the increase in bad debt, in 2019 Toronto Hydro forecasts an increase of $1.3 million for field collection costs and collection agency fees, $0.9 million for internal labour requirements, $0.7 million for billing related costs such as postage and bank fees, and printing due to inflationary pressures and customer growth, and $0.6 million for outsourced labour costs due to the continuing effects of the minimum wage increase.

2.15 Human Resources and Safety

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 15 for information about this program, including detailed variance analyses.

2.16 Finance

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 16 for information about this program, including detailed variance analyses.

2.17 Information Technology

Table 11 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Information Technology program by segment.

Table 11: Information Technology Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
IT Governance	2.7	2.9	3.0	3.2	3.3	3.4
IT Operations	27.9	28.3	30.9	31.4	35.3	35.6
Project Execution	1.6	1.4	1.6	3.2	1.6	1.7
Security & Enterprise Architecture	2.7	2.4	2.9	3.2	3.3	3.4
Total	**34.4**	**35.0**	**38.4**	**41.0**	**43.5**	**44.0**

In 2018, the cost of the program was aligned with the forecast in Exhibit 4A, Tab 4, Schedule 17. However, there were variances at the segment level. In the Projection Execution segment, there was a one-time increase for additional labour resources required to support migration and training activities related to then ERP project. This increase was offset by lower than forecasted costs in the IT Operations segment related to maintenance for newly implemented or upgraded systems. The unrealized maintenance costs are expected to commence in 2019, contributing to a higher increase from 2018 to 2019 in the IT Operations segment. Additional labour requirements to support new systems and higher costs for purchased services contracts are also contributing to the variance between 2018 and 2019.

2.18 Legal and Regulatory

Table 12 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) expenditures for the Legal and Regulatory program by segment.

Table 12: Legal and Regulatory Program Costs by Segment ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Legal Services	4.5	4.7	5.4	5.7	5.1	5.3
Regulatory Affairs	6.7	7.5	7.6	7.6	9.1	8.9
Amortized Costs of 2015-2019 CIR Application	0.9	1.1	1.0	1.0	1.0	-
Amortized Costs of 2020-2024 CIR Application	-	-	-	-	-	1.7
Total	**12.1**	**13.4**	**14.0**	**14.3**	**15.1**	**15.9**

The cost of the program in 2018 was approximately $1 million lower than the forecast in Exhibit 4A, Tab 4, Schedule 18. The differences are attributable to lower than expected OEB fees and external services costs in the Regulatory Affairs segment, offset by higher than forecasted litigation claims costs in the Legal Services segment. The external services costs that were expected to materialize in 2018 were related to supporting regulatory work activities while internal staff are reallocated to the rate application. These costs are now forecasted to materialize in 2019. Furthermore, the duration for which external services will be required is expected to increase commensurate with the timeline of the rate application lasting through three quarters of 2019.

2.19 Charitable Donations (LEAP)

There were no material changes in 2018. Please refer to Exhibit 4A, Tab 2, Schedule 19 for information about this program, including detailed variance analyses.

2.20 Common Costs and Adjustments

Table 13 below provides the Historical (2015-2018), Bridge (2019), and Test Year (2020) common corporate costs and adjustments.

Table 13: Common Corporate Costs and Adjustments Summary ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Ongoing or Recurring	1.1	(0.1)	1.6	(1.4)	(1.3)	0.8
Total	**1.1**	**(0.1)**	**1.6**	**(1.4)**	**(1.3)**	**0.8**

Note: Variances due to rounding may exist.

From 2017 to 2018, costs decreased by $3.0 million primarily due to differences in forecast and actual employee benefit cost and corporate risk and compliance activities. These reductions were offset by higher tax related charges.

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

(in $ Millions)

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	-	$ 48.6	$ 56.9	$ 55.1	$ 57.7	$ 60.2	$ 59.4
Maintenance	-	$ 67.1	$ 63.1	$ 64.3	$ 74.0	$ 67.1	$ 67.7
SubTotal	**-**	**$ 115.7**	**$ 120.0**	**$ 119.3**	**$ 131.7**	**$ 127.3**	**$ 127.1**
%Change (year over year)			3.7%	-0.5%	10.4%	-3.4%	-0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							9.9%
Billing and Collecting	-	$ 36.7	$ 33.4	$ 34.9	$ 32.5	$ 38.4	$ 38.8
Community Relations	-	$ 3.5	$ 2.5	$ 2.3	$ 2.4	$ 2.7	$ 2.8
Administrative and General	-	$ 81.9	$ 88.3	$ 92.5	$ 95.9	$ 93.4	$ 95.0
Taxes Other Than Income Taxes	-	$ 5.2	$ 4.6	$ 5.3	$ 4.9	$ 5.4	$ 5.5
Donations	-	$ 1.0	$ 1.0	$ 1.0	$ 0.8	$ 0.9	$ 1.0
SubTotal	**-**	**$ 128.3**	**$ 129.9**	**$ 135.9**	**$ 136.6**	**$ 140.9**	**$ 143.1**
%Change (year over year)			1.2%	4.7%	0.5%	3.1%	1.5%
%Change (Test Year vs Last Rebasing Year - Actual)							11.5%
Total	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 270.2**
%Change (year over year)			2.4%	2.2%	5.1%	-0.1%	0.8%
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	$ 7.3
Total - including Cash vs. Accrual OPEB and Monthly Billing	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 277.5**
%Change (year over year)			2.4%	2.2%	5.1%	-0.1%	3.5%

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Operations	-	$ 48.6	$ 56.9	$ 55.1	$ 57.7	$ 60.2	$ 59.4
Maintenance	-	$ 67.1	$ 63.1	$ 64.3	$ 74.0	$ 67.1	$ 67.7
Billing and Collecting	-	$ 36.7	$ 33.4	$ 34.9	$ 32.5	$ 38.4	$ 38.8
Community Relations	-	$ 3.5	$ 2.5	$ 2.3	$ 2.4	$ 2.7	$ 2.8
Administrative and General	-	$ 81.9	$ 88.3	$ 92.5	$ 95.9	$ 93.4	$ 95.0
Taxes Other Than Income Taxes	-	$ 5.2	$ 4.6	$ 5.3	$ 4.9	$ 5.4	$ 5.5
Donations	-	$ 1.0	$ 1.0	$ 1.0	$ 0.8	$ 0.9	$ 1.0
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	$ 7.3
Total	**$ 243.9**	**$ 244.0**	**$ 249.8**	**$ 255.3**	**$ 268.3**	**$ 268.2**	**$ 277.5**
%Change (year over year)			2.4%	2.2%	5.1%	-0.1%	3.5%

OEB Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	Variance 2015 BA - 2015 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Actuals	Variance 2017 Actuals vs. 2016 Actuals	2018 Actuals	Variance 2018 Actuals vs. 2017 Actuals	2019 Bridge Year	Variance 2019 Bridge vs. 2018 Actuals	2020 Test Year	Variance 2020 Test vs. 2019 Bridge
Operations	-	$ 48.6	$ (48.6)	$ 56.9	$ 8.3	$ 55.1	$ (1.9)	$ 57.7	$ 2.7	$ 60.2	$ 2.5	$ 59.4	$ (0.8)
Maintenance	-	$ 67.1	$ (67.1)	$ 63.1	$ (4.1)	$ 64.3	$ 1.2	$ 74.0	$ 9.7	$ 67.1	$ (6.9)	$ 67.7	$ 0.6
Billing and Collecting	-	$ 36.7	$ (36.7)	$ 33.4	$ (3.4)	$ 34.9	$ 1.5	$ 32.5	$ (2.4)	$ 38.4	$ 5.9	$ 38.8	$ 0.4
Community Relations	-	$ 3.5	$ (3.5)	$ 2.5	$ (1.0)	$ 2.3	$ (0.2)	$ 2.4	$ 0.1	$ 2.7	$ 0.3	$ 2.8	$ 0.1
Administrative and General	-	$ 81.9	$ (81.9)	$ 88.3	$ 6.4	$ 92.5	$ 4.1	$ 95.9	$ 3.5	$ 93.4	$ (2.5)	$ 95.0	$ 1.5
Taxes Other Than Income Taxes	-	$ 5.2	$ (5.2)	$ 4.6	$ (0.5)	$ 5.3	$ 0.6	$ 4.9	$ (0.4)	$ 5.4	$ 0.5	$ 5.5	$ 0.1
Donations	-	$ 1.0	$ (1.0)	$ 1.0	$ (0.0)	$ 1.0	$ (0.0)	$ 0.8	$ (0.1)	$ 0.9	$ 0.1	$ 1.0	$ 0.0
Cash vs. Accrual OPEB and Monthly Billing	-	-	-	-	-	-	-	-	-	-	-	$ 7.3	$ 7.3
Total OM&A Expenses	$ 243.9	$ 244.0	$ (244.0)	$ 249.8	$ 5.8	$ 255.3	$ 5.4	$ 268.3	$ 13.0	$ 268.2	$ (0.1)	$ 277.5	$ 9.3
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Recoverable OM&A Expenses	$ 243.9	$ 244.0	$ (244.0)	$ 249.8	$ 5.8	$ 255.3	$ 5.4	$ 268.3	$ 13.0	$ 268.2	$ (0.1)	$ 277.5	$ 9.3
Variance from previous year					$ 5.8		$ 5.4		$ 13.0		$ (0.1)		$ 9.3
Percent change (year over year)					2.4%		2.2%		5.1%		-0.1%		3.5%
Percent Change: Test year vs. Most Current Actual													3.7%
Simple average of % variance for all years													2.6%
Compound Annual Growth Rate for all years													2.6%

Note:

1 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	**$243.9**	**$244.0**	**$249.8**	**$255.3**	**$268.3**	**$268.2**
Distribution Operations						
Predictive and Preventative Maintenance Overhead	-	$1.3	($0.9)	($0.2)	$0.2	($0.7)
Predictive and Preventative Maintenance Underground	-	$0.3	$0.3	$1.4	$0.6	$0.2
Predictive and Preventative Maintenance Stations	-	($0.3)	$0.3	$0.4	($0.3)	($0.1)
Corrective Maintenance	-	$0.7	$3.5	($0.8)	($2.6)	$0.2
Emergency Response	-	($1.2)	$0.7	$11.4	($10.8)	$0.1
Disaster Preparedness Management	-	$0.0	($0.2)	$0.7	($0.1)	($0.1)
Control Centre Operations	-	$0.0	$0.8	$0.9	$1.5	$0.1
Customer Driven Work	-	($0.2)	$1.7	($0.8)	($1.3)	$0.0
Asset and Program Management	-	$6.9	($6.6)	$3.2	$0.6	($2.2)
Work Program Execution	-	($0.0)	$1.0	($1.2)	$0.9	$1.5
Fleet and Equipment	-	($0.3)	$1.2	($0.9)	$0.8	$0.0
Supply Chain	-	$3.0	($2.0)	($1.0)	$1.9	$0.3
Customer Service and Communications						
Billing, Remittance & Meter Data Management	-	($2.3)	$2.2	($0.6)	$1.3	$4.5
Collections	-	($0.5)	($1.0)	($1.2)	$4.4	$0.1
Customer Relationship Management	-	$0.2	($0.1)	($1.0)	$0.0	$0.7
Communications & Public Affairs	-	($0.2)	$0.4	$0.9	$0.6	$0.1
LEAP	-	$0.2	($0.1)	$0.0	$0.0	$0.0
Human Resources and Safety						
Human Resource Services and Employee Labour Relations	-	$0.6	($0.0)	($0.5)	$0.2	$0.1
Environment Health and Safety	-	$0.1	($0.2)	$0.1	$0.2	$0.1
Talent Management & Organizational Effectiveness	-	$0.3	($0.3)	$0.9	($0.0)	$0.2
Information Technology						
IT Governance	-	$0.2	$0.0	$0.3	$0.0	$0.1
IT Operations	-	$0.4	$2.6	$0.4	$3.9	$0.3
Project Execution	-	$0.2	$0.2	$1.7	($1.6)	$0.1
Security & Enterprise Architecture	-	($0.2)	$0.4	$0.3	$0.1	$0.1
Common Corporate Costs						
Common Corporate Costs	-	($1.2)	$1.7	($3.0)	$0.1	$2.1

OEB Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2015 Board-Approved)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	**$243.9**	**$244.0**	**$249.8**	**$255.3**	**$268.3**	**$268.2**
Facilities Management						
Facilities Maintenance Services	-	$0.9	($0.1)	($0.1)	($0.6)	$0.4
Rentals & Leases	-	$0.1	($3.6)	($1.5)	$0.1	$0.0
Utilities & Communications	-	($0.1)	$0.3	($0.0)	$0.4	$0.1
Property Taxes	-	($0.6)	$1.0	($0.7)	$0.5	$0.1
Other Various						
Finance	-	($1.1)	($1.4)	$1.4	$1.2	$0.0
Legal and Regulatory	-	$1.3	$0.6	$0.3	$0.8	$0.7
Allocations and Recoveries	-	($2.9)	$3.0	$2.1	($3.1)	$0.0
Closing Balance	**$244.0**	**$249.8**	**$255.3**	**$268.3**	**$268.2**	**$277.5**

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS		
Distribution Operations									
Predictive and Preventative Maintenance Overhead	-	6.3	7.6	6.7	6.5	6.8	6.0	(0.5)	6.0
Predictive and Preventative Maintenance Underground	-	2.6	2.9	3.2	4.7	5.2	5.5	0.8	5.5
Predictive and Preventative Maintenance Stations	-	5.6	5.3	5.6	6.0	5.6	5.6	(0.4)	5.6
Corrective Maintenance	-	16.1	16.8	20.3	19.6	17.0	17.2	(2.4)	17.2
Emergency Response	-	16.4	15.2	15.9	27.4	16.5	16.6	(10.7)	16.6
Disaster Preparedness Management	-	2.3	2.4	2.2	2.9	2.8	2.7	(0.2)	2.7
Control Centre Operations	-	5.4	5.4	6.3	7.2	8.7	8.7	1.6	8.7
Customer Driven Work	-	10.2	10.0	11.6	10.9	9.6	9.6	(1.3)	9.6
Asset and Program Management	-	11.2	18.1	11.5	14.7	15.3	13.1	(1.6)	13.1
Work Program Execution	-	19.5	19.5	20.5	19.4	20.3	21.8	2.4	21.8
Fleet and Equipment	-	10.1	9.8	11.0	10.1	11.0	11.0	0.8	11.0
Supply Chain	-	10.4	13.4	11.4	10.4	12.3	12.6	2.2	12.6
Sub-Total	-	116.1	126.5	126.3	139.6	131.0	130.4	(9.2)	130.4
Customer Care									
Billing, Remittance & Meter Data Management	-	15.7	13.4	15.5	15.0	16.2	20.7	5.7	20.7
Collections	-	10.8	10.3	9.2	8.0	12.4	12.6	4.5	12.6
Customer Relationship Management	-	11.4	11.6	11.5	10.5	10.6	11.3	0.7	11.3
Communications & Public Affairs	-	3.1	2.9	3.3	4.2	4.7	4.9	0.7	4.9
Sub-Total	-	41.0	38.1	39.6	37.7	44.0	49.4	11.7	49.4
Charitable Donations and LEAP									
LEAP	-	0.7	0.9	0.8	0.8	0.8	0.9	0.0	0.9
Sub-Total	-	0.7	0.9	0.8	0.8	0.8	0.9	0.0	0.9

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS		
Human Resources and Safety									
Human Resource Services and Employee Labour Relations	-	4.6	5.2	5.1	4.6	4.8	5.0	0.4	5.0
Environment Health and Safety	-	2.5	2.7	2.5	2.6	2.8	2.9	0.3	2.9
Talent Management & Organizational Effectiveness	-	7.0	7.3	7.0	7.9	7.9	8.1	0.2	8.1
Sub-Total	-	14.1	15.2	14.7	15.1	15.5	15.9	0.9	15.9
Information Technology									
IT Governance	-	2.7	2.9	3.0	3.2	3.3	3.4	0.1	3.4
IT Operations	-	27.9	28.3	30.9	31.4	35.3	35.6	4.2	35.6
Project Execution	-	1.2	1.4	1.6	3.2	1.6	1.7	(1.5)	1.7
Security & Enterprise Architecture	-	2.7	2.4	2.9	3.2	3.3	3.4	0.2	3.4
Sub-Total	-	34.4	35.0	38.4	41.0	43.5	44.0	3.0	44.0
Common Costs and Adjustments									
Common Corporate Costs	-	1.1	(0.1)	1.6	(1.4)	(1.3)	0.8	2.2	0.8
Sub-Total	-	1.1	(0.1)	1.6	(1.4)	(1.3)	0.8	2.2	0.8
Facilities Management									
Facilities Maintenance Services	-	14.6	15.4	15.3	15.3	14.7	15.1	(0.2)	15.1
Rentals & Leases	-	5.2	5.3	1.7	0.3	0.4	0.4	0.1	0.4
Utilities & Communications	-	2.4	2.4	2.6	2.6	3.0	3.1	0.5	3.1
Property Taxes	-	5.2	4.6	5.6	4.9	5.4	5.5	0.7	5.5
Sub-Total	-	27.4	27.8	25.3	23.1	23.4	24.0	1.0	24.0
Finance									
Controllership	-	8.4	7.3	6.4	7.0	7.2	7.0	0.0	7.0
External Reporting	-	2.5	2.7	2.7	2.7	3.1	3.2	0.4	3.2
Financial Services	-	5.2	5.0	4.6	5.3	5.9	6.1	0.8	6.1
Sub-Total	-	16.1	15.0	13.6	15.0	16.2	16.2	1.2	16.2

OEB Appendix 2-JC
OM&A Programs Table

(in $ Millions)

Programs	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-Approved)
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS		
Legal and Regulatory									
Legal and Regulatory Program	-	12.1	13.4	14.0	14.3	15.1	15.9	1.5	15.9
Sub-Total	-	12.1	13.4	14.0	14.3	15.1	15.9	1.5	15.9
Allocations and Recoveries									
On-cost recovery	-	(10.6)	(11.5)	(11.3)	(10.6)	(11.8)	(11.8)	(1.1)	(11.8)
Fleet Recovery Offset	-	(12.5)	(12.4)	(11.5)	(10.6)	(11.4)	(11.6)	(0.9)	(11.6)
IT and Occupancy Charges	-	(0.7)	(1.1)	(1.0)	(1.0)	(1.0)	(1.0)	(0.1)	(1.0)
Shared Services	-	4.8	2.9	4.8	5.1	4.4	4.6	(0.6)	4.6
Other Allocated Costs	-	0.0	0.1	0.2	0.3	(0.1)	(0.1)	(0.4)	(0.1)
Sub-Total	-	(19.0)	(21.9)	(18.9)	(16.8)	(20.0)	(19.9)	(3.1)	(19.9)
Miscellaneous	-	-	-	-		-	-	-	-
Total	**243.9**	**244.0**	**249.8**	**255.3**	**268.3**	**268.2**	**277.5**	**9.2**	**33.6**

Notes:

as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

OEB Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year (2015 Board-Approved)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis							
OM&A Costs							
O&M	-	$ 115.7	$ 120.0	$ 119.3	$ 131.7	$ 127.3	$ 127.1
Admin Expenses	-	$ 128.3	$ 129.9	$ 135.9	$ 136.6	$ 140.9	$ 150.4
Total Recoverable OM&A from Appendix 2-JB [5]	$ 243.9	$ 244.0	$ 249.8	$ 255.3	$ 268.3	$ 268.2	$ 277.5
Number of Customers [2,4]	747,812	747,812	759,032	765,560	769,691	776,787	784,331
Number of FTEs [3,4,6]	1,630	1,630	1,605	1,589	1,545	1,646	1,639
Customers/FTEs	458.89	458.89	472.96	481.92	498.18	472.04	478.52
OM&A cost per customer							
O&M per customer	-	154.7	158.0	155.8	171.1	163.8	162.1
Admin per customer	-	171.6	171.1	177.6	177.5	181.4	191.7
Total OM&A per customer	326.2	326.3	329.1	333.4	348.6	345.2	353.8
OM&A cost per FTE							
O&M per FTE	-	70,984.6	74,748.3	75,105.8	85,242.6	77,339.4	77,563.5
Admin per FTE	-	78,732.1	80,913.3	85,579.5	88,415.8	85,617.0	91,737.1
Total OM&A per FTE	149,666.7	149,716.7	155,661.6	160,685.4	173,658.4	162,956.4	169,300.6

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers is the year end method

3 The method of calculating the number of FTEs is the mid year average

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

6 Difference to compensation table (appendix 2-K) FTE figures due to students

PURCHASES OF NON-AFFILIATE SERVICES

The evidence at Exhibit 4A, Tab 3, Schedule 1 provides detailed information about Toronto Hydro's procurement practices, including a copy of Toronto Hydro's Procurement Policy at Appendix A, and at Appendix B, a listing of the services that were sole sourced in 2015-2017. Table 1 below lists and describes the non-affiliate services that were procured in 2018 pursuant to the sole source methodology in the Procurement Policy.

Table 1: 2018 Sole Sourced Non-Affiliate Services

Vendor	Nature of the Transaction	Cost
Bell Canada	Purchase of demand reduction services for capacity management	$2,226,000
Renewable Energy Systems (RES)	Installation of a Battery Energy Storage System (BESS)	$2,995,000
Siemens	Maintenance and support for EnergyIP for Operational Data Store (ODS) System	$2,220,000
Dynatrace Corporation of Canada	Support services for suite of Dynatrace application monitoring products	$1,190,000

WORKFORCE STAFFING AND COMPENSATION

Toronto Hydro's workforce and compensation evidence is detailed in Exhibit 4A, Tab 4. This schedule provides a summary of the 2018 actual compensation costs and explains the materials variances resulting from the 2018 actuals.

1. Employee Cost Breakdown (OEB Appendix 2-K)

Toronto Hydro's updated historical (2015-2018) and forecast (2019-2020) staffing levels and compensation costs (i.e. OEB Appendix 2-K) are filed as Appendix A to this Schedule. A more detailed view of the compensation table broken down by employee category is provided in Appendix B.[1]

2. Compensation Costs

Table 1 below summarizes Toronto Hydro's total compensation costs, which include base salary wages, overtime and incentive payments, and actual and accrued benefits.

Table 1: Total Compensation ($ Millions)

Year	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Management (including executive)	15.9	18.1	19.2	20.0	20.3	21.0
Non-Management (union and non-union)	195.2	194.3	197.3	197.7	215.2	223.2
Total	**211.1**	**212.4**	**216.4**	**217.7**	**235.5**	**244.2**

[1] For 2018, IT professionals were non-unionized. The breakdown provided here does not include the IT professionals in the Society union category.

In 2018, Toronto Hydro's total compensation was $8.2 million below the forecast in Exhibit 4A, Tab 4. This variance is mainly attributable to a lower number of FTEs than forecasted, as explained below in section 3.

In 2019, Toronto Hydro expects total compensation costs to increase by $17.8 million relative to 2018 Actuals. This variance is primarily driven by general salary increases, expected FTE increases, and associated benefit costs.

3. Staffing Levels

Toronto Hydro hired a lower number of FTEs in 2018 than the utility forecasted. This was in large part due to the delay experienced in hiring Certified Power Line Persons (CPLP) resources as a result of the utility's efforts to negotiate a harmonized Power Line Technician ("PLT") role with the Power Workers Union (PWU) during the 2017-2018 labour bargaining process. The PLT role offers Toronto Hydro access to trades that have broader skillset as PLTs can work on both underground and overhead distribution assets. The role provides the utility more resource flexibility to execute planned work and respond to operational challenges on the ground, such as weather related contingencies. Toronto Hydro pursued this role in the bargaining process as part of its continuous efforts to find efficiencies in the execution of its capital and operational work programs. Despite Toronto Hydro's best efforts, the PLT role could not be negotiated with the PWU, and this contributed to delays in hiring CPLP trades.

The remainder of the variance is due to vacancies resulting from the utility's efforts to manage cost pressures within the rates set for the 2015 to 2019 period.

4. Unionization of Information Technology Employees

The Society of United Professionals were certified as the bargaining agent for Information Technology ("IT") Professionals on November 21, 2018. This bargaining unit represents 75 employees. Toronto Hydro received notice to bargain in March 2019, and is in the process of initiating bargaining with the Society of United Professionals for a first collective agreement. Table 2 below, provides the 2018 costs for IT professionals. Note that the amounts shown below may not be reflective of union wages following the first collective agreement.

Table 2: 2018 FTE and Total Compensation for IT Professionals ($ Millions)

Category	Totals
FTEs	78
Total Salaries and Wages	$9.62
Total Benefits	$2.90
Total Compensation	$12.52

5. Benefits and Pension

Table 3 below includes the historical (2015-2018) and forecast (2019-2020) cost of employee benefits.

Table 3: Employee Benefit Costs (2015-2020) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Employee Benefit Total Cost	52.8	52.1	53.3	51.0	59.5	64.8

Toronto Hydro's benefit cost in 2018 were $51 million, which is $4.7 million lower than the utility's forecast in the Exhibit 4A, Tab 4. The variance is due to the staffing levels as discussed above, and an actuarial gain of $4.7 million as a result of the updated valuation.

Table 4 below summarizes Toronto Hydro's historical (2015-2018) and forecast (2019-2020) pension costs, including capitalized and expensed amounts each year.

Table 4: Pension Costs (2015-2020) ($ Millions)

	2015 Actual	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Bridge**	**2020 Test**
Pension Contributions	16.9	16.8	16.9	17.3	19.2	19.6
Less: Amount Capitalized	7.3	7.1	7.7	8.0	8.5	8.7
Amount Expensed in Each Year	9.5	9.8	9.2	9.3	10.7	10.9

Table 5 below, presents Toronto Hydro's historical (2015-2018) and forecasted (2019-2020) post-employment benefit costs, including capitalized and expensed amounts.

Table 5: Post-employment Benefit Costs (2015-2020) ($ Millions)

	2015 Actual	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Bridge**	**2020 Test**
Benefit Costs	17.7	15.3	18.0	10.6	15.7	16.0
Capitalized Amounts	7.7	6.4	8.1	4.8	7.0	7.2
Expensed Amounts	10.0	8.9	9.9	5.8	8.7	8.8

The 2018 actuals for post-employment benefit costs reflects a gain of $4.7 million as a result of the actuarial valuation as of January 1, 2018. This study is attached as Appendix C to this Schedule.

OEB Appendix 2-K
EMPLOYEE COSTS/ COMPENSATION TABLE

	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge	2020 Test
Number of Employees (FTEs including Part-Time)						
Management (including executive)	61	69	69	72	68	67
Non-Management (union and non-union)	1422	1415	1403	1353	1455	1450
TOTAL	**1483**	**1484**	**1473**	**1425**	**1523**	**1517**
Total Salary and Wages (including overtime and incentive pay)						
Management (including executive)	$ 12,292,778	$ 14,152,809	$ 14,971,880	$ 15,718,629	$ 15,478,739	$ 15,719,811
Non-Management (union and non-union)	$ 145,975,363	$ 146,148,053	$ 148,139,852	$ 151,009,285	$ 160,518,242	$ 163,720,633
TOTAL	**$ 158,268,141**	**$ 160,300,862**	**$ 163,111,731**	**$ 166,727,914**	**$ 175,996,982**	**$ 179,440,444**
Total Benefits (Current + Accrued)						
Management (including executive)	$ 3,573,323	$ 3,919,134	$ 4,202,856	$ 4,306,945	$ 4,844,923	$ 5,260,044
Non-Management (union and non-union)	$ 49,254,110	$ 48,138,488	$ 49,111,532	$ 46,686,723	$ 54,655,848	$ 59,509,241
TOTAL	**$ 52,827,432**	**$ 52,057,622**	**$ 53,314,387**	**$ 50,993,668**	**$ 59,500,771**	**$ 64,769,286**
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 15,866,100	$ 18,071,943	$ 19,174,735	$ 20,025,575	$ 20,323,662	$ 20,979,856
Non-Management (union and non-union)	$ 195,229,473	$ 194,286,540	$ 197,251,383	$ 197,696,008	$ 215,174,090	$ 223,229,874
TOTAL	**$ 211,095,573**	**$ 212,358,484**	**$ 216,426,119**	**$ 217,721,582**	**$ 235,497,752**	**$ 244,209,730**

Updated JTC3.22
COMPENSATION TABLE BROKEN DOWN BY CATEGORY

	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge	2020 Test
Number of Employees (FTEs including Part-Time)						
EXECUTIVE	6	6	7	5	5	5
MANAGERIAL	55	63	63	67	63	62
NON-MANAGEMENT, NON-UNION	433	467	487	498	575	571
CONTRACT FOR A DEFINED TERM	62	54	62	66	32	32
SOCIETY	53	56	60	65	68	69
PWU	874	837	794	724	779	778
TOTAL	**1483**	**1484**	**1473**	**1425**	**1523**	**1517**
Total Salary and Wages (including overtime and incentive pay)						
EXECUTIVE	$ 2,486,891	$ 2,397,404	$ 2,704,552	$ 2,378,602	$ 2,369,718	$ 2,447,034
MANAGERIAL	$ 9,805,887	$ 11,755,405	$ 12,267,327	$ 13,340,028	$ 13,109,022	$ 13,272,778
NON-MANAGEMENT, NON-UNION	$ 48,506,203	$ 52,019,203	$ 55,078,497	$ 59,303,319	$ 67,065,064	$ 68,706,809
CONTRACT FOR A DEFINED TERM	$ 4,069,184	$ 3,102,383	$ 3,720,714	$ 4,373,705	$ 2,021,081	$ 2,079,265
SOCIETY	$ 6,273,163	$ 6,387,993	$ 7,345,852	$ 7,857,253	$ 8,730,321	$ 9,026,473
PWU	$ 87,126,813	$ 84,638,474	$ 81,994,788	$ 79,475,009	$ 82,701,776	$ 83,908,086
TOTAL	**$ 158,268,141**	**$ 160,300,862**	**$ 163,111,731**	**$ 166,727,914**	**$ 175,996,982**	**$ 179,440,444**
Total Benefits (Current + Accrued)						
EXECUTIVE	$ 598,384	$ 566,562	$ 632,406	$ 539,960	$ 665,170	$ 734,128
MANAGERIAL	$ 2,974,938	$ 3,352,572	$ 3,570,450	$ 3,766,985	$ 4,179,752	$ 4,525,916
NON-MANAGEMENT, NON-UNION	$ 16,385,374	$ 17,012,868	$ 18,183,579	$ 18,346,608	$ 23,558,997	$ 25,786,722
CONTRACT FOR A DEFINED TERM	$ 325,760	$ 255,326	$ 298,873	$ 347,999	$ 154,150	$ 157,539
SOCIETY	$ 2,186,586	$ 2,147,661	$ 2,485,728	$ 2,558,950	$ 2,828,604	$ 3,115,494
PWU	$ 30,356,391	$ 28,722,633	$ 28,143,352	$ 25,433,165	$ 28,114,097	$ 30,449,486
TOTAL	**$ 52,827,432**	**$ 52,057,622**	**$ 53,314,387**	**$ 50,993,668**	**$ 59,500,771**	**$ 64,769,286**
Total Compensation (Salary, Wages, & Benefits)						
EXECUTIVE	$ 3,085,275	$ 2,963,967	$ 3,336,959	$ 2,918,562	$ 3,034,888	$ 3,181,162
MANAGERIAL	$ 12,780,825	$ 15,107,977	$ 15,837,777	$ 17,107,012	$ 17,288,774	$ 17,798,694
NON-MANAGEMENT, NON-UNION	$ 64,891,577	$ 69,032,071	$ 73,262,076	$ 77,649,927	$ 90,624,061	$ 94,493,531
CONTRACT FOR A DEFINED TERM	$ 4,394,944	$ 3,357,709	$ 4,019,587	$ 4,721,704	$ 2,175,231	$ 2,236,804
SOCIETY	$ 8,459,748	$ 8,535,654	$ 9,831,580	$ 10,416,204	$ 11,558,925	$ 12,141,967
PWU	$ 117,483,204	$ 113,361,107	$ 110,138,140	$ 104,908,173	$ 110,815,873	$ 114,357,572
TOTAL	**$ 211,095,573**	**$ 212,358,484**	**$ 216,426,119**	**$ 217,721,582**	**$ 235,497,752**	**$ 244,209,730**

Willis Towers Watson

Private and Confidential

January 14, 2019

Ms. Cynthia Chan
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Cynthia:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2018 YEAR-END DISCLOSURES AND ESTIMATED 2019-2024 BENEFIT EXPENSE UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on disability;
- Dental benefits for retirees and members on disability;
- Life insurance benefits for retirees;
- Vested and non-vested sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company and its external reporting, for the following purposes:

- Determining the final calculation of the 2018 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 revised in 2011,

175 Bloor Street East
South Tower
Suite 1701
Toronto, Ontario
M4W 3T6

T +1 416 960.2700
W willistowerswatson.com

Towers Watson Canada Inc.

- Providing the required information for year-end disclosure purposes as of December 31, 2018 under IAS 19 rev. 2011,

- Determining an estimate of the 2019-2024 benefit expense under IAS 19 rev. 2011.

The information contained in this letter and appendices are presented in thousands of Canadian dollars, and are in respect of the benefits mentioned above only.

The fiscal 2018 net periodic benefit cost is based on the results of the January 1, 2016 actuarial valuation.

The 2018 year-end disclosure obligation and extrapolations for 2019-2024 are based on the results of the January 1, 2018 actuarial valuation.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2016 and January 1, 2018 actuarial valuation reports prepared by Willis Towers Watson dated November 18, 2016 and December 17, 2018, respectively for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuations.

Actuarial Assumptions and Methods

- The measurement date used for Fiscal 2018 year-end financial reporting is December 31, 2018.

- The 2018 benefit expense is based on a discount rate of 3.50% per annum and the defined benefit obligation ("DBO") at December 31, 2018 is based on a discount rate of 3.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2017 and December 31, 2018 respectively.

- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2018 net periodic benefit cost are consistent with those used for the 2017 year-end disclosures and the actuarial methods and assumptions used for the December 31, 2018 obligation are consistent with those used for the January 1, 2018 actuarial valuation.

- The obligation as of December 31, 2018 and the 2019-2024 expense estimates are based on extrapolations from the January 1, 2018 valuation results for the medical, dental, life insurance, sick leave, OMERS and retirement allowance benefit plans, assuming no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

Accounting Methods

- Under IAS 19 rev. 2011, we understand that Toronto Hydro has determined that both the non-vested sick leave benefit program and the vested sick leave benefit program should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 rev. 2011 presented in this letter.

- On an ongoing basis, actuarial gains and losses for all benefit plans other than the sick leave benefits plan and the incentive plan retirement allowance will be immediately recognized in other comprehensive income. Actuarial gains and losses for the sick leave benefit plan and the incentive plan retirement allowance will be recognized immediately in expense.

- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

Summary of Financial Results

The summary of Fiscal 2018 benefit expense, the defined benefit liability and the DBO as at December 31, 2018, under IAS 19 rev. 2011 is as follows (in $ 000s):

	Fiscal 2018 Net Periodic Benefit Costs	Defined Benefit Asset/(Liability) at December 31, 2018	DBO at December 31, 2018
Electric System Limited	$ 10,625	$ (270,910)	$ 270,910
Toronto Hydro Corporation	204	(2,697)	2,697
Energy Service Incorporated	29	(959)	959
LDC Unregulated	108	(1,294)	1,294
Consolidated	$ 10,966	$ (275,860)	$ 275,860

- Actual benefit payments for 2018 of $10,919,000 are based on information provided by the Company on January 9, 2019. We have projected 2019-2024 benefit payments based on the valuation assumptions.

The breakdown of net actuarial (gain)/loss as at December 31, 2018 is as follows (in $000s):

	Electric System Limited	Toronto Hydro Corporation	Energy Service Incorporated	LDC Unregulated
Demographic Assumptions:				
Sick Leave Program	$0	$0	$0	$0
Retirement Allowance #1	0	0	0	0
Other Plans	(22,034)	(142)	(68)	(144)
Economic Assumptions:				
Sick Leave Program	(433)	0	0	0
Retirement Allowance #1	0	(15)	0	0
Other Plans	(10,808)	(72)	(38)	(64)
Plan Experience:				
Sick Leave Program	(4,243)	0	(59)	0
Retirement Allowance #1	0	(61)	0	0
Other Plans	(3,164)	436	(1,070)	11
Total Net Actuarial (Gain)/Loss:				
Sick Leave Program	(4,676)	0	(59)	0
Retirement Allowance #1	0	(76)	0	0
Other Plans	(36,006)	222	(1,176)	(197)
Sub-Total	**$(40,682)**	**$146**	**$(1,235)**	**$(197)**

Other Comments

- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.
- As directed by the Company, the full defined benefit liability has been classified as a non-current liability.
- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2018 for all benefit plans, that would materially affect the results of our valuations.

Actuarial Certification

The Company may make a copy of this report available to its auditors, but we make no representation as to the suitability of this report for any purpose other than that for which it was originally provided and accept no responsibility or liability to the Company's auditors in this regard. We are aware that the information contained in this report will be used to support the audit of the Company's financial statements. Except where we expressly agree in writing, this report should not be disclosed or provided to any third party, other than as provided above. Willis Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

In preparing these results, we have relied upon information and data provided to us orally, electronically and/or in writing by the Company and other persons or organizations designated by the Company. We have relied on all the data and information provided, including plan provisions and membership data as being complete and accurate. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We have not independently verified the accuracy or completeness of the data or information provided, but we have performed limited checks for consistency.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies may produce materially different results that could require that a revised report be issued.

The results summarized in this report involve actuarial calculations that require assumptions about future events. The Company is responsible for the selection of the assumptions, as required by IAS 19. Other assumptions may also be reasonable and appropriate and their use would produce different results.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of future experience gains or losses. None of these changes has been anticipated at this time, but will be revealed in future accounting valuations.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

In our opinion:

- the membership data on which the valuation is based are sufficient and reliable for purposes of the valuation;
- the assumptions are appropriate for the purposes of the valuation(s);
- the methods employed in the valuation are appropriate for the purposes of the valuation(s);
- the calculations have been made in accordance with our understanding of the requirements of IAS 19 and the Company's accounting policies.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Willis Towers Watson

Andrea Firmani, FCIA, FSA
Mobile: (416) 258-0987

Olga Baliakina, FCIA, FSA
Direct Dial: (416) 960-7094

Enclosures

cc: Claudia Oancea — Toronto Hydro Corporation
Cindy Dieng — Toronto Hydro Corporation

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2018 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2018		
Defined Benefit Asset/(Liability) at Beginning of Period	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Reconciliation of Defined Benefit Obligation			2018		
Defined Benefit Obligation at Beginning of Period	307,147	2,296	2,117	1,410	312,970
Employer Service Cost at Beginning of Period	4,554	197	14	57	4,822
Interest Cost	10,747	83	74	51	10,955
Net Actuarial (Gain) or Loss					
Sick Leave Plan	*(4,676)*	-	*(59)*	-	*(4,735)*
Retirement Allowance Benefit #1	-	*(76)*	-	-	*(76)*
Other Plans	*(36,006)*	*222*	*(1,176)*	*(197)*	*(37,157)*
Total Net Actuarial (Gain) or Loss	(40,682)	146	(1,235)	(197)	(41,968)
Benefits Paid Directly by the Employer	(10,856)	(25)	(11)	(27)	(10,919)
Defined Benefit Obligation at Current Period End	270,910	2,697	959	1,294	275,860
Change in Plan Assets			2018		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,856	25	11	27	10,919
Benefits Paid	(10,856)	(25)	(11)	(27)	(10,919)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2018		
Employer Service Cost at Beginning of Period	4,554	197	14	57	4,822
Interest Cost	10,747	83	74	51	10,955
Actuarial (Gain)/Loss Recognized in Expense	(4,676)	(76)	(59)	-	(4,811)
Total Benefit Expense/(Income)	10,625	204	29	108	10,966
Reconciliation of Balance Sheet			2018		
Defined Benefit Asset/(Liability) at Prior Period End	(307,147)	(2,296)	(2,117)	(1,410)	(312,970)
Total Benefit (Expense)/Income for Period	(10,625)	(204)	(29)	(108)	(10,966)
Benefits Paid Directly by the Employer	10,856	25	11	27	10,919
Gain/(Loss) Recognized via OCI	36,006	(222)	1,176	197	37,157
Defined Benefit Asset/(Liability) at Current Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Change in Accumulated Other Comprehensive Income			2018		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	52,414	(1,099)	(1,226)	112	50,201
Actuarial (Gain)/Loss Recognized via OCI for Period	(36,006)	222	(1,176)	(197)	(37,157)
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2018		
Defined Benefit Asset/(Liability) at Current Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2018		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Defined Benefit Asset/(Liability) at Current Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2018 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2018					
1% point increase	2,231	9	15	20	2,275
1% point decrease	(1,990)	(6)	(13)	(17)	(2,026)
Effect on accrued benefit obligation at December 31, 2018					
1% point increase	35,180	203	123	201	35,707
1% point decrease	(31,476)	(180)	(110)	(172)	(31,938)
Sensitivity to Changes in Discount Rate Assumption					
Effect on total of service and interest cost for 2018					
1% point increase	(73)	(9)	1	(11)	(92)
1% point decrease	(132)	6	(4)	13	(117)
Effect on accrued benefit obligation at December 31, 2018					
1% point increase	(40,659)	(322)	(139)	(229)	(41,349)
1% point decrease	52,254	412	176	299	53,141
Sensitivity to Changes in Mortality Rates Assumption					
Effect on accrued benefit obligation at December 31, 2018					
Set back 1 year	9,755	62	32	49	9,898
Set forward 1 year	(9,521)	(60)	(31)	(48)	(9,660)
Key Assumptions					
Discount rate at Dec 31/18 (used for Dec 31/18 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/17 (used for 2018 Benefit Costs)	3.50%	3.50%	3.50%	3.50%	3.50%
Assumed medical and dental cost trend rate at December 31, 2018					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments					
Following Year	8,942	170	35	19	9,166
Following Year +1	9,201	139	36	20	9,396
Following Year +2	9,701	151	37	22	9,911
Following Year +3	10,186	156	37	26	10,405
Following Year +4	10,637	259	38	31	10,965
Following Year +5	11,009	1,566	38	34	12,647
Following Year +6	11,118	50	37	38	11,243
Modified Duration at the end of the year	17.2	11.5	16.1	19.5	16.7

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2019 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2019		
Defined Benefit Asset/(Liability) at Beginning of Period	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Reconciliation of Defined Benefit Obligation			2019		
Defined Benefit Obligation at Beginning of Period	270,910	2,697	959	1,294	275,860
Employer Service Cost at Beginning of Period	2,968	213	-	54	3,235
Interest Cost	10,103	106	35	50	10,294
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,942)	(170)	(35)	(19)	(9,166)
Defined Benefit Obligation at Current Period End	275,039	2,846	959	1,379	280,223
Change in Plan Assets			2019		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,942	170	35	19	9,166
Benefits Paid	(8,942)	(170)	(35)	(19)	(9,166)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2019		
Employer Service Cost at Beginning of Period	2,968	213	-	54	3,235
Interest Cost	10,103	106	35	50	10,294
Total Benefit Expense/(Income)	13,071	319	35	104	13,529
Reconciliation of Balance Sheet			2019		
Defined Benefit Asset/(Liability) at Prior Period End	(270,910)	(2,697)	(959)	(1,294)	(275,860)
Total Benefit (Expense)/Income for Period	(13,071)	(319)	(35)	(104)	(13,529)
Benefits Paid Directly by the Employer	8,942	170	35	19	9,166
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Change in Accumulated Other Comprehensive Income			2019		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2019		
Defined Benefit Asset/(Liability) at Current Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2019		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Defined Benefit Asset/(Liability) at Current Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2019 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2019 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2019					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	9,201	139	36	20	9,396

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2020 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2020		
Defined Benefit Asset/(Liability) at Beginning of Period	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Reconciliation of Defined Benefit Obligation			2020		
Defined Benefit Obligation at Beginning of Period	275,039	2,846	959	1,379	280,223
Employer Service Cost at Beginning of Period	3,079	221	-	56	3,356
Interest Cost	10,257	112	35	53	10,457
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(9,201)	(139)	(36)	(20)	(9,396)
Defined Benefit Obligation at Current Period End	279,174	3,040	958	1,468	284,640
Change in Plan Assets			2020		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	9,201	139	36	20	9,396
Benefits Paid	(9,201)	(139)	(36)	(20)	(9,396)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2020		
Employer Service Cost at Beginning of Period	3,079	221	-	56	3,356
Interest Cost	10,257	112	35	53	10,457
Total Benefit Expense/(Income)	13,336	333	35	109	13,813
Reconciliation of Balance Sheet			2020		
Defined Benefit Asset/(Liability) at Prior Period End	(275,039)	(2,846)	(959)	(1,379)	(280,223)
Total Benefit (Expense)/Income for Period	(13,336)	(333)	(35)	(109)	(13,813)
Benefits Paid Directly by the Employer	9,201	139	36	20	9,396
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Change in Accumulated Other Comprehensive Income			2020		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2020		
Defined Benefit Asset/(Liability) at Current Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2020		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Defined Benefit Asset/(Liability) at Current Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2020 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2020 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2020					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	9,701	151	37	22	9,911

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2021 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2021		
Defined Benefit Asset/(Liability) at Beginning of Period	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Reconciliation of Defined Benefit Obligation			2021		
Defined Benefit Obligation at Beginning of Period	279,174	3,040	958	1,468	284,640
Employer Service Cost at Beginning of Period	3,194	229	-	58	3,481
Interest Cost	10,407	120	35	57	10,619
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(9,701)	(151)	(37)	(22)	(9,911)
Defined Benefit Obligation at Current Period End	283,074	3,238	956	1,561	288,829
Change in Plan Assets			2021		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	9,701	151	37	22	9,911
Benefits Paid	(9,701)	(151)	(37)	(22)	(9,911)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2021		
Employer Service Cost at Beginning of Period	3,194	229	-	58	3,481
Interest Cost	10,407	120	35	57	10,619
Total Benefit Expense/(Income)	13,601	349	35	115	14,100
Reconciliation of Balance Sheet			2021		
Defined Benefit Asset/(Liability) at Prior Period End	(279,174)	(3,040)	(958)	(1,468)	(284,640)
Total Benefit (Expense)/Income for Period	(13,601)	(349)	(35)	(115)	(14,100)
Benefits Paid Directly by the Employer	9,701	151	37	22	9,911
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Change in Accumulated Other Comprehensive Income			2021		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2021		
Defined Benefit Asset/(Liability) at Current Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2021		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Defined Benefit Asset/(Liability) at Current Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2021 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2021 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2021					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	10,186	156	37	26	10,405

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2022 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2022		
Defined Benefit Asset/(Liability) at Beginning of Period	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Reconciliation of Defined Benefit Obligation			2022		
Defined Benefit Obligation at Beginning of Period	283,074	3,238	956	1,561	288,829
Employer Service Cost at Beginning of Period	3,314	238	-	60	3,612
Interest Cost	10,549	127	35	60	10,771
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(10,186)	(156)	(37)	(26)	(10,405)
Defined Benefit Obligation at Current Period End	286,751	3,447	954	1,655	292,807
Change in Plan Assets			2022		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,186	156	37	26	10,405
Benefits Paid	(10,186)	(156)	(37)	(26)	(10,405)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2022		
Employer Service Cost at Beginning of Period	3,314	238	-	60	3,612
Interest Cost	10,549	127	35	60	10,771
Total Benefit Expense/(Income)	13,863	365	35	120	14,383
Reconciliation of Balance Sheet			2022		
Defined Benefit Asset/(Liability) at Prior Period End	(283,074)	(3,238)	(956)	(1,561)	(288,829)
Total Benefit (Expense)/Income for Period	(13,863)	(365)	(35)	(120)	(14,383)
Benefits Paid Directly by the Employer	10,186	156	37	26	10,405
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Change in Accumulated Other Comprehensive Income			2022		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2022		
Defined Benefit Asset/(Liability) at Current Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2022		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Defined Benefit Asset/(Liability) at Current Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2022 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2022 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2022					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	10,637	259	38	31	10,965

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2023 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2023		
Defined Benefit Asset/(Liability) at Beginning of Period	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Reconciliation of Defined Benefit Obligation			2023		
Defined Benefit Obligation at Beginning of Period	286,751	3,447	954	1,655	292,807
Employer Service Cost at Beginning of Period	3,438	247	-	62	3,747
Interest Cost	10,683	134	35	64	10,916
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(10,637)	(259)	(38)	(31)	(10,965)
Defined Benefit Obligation at Current Period End	290,235	3,569	951	1,750	296,505
Change in Plan Assets			2023		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,637	259	38	31	10,965
Benefits Paid	(10,637)	(259)	(38)	(31)	(10,965)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2023		
Employer Service Cost at Beginning of Period	3,438	247	-	62	3,747
Interest Cost	10,683	134	35	64	10,916
Total Benefit Expense/(Income)	14,121	381	35	126	14,663
Reconciliation of Balance Sheet			2023		
Defined Benefit Asset/(Liability) at Prior Period End	(286,751)	(3,447)	(954)	(1,655)	(292,807)
Total Benefit (Expense)/Income for Period	(14,121)	(381)	(35)	(126)	(14,663)
Benefits Paid Directly by the Employer	10,637	259	38	31	10,965
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Change in Accumulated Other Comprehensive Income			2023		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2023		
Defined Benefit Asset/(Liability) at Current Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2023		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Defined Benefit Asset/(Liability) at Current Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2023 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2023 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2023					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	11,009	1,566	38	34	12,647

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2024 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2024		
Defined Benefit Asset/(Liability) at Beginning of Period	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Reconciliation of Defined Benefit Obligation			2024		
Defined Benefit Obligation at Beginning of Period	290,235	3,569	951	1,750	296,505
Employer Service Cost at Beginning of Period	3,567	256	-	64	3,887
Interest Cost	10,811	114	35	67	11,027
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(11,009)	(1,566)	(38)	(34)	(12,647)
Defined Benefit Obligation at Current Period End	293,604	2,373	948	1,847	298,772
Change in Plan Assets			2024		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	11,009	1,566	38	34	12,647
Benefits Paid	(11,009)	(1,566)	(38)	(34)	(12,647)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2024		
Employer Service Cost at Beginning of Period	3,567	256	-	64	3,887
Interest Cost	10,811	114	35	67	11,027
Total Benefit Expense/(Income)	14,378	370	35	131	14,914
Reconciliation of Balance Sheet			2024		
Defined Benefit Asset/(Liability) at Prior Period End	(290,235)	(3,569)	(951)	(1,750)	(296,505)
Total Benefit (Expense)/Income for Period	(14,378)	(370)	(35)	(131)	(14,914)
Benefits Paid Directly by the Employer	11,009	1,566	38	34	12,647
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Change in Accumulated Other Comprehensive Income			2024		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	16,408	(877)	(2,402)	(85)	13,044
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	16,408	(877)	(2,402)	(85)	13,044
Statement of Financial Position at End of Period			December 31, 2024		
Defined Benefit Asset/(Liability) at Current Period End	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2024		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Defined Benefit Asset/(Liability) at Current Period End	(293,604)	(2,373)	(948)	(1,847)	(298,772)
Key Assumptions					
Discount rate at Dec 31/18 (used for December 31, 2024 obligation)	3.75%	3.75%	3.75%	3.75%	3.75%
Discount rate at Dec 31/18 (used for 2024 Benefit Costs)	3.75%	3.75%	3.75%	3.75%	3.75%
Assumed medical and dental cost trend rate at December 31, 2024					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.00%	5.00%	5.00%	5.00%	5.00%
Expected Benefit Payments for Following Year	11,118	50	37	38	11,243

SHARED SERVICES VARIANCE ANALYSIS

1. SHARED SERVICES

Exhibit 4A, Tab 5, Schedule 1 contains detailed information about shared services and corporate costs allocations between Toronto Hydro and its affiliated corporate entities. This schedules provides summary of the 2018 actuals, and explains the material variances resulting from the 2018 actuals.

An updated copy of OEB Appendix 2-N is filed as Appendix A to this schedule. This appendix provides cost information and allocation details relating to each shared service provided or received by Toronto Hydro in the historical years (2015 to 2018), the forecast years (2019 and 2020).

1.1 Toronto Hydro (TH) Energy

Table 1: Summary of the Cost of Shared Services Provided by and Received by Toronto Hydro to/from TH Energy ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	2.0	2.1	1.1	2.2	1.6	1.6
Services Received by Toronto Hydro	1.9	2.6	0.3	0.0	0.0	0.0

There are no material variances resulting from the 2018 actuals.

1.2 Non-Rate Regulated Toronto Hydro Activities

Table 2: Summary of the Cost of Services relating to Non-Rate Regulated Toronto Hydro Activities

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	1.3	1.7	1.9	1.7	1.6	1.7

There are no material variances resulting from the 2018 actuals.

1.3 Toronto Hydro Corporation (THC)

Table 3: Summary of the Cost of Shared Services Provided by and Received by Toronto Hydro to/from THC ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services Provided by Toronto Hydro	1.2	1.3	3.2	3.2	3.9	3.9
Services Received by Toronto Hydro	4.8	2.9	4.8	5.1	4.4	4.6

In 2018, Toronto Hydro provided less services to its affiliate THC than what the utility forecast in Exhibit 4A, Tab 5. The value of the services received by Toronto Hydro from THC in 2018 was higher than forecasted primarily due to one-time costs associated with the transition of the CFO. These costs are expected to return to historical levels in the 2020 Test Year.

OEB 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			$	$
THESL	THESI	Fleet*	Fully allocated-cost	0.38	0.38
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.52	0.48
THESI	THESL	Design	Market**	0.04	0.04
THESI	THESL	Emergency/Field Work	Market**	1.82	1.59

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury	Fully allocated-cost	2.9%	0.49
THESL	THESI	EHS	Fully allocated-cost	0.4%	0.01
THESL	THESI	Legal/Insurance	Fully allocated-cost	3.6%	0.18
THESL	THESI	HR&OE	Fully allocated-cost	1.3%	0.17
THESL	THESI	Procurement	Fully allocated-cost	1.7%	0.04
THESL	THESI	Consolidated Billing	Fully allocated-cost	0.0%	-
THESL	THESI	IT&S	Fully allocated-cost	0.8%	0.06
THESL	THESI	Facilities	Fully allocated-cost	0.5%	0.11
THESL	THESU	Finance/Treasury	Fully allocated-cost	2.3%	0.39
THESL	THESU	Legal/Insurance	Fully allocated-cost	0.6%	0.03
THESL	THESU	HR&OE	Fully allocated-cost	2.5%	0.37
THESL	THESU	Procurement	Fully allocated-cost	5.4%	0.12
THESL	THESU	IT&S	Fully allocated-cost	0.9%	0.07
THESL	THESU	Facilities	Fully allocated-cost	1.6%	0.37
THESL	THC	Finance/Treasury	Fully allocated-cost	2.8%	0.47
THESL	THC	Legal/Insurance	Fully allocated-cost	13.9%	0.71
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.1%	0.01
THESL	THC	Facilities	Fully allocated-cost	0.2%	0.04
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.71
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.22
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.89
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.01

OEB 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			$	$
THESL	THESI	Fleet*	Fully allocated-cost	0.43	0.43
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.46	0.38
THESI	THESL	Emergency/Field Work	Market**	2.39	2.07
THESI	THESL	Design	Market**	0.19	0.16

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	3.0%	0.480
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.006
THESL	THESI	Legal	Fully allocated-cost	4.6%	0.244
THESL	THESI	HR&OE	Fully allocated-cost	1.2%	0.163
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.075
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	11.1%	0.049
THESL	THESI	IT&S	Fully allocated-cost	0.3%	0.11
THESL	THESI	Facilities	Fully allocated-cost	0.4%	0.11
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.369
THESL	THESU	Legal	Fully allocated-cost	1.0%	0.056
THESL	THESU	HR&OE	Fully allocated-cost	2.4%	0.320
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.212
THESL	THESU	IT&S	Fully allocated-cost	0.7%	0.26
THESL	THESU	Facilities	Fully allocated-cost	2.0%	0.50
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.5%	0.393
THESL	THC	Legal	Fully allocated-cost	15.4%	0.824
THESL	THC	HR&OE	Fully allocated-cost	0.0%	0.006
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.014
THESL	THC	IT&S	Fully allocated-cost	0.0%	0.01
THESL	THC	Facilities	Fully allocated-cost	0.3%	0.07
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	1.88
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.29
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	0.69
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

OEB 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			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.33	0.30
THESI	THESL	Emergency/Field Work	Market**	0.21	0.21
THESI	THESL	Design	Market**	0.07	0.07

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.3%	0.32
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.7%	0.33
THESL	THESI	HR&OE	Fully allocated-cost	0.0%	-
THESL	THESI	Procurement	Fully allocated-cost	1.1%	0.04
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.0%	0.05
THESL	THESI	IT&S	Fully allocated-cost		-
THESL	THESI	Facilities	Fully allocated-cost		-
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	4.3%	0.61
THESL	THESU	Legal	Fully allocated-cost	1.9%	0.11
THESL	THESU	HR&OE	Fully allocated-cost	1.5%	0.21
THESL	THESU	Procurement	Fully allocated-cost	5.6%	0.21
THESL	THESU	IT&S	Fully allocated-cost	0.6%	0.25
THESL	THESU	Facilities	Fully allocated-cost	2.3%	0.54
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	2.6%	0.37
THESL	THC	Legal	Fully allocated-cost	14.0%	0.82
THESL	THC	HR&OE	Fully allocated-cost	0.2%	0.03
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.2%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.01
THESL	THC	Facilities	Fully allocated-cost	1.0%	0.22
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	3.02
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.27
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	90.0%	1.47
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

OEB 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			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	1.37	1.30
THESI	THESL	Emergency/Field Work	Market**	0.02	0.02
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.
** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.8%	0.47
THESL	THESI	EHS	Fully allocated-cost	0.0%	-
THESL	THESI	Legal	Fully allocated-cost	5.7%	0.36
THESL	THESI	HR&OE	Fully allocated-cost	0.0%	-
THESL	THESI	Procurement	Fully allocated-cost	1.0%	0.01
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	4.5%	0.03
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.0%	0.49
THESL	THESU	Legal	Fully allocated-cost	1.8%	0.11
THESL	THESU	HR&OE	Fully allocated-cost	2.2%	0.30
THESL	THESU	Procurement	Fully allocated-cost	4.5%	0.05
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.35
THESL	THESU	Facilities	Fully allocated-cost	1.6%	0.35
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	6.5%	1.08
THESL	THC	Legal	Fully allocated-cost	15.2%	0.96
THESL	THC	HR&OE	Fully allocated-cost	0.3%	0.04
THESL	THC	Office of the President	Fully allocated-cost	***	0.80
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.00
THESL	THC	IT&S	Fully allocated-cost	0.1%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.0%	0.23
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	3.07
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.27
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	90.0%	1.80
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02
THC	THESI	Finance Stewardship - CFO	Fully allocated-cost	5.0%	0.10

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.2%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.8%	0.32
THESL	THESI	HR&OE	Fully allocated-cost	1.0%	0.13
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.3%	0.05
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.9%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.1%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	2.7%	0.37
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.36
THESL	THESU	Facilities	Fully allocated-cost	1.3%	0.37
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	5.9%	1.07
THESL	THC	Legal	Fully allocated-cost	15.4%	0.85
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.4%	0.24
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.76
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.32
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2020

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
THESL	THESI	Fleet*	Fully allocated-cost	-	-
THESL	THESI	Emergency Calls / Streetlighting Relamping	Market**	0.67	0.57
THESI	THESL	Emergency/Field Work	Market**	-	-
THESI	THESL	Design	Market**	-	-

* A portion of the fleet charge is allocated from THESI to THESU.

** Because of cost-benefit impacts and impracticability, there was no study done to verify market amounts.

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
THESL	THESI	Finance/Treasury/Insurance	Fully allocated-cost	2.2%	0.40
THESL	THESI	EHS	Fully allocated-cost	0.3%	0.01
THESL	THESI	Legal	Fully allocated-cost	5.8%	0.33
THESL	THESI	HR&OE	Fully allocated-cost	0.9%	0.13
THESL	THESI	Billing and Settlement Services	Fully allocated-cost	5.4%	0.05
THESL	THESI	Procurement	Fully allocated-cost	1.3%	0.05
THESL	THESI	IT&S	Fully allocated-cost		
THESL	THESI	Facilities	Fully allocated-cost		
THESL	THESU	Finance/Treasury/Insurance	Fully allocated-cost	1.9%	0.35
THESL	THESU	Legal	Fully allocated-cost	1.1%	0.06
THESL	THESU	HR&OE	Fully allocated-cost	2.7%	0.38
THESL	THESU	Procurement	Fully allocated-cost	3.7%	0.13
THESL	THESU	IT&S	Fully allocated-cost	0.8%	0.37
THESL	THESU	Facilities	Fully allocated-cost	3.7%	0.38
THESL	THC	Finance/Treasury/Insurance	Fully allocated-cost	5.6%	1.01
THESL	THC	Legal	Fully allocated-cost	15.4%	0.89
THESL	THC	HR&OE	Fully allocated-cost	0.1%	0.01
THESL	THC	Office of the President	Fully allocated-cost	***	1.70
THESL	THC	Procurement	Fully allocated-cost	0.3%	0.01
THESL	THC	IT&S	Fully allocated-cost	0.03%	0.04
THESL	THC	Facilities	Fully allocated-cost	1.4%	0.24
THC	THESL	Corporate Stewardship - CEO	Fully allocated-cost	95.0%	2.86
THC	THESL	Corporate Governance - Board of Directors	Fully allocated-cost	90.0%	0.36
THC	THESL	Finance Stewardship - CFO	Fully allocated-cost	95.0%	1.35
THC	THESI	Corporate Governance - Board of Directors	Fully allocated-cost	5.0%	0.02

***Based on time allocation of multiple functions across the organization.

OEB Appendix 2-N
Shared Services and Corporate Cost Allocation

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

OPERATING COSTS: DEPRECIATION VARIANCE ANALYSIS

1. DEPRECIATION AND AMORTIZATION

Exhibit 4B, Tab 1 includes detailed information about Toronto Hydro's depreciation and amortization rates and expenses. This schedules provides a summary of the utility's 2018 expenses, explains the material variances and identifies changes to 2019 forecasts. Toronto Hydro has not made any changes to the 2020-2024 forecast.

1.1 Decommissioning Provision

The tables below provide the historical (2015-2018) and forecasted (2019-2020) decommissioning costs and the related depreciation expense (Table 1), as well as the corresponding decommissioning liability and related accretion expenses (Table 2). There were no material variances in 2018.

Table 1: Historical and Forecasted Decommissioning Costs and Related Depreciation Expense ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Decommissioning Costs	1.0	0.8	0.8	0.7	0.6	0.6
Related Depreciation Expense	0.1	0.1	0.1	0.1	0.1	0.1

Table 2: Historical and Forecasted Decommissioning Liability and Related Accretion Expense ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Decommissioning Liability	1.9	1.5	1.5	1.4	1.3	1.2
Related Accretion Expense	-	-	-	-	-	-

1.2 Depreciation and Amortization Expense

Toronto Hydro's depreciation and amortization expense from 2015 to 2020 is presented in Table 3 below. This summary is supported by Appendix A, which provides a breakdown of 2015-2020 depreciation expense by Uniform System of Accounts. An updated version of OEB Appendix 2-C is filed as Appendix B to this schedule.

Table 3: Depreciation and Amortization Expense[1] 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Depreciation and Amortization Expense	166.0	179.1	192.5	205.3	223.6	242.9

The 2018 actual and 2019 bridge depreciation and amortization expenses are $5.4 million and $4.6 million lower, respectively, than the forecasts included in Exhibit 4B, Tab 1, Schedule 1, page 6.

The differences in 2018 are primarily due to timing differences associated with the completion of the ERP and Copeland TS projects. The depreciation expense for 2019 is expected to be lower due to the reduced opening balance for fixed assets in 2019, and changes in the timing of in-service additions in the year resulting from the work that is being carried over from 2018 into 2019.

[1] Includes depreciation of the decommissioning costs and excludes derecognition. For inofmraiton about asset derecognition please see section 2.1 below and Exhibit 4B, Tab 1, Schedule 2.

2. DERECOGNITION

2.1 Derecognition Expense

Table 4 below summarizes Toronto Hydro's 2015 to 2020 derecognition expense. The 2018 actual and 2019 bridge expenses are $3.7 million and $2.3 million higher, respectively, than the forecasts included in Exhibit 4B, Tab 1, Schedule 2, page 1.

The differences in 2018 relate to overhead and underground distribution assets, as well as software assets. Toronto Hydro updated 2019 forecast based on a four year average of derecognition as opposed to a three year average in the original filing.

Table 4: Derecognition from 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	2020 Forecast
Derecognition	24.1	27.0	24.5	24.5	22.4	25.8

Table 1: Summary of Depreciation Expense

		2018 MIFRS			2019 MIFRS		
OEB	**Description**	**Depreciation Expense**	**Derecognition**	**Total Depreciation Expense**	**Depreciation Expense**	**Derecognition**	**Total Depreciation Expense**
1611	Computer Software (Formally known as Account 1925)	$ 20,892,805	$ 1,385,063	$ 22,277,868	$ 27,968,318	$ -	$ 27,968,318
1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 3,308,486	$ 9,993	$ 3,318,479	$ 3,576,986	$ -	$ 3,576,986
1815	Transformer Station Equipment >50 kV	$ 1,298,265	$ -	$ 1,298,265	$ 1,339,480	$ -	$ 1,339,480
1820	Distribution Station Equipment <50 kV	$ 8,622,713	$ 751,097	$ 9,373,810	$ 9,828,871	$ 155,775	$ 9,984,646
1830	Poles, Towers & Fixtures	$ 10,921,669	$ 2,376,041	$ 13,297,709	$ 11,163,183	$ 5,081,606	$ 16,244,788
1835	Overhead Conductors & Devices	$ 10,827,432	$ 2,228,085	$ 13,055,516	$ 11,552,701	$ 1,895,332	$ 13,448,034
1840	Underground Conduit	$ 44,888,220	$ 267,741	$ 45,155,961	$ 47,764,130	$ 462,445	$ 48,226,575
1845	Underground Conductors & Devices	$ 25,369,256	$ 7,220,345	$ 32,589,601	$ 26,963,221	$ 4,270,576	$ 31,233,797
1850	Line Transformers	$ 23,997,546	$ 7,327,460	$ 31,325,006	$ 25,545,270	$ 6,767,188	$ 32,312,458
1855	Services (Overhead & Underground)	$ 2,947,558	$ 480,467	$ 3,428,026	$ 3,062,482	$ 311,266	$ 3,373,747
1860	Meters	$ 16,018,913	$ 2,559,854	$ 18,578,767	$ 16,785,423	$ 3,367,079	$ 20,152,502
1905	Land	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,318,351	$ 113,573	$ 11,431,924	$ 11,325,101	$ -	$ 11,325,101
1910	Leasehold Improvements	$ 10,481	$ -	$ 10,481	$ 8,734	$ -	$ 8,734
1915	Office Furniture & Equipment	$ 2,051,264	$ 3,544	$ 2,054,807	$ 2,067,790	$ -	$ 2,067,790
1920	Computer Equipment - Hardware	$ 10,714,855	$ -	$ 10,714,855	$ 10,812,376	$ -	$ 10,812,376
1930	Transportation Equipment	$ 3,636,383	$ -	$ 3,636,383	$ 3,141,469	$ -	$ 3,141,469
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 2,257,857	$ -	$ 2,257,857	$ 2,443,955	$ -	$ 2,443,955
1945	Measurement & Testing Equipment	$ 59,822	$ -	$ 59,822	$ 61,540	$ -	$ 61,540
1950	Power Operated Equipment	$ 159,091	$ -	$ 159,091	$ 131,053	$ -	$ 131,053
1955	Communications Equipment	$ 4,690,337	$ -	$ 4,690,337	$ 4,719,684	$ -	$ 4,719,684
1960	Miscellaneous Equipment	$ 37,310	$ -	$ 37,310	$ 37,310	$ -	$ 37,310
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 2,802,429	$ 308,612	$ 3,111,041	$ 3,134,194	$ 449,144	$ 3,583,337
2440	Contributions & Grants	($ 5,263,537)	($ 522,605)	($ 5,786,142)	($ 5,711,872)	($ 375,099)	($ 6,086,971)
1609	Capital Contributions Paid	$ 3,538,390	$ -	$ 3,538,390	$ 7,235,447	$ -	$ 7,235,447
2005	Property Under Capital Leases	$ 1,320,504	$ -	$ 1,320,504	$ 652,639	$ -	$ 652,639
	Sub-Total	$ 206,426,400	$ 24,509,267	$ 230,935,667	$ 225,609,486	$ 22,385,311	$ 247,994,797
	Less Socialized Renewable Energy Generation Investments **(input as negative)**	$ -	$ -	$ -	($ 34,127)	$ -	($ 34,127)
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	($ 133,468)	$ -	($ 133,468)	($ 202,609)	$ -	($ 202,609)
	Total	$ 206,292,932	$ 24,509,267	$ 230,802,199	$ 225,372,751	$ 22,385,311	$ 247,758,062

Less: *Fully Allocated Depreciation* Transportation	($ 961,328)		($ 961,328)	($ 1,759,521)		($ 1,759,521)
Net Depreciation	**$ 205,331,604**	**$ 24,509,267**	**$ 229,840,871**	**$ 223,613,230**	**$ 22,385,311**	**$ 245,998,541**

OEB Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2018	MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$69,572,669	$36,877,357	$32,695,312	$67,387,997	$5,290,961	$62,097,036	$73,814,110	4.91	20.36%	6.89	14.51%	$6,655,322	$9,008,172	$5,353,961	$21,017,455	$20,892,805	**-$124,650**
1612	Land Rights	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1805	Land	$7,588,531	$0	$7,588,531	-$8,030	$0	-$8,030	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1808	Buildings	$29,677,626	$3,203,894	$26,473,732	$87,327,434	$5,350	$87,322,084	$20,897,786	18.08	5.53%	66.77	1.50%	$1,464,400	$1,307,735	$156,483	$2,928,618	$3,308,486	**$379,868**
1815	Transformer Station Equipment >50 kV	$5,839,955	$13,224	$5,826,730	$31,091,235	$0	$31,091,235	$944,609	14.45	6.92%	37.03	2.70%	$403,185	$839,565	$12,754	$1,255,504	$1,298,265	**$42,761**
1820	Distribution Station Equipment <50 kV	$112,667,455	$1,707,056	$110,960,399	$73,489,735	$0	$73,489,735	$30,319,716	19.20	5.21%	30.55	3.27%	$5,779,142	$2,405,269	$496,172	$8,680,583	$8,622,713	**-$57,871**
1830	Poles, Towers & Fixtures	$208,620,348	$763,354	$207,856,994	$169,783,390	$1,311,076	$168,472,314	$21,287,951	31.60	3.16%	38.06	2.63%	$6,576,912	$4,426,310	$279,652	$11,282,874	$10,921,669	**-$361,205**
1835	Overhead Conductors & Devices	$197,786,423	$735,569	$197,050,854	$200,296,773	$1,434,382	$198,862,391	$41,090,486	34.02	2.94%	44.52	2.25%	$5,792,421	$4,466,999	$461,503	$10,720,923	$10,827,432	**$106,508**
1840	Underground Conduit	$639,376,710	$5,008,668	$634,368,042	$490,165,792	$205,791	$489,960,001	$78,574,199	22.27	4.49%	33.03	3.03%	$28,489,806	$14,832,912	$1,189,367	$44,512,085	$44,888,220	**$376,135**
1845	Underground Conductors & Devices	$397,494,067	$6,633,322	$390,860,745	$402,623,384	$5,111,479	$397,511,905	$87,194,048	31.09	3.22%	37.25	2.68%	$12,571,810	$10,672,600	$1,170,515	$24,414,925	$25,369,256	**$954,331**
1850	Line Transformers	$305,215,157	$8,045,785	$297,169,373	$245,905,202	$1,520,860	$244,384,342	$62,025,718	18.14	5.51%	27.47	3.64%	$16,381,002	$8,898,024	$1,129,177	$26,408,203	$23,997,546	**-$2,410,657**
1855	Services (Overhead & Underground)	$61,419,385	$720,464	$60,698,921	$62,815,335	$76,476	$62,738,858	$3,010,082	40.50	2.47%	43.98	2.27%	$1,498,869	$1,426,559	$34,222	$2,959,650	$2,947,558	**-$12,091**
1860	Meters	$44,538,583	$1,198,476	$43,340,106	$38,342,883	$235,731	$38,107,151	$8,057,288	19.72	5.07%	20.75	4.82%	$2,198,305	$1,836,741	$194,178	$4,229,223	$4,490,265	**$261,042**
1860	Meters (Smart Meters)	$94,589,513	$2,176,233	$92,413,280	$34,509,395	$106,085	$34,403,310	$16,301,957	9.75	10.25%	15.00	6.67%	$9,474,408	$2,293,554	$543,399	$12,311,360	$11,528,648	**-$782,712**
1905	Land	$9,150,994	$0	$9,150,994	$9,250,332	$0	$9,250,332	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1908	Buildings & Fixtures	$65,356,634	$16,446,753	$48,909,881	$185,015,240	$2,372,563	$182,642,677	$4,456,339	12.89	7.76%	31.04	3.22%	$3,793,552	$5,883,283	$71,774	$9,748,608	$11,318,351	**$1,569,743**
1910	Leasehold Improvements	$701,434	$701,434	$0	$52,406	$0	$52,406	$0	3.03	32.97%	5.00	20.00%	$0	$10,481	$0	$10,481	$10,481	**$0**
1915	Office Furniture & Equipment	$9,802,431	$2,404,395	$7,398,035	$9,227,322	$0	$9,227,322	$673,247	5.87	17.02%	10.00	10.00%	$1,259,422	$922,732	$33,662	$2,215,817	$2,051,264	**-$164,553**
1920	Computer Equipment - Hardware	$11,192,631	$11,254,107	-$61,476	$47,490,710	$4,698,090	$42,792,621	$8,077,721	3.34	29.93%	4.92	20.34%	-$18,400	$8,703,776	$821,481	$9,506,857	$10,714,855	**$1,207,999**
1930	Transportation Equipment	$21,967,081	$15,357,998	$6,609,083	$12,088,500	$0	$12,088,500	$2,912,073	4.03	24.80%	7.32	13.66%	$1,639,126	$1,650,822	$198,838	$3,488,786	$3,636,383	**$147,597**
1935	Stores Equipment	$7,066	$7,066	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1940	Tools, Shop & Garage Equipment	$11,036,987	$3,173,694	$7,863,293	$10,159,910	$0	$10,159,910	$2,199,041	5.61	17.81%	9.95	10.05%	$1,400,830	$1,021,143	$110,510	$2,532,483	$2,257,857	**-$274,626**
1945	Measurement & Testing Equipment	$9,367,510	$35,289	$9,332,221	-$8,887,268	$0	-$8,887,268	$0	4.39	22.77%	4.39	22.77%	$2,124,778	-$2,023,470	$0	$101,308	$59,822	**-$41,486**
1950	Service Equipment	$615,688	$266,460	$349,228	$230,085	$0	$230,085	$544,550	5.09	19.66%	8.00	12.50%	$68,668	$28,761	$34,034	$131,463	$159,091	**$27,627**
1955	Communications Equipment	$4,593,288	$4,444,612	$148,676	$40,764,758	$0	$40,764,758	$4,530,356	2.94	34.04%	12.85	7.78%	$50,608	$3,171,712	$176,243	$3,398,563	$4,690,337	**$1,291,774**
1960	Miscellaneous Equipment	$267,071	$0	$267,071	$3,907	$0	$3,907	$0	7.23	13.82%	10.00	10.00%	$36,919	$391	$0	$37,310	$37,310	**$0**
1970	Load Management Controls Customer Premises	$3,022,834	$3,022,834	$0	$0	$0	$0	$0	2.85	35.12%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1980	System Supervisor Equipment	$19,174,795	$1,725,140	$17,449,656	$18,172,795	$70,327	$18,102,468	$6,524,511	11.09	9.02%	14.96	6.68%	$1,573,518	$1,209,964	$218,048	$3,001,531	$2,802,429	**-$199,102**
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
2440	Contributions & Grants (Formally known as Account 1995)	$0	$0	$0	-$120,141,389	-$6,053,553	-$114,087,836	-$39,248,789	-	0.00%	35.20	2.84%	$0	-$3,241,115	-$557,508	-$3,798,624	-$5,263,537	**-$1,464,913**
1609	Capital Contributions Paid	$19,104,312	$0	$19,104,312	$56,470,186	$0	$56,470,186	$88,593,906	21.68	4.61%	24.97	4.01%	$881,195	$2,261,726	$1,774,167	$4,917,089	$3,538,390	**-$1,378,699**
2005	Property Under Capital Leases	$7,191,090	$0	$7,191,090	$10,979,744	$10,979,744	$0	$1,576,880	80.42	1.24%	6.66	15.02%	$89,423	$0	$118,429	$207,852	$1,320,504	**$1,112,652**
	Sub-Total	**$2,366,938,267**	**$125,923,184**	**$2,241,015,083**	**$2,174,607,766**	**$27,365,363**	**$2,147,242,402**	**$524,357,783**					**$110,185,220**	**$82,014,646**	**$14,021,059**	**$206,220,925**	**$206,426,400**	**$205,475**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$0		$0	$0		$0	$0		0.00%	10.00	10.00%	$0	$0	$0	$0	$0	**$0**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$0		$0	-$2,002,023		-$2,002,023	$0		0.00%	15.00	6.67%	$0	-$133,468	$0	-$133,468	-$133,468	**$0**
	Total	**$2,366,938,267**	**$125,923,184**	**$2,241,015,083**	**$2,172,605,743**	**$27,365,363**	**$2,145,240,380**	**$524,357,783**					**$110,185,220**	**$81,881,178**	**$14,021,059**	**$206,087,457**	**$206,292,932**	**$205,475**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

OEB Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Already rebased with depreciation policy changes in a prior rate application ☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2019	MIFRS

		Book Values						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1611	Computer Software (Formally known as Account 1925)	$69,572,669	$36,877,357	$32,695,312	$141,202,106	$19,277,944	$121,924,162	$40,029,185
1612	Land Rights	$0	$0	$0	$0	$0	$0	$0
1805	Land	$7,588,531	$0	$7,588,531	-$8,030	$0	-$8,030	$0
1808	Buildings	$29,677,626	$3,292,155	$26,385,471	$108,225,220	$5,350	$108,219,870	$9,342,754
1815	Transformer Station Equipment >50 kV	$5,839,955	$13,224	$5,826,730	$32,035,844	$0	$32,035,844	$1,030,716
1820	Distribution Station Equipment <50 kV	$112,667,455	$2,585,570	$110,081,886	$103,809,451	$0	$103,809,451	$20,600,010
1830	Poles, Towers & Fixtures	$208,620,348	$763,354	$207,856,994	$191,071,341	$1,397,281	$189,674,060	$28,474,609
1835	Overhead Conductors & Devices	$197,786,423	$934,614	$196,851,809	$241,387,259	$1,713,413	$239,673,846	$42,197,486
1840	Underground Conduit	$639,376,710	$7,697,861	$631,678,849	$568,739,992	$205,791	$568,534,200	$101,150,177
1845	Underground Conductors & Devices	$397,494,067	$6,914,611	$390,579,456	$489,817,432	$5,858,818	$483,958,614	$98,357,471
1850	Line Transformers	$305,215,157	$10,840,283	$294,374,874	$307,930,921	$1,520,860	$306,410,060	$82,017,280
1855	Services (Overhead & Underground)	$61,419,385	$720,464	$60,698,921	$65,825,416	$77,979	$65,747,437	$17,117,258
1860	Meters	$44,538,583	$1,198,476	$43,340,106	$46,400,170	$273,348	$46,126,822	$19,232,313
1860	Meters (Smart Meters)	$94,589,513	$2,176,233	$92,413,280	$50,811,352	$106,085	$50,705,267	$8,807,217
1905	Land	$9,150,994	$0	$9,150,994	$9,250,332	$0	$9,250,332	$0
1908	Buildings & Fixtures	$65,356,634	$5,140,983	$60,215,651	$189,471,579	$2,372,563	$187,099,016	$1,250,623
1910	Leasehold Improvements	$701,434	$701,434	$0	$52,406	$52,406	$0	$0
1915	Office Furniture & Equipment	$9,802,431	$2,499,302	$7,303,129	$9,900,570	$0	$9,900,570	$448,337
1920	Computer Equipment - Hardware	$11,192,631	$11,254,520	-$61,889	$55,568,432	$13,726,866	$41,841,565	$7,398,534
1930	Transportation Equipment	$21,967,081	$21,164,466	$802,615	$15,000,573	$0	$15,000,573	$4,995,050
1935	Stores Equipment	$7,066	$7,066	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$11,036,987	$3,804,933	$7,232,054	$12,358,951	$0	$12,358,951	$5,530,796
1945	Measurement & Testing Equipment	$9,367,510	$35,289	$9,332,221	-$8,887,268	$0	-$8,887,268	$19,437
1950	Service Equipment	$615,688	$390,650	$225,037	$774,636	$0	$774,636	$122,762
1955	Communications Equipment	$4,593,288	$4,444,612	$148,676	$45,295,114	$2,487,921	$42,807,193	$802,266
1960	Miscellaneous Equipment	$267,071	$0	$267,071	$3,907	$0	$3,907	$0
1970	Load Management Controls Customer Premises	$3,022,834	$3,022,834	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$19,174,795	$1,993,489	$17,181,306	$24,697,306	$70,327	$24,626,979	$10,865,041
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0
2440	Contributions & Grants (Formally known as Account 1995)	$0	$0	$0	-$159,390,178	-$6,958,091	-$152,432,087	-$79,065,880
1609	Capital Contributions Paid	$19,104,312	$0	$19,104,312	$145,064,091	$0	$145,064,091	$26,301,319
2005	Property Under Capital Leases	$7,191,090	$0	$7,191,090	$12,556,624	$10,979,744	$1,576,880	$0
	Sub-Total	**$2,366,938,267**	**$128,473,782**	**$2,238,464,486**	**$2,698,965,549**	**$53,168,607**	**$2,645,796,942**	**$447,024,759**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***	$0		$0	$0		$0	-$2,730,141
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$0		$0	-$2,002,023		-$2,002,023	-$3,702,262
	Total	**$2,366,938,267**	**$128,473,782**	**$2,238,464,486**	**$2,696,963,526**	**$53,168,607**	**$2,643,794,920**	**$440,592,356**

		Service Lives				Depreciation Expense					
Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	4.91	20.36%	6.66	15.03%	$6,655,322	$18,320,573	$3,007,433	$27,983,329	$27,968,318	**-$15,010**
1612	Land Rights	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1805	Land	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1808	Buildings	18.08	5.53%	65.76	1.52%	$1,459,518	$1,645,597	$71,033	$3,176,148	$3,576,986	**$400,838**
1815	Transformer Station Equipment >50 kV	14.45	6.92%	34.94	2.86%	$403,185	$916,780	$14,748	$1,334,713	$1,339,480	**$4,767**
1820	Distribution Station Equipment <50 kV	19.20	5.21%	30.95	3.23%	$5,733,387	$3,354,157	$332,800	$9,420,344	$9,828,871	**$408,527**
1830	Poles, Towers & Fixtures	31.60	3.16%	38.34	2.61%	$6,576,912	$4,947,551	$371,373	$11,895,836	$11,163,183	**-$732,653**
1835	Overhead Conductors & Devices	34.02	2.94%	44.47	2.25%	$5,786,570	$5,389,226	$474,419	$11,650,216	$11,552,701	**-$97,515**
1840	Underground Conduit	22.27	4.49%	33.18	3.01%	$28,369,033	$17,136,131	$1,524,379	$47,029,542	$47,764,130	**$734,588**
1845	Underground Conductors & Devices	31.09	3.22%	37.06	2.70%	$12,562,762	$13,059,939	$1,327,120	$26,949,822	$26,963,221	**$13,399**
1850	Line Transformers	18.14	5.51%	27.46	3.64%	$16,226,960	$11,160,087	$1,493,619	$28,880,666	$25,545,270	**-$3,335,396**
1855	Services (Overhead & Underground)	40.50	2.47%	44.24	2.26%	$1,498,869	$1,486,107	$193,453	$3,178,429	$3,062,482	**-$115,947**
1860	Meters	19.72	5.07%	20.83	4.80%	$2,198,305	$2,214,168	$461,592	$4,874,065	$4,819,143	**-$54,922**
1860	Meters (Smart Meters)	9.75	10.25%	15.00	6.67%	$9,474,408	$3,380,351	$293,574	$13,148,333	$11,966,280	**-$1,182,053**
1905	Land	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1908	Buildings & Fixtures	12.89	7.76%	30.99	3.23%	$4,670,451	$6,036,520	$20,175	$10,727,146	$11,325,101	**$597,955**
1910	Leasehold Improvements	3.03	32.97%	5.00	20.00%	$0	$0	$0	$0	$8,734	**$8,734**
1915	Office Furniture & Equipment	5.87	17.02%	10.00	10.00%	$1,243,266	$990,057	$22,417	$2,255,739	$2,067,790	**-$187,949**
1920	Computer Equipment - Hardware	3.34	29.93%	4.82	20.75%	-$18,524	$8,682,131	$767,598	$9,431,206	$10,812,376	**$1,381,170**
1930	Transportation Equipment	4.03	24.80%	7.37	13.56%	$199,057	$2,034,725	$338,772	$2,572,554	$3,141,469	**$568,915**
1935	Stores Equipment	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1940	Tools, Shop & Garage Equipment	5.61	17.81%	9.97	10.03%	$1,288,376	$1,240,166	$277,495	$2,806,037	$2,443,955	**-$362,082**
1945	Measurement & Testing Equipment	4.39	22.77%	4.39	22.77%	$2,124,778	-$2,023,470	$2,213	$103,520	$61,540	**-$41,980**
1950	Service Equipment	5.09	19.66%	8.00	12.50%	$44,249	$96,829	$7,673	$148,751	$131,053	**-$17,698**
1955	Communications Equipment	2.94	34.04%	12.77	7.83%	$50,608	$3,351,163	$31,403	$3,433,173	$4,719,684	**$1,286,510**
1960	Miscellaneous Equipment	7.23	13.82%	10.00	10.00%	$36,919	$391	$0	$37,310	$37,310	**$0**
1970	Load Management Controls Customer Premises	2.85	35.12%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1975	Load Management Controls Utility Premises	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
1980	System Supervisor Equipment	11.09	9.02%	14.98	6.68%	$1,549,320	$1,644,519	$362,768	$3,556,607	$3,134,194	**-$422,414**
1985	Miscellaneous Fixed Assets	-	0.00%	-	0.00%	$0	$0	$0	$0	$0	**$0**
2440	Contributions & Grants (Formally known as Account 1995)	-	0.00%	34.28	2.92%	$0	-$4,446,901	-$1,153,294	-$5,600,195	-$5,711,872	**-$111,677**
1609	Capital Contributions Paid	21.68	4.61%	24.97	4.01%	$881,195	$5,809,859	$526,688	$7,217,742	$7,235,447	**$17,705**
2005	Property Under Capital Leases	80.42	1.24%	6.66	15.02%	$89,423	$236,857	$0	$326,280	$652,639	**$326,359**
	Sub-Total					**$109,104,347**	**$106,663,514**	**$10,769,452**	**$226,537,313**	**$225,609,486**	**-$927,827**
	Less Socialized Renewable Energy Generation Investments ***(input as negative)***		0.00%	10.00	10.00%	$0	$0	-$136,507	-$136,507	-$34,127	**$102,380**
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***		0.00%	15.00	6.67%	$0	-$133,468	-$123,409	-$256,877	-$202,609	**$54,268**
	Total					**$109,104,347**	**$106,530,046**	**$10,509,536**	**$226,143,929**	**$225,372,751**	**-$771,178**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that have become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

OPERATING COSTS: PILs VARIANCE ANALYSIS

1. CORPORATE TAXES (PILS)

1.1 Tax Payable Filings

Table 1 below provides a summary of Toronto Hydro's actual PILs from 2014 to 2017, as well as the forecasted PILs for 2018 and 2019. A copy of Toronto Hydro's 2017 tax return can be found in Toronto Hydro's response to interrogatory 4B-Staff-142 (b) at Appendix A.

Table 1: Summary of PILs by Year ($ Millions)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast	2019 Bridge	2020 Test
Income Taxes	10.5	3.2	18.8	29.4	32.6	22.1	34.7

Toronto Hydro's actual PILs for 2017 was the same as the forecast provided in Exhibit 4B, Tab 2, Schedule 1. The 2018 and 2019 PILs forecast are $1.8 million and $1.7 million higher, respectively, than the forecasts in Exhibit 4B, Tab 2, Schedule 1 at page 6. The differences are primarily due to project completion timing changes, particularly relating to timing differences accociated with the ERP and Copeland TS projects in 2018, and changes in the timing of in-service additions in 2019 resulting from the work that is being carried over from 2018 into 2019.

COST OF CAPITAL

Exhibit 5, Tab 1 includes information about Toronto Hydro's capital structure and financing plans. There were no changes to this information as a result of 2018 actuals.

REVENUE REQUIREMENT

1. BASE REVENUE REQUIREMENT

Exhibit 6 presents the 2020 revenue requirement that Toronto Hydro is asking the OEB to approve in its application. As part of this application update, a number of relatively minor changes have been identified throughout Exhibit U that affect the 2020 revenue requirement. These changes are summarized in Table 1 below. The estimated net impact of the changes is an increase in revenue requirement of $0.9 million.

Table 1: Identified Changes to 2020 Forecast Revenue Requirement ($ Millions)

	2020 Test Year	Identified Changes	Reference
OM&A Expenses (incl. property taxes)	277.5	0.5	Exhibit U, Tab 4A, Schedule 1, page 1
Amortization/Depreciation	268.7	-	
Income Taxes (Grossed up)	34.7	(0.1)	Exhibit U, Tab 2, Schedule 1, section 3
Deemed Interest Expense	100.8	(0.2)	
Return on Deemed Equity	162.8	(0.3)	
Service Revenue Requirement	**844.5**	**844.4**	
Revenue Offsets	47.7	(1.0)	Exhibit U, Tab 3, Schedule 2, page 2
Base Revenue Requirement	**796.8**	**797.7**	

In the interest of efficiency, Toronto Hydro has decided not to flow these changes through the revenue requirement work form and cost allocation models. The utility requests that the OEB approve these changes as part of the 2020 test year, and proposes to make the updates as part of the Draft Rate Order process.

The 2020 Revenue Requirement Workform is attached as Appendix A to this schedule and reflects updates to the Load Forecast, Cost Allocation, and Rate Design.

2. OVERALL REVENUE DEFICIENCY

The overall revenue deficiency for 2020 is not expected to materially change as a result of this update.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Version 7.02

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Data Input [1]

		Initial Application				Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$5,616,709,673		$5,616,709,673		$5,616,709,673	
	Accumulated Depreciation (average)	($1,236,603,102)	(5)	($1,236,603,102)		($1,236,603,102)	
	Allowance for Working Capital:						
	Controllable Expenses	$277,497,844		$ 277,497,844		$277,497,844	
	Cost of Power	$3,384,043,227		$3,384,043,227		$3,384,043,227	
	Working Capital Rate (%)	6.42%	(9)		(9)		(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$771,352,779					
	Distribution Revenue at Proposed Rates	$796,824,614					
	Other Revenue:						
	Specific Service Charges	$6,581,270					
	Late Payment Charges	$3,751,641					
	Other Distribution Revenue	$35,898,269					
	Other Income and Deductions	$1,455,901					
	Total Revenue Offsets	$47,687,081	(7)				
	Operating Expenses:						
	OM+A Expenses	$271,962,868		$ 271,962,868		$271,962,868	
	Depreciation/Amortization	$268,664,188		$ 268,664,188		$268,664,188	
	Property taxes	$5,534,976		$ 5,534,976		$5,534,976	
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($61,393,745)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$25,522,176	(10)				
	Income taxes (grossed up)	$34,724,049					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	($2,736,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	3.71%					
	Short-term debt Cost Rate (%)	2.61%					
	Common Equity Cost Rate (%)	8.82%					
	Prefered Shares Cost Rate (%)						

Column headings: Initial Application (2); (6); Per Board Decision.

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

(10) This value is adjusted from PILS model to reflect inclusion of tax credits in OM&A. See Exhibit 4B, Tab 2, Schedule 1

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(2)	$5,616,709,673	$ -	$5,616,709,673	$ -	$5,616,709,673
2	Accumulated Depreciation (average)	(2)	($1,236,603,102)	$ -	#############	$ -	($1,236,603,102)
3	Net Fixed Assets (average)	(2)	$4,380,106,571	$ -	$4,380,106,571	$ -	$4,380,106,571
4	Allowance for Working Capital	(1)	$235,187,789	($235,187,789)	$ -	$ -	$ -
5	**Total Rate Base**		$4,615,294,360	($235,187,789)	$4,380,106,571	$ -	$4,380,106,571

(1) **Allowance for Working Capital - Derivation**

6	Controllable Expenses		$277,497,844	$ -	$277,497,844	$ -	$277,497,844
7	Cost of Power		$3,384,043,227	$ -	$3,384,043,227	$ -	$3,384,043,227
8	Working Capital Base		$3,661,541,071	$ -	$3,661,541,071	$ -	$3,661,541,071
9	Working Capital Rate %	(1)	6.42%	-6.42%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$235,187,789	($235,187,789)	$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$796,824,614	($796,824,614)	$ -	$ -	$ -
2	Other Revenue	(1)	$47,687,081	($47,687,081)	$ -	$ -	$ -
3	Total Operating Revenues		$844,511,695	($844,511,695)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$271,962,868	$ -	$271,962,868	$ -	$271,962,868
5	Depreciation/Amortization		$268,664,188	$ -	$268,664,188	$ -	$268,664,188
6	Property taxes		$5,534,976	$ -	$5,534,976	$ -	$5,534,976
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$546,162,032	$ -	$546,162,032	$ -	$546,162,032
10	Deemed Interest Expense		$100,798,029	($100,798,029)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$646,960,061	($100,798,029)	$546,162,032	$ -	$546,162,032
12	**Utility income before income taxes**		$197,551,634	($743,713,666)	($546,162,032)	$ -	($546,162,032)
13	Income taxes (grossed-up)		$34,724,049	$ -	$34,724,049	$ -	$34,724,049
14	**Utility net income**		$162,827,585	($743,713,666)	($580,886,081)	$ -	($580,886,081)

Notes

Other Revenues / Revenue Offsets

Note						
(1)	Specific Service Charges	$6,581,270		$ -		$ -
	Late Payment Charges	$3,751,641		$ -		$ -
	Other Distribution Revenue	$35,898,269		$ -		$ -
	Other Income and Deductions	$1,455,901		$ -		$ -
	Total Revenue Offsets	$47,687,081	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Taxes/PILs

Line No.	Particulars	Application				Per Board Decision
	Determination of Taxable Income					
1	Utility net income before taxes	$162,827,585		$ -		$ -
2	Adjustments required to arrive at taxable utility income	($61,393,745)		$ -		$ -
3	Taxable income	$101,433,840		$ -		$ -
	Calculation of Utility income Taxes					
4	Income taxes	$25,522,176	(1)	$25,522,176		$25,522,176
6	Total taxes	$25,522,176		$25,522,176		$25,522,176
7	Gross-up of Income Taxes	$9,201,873		$9,201,873		$9,201,873
8	Grossed-up Income Taxes	$34,724,049		$34,724,049		$34,724,049
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$34,724,049		$34,724,049		$34,724,049
10	Other tax Credits	($2,736,000)		($2,736,000)		($2,736,000)
	Tax Rates					
11	Federal tax (%)	15.00%		15.00%		15.00%
12	Provincial tax (%)	11.50%		11.50%		11.50%
13	Total tax rate (%)	26.50%		26.50%		26.50%

Notes

1 See Note 10 on Tab 3 - Data Input Sheet

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$2,584,564,841	3.71%	$95,979,661
2	Short-term Debt	4.00%	$184,611,774	2.61%	$4,818,367
3	**Total Debt**	60.00%	$2,769,176,616	3.64%	$100,798,029
	Equity				
4	Common Equity	40.00%	$1,846,117,744	8.82%	$162,827,585
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$1,846,117,744	8.82%	$162,827,585
7	**Total**	100.00%	$4,615,294,360	5.71%	$263,625,614
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$4,380,106,571	0.00%	$ -
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	3.71%	$ -
9	Short-term Debt	0.00%	$ -	2.61%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.82%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$4,380,106,571	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$23,596,721		($251,048,356)		$743,077,595
2	Distribution Revenue	$771,352,779	$773,227,893	$771,352,779	$1,047,872,970	$ -	($743,077,595)
3	Other Operating Revenue Offsets - net	$47,687,081	$47,687,081	$ -	$ -	$ -	$ -
4	**Total Revenue**	$819,039,860	$844,511,695	$771,352,779	$796,824,614	$ -	$ -
5	Operating Expenses	$546,162,032	$546,162,032	$546,162,032	$546,162,032	$546,162,032	$546,162,032
6	Deemed Interest Expense	$100,798,029	$100,798,029	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$646,960,061	$646,960,061	$546,162,032	$546,162,032	$546,162,032	$546,162,032
9	**Utility Income Before Income Taxes**	$172,079,800	$197,551,634	$225,190,747	$250,662,582	($546,162,032)	($546,162,032)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($61,393,745)	($61,393,745)	($61,393,745)	($61,393,745)	$ -	$ -
11	**Taxable Income**	$110,686,055	$136,157,889	$163,797,002	$189,268,837	($546,162,032)	($546,162,032)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$29,331,804	$36,081,841	$43,406,206	$50,156,242	$ -	$ -
14	**Income Tax Credits**	($2,736,000)	($2,736,000)	($2,736,000)	($2,736,000)	$ -	$ -
15	**Utility Net Income**	$145,483,995	$162,827,585	$184,520,542	($580,886,081)	($546,162,032)	($580,886,081)
16	**Utility Rate Base**	$4,615,294,360	$4,615,294,360	$4,380,106,571	$4,380,106,571	$4,380,106,571	$4,380,106,571
17	Deemed Equity Portion of Rate Base	$1,846,117,744	$1,846,117,744	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.88%	8.82%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.82%	8.82%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-0.94%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.34%	5.71%	4.21%	0.00%	-12.47%	0.00%
22	Requested Rate of Return on Rate Base	5.71%	5.71%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.38%	0.00%	4.21%	0.00%	-12.47%	0.00%
24	Target Return on Equity	$162,827,585	$162,827,585	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$17,343,590	$0	($184,520,542)	$ -	$546,162,032	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$23,596,721 (1)		($251,048,356) (1)		$743,077,595 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(1) The Revenue deficiency calculated in this table does not include an adjustment for Tax Credit reclass to OM&A. See Exhibit 4B, Tab 2, Schedule 1.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$271,962,868		$271,962,868		$271,962,868	
2	Amortization/Depreciation	$268,664,188		$268,664,188		$268,664,188	
3	Property Taxes	$5,534,976		$5,534,976		$5,534,976	
5	Income Taxes (Grossed up)	$34,724,049		$34,724,049		$34,724,049	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$100,798,029		$ -		$ -	
	Return on Deemed Equity	$162,827,585		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$844,511,695		$580,886,081		$580,886,081	
9	Revenue Offsets	$47,687,081		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$796,824,614		$580,886,081		$580,886,081	
11	Distribution revenue	$796,824,614		$ -		$ -	
12	Other revenue	$47,687,081		$ -		$ -	
13	**Total revenue**	$844,511,695		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($580,886,081)	(1)	($580,886,081)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$844,511,695	$580,886,081	($0)	$580,886,081	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$23,596,721	($251,048,356)	($12)	$743,077,595	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$796,824,614	$580,886,081	($0)	$580,886,081	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$25,471,835	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	**Initial Application**						**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential	615,118	4,531,218,421							
2	Competitive Sector Multi-Unit Residential	85,852	297,763,685							
3	GS <50	71,599	2,299,006,608							
4	GS - 50 to 999	10,417	9,608,309,249	24,899,004						
5	GS - 1000 to 4999	430	4,595,015,405	10,406,674						
6	Large Use >5MW	38	1,889,478,427	4,600,360						
7	Street Light	165,274	116,219,746	326,300						
8	Unmetered Scattered Load	825	40,588,612							
9	Unmetered Scattered Load (Connections)	12,180								
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**23,377,600,153**	**40,232,337**		**-**	**-**		**-**	**-**

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
	From Sheet 10. Load Forecast				
1	Residential	$ 287,079,871	42.26%	$ 324,468,984	38.42%
2	Competitive Sector Multi-Unit Residenti	$ 19,267,312	2.84%	$ 36,492,998	4.32%
3	GS <50	$ 99,019,246	14.58%	$ 134,212,761	15.89%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 209,018,766	24.75%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 77,793,881	9.21%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 36,996,946	4.38%
7	Street Light	$ 25,331,820	3.73%	$ 22,554,676	2.67%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 2,972,681	0.35%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 844,511,695**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 844,511,695**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 305,551,446	$ 315,630,428	$ 315,630,428	$ 19,227,963
2	Competitive Sector Multi-Unit Residenti	$ 34,456,025	$ 35,592,598	$ 34,805,467	$ 1,687,531
3	GS <50	$ 107,331,623	$ 110,872,086	$ 111,600,949	$ 8,463,061
4	GS - 50 to 999	$ 207,127,185	$ 213,959,524	$ 213,959,524	$ 7,210,004
5	GS - 1000 to 4999	$ 66,947,592	$ 69,155,939	$ 69,508,331	$ 1,444,895
6	Large Use >5MW	$ 31,074,780	$ 32,099,819	$ 32,314,210	$ 520,946
7	Street Light	$ 15,068,574	$ 15,565,629	$ 15,565,629	$ 9,005,538
8	Unmetered Scattered Load	$ 3,822,500	$ 3,948,590	$ 3,440,075	$ 127,143
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 771,379,725	$ 796,824,614	$ 796,824,614	$ 47,687,081

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	103.2%	103.2%	85 - 115
2	Competitive Sector Multi-Unit Residenti	100.0%	102.2%	100.0%	80 - 120
3	GS <50	91.5%	88.9%	89.5%	80 - 120
4	GS - 50 to 999	119.0%	105.8%	105.8%	80 - 120
5	GS - 1000 to 4999	101.9%	90.8%	91.2%	80 - 120
6	Large Use >5MW	95.3%	88.2%	88.8%	85 - 115
7	Street Light	82.7%	108.9%	108.9%	80 - 120
8	Unmetered Scattered Load	90.5%	137.1%	120.0%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.
(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".
(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year 2020	Price Cap IR Period 2021	Price Cap IR Period 2022	Policy Range
1	Residential	103.20%			85 - 115
2	Competitive Sector Multi-Unit Residenti	100.00%			100-100
3	GS <50	89.46%			80 - 120
4	GS - 50 to 999	105.81%			80 - 120
5	GS - 1000 to 4999	91.21%			80 - 120
6	Large Use >5MW	88.75%			85 - 115
7	Street Light	108.94%			80 - 120
8	Unmetered Scattered Load	120.00%			80 - 120
9	Unmetered Scattered Load (Connectior				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2018 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2019 and 2020 Price Cap IR models, as necessary. For 2019 and 2020, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	615,118
kWh	4,531,218,421

Proposed Residential Class Specific Revenue Requirement[1]	$ 315,630,428.18

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 38.00
Distribution Volumetric Rate ($/kWh)	$ 0.00553

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	38	615,118	$ 280,493,808.00	91.80%
Variable	0.00553	4,531,218,421	$ 25,057,637.87	8.20%
TOTAL	-	-	$ 305,551,445.87	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 289,746,233.95	39.25	$ 289,720,578.00
Variable	$ 25,884,194.22	0.0057	$ 25,827,945.00
TOTAL	$ 315,630,428.18	-	$ 315,548,523.00

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 315,630,428.18	$ 42.76	$ 315,629,348.16
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 315,630,428.18	-	$ 315,629,348.16

Checks[3]	
Change in Fixed Rate	$ 3.51
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	($1,080.02)
	0.00%

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

New Rate Design Policy For Competitive Sector Multi-Unit Customers (CSMUR)

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for CSMUR	
Customers	85,852
kWh	297,763,685

Proposed CSMUR Class Specific Revenue Requirement[1]	$ 34,805,466.91

CSMUR Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 31.00
Distribution Volumetric Rate ($/kWh)	$ 0.00846

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	31	85,852	$ 31,936,944.00	92.69%
Variable	0.00846	297,763,685	$ 2,519,080.77	7.31%
TOTAL	-	-	$ 34,456,024.77	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 32,260,838.41	31.31	$ 32,256,313.44
Variable	$ 2,544,628.50	0.0085	$ 2,530,991.32
TOTAL	$ 34,805,466.91	-	$ 34,787,304.76

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 34,805,466.91	$ 33.78	$ 34,800,966.72
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 34,805,466.91	-	$ 34,800,966.72

Checks[3]	
Change in Fixed Rate	$ 2.47
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	($4,500.19)
	-0.01%

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2020 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates					Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate			1.013888889		
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	615,118	4,531,218,421	-	$ 315,630,428	$ 315,630,428	$ -	100.00%	0.00%	$ -	$42.17	2	$0.00000	/kWh	5	315,597,567	-	315,597,567
2	Competitive Sector Multi-Unit Residential	kWh	85,852	297,763,685	-	$ 34,805,467	$ 34,805,467	$ -	100.00%	0.00%	$ -	$33.32		$0.00000	/kWh	5	34,803,828	-	34,803,828
3	GS <50	kWh	71,599	2,299,006,608	-	$ 111,600,949	$ 32,429,109	$ 79,171,840	29.06%	70.94%	$ -	$37.23		$0.03444	/kWh	5	32,431,841	79,177,788	111,609,629
4	GS - 50 to 999	kVA	10,417	9,608,309,249	24,899,004	$ 213,959,524	$ 6,614,793	$ 207,344,731	3.09%	96.91%	$ 4,015,556	$52.19		$8.3724	/kVA	4	6,614,569	211,359,756	213,958,770
5	GS - 1000 to 4999	kVA	430	4,595,015,405	10,406,674	$ 69,508,331	$ 4,939,039	$ 64,569,292	7.11%	92.89%	$ 5,480,116	$944.07		$6.6390	/kVA	4	4,939,060	70,049,490	69,508,433
6	Large Use >5MW	kVA	38	1,889,478,427	4,600,360	$ 32,314,210	$ 1,912,842	$ 30,401,368	5.92%	94.08%	$ 2,839,494	$4,137.37		$7.1267	/kVA	4	1,912,844	33,240,736	32,314,087
7	Street Light	kVA	165,274	116,219,746	326,300	$ 15,565,629	$ 3,339,396	$ 12,226,233	21.45%	78.55%	$ -	$1.66		$36.9560	/kVA	4	3,337,984	12,226,225	15,564,209
8	***Unmetered Scattered Load***	kWh	825	40,588,612	-	$ 3,440,075	$ 64,505	$ 3,276,916	1.88%	95.26%	$ -	$6.43		$0.08073	/kWh	5	64,541	3,276,719	3,341,260
9	***Unmetered Scattered Load (Connections)***		12,180	-	-		$ 98,653	$ -	2.87%		$ -	$0.67					99,287	-	99,287
10			-	-	-												-	-	-
11			-	-	-												-	-	-
12			-	-	-												-	-	-
13			-	-	-												-	-	-
14			-	-	-												-	-	-
15			-	-	-												-	-	-
16			-	-	-												-	-	-
17			-	-	-												-	-	-
18			-	-	-												-	-	-
19			-	-	-												-	-	-
20			-	-	-												-	-	-

Total Transformer Ownership Allowance $ 12,335,166

Total Distribution Revenues		796,797,070
Rates recover revenue requirement — **Base Revenue Requirement**		796,824,614
Difference	-	27,543
% Difference		0.00%

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 263,625,614	5.71%	$4,615,294,360	$3,661,541,071	$ 235,187,789	$ 268,664,188	$ 34,724,049	$ 271,962,868	$ 844,511,695	$ 47,687,081	$ 796,824,614	$ 23,596,721
1		Change												
2														

COST ALLOCATION

Exhibit 7 provides information on the allocation of Toronto Hydro's total revenue requirement to rate classes as the basis for determining rates for the 2020 rebasing year. This schedule provides an update to the cost allocation model for 2020. Specifically, the model has been updated for the following:

a) Billing weighting factors have been corrected (Tab I5.2 of the model), as identified in interrogatory 7-Staff-144.
b) The forecast number of customers, kWh and kVA loads for 2020 have been updated (Tab I6.1 of the model) to reflect the updated load and customer forecasts (see Exhibit U, Tab 3, Schedule 1).
c) A correction to the number of bills for the Unmetered Scattered Load class (Tab I6.2 of the model). The original filing used the number of USL devices as the basis for number of bills. However, customers in this class receive a single monthly bill that contains charges for more than one device. The update correctly captures the number of bills issued to the USL class. (Tab I6.2 of the model)
d) Demands for the Large Use and GS 1000-4999 kW classes were adjusted (Tab I8 of the model). Due to the reduction in the number of customers in the Large Use class (who were reclassed into the GS 1000-4999 kW rate class in 2018), it was appropriate to reflect the reduction in Large Use class contribution to peak demands (and subsequently increase the contribution of the GS 1000-4999 kW class). Due to the small size of the Large Use class, if demand information for cost allocation purposes was left unadjusted, the updated load and customer forecast would have a material impact for the revenue to cost ratios for this class and not appropriately reflect cost causality.

The resulting revenue to cost ratios, before rate design, compared with the previously filed evidence, are provided in Table 1 below.

Table 1: Revenue to Cost Ratios from Cost Allocation Model

Rate Class	Original R/C ratio before Rate Design	Updated R/C ratio before Rate Design
Residential	103.2	103.2
CSMUR	101.4	102.2
GS <50 kW	89.6	88.9
GS 50-999 kW	105.3	105.8
GS 1000-4999 kW	94.9	90.8
Large Use	84.6	88.2
Street Lighting	108.9	108.9
USL	94.6	137.1

The main driver of the change in the USL class is the update for the number of bills issued. Due to the revenues for this class being small relative to other classes, the change results in a material change in the calculated revenue to cost ratio. This ratio is now outside the OEB's Guideline range for this class. This issue is addressed further in Exhibit U, Tab 8, Schedule 1.

The main driver of the change in the Large Use and GS 1000-4999 kW class is the update in the demands (CP and NCP) for these classes, due to the reclass of 6 Large Use customers into the GS 1000-4999 kW class.

For all rate classes other than the USL class, the resulting ratios are within the OEB's guideline ranges.

The updated Cost Allocation Model is filed as Appendix A to this schedule.

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	23,377,600,153
Total kWs from Load Forecast	40,232,337
Deficiency/sufficiency (RRWF 8. cell F51)	- 25,444,889
Miscellaneous Revenue (RRWF 5. cell F48)	47,687,081

			1	2	4	5	6	7	9	10
Billing Data	**ID**	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**
Forecast kWh	**CEN**	23,377,600,153	4,531,218,421	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	297,763,685
Forecast kW	**CDEM**	40,232,337			24,899,004	10,406,674	4,600,360	326,300		
Forecast kW, included in CDEM, of customers receiving line transformer allowance		19,579,628			6,373,898	8,698,598	4,507,133			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	23,377,600,153	4,531,218,421	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	297,763,685
Existing Monthly Charge			$38.00	$36.30	$52.22	$997.38	$4,402.54	$1.63	$7.24	$31.00
Existing Distribution kWh Rate			$0.0055	$0.0331					$0.0897	$0.0085
Existing Distribution kW Rate					$8.22	$6.47	$6.94	$36.27	$0.75	
Existing TOA Rate			$0.63	$0.63	$0.63	$0.63	$0.63	$0.63	$0.63	$0.63
Additional Charges										
Distribution Revenue from Rates		$783,714,891	$305,551,446	$107,331,623	$211,142,740	$72,427,709	$33,914,273	$15,068,574	$3,822,500	$34,456,025
Transformer Ownership Allowance		$12,335,166	$0	$0	$4,015,556	$5,480,116	$2,839,494	$0	$0	$0
Net Class Revenue	**CREV**	$771,379,725	$305,551,446	$107,331,623	$207,127,185	$66,947,592	$31,074,780	$15,068,574	$3,822,500	$34,456,025

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$7,377,253	$3,890,292	$2,111,101	$828,264	$261,154	$0	$0	$0	$286,442
Late Payment 3 Year Historical Average	LPHA	$4,287,180	$2,487,420	$919,878	$596,564	$77,959	$16,058		$5,649	$183,652
Number of Bills	CNB	9,411,468	7,381,416.00	859,188.00	125,004.00	5,160.00	456.00	120.00	9,900.00	1,030,224.00
Number of Devices	CDEV							165,274		
Number of Connections (Unmetered)	CCON	103,999						91,819	12,180	
Total Number of Customers	CCA	784,280	615,118	71,599	10,417	430	38	1	825	85,852
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	802,785	615,118	71,599	10,417	430	38	18,506	825	85,852
Line Transformer Customer Base	CCLT	800,327	615,118	71,599	8,333	94	-	18,506	825	85,852
Secondary Customer Base	CCS	775,441	615,118	71,599	2,041	5	-	1	825	85,852
Weighted - Services	CWCS	689,087	615,118	71,599	2,041	5	-	-	-	325
Weighted Meter -Capital	CWMC	137,068,160	87,346,756	36,658,688	11,167,024	1,675,710	219,982	-	-	-
Weighted Meter Reading	CWMR	9,715,948	7,381,416	988,066	1,211,289	124,201	10,976	-	-	-
Weighted Bills	CWNB	11,415,791	7,381,416	2,319,808	625,020	30,444	3,055	84	25,740	1,030,224

Bad Debt Data

		Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Historic Year:	2015	5,920,268	3,264,885	1,679,206	910,835	-				65,342
Historic Year:	2016	9,841,560	4,872,078	2,746,113	1,039,975	783,461				399,934
Historic Year:	2017	6,369,929	3,533,912	1,907,985	533,980	-				394,051
Three-year average		**7,377,253**	**3,890,292**	**2,111,101**	**828,264**	**261,154**	**-**	**-**	**-**	**286,442**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	615,118	4,129,569	615,118	4,129,569
Street Light	165,274	124,238	165,274	124,238

Street Lighting Adjustment Factors	
Primary	8.9309
Line Transformer	8.9309

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	4	5	6	7	9	10
Customer Classes		Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
		CP Sanity Check	Pass	Pass	Pass	Check 4CP	Check 4CP and 12CP	Check 12CP	Check 4CP and 12CP	Pass
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	4,262,830	972,614	578,946	1,662,853	764,853	239,922	-	3,548	40,093
Bulk Delivery CP	BCP1	4,262,830	972,614	578,946	1,662,853	764,853	239,922	-	3,548	40,093
Total Sytem CP	DCP1	4,262,830	972,614	578,946	1,662,853	764,853	239,922	-	3,548	40,093
4 CP										
Transformation CP	TCP4	16,449,304	3,718,466	1,992,718	6,532,784	3,069,430	966,675	-	16,832	152,399
Bulk Delivery CP	BCP4	16,449,304	3,718,466	1,992,718	6,532,784	3,069,430	966,675	-	16,832	152,399
Total Sytem CP	DCP4	16,449,304	3,718,466	1,992,718	6,532,784	3,069,430	966,675	-	16,832	152,399
12 CP										
Transformation CP	TCP12	45,262,168	8,853,188	5,623,085	18,460,316	8,322,601	3,323,660	171,288	58,103	449,926
Bulk Delivery CP	BCP12	45,262,168	8,853,188	5,623,085	18,460,316	8,322,601	3,323,660	171,288	58,103	449,926
Total Sytem CP	DCP12	45,262,168	8,853,188	5,623,085	18,460,316	8,322,601	3,323,660	171,288	58,103	449,926
NON CO_INCIDENT PEAK										
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP										
Classification NCP from Load Data Provider	DNCP1	4,603,543	1,085,007	601,583	1,674,421	782,816	364,037	31,399	5,833	58,447
Primary NCP	PNCP1	4,489,529	1,085,007	601,583	1,560,710	782,816	364,037	31,399	5,530	58,447
Line Transformer NCP	LTNCP1	3,383,973	1,085,007	601,583	1,399,700	202,306	-	31,399	5,530	58,447
Secondary NCP	SNCP1	2,218,380	1,085,007	601,583	419,910	16,504	-	31,399	5,530	58,447
4 NCP										
Classification NCP from Load Data Provider	DNCP4	17,678,767	4,129,569	2,275,913	6,481,669	3,096,720	1,325,478	124,238	22,521	222,660
Primary NCP	PNCP4	17,237,427	4,129,569	2,275,913	6,041,495	3,096,720	1,325,478	124,238	21,354	222,660
Line Transformer NCP	LTNCP4	12,980,524	4,129,569	2,275,913	5,418,227	788,565	-	124,238	21,354	222,660
Secondary NCP	SNCP4	8,464,488	4,129,569	2,275,913	1,625,468	65,287	-	124,238	21,354	222,660
12 NCP										
Classification NCP from Load Data Provider	DNCP12	48,381,915	10,395,631	6,389,304	18,220,979	8,564,929	3,805,731	320,510	63,331	621,500
Primary NCP	PNCP12	47,141,234	10,395,631	6,389,304	16,983,582	8,564,929	3,805,731	320,510	60,047	621,500
Line Transformer NCP	LTNCP12	35,213,790	10,395,631	6,389,304	15,231,478	2,195,321	-	320,510	60,047	621,500
Secondary NCP	SNCP12	22,537,005	10,395,631	6,389,304	4,569,443	180,571	-	320,510	60,047	621,500

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	4	5	6	7	9	10
Rate Base Assets		Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
crev	Distribution Revenue at Existing Rates	$771,379,725	$305,551,446	$107,331,623	$207,127,185	$66,947,592	$31,074,780	$15,068,574	$3,822,500	$34,456,025
mi	Miscellaneous Revenue (mi)	$47,687,081	$19,227,963	$8,463,061	$7,210,004	$1,444,895	$520,946	$9,005,538	$127,143	$1,687,531
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$819,066,806	$324,779,409	$115,794,685	$214,337,189	$68,392,487	$31,595,725	$24,074,112	$3,949,644	$36,143,556
	Factor required to recover deficiency (1 + D)	1.0330								
	Distribution Revenue at Status Quo Rates	$796,824,614	$315,630,428	$110,872,086	$213,959,524	$69,155,939	$32,099,819	$15,565,629	$3,948,590	$35,592,598
	Miscellaneous Revenue (mi)	$47,687,081	$19,227,963	$8,463,061	$7,210,004	$1,444,895	$520,946	$9,005,538	$127,143	$1,687,531
	Total Revenue at Status Quo Rates	$844,511,695	$334,858,391	$119,335,147	$221,169,528	$70,600,834	$32,620,764	$24,571,168	$4,075,733	$37,280,129
	Expenses									
di	Distribution Costs (di)	$126,815,041	$43,200,057	$19,858,165	$37,795,391	$15,239,907	$6,112,987	$1,416,594	$329,419	$2,862,520
cu	Customer Related Costs (cu)	$44,768,626	$28,551,737	$9,144,554	$2,964,784	$371,267	$12,785	$218,594	$102,269	$3,402,637
ad	General and Administration (ad)	$101,234,363	$40,901,585	$16,573,389	$23,716,793	$9,076,787	$3,739,764	$2,564,951	$336,523	$4,324,571
dep	Depreciation and Amortization (dep)	$260,980,412	$103,149,700	$43,520,685	$68,682,668	$24,056,013	$9,623,040	$3,865,370	$787,730	$7,295,207
INPUT	PILs (INPUT)	$33,544,822	$12,647,309	$5,250,916	$8,775,947	$3,270,281	$1,514,356	$751,274	$115,676	$1,219,063
INT	Interest	$97,374,932	$36,712,993	$15,242,520	$25,475,087	$9,493,072	$4,395,920	$2,180,821	$335,787	$3,538,732
	Total Expenses	$664,718,195	$265,163,380	$109,590,229	$167,410,671	$61,507,327	$25,398,852	$10,997,603	$2,007,404	$22,642,730
	Direct Allocation	$22,495,532	$0	$0	$456,032	$951,591	$4,496,993	$8,034,208	$422,853	$8,133,855
NI	Allocated Net Income (NI)	$157,297,967	$59,305,605	$24,622,532	$41,152,063	$15,334,963	$7,101,101	$3,522,865	$542,425	$5,716,414
	Revenue Requirement (includes NI)	$844,511,695	$324,468,984	$134,212,761	$209,018,766	$77,793,881	$36,996,946	$22,554,676	$2,972,681	$36,492,998
		Revenue Requirement Input equals Output								

EB-2018-0165

Sheet O1 Revenue to Cost Summary Worksheet -

	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$4,690,749,227	$1,842,559,092	$768,203,854	$1,258,314,737	$458,523,436	$176,256,462	$55,526,926	$13,823,397	$117,541,322
gp	General Plant - Gross	$839,667,754	$314,887,139	$130,637,881	$218,273,061	$81,462,265	$38,869,747	$20,386,714	$2,968,007	$32,182,940
accum dep	Accumulated Depreciation	($1,209,717,480)	($476,308,741)	($201,391,666)	($315,771,679)	($113,649,531)	($46,497,428)	($18,364,710)	($3,642,639)	($34,091,086)
co	Capital Contribution	($73,594,426)	($30,652,768)	($12,254,589)	($18,914,367)	($6,303,924)	($2,329,502)	($924,086)	($233,144)	($1,982,045)
	Total Net Plant	$4,247,105,075	$1,650,484,722	$685,195,481	$1,141,901,752	$420,032,246	$166,299,279	$56,624,844	$12,915,621	$113,651,130
	Directly Allocated Net Fixed Assets	$133,001,496	$0	$0	$3,241,784	$6,764,514	$31,969,399	$42,348,089	$2,228,847	$46,448,864
COP	Cost of Power (COP)	$3,384,043,227	$655,920,150	$332,794,542	$1,390,858,498	$665,155,134	$273,512,962	$16,823,482	$5,875,437	$43,103,021
	OM&A Expenses	$272,818,030	$112,653,378	$45,576,108	$64,476,969	$24,687,961	$9,865,537	$4,200,139	$768,211	$10,589,728
	Directly Allocated Expenses	$4,679,814	$0	$0	$22,111	$46,138	$218,029	$2,872,171	$151,167	$1,370,198
	Subtotal	*$3,661,541,071*	*$768,573,528*	*$378,370,650*	*$1,455,357,578*	*$689,889,233*	*$283,596,528*	*$23,895,792*	*$6,794,815*	*$55,062,947*
	Working Capital	$235,187,789	$49,366,948	$24,303,471	$93,480,402	$44,312,905	$18,215,948	$1,534,872	$436,444	$3,536,798
	Total Rate Base	$4,615,294,360	$1,699,851,671	$709,498,951	$1,238,623,938	$471,109,665	$216,484,625	$100,507,805	$15,580,912	$163,636,793
		Rate Base Input equals Output								
	Equity Component of Rate Base	$1,846,117,744	$679,940,668	$283,799,581	$495,449,575	$188,443,866	$86,593,850	$40,203,122	$6,232,365	$65,454,717
	Net Income on Allocated Assets	$157,297,967	$69,695,011	$9,744,918	$53,302,825	$8,141,915	$2,724,919	$5,539,356	$1,645,477	$6,503,545
	Net Income on Direct Allocation Assets	$5,529,618	$0	$0	$134,779	$281,239	$1,329,147	$1,760,648	$92,666	$1,931,140
	Net Income	$162,827,585	$69,695,011	$9,744,918	$53,437,604	$8,423,154	$4,054,067	$7,300,003	$1,738,142	$8,434,685
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	103.20%	88.91%	105.81%	90.75%	88.17%	108.94%	137.11%	102.16%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($25,444,889)	$310,424	($18,418,077)	$5,318,422	($9,401,395)	($5,401,220)	$1,519,436	$976,962	($349,442)
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$10,389,407	($14,877,614)	$12,150,762	($7,193,048)	($4,376,181)	$2,016,491	$1,103,052	$787,131
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.82%	10.25%	3.43%	10.79%	4.47%	4.68%	18.16%	27.89%	12.89%

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	4	5	6	7	9	10
Summary	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**
Customer Unit Cost per month - Avoided Cost	$5.11	$14.82	$23.60	$11.50	-$194.89	$0.15	$0.58	$2.69
Customer Unit Cost per month - Directly Related	$7.25	$20.40	$35.51	$32.68	-$168.22	$0.26	$0.98	$4.37
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.86	$35.20	$53.24	$129.36	-$76.93	$5.06	$2.81	$12.30
Existing Approved Fixed Charge	$38.00	$36.30	$52.22	$997.38	$4,402.54	$1.63	$7.24	$31.00

		1	2	4	5	6	7	9	10
Information to be Used to Allocate PILs, ROD, ROE and A&G	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**
General Plant - Gross Assets	$839,667,754	$314,887,139	$130,637,881	$218,273,061	$81,462,265	$38,869,747	$20,386,714	$2,968,007	$32,182,940
General Plant - Accumulated Depreciation	($375,982,230)	($140,998,589)	($58,496,377)	($97,737,220)	($36,476,766)	($17,404,901)	($9,128,661)	($1,329,000)	($14,410,716)
General Plant - Net Fixed Assets	$463,685,525	$173,888,550	$72,141,504	$120,535,841	$44,985,499	$21,464,846	$11,258,053	$1,639,008	$17,772,224
General Plant - Depreciation	$71,867,332	$26,951,254	$11,181,323	$18,682,035	$6,972,372	$3,326,869	$1,744,903	$254,032	$2,754,544
Total Net Fixed Assets Excluding General Plant	$3,916,418,640	$1,476,596,172	$613,053,977	$1,024,607,695	$381,811,260	$176,803,831	$87,712,594	$13,505,340	$142,327,770
Total Administration and General Expense	$101,234,363	$40,901,585	$16,573,389	$23,716,793	$9,076,787	$3,739,764	$2,564,951	$336,523	$4,324,571
Total O&M	$176,262,465	$71,751,793	$29,002,719	$40,782,287	$15,657,312	$6,343,801	$4,506,393	$582,804	$7,635,355

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	4	5	6	7	9	10	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**	
	Distribution Plant										
1860	Meters	$206,044,239	$131,301,798	$55,106,244	$16,786,546	$2,518,969	$330,682	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($95,621,684)	($60,934,968)	($25,573,886)	($7,790,355)	($1,169,011)	($153,464)	$0	$0	$0	
	Meter Net Fixed Assets	**$110,422,555**	**$70,366,831**	**$29,532,358**	**$8,996,191**	**$1,349,957**	**$177,218**	**$0**	**$0**	**$0**	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,473)	($45,908)	($64,946)	($24,868)	($9,937)	($4,231)	($774)	($10,667)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,079)	($402,174)	($568,960)	($217,852)	($87,056)	($37,063)	($6,779)	($93,446)	CWNB
4220	Other Electric Revenues	($912,869)	($376,947)	($152,501)	($215,745)	($82,608)	($33,011)	($14,054)	($2,570)	($35,434)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
	Sub-total	*($7,346,723)*	*($3,661,200)*	*($1,405,553)*	*($1,371,694)*	*($393,548)*	*($144,056)*	*($55,348)*	*($15,067)*	*($300,258)*	
	Operation										
5065	Meter Expense	$476,757	$303,813	$127,508	$38,842	$5,829	$765	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,018,966	$118,606	$17,256	$712	$63	$152,101	$20,177	$142,217	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$443,845	$51,663	$7,517	$310	$27	$66,253	$8,789	$61,947	CCA
	Sub-total	*$2,587,207*	*$1,766,625*	*$297,777*	*$63,614*	*$6,851*	*$856*	*$218,354*	*$28,965*	*$204,165*	
	Maintenance										
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$2,857,700	$2,171,057	$290,615	$356,270	$36,531	$3,228	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,123,488	$1,924,470	$518,505	$25,256	$2,535	$70	$21,353	$854,655	CWNB
5320	Collecting	$22,254,548	$14,389,724	$4,522,356	$1,218,447	$59,349	$5,956	$164	$50,179	$2,008,373	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	$34,582,580	$22,684,268	$6,737,441	$2,093,222	$121,136	$11,719	$233	$71,532	$2,863,028	
	Total Operation, Maintenance and Billing	$37,169,787	$24,450,893	$7,035,218	$2,156,837	$127,987	$12,574	$218,588	$100,498	$3,067,193	
	Amortization Expense - Meters	$19,305,119	$12,302,197	$5,163,127	$1,572,799	$236,012	$30,983	$0	$0	$0	
	Allocated PILs	$846,165	$539,206	$226,318	$68,943	$10,344	$1,354	$0	$0	$0	
	Allocated Debt Return	$2,456,272	$1,565,223	$656,962	$200,131	$30,027	$3,929	$0	$0	$0	
	Allocated Equity Return	$3,967,824	$2,528,437	$1,061,247	$323,289	$48,504	$6,347	$0	$0	$0	
	Total	**$56,398,443**	**$37,724,757**	**$12,737,319**	**$2,950,305**	**$59,326**	**($88,869)**	**$163,240**	**$85,431**	**$2,766,935**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	4 GS - 50 to 999	5 GS - 1000 to 4999	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	10 Competitive Sector Multi-Unit Residential	
	Distribution Plant										
1860	Meters	$206,044,239	$131,301,798	$55,106,244	$16,786,546	$2,518,969	$330,682	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($95,621,684)	($60,934,968)	($25,573,886)	($7,790,355)	($1,169,011)	($153,464)	$0	$0	$0	
	Meter Net Fixed Assets	$110,422,555	$70,366,831	$29,532,358	$8,996,191	$1,349,957	$177,218	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$13,000,744	$8,286,616	$3,475,238	$1,058,321	$159,054	$21,515	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$123,423,300	$78,653,447	$33,007,597	$10,054,511	$1,509,011	$198,733	$0	$0	$0	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,473)	($45,908)	($64,946)	($24,868)	($9,937)	($4,231)	($774)	($10,667)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,079)	($402,174)	($568,960)	($217,852)	($87,056)	($37,063)	($6,779)	($93,446)	CWNB
4220	Other Electric Revenues	($912,869)	($376,947)	($152,501)	($215,745)	($82,608)	($33,011)	($14,054)	($2,570)	($35,434)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
	Sub-total	*($7,346,723)*	*($3,661,200)*	*($1,405,553)*	*($1,371,694)*	*($393,548)*	*($144,056)*	*($55,348)*	*($15,067)*	*($300,258)*	
	Operation										
5065	Meter Expense	$476,757	$303,813	$127,508	$38,842	$5,829	$765	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,018,966	$118,606	$17,256	$712	$63	$152,101	$20,177	$142,217	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$443,845	$51,663	$7,517	$310	$27	$66,253	$8,789	$61,947	CCA
	Sub-total	*$2,587,207*	*$1,766,625*	*$297,777*	*$63,614*	*$6,851*	*$856*	*$218,354*	*$28,965*	*$204,165*	
	Maintenance										
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$2,857,700	$2,171,057	$290,615	$356,270	$36,531	$3,228	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,123,488	$1,924,470	$518,505	$25,256	$2,535	$70	$21,353	$854,655	CWNB
5320	Collecting	$22,254,548	$14,389,724	$4,522,356	$1,218,447	$59,349	$5,956	$164	$50,179	$2,008,373	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$34,582,580*	*$22,684,268*	*$6,737,441*	*$2,093,222*	*$121,136*	*$11,719*	*$233*	*$71,532*	*$2,863,028*	
	Total Operation, Maintenance and Billing	$37,169,787	$24,450,893	$7,035,218	$2,156,837	$127,987	$12,574	$218,588	$100,498	$3,067,193	
	Amortization Expense - Meters	$19,305,119	$12,302,197	$5,163,127	$1,572,799	$236,012	$30,983	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$2,015,005*	*$1,284,355*	*$538,633*	*$164,031*	*$24,652*	*$3,335*	*$0*	*$0*	*$0*	
	Admin and General	$21,213,850	$13,938,053	$4,020,223	$1,254,301	$74,196	$7,413	$124,416	$58,029	$1,737,220	
	Allocated PILs	$945,789	$602,704	$252,950	$77,054	$11,563	$1,518	$0	$0	$0	
	Allocated Debt Return	$2,745,465	$1,749,549	$734,271	$223,675	$33,564	$4,406	$0	$0	$0	
	Allocated Equity Return	$4,434,981	$2,826,194	$1,186,130	$361,321	$54,219	$7,118	$0	$0	$0	
	Total	**$80,483,273**	**$53,492,746**	**$17,524,998**	**$4,438,322**	**$168,645**	**($76,709)**	**$287,656**	**$143,461**	**$4,504,155**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1	2	4	5	6	7	9	10	
			Residential	**GS <50**	**GS - 50 to 999**	**GS - 1000 to 4999**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Competitive Sector Multi-Unit Residential**	
	Distribution Plant										
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$53,669,039	$40,549,293	$4,719,889	$686,701	$28,346	$2,505	$1,219,922	$802,920	$5,659,464	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$34,312,992	$24,022,552	$2,796,196	$79,694	$195	$0	$3,585,855	$475,672	$3,352,827	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$68,757,879	$51,949,568	$6,046,868	$879,764	$36,315	$3,209	$1,562,898	$1,028,657	$7,250,600	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$43,959,956	$30,776,398	$3,582,336	$102,100	$250	$0	$4,594,004	$609,406	$4,295,461	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$220,743,819	$166,781,555	$19,413,174	$2,824,439	$116,589	$10,303	$5,017,607	$3,302,455	$23,277,696	PNCP
1840-5	Underground Conduit - Secondary	$87,988,795	$61,601,022	$7,170,285	$204,360	$501	$0	$9,195,207	$1,219,767	$8,597,653	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$159,500,636	$120,509,667	$14,027,181	$2,040,827	$84,243	$7,445	$3,625,522	$2,386,221	$16,819,530	PNCP
1845-5	Underground Conductors and Devices - Secondary	$63,577,177	$44,510,429	$5,180,961	$147,663	$362	$0	$6,644,088	$881,355	$6,212,319	SNCP
1850	Line Transformers	$156,379,002	$118,508,828	$13,794,286	$1,605,507	$18,180	$0	$3,565,327	$2,346,603	$16,540,273	LTNCP
1855	Services	$165,577,509	$147,803,787	$17,204,184	$490,337	$1,201	$0	$0	$0	$78,000	CWCS
1860	Meters	$206,122,239	$131,301,798	$55,106,244	$16,786,546	$2,518,969	$330,682	$0	$0	$78,000	CWMC
											0
	Sub-total	*$1,260,589,042*	*$938,314,897*	*$149,041,604*	*$25,847,938*	*$2,805,151*	*$354,145*	*$39,010,429*	*$13,053,056*	*$92,161,822*	
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($279,813,864)	($200,635,099)	($41,834,814)	($9,445,461)	($1,220,981)	($157,675)	($7,041,594)	($2,418,927)	($17,059,314)	
	Customer Related Net Fixed Assets	$980,775,178	$737,679,798	$107,206,790	$16,402,477	$1,584,170	$196,470	$31,968,836	$10,634,129	$75,102,509	
	Allocated General Plant Net Fixed Assets	$116,398,924	$86,871,463	$12,615,625	$1,929,603	$186,649	$23,852	$4,103,252	$1,290,558	$9,377,921	
	Customer Related NFA Including General Plant	$1,097,174,102	$824,551,261	$119,822,415	$18,332,081	$1,770,819	$220,322	$36,072,087	$11,924,686	$84,480,430	
	Misc Revenue										
4082	Retail Services Revenues	($274,804)	($113,473)	($45,908)	($64,946)	($24,868)	($9,937)	($4,231)	($774)	($10,667)	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	($2,407,409)	($994,079)	($402,174)	($568,960)	($217,852)	($87,056)	($37,063)	($6,779)	($93,446)	CWNB
4220	Other Electric Revenues	($912,869)	($376,947)	($152,501)	($215,745)	($82,608)	($33,011)	($14,054)	($2,570)	($35,434)	NFA
4225	Late Payment Charges	($3,751,641)	($2,176,700)	($804,970)	($522,043)	($68,221)	($14,052)	$0	($4,943)	($160,711)	LPHA
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*($7,346,723)*	*($3,661,200)*	*($1,405,553)*	*($1,371,694)*	*($393,548)*	*($144,056)*	*($55,348)*	*($15,067)*	*($300,258)*	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

	Operating and Maintenance										
5005	Operation Supervision and Engineering	$7,790,742	$5,931,316	$694,530	$88,888	$12,816	$4,579	$286,476	$95,860	$676,279	1815-1855
5010	Load Dispatching	$2,007,476	$1,528,350	$178,963	$22,904	$3,302	$1,180	$73,818	$24,701	$174,260	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$133,829	$98,220	$11,433	$1,166	$43	$4	$7,310	$1,945	$13,708	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$188,759	$138,534	$16,125	$1,644	$61	$5	$10,310	$2,743	$19,335	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$127,555	$94,357	$10,983	$1,251	$48	$4	$5,872	$1,868	$13,169	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$616,551	$456,089	$53,088	$6,049	$234	$21	$28,384	$9,031	$63,656	1840 & 1845
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5065	Meter Expense	$476,757	$303,813	$127,508	$38,842	$5,829	$765	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,470,099	$1,018,966	$118,606	$17,256	$712	$63	$152,101	$20,177	$142,217	CCA
5075	Customer Premises - Materials and Expenses	$640,352	$443,845	$51,663	$7,517	$310	$27	$66,253	$8,789	$61,947	CCA
5085	Miscellaneous Distribution Expense	$1,397,837	$1,064,214	$124,615	$15,948	$2,299	$822	$51,400	$17,199	$121,340	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$3,871,554	$2,947,526	$345,142	$44,172	$6,369	$2,275	$142,362	$47,637	$336,072	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	1830
5125	Maintenance of Overhead Conductors and Devices	$4,292,769	$3,150,553	$366,721	$37,394	$1,393	$122	$234,481	$62,384	$439,723	1835
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$771,935	$566,539	$65,945	$6,724	$250	$22	$42,165	$11,218	$79,072	1830 & 1835
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840
5150	Maintenance of Underground Conductors and Devices	$1,272,324	$941,192	$109,554	$12,482	$483	$42	$58,573	$18,637	$131,362	1845
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	1855
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	1860
	Sub-total	*$25,058,539*	*$18,683,514*	*$2,274,874*	*$302,236*	*$34,149*	*$9,931*	*$1,159,504*	*$322,189*	*$2,272,141*	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

	Billing and Collection										
5305	Supervision	$785,685	$508,021	$159,659	$43,017	$2,095	$210	$6	$1,772	$70,905	CWNB
5310	Meter Reading Expense	$2,857,700	$2,171,057	$290,615	$356,270	$36,531	$3,228	$0	$0	$0	CWMR
5315	Customer Billing	$9,470,331	$6,123,488	$1,924,470	$518,505	$25,256	$2,535	$70	$21,353	$854,655	CWNB
5320	Collecting	$22,254,548	$14,389,724	$4,522,356	$1,218,447	$59,349	$5,956	$164	$50,179	$2,008,373	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5335	Bad Debt Expense	$6,813,154	$3,592,822	$1,949,677	$764,931	$241,185	$0	$0	$0	$264,540	BDHA
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$42,181,418*	*$26,785,112*	*$8,846,777*	*$2,901,170*	*$364,415*	*$11,929*	*$239*	*$73,304*	*$3,198,473*	
	Sub Total Operating, Maintenance and Biling	*$67,239,957*	*$45,468,626*	*$11,121,650*	*$3,203,406*	*$398,565*	*$21,860*	*$1,159,744*	*$395,493*	*$5,470,613*	
	Amortization Expense - Customer Related	$58,116,163	$41,569,429	$8,593,393	$2,046,722	$307,718	$56,984	$1,455,378	$507,477	$3,579,063	
	Amortization Expense - General Plant assigned to Meters	$18,040,848	$13,464,342	$1,955,315	$299,072	$28,929	$3,697	$635,969	$200,026	$1,453,498	
	Admin and General	$38,368,270	$25,919,058	$6,355,384	$1,862,929	$231,054	$12,887	$660,104	$228,366	$3,098,488	
	Allocated PILs	$8,400,514	$6,318,359	$918,245	$140,490	$13,569	$1,683	$273,819	$91,083	$643,266	
	Allocated Debt Return	$24,385,268	$18,341,124	$2,665,510	$407,819	$39,388	$4,885	$794,849	$264,399	$1,867,293	
	Allocated Equity Return	$39,391,586	$29,627,970	$4,305,824	$658,785	$63,626	$7,891	$1,283,988	$427,106	$3,016,397	
	PLCC Adjustment for Line Transformer	$8,199,926	$6,208,603	$722,620	$84,103	$952	$0	$188,490	$123,318	$871,840	
	PLCC Adjustment for Primary Costs	$19,676,211	$14,858,248	$1,729,526	$250,004	$10,270	$911	$445,627	$295,311	$2,086,315	
	PLCC Adjustment for Secondary Costs	$23,339,420	$16,787,817	$1,813,017	$258,076	$10,596	$0	$0	$1,269,143	$3,200,771	
	Total	$195,380,325	**$139,193,039**	**$30,244,606**	**$6,655,347**	**$667,482**	**($35,080)**	**$5,574,386**	**$411,111**	**$12,669,434**	

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Distribution Plant									
CWMC	$ 206,044,239	$ 131,301,798	$ 55,106,244	$ 16,786,546	$ 2,518,969	$ 330,682	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (95,621,684)	$ (60,934,968)	$ (25,573,886)	$ (7,790,355)	$ (1,169,011)	$ (153,464)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 110,422,555	$ 70,366,831	$ 29,532,358	$ 8,996,191	$ 1,349,957	$ 177,218	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (2,682,213)	$ (1,107,553)	$ (448,082)	$ (633,906)	$ (242,720)	$ (96,993)	$ (41,294)	$ (7,553)	$ (104,113)
NFA	$ (912,869)	$ (376,947)	$ (152,501)	$ (215,745)	$ (82,608)	$ (33,011)	$ (14,054)	$ (2,570)	$ (35,434)
LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
Sub-total	$ (7,346,723)	$ (3,661,200)	$ (1,405,553)	$ (1,371,694)	$ (393,548)	$ (144,056)	$ (55,348)	$ (15,067)	$ (300,258)
Operation									
CWMC	$ 476,757	$ 303,813	$ 127,508	$ 38,842	$ 5,829	$ 765	$ -	$ -	$ -
CCA	$ 2,110,451	$ 1,462,811	$ 170,269	$ 24,773	$ 1,023	$ 90	$ 218,354	$ 28,965	$ 204,165
Sub-total	$ 2,587,207	$ 1,766,625	$ 297,777	$ 63,614	$ 6,851	$ 856	$ 218,354	$ 28,965	$ 204,165
Maintenance									
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 2,857,700	$ 2,171,057	$ 290,615	$ 356,270	$ 36,531	$ 3,228	$ -	$ -	$ -
CWNB	$ 31,724,879	$ 20,513,212	$ 6,446,826	$ 1,736,952	$ 84,605	$ 8,491	$ 233	$ 71,532	$ 2,863,028
Sub-total	$ 34,582,580	$ 22,684,268	$ 6,737,441	$ 2,093,222	$ 121,136	$ 11,719	$ 233	$ 71,532	$ 2,863,028
Total Operation, Maintenance and Billing	$ 37,169,787	$ 24,450,893	$ 7,035,218	$ 2,156,837	$ 127,987	$ 12,574	$ 218,588	$ 100,498	$ 3,067,193
Amortization Expense - Meters	$ 19,305,119	$ 12,302,197	$ 5,163,127	$ 1,572,799	$ 236,012	$ 30,983	$ -	$ -	$ -
Allocated PILs	$ 846,165	$ 539,206	$ 226,318	$ 68,943	$ 10,344	$ 1,354	$ -	$ -	$ -
Allocated Debt Return	$ 2,456,272	$ 1,565,223	$ 656,962	$ 200,131	$ 30,027	$ 3,929	$ -	$ -	$ -
Allocated Equity Return	$ 3,967,824	$ 2,528,437	$ 1,061,247	$ 323,289	$ 48,504	$ 6,347	$ -	$ -	$ -
Total	**$ 56,398,443**	**$ 37,724,757**	**$ 12,737,319**	**$ 2,950,305**	**$ 59,326**	**$ (88,869)**	**$ 163,240**	**$ 85,431**	**$ 2,766,935**

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
Distribution Plant									
CWMC	$ 206,044,239	$ 131,301,798	$ 55,106,244	$ 16,786,546	$ 2,518,969	$ 330,682	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (95,621,684)	$ (60,934,968)	$ (25,573,886)	$ (7,790,355)	$ (1,169,011)	$ (153,464)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 110,422,555	$ 70,366,831	$ 29,532,358	$ 8,996,191	$ 1,349,957	$ 177,218	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 13,000,744	$ 8,286,616	$ 3,475,238	$ 1,058,321	$ 159,054	$ 21,515	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 123,423,300	$ 78,653,447	$ 33,007,597	$ 10,054,511	$ 1,509,011	$ 198,733	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (2,682,213)	$ (1,107,553)	$ (448,082)	$ (633,906)	$ (242,720)	$ (96,993)	$ (41,294)	$ (7,553)	$ (104,113)
NFA	$ (912,869)	$ (376,947)	$ (152,501)	$ (215,745)	$ (82,608)	$ (33,011)	$ (14,054)	$ (2,570)	$ (35,434)
LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
Sub-total	*$ (7,346,723)*	*$ (3,661,200)*	*$ (1,405,553)*	*$ (1,371,694)*	*$ (393,548)*	*$ (144,056)*	*$ (55,348)*	*$ (15,067)*	*$ (300,258)*
Operation									
CWMC	$ 476,757	$ 303,813	$ 127,508	$ 38,842	$ 5,829	$ 765	$ -	$ -	$ -
CCA	$ 2,110,451	$ 1,462,811	$ 170,269	$ 24,773	$ 1,023	$ 90	$ 218,354	$ 28,965	$ 204,165
Sub-total	*$ 2,587,207*	*$ 1,766,625*	*$ 297,777*	*$ 63,614*	*$ 6,851*	*$ 856*	*$ 218,354*	*$ 28,965*	*$ 204,165*
Maintenance									
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 2,857,700	$ 2,171,057	$ 290,615	$ 356,270	$ 36,531	$ 3,228	$ -	$ -	$ -
CWNB	$ 31,724,879	$ 20,513,212	$ 6,446,826	$ 1,736,952	$ 84,605	$ 8,491	$ 233	$ 71,532	$ 2,863,028
Sub-total	*$ 34,582,580*	*$ 22,684,268*	*$ 6,737,441*	*$ 2,093,222*	*$ 121,136*	*$ 11,719*	*$ 233*	*$ 71,532*	*$ 2,863,028*
Total Operation, Maintenance and Billing	$ 37,169,787	$ 24,450,893	$ 7,035,218	$ 2,156,837	$ 127,987	$ 12,574	$ 218,588	$ 100,498	$ 3,067,193
Amortization Expense - Meters	$ 19,305,119	$ 12,302,197	$ 5,163,127	$ 1,572,799	$ 236,012	$ 30,983	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 2,015,005	$ 1,284,355	$ 538,633	$ 164,031	$ 24,652	$ 3,335	$ -	$ -	$ -
Admin and General	$ 21,213,850	$ 13,938,053	$ 4,020,223	$ 1,254,301	$ 74,196	$ 7,413	$ 124,416	$ 58,029	$ 1,737,220
Allocated PILs	$ 945,789	$ 602,704	$ 252,950	$ 77,054	$ 11,563	$ 1,518	$ -	$ -	$ -
Allocated Debt Return	$ 2,745,465	$ 1,749,549	$ 734,271	$ 223,675	$ 33,564	$ 4,406	$ -	$ -	$ -
Allocated Equity Return	$ 4,434,981	$ 2,826,194	$ 1,186,130	$ 361,321	$ 54,219	$ 7,118	$ -	$ -	$ -
Total	**$ 80,483,273**	**$ 53,492,746**	**$ 17,524,998**	**$ 4,438,322**	**$ 168,645**	**$ (76,709)**	**$ 287,656**	**$ 143,461**	**$ 4,504,155**

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS - 50 to 999	GS - 1000 to 4999	Large Use >5MW	Street Light	Unmetered Scattered Load	Competitive Sector Multi-Unit Residential
	Distribution Plant									
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 502,671,373	$ 379,790,083	$ 44,207,112	$ 6,431,731	$ 265,493	$ 23,462	$ 11,425,948	$ 7,520,253	$ 53,007,290
	SNCP	$ 229,838,919	$ 160,910,401	$ 18,729,778	$ 533,818	$ 1,308	$ -	$ 24,019,154	$ 3,186,200	$ 22,458,260
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 156,379,002	$ 118,508,828	$ 13,794,286	$ 1,605,507	$ 18,180	$ -	$ 3,565,327	$ 2,346,603	$ 16,540,273
	CWCS	$ 165,577,509	$ 147,803,787	$ 17,204,184	$ 490,337	$ 1,201	$ -	$ -	$ -	$ 78,000
	CWMC	$ 206,122,239	$ 131,301,798	$ 55,106,244	$ 16,786,546	$ 2,518,969	$ 330,682	$ -	$ -	$ 78,000
	Sub-total	*$ 1,260,589,042*	*$ 938,314,897*	*$ 149,041,604*	*$ 25,847,938*	*$ 2,805,151*	*$ 354,145*	*$ 39,010,429*	*$ 13,053,056*	*$ 92,161,822*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (279,813,864)	$ (200,635,099)	$ (41,834,814)	$ (9,445,461)	$ (1,220,981)	$ (157,675)	$ (7,041,594)	$ (2,418,927)	$ (17,059,314)
	Customer Related Net Fixed Assets	$ 980,775,178	$ 737,679,798	$ 107,206,790	$ 16,402,477	$ 1,584,170	$ 196,470	$ 31,968,836	$ 10,634,129	$ 75,102,509
	Allocated General Plant Net Fixed Assets	$ 116,398,924	$ 86,871,463	$ 12,615,625	$ 1,929,603	$ 186,649	$ 23,852	$ 4,103,252	$ 1,290,558	$ 9,377,921
	Customer Related NFA Including General Plant	$ 1,097,174,102	$ 824,551,261	$ 119,822,415	$ 18,332,081	$ 1,770,819	$ 220,322	$ 36,072,087	$ 11,924,686	$ 84,480,430
	Misc Revenue									
	CWNB	$ (2,682,213)	$ (1,107,553)	$ (448,082)	$ (633,906)	$ (242,720)	$ (96,993)	$ (41,294)	$ (7,553)	$ (104,113)
	NFA	$ (912,869)	$ (376,947)	$ (152,501)	$ (215,745)	$ (82,608)	$ (33,011)	$ (14,054)	$ (2,570)	$ (35,434)
	LPHA	$ (3,751,641)	$ (2,176,700)	$ (804,970)	$ (522,043)	$ (68,221)	$ (14,052)	$ -	$ (4,943)	$ (160,711)
	Sub-total	*$ (7,346,723)*	*$ (3,661,200)*	*$ (1,405,553)*	*$ (1,371,694)*	*$ (393,548)*	*$ (144,056)*	*$ (55,348)*	*$ (15,067)*	*$ (300,258)*
	Operating and Maintenance									
	1815-1855	$ 15,067,610	$ 11,471,406	$ 1,343,248	$ 171,912	$ 24,786	$ 8,855	$ 554,056	$ 185,397	$ 1,307,950
	1830 & 1835	$ 1,094,523	$ 803,293	$ 93,502	$ 9,534	$ 355	$ 31	$ 59,785	$ 15,906	$ 112,116
	1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840 & 1845	$ 744,106	$ 550,446	$ 64,071	$ 7,300	$ 282	$ 25	$ 34,256	$ 10,899	$ 76,826
	CWMC	$ 476,757	$ 303,813	$ 127,508	$ 38,842	$ 5,829	$ 765	$ -	$ -	$ -
	CCA	$ 2,110,451	$ 1,462,811	$ 170,269	$ 24,773	$ 1,023	$ 90	$ 218,354	$ 28,965	$ 204,165
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1835	$ 4,292,769	$ 3,150,553	$ 366,721	$ 37,394	$ 1,393	$ 122	$ 234,481	$ 62,384	$ 439,723
	1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 1,272,324	$ 941,192	$ 109,554	$ 12,482	$ 483	$ 42	$ 58,573	$ 18,637	$ 131,362
	1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 25,058,539*	*$ 18,683,514*	*$ 2,274,874*	*$ 302,236*	*$ 34,149*	*$ 9,931*	*$ 1,159,504*	*$ 322,189*	*$ 2,272,141*

EB-2018-0165

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Billing and Collection									
CWNB	$ 32,510,564	$ 21,021,233	$ 6,606,485	$ 1,779,969	$ 86,700	$ 8,701	$ 239	$ 73,304	$ 2,933,933
CWMR	$ 2,857,700	$ 2,171,057	$ 290,615	$ 356,270	$ 36,531	$ 3,228	$ -	$ -	$ -
BDHA	$ 6,813,154	$ 3,592,822	$ 1,949,677	$ 764,931	$ 241,185	$ -	$ -	$ -	$ 264,540
Sub-total	*$ 42,181,418*	*$ 26,785,112*	*$ 8,846,777*	*$ 2,901,170*	*$ 364,415*	*$ 11,929*	*$ 239*	*$ 73,304*	*$ 3,198,473*
Sub Total Operating, Maintenance and Biling	*$ 67,239,957*	*$ 45,468,626*	*$ 11,121,650*	*$ 3,203,406*	*$ 398,565*	*$ 21,860*	*$ 1,159,744*	*$ 395,493*	*$ 5,470,613*
Amortization Expense - Customer Related	$ 58,116,163	$ 41,569,429	$ 8,593,393	$ 2,046,722	$ 307,718	$ 56,984	$ 1,455,378	$ 507,477	$ 3,579,063
Amortization Expense - General Plant assigned to Meters	$ 18,040,848	$ 13,464,342	$ 1,955,315	$ 299,072	$ 28,929	$ 3,697	$ 635,969	$ 200,026	$ 1,453,498
Admin and General	$ 38,368,270	$ 25,919,058	$ 6,355,384	$ 1,862,929	$ 231,054	$ 12,887	$ 660,104	$ 228,366	$ 3,098,488
Allocated PILs	$ 8,400,514	$ 6,318,359	$ 918,245	$ 140,490	$ 13,569	$ 1,683	$ 273,819	$ 91,083	$ 643,266
Allocated Debt Return	$ 24,385,268	$ 18,341,124	$ 2,665,510	$ 407,819	$ 39,388	$ 4,885	$ 794,849	$ 264,399	$ 1,867,293
Allocated Equity Return	$ 39,391,586	$ 29,627,970	$ 4,305,824	$ 658,785	$ 63,626	$ 7,891	$ 1,283,988	$ 427,106	$ 3,016,397
PLCC Adjustment for Line Transformer	$ 8,199,926	$ 6,208,603	$ 722,620	$ 84,103	$ 952	$ -	$ 188,490	$ 123,318	$ 871,840
PLCC Adjustment for Primary Costs	$ 19,676,211	$ 14,858,248	$ 1,729,526	$ 250,004	$ 10,270	$ 911	$ 445,627	$ 295,311	$ 2,086,315
PLCC Adjustment for Secondary Costs	$ 23,339,420	$ 16,787,817	$ 1,813,017	$ 258,076	$ 10,596	$ -	$ -	$ 1,269,143	$ 3,200,771
Total	**$ 195,380,325**	**$ 139,193,039**	**$ 30,244,606**	**$ 6,655,347**	**$ 667,482**	**$ (35,080)**	**$ 5,574,386**	**$ 411,111**	**$ 12,669,434**

RATE DESIGN

1. RATE DESIGN

Updated 2020-24 proposed rates reflect the following:

a) Updated load and customer forecast, which impacts rebased 2020 rates, and the calculation of the growth factor, “g”, in the Custom Price Cap Index proposal for setting rates in the 2021-24 period.
b) Updated results of the Cost Allocation model.
c) Updated rate riders for clearance of Group I and Group II deferral and variance accounts.

As noted in the Cost Allocation update section, the updated revenue to cost ratios for all classes, other than the USL class, are within the OEB’s guideline ranges. The rates for the USL class have been designed to bring their revenue to cost ratio within the guideline for the class. Additionally, and as originally filed and ordered by the OEB, the CSMUR class rates have been designed to achieve a revenue to cost ratio of 1.0. The additional revenue responsibility necessary to achieve these adjustments has been allocated to the GS <50 kW, GS 1000-4999 kW, and Large Use classes proportionally to the amounts those classes were below their allocated costs (same treatment as originally proposal for reallocation of revenue responsibility).

The proposed revenue to cost ratios, after rate design, are provided and compared to the prefiled ratios, in Table 1.

Table 1: Revenue to Cost Ratios after Rate Design

Rate Class	Original R/C ratio	Updated R/C ratio	OEB's Guideline Ranges
Residential	103.2	103.2	85-115
CSMUR	100.0	100.0	
GS <50 kW	89.8	89.5	80-120
GS 50-999 kW	105.3	105.8	80-120
GS 1000-4999 kW	95.0	91.2	80-120
Large Use	85.0	88.8	85-115
Streetlighting	108.9	108.9	80-120
USL	94.7	120.0	80-120

The full calculation of the updated 2020 distribution rates is provided in the Revenue Requirement Workform filed as Appendix A under Exhibit U, Tab 6, Schedule 1.

The updated growth factor, "g", derived from the updated load and customer forecast, is unchanged from 0.2, as filed in Exhibit 1B, Tab 4, Schedule 1, section 3.4. Table 2 shows the derivation of the updated "g".

Table 2: Forecast Revenue at 2020 Proposed Rates

	2020	2021	2022	2023	2024	Annual Average ("g")
Revenue at 2020 Rates	$796.9	$797.3	$799.8	$801.8	$804.3	
Annual Growth Rate		0.0%	0.3%	0.2%	0.3%	0.2%

Updated rate riders associated with deferral and variance accounts are discussed and provided in Tab 9, Schedule 1.

2. BILL IMPACTS TABLES

The OEB Appendix 2-W Bill Impact tables, detailing the updated proposed rates, are provided for all rate classes at Appendix A to this schedule.

A summary of the bill impacts (including all rate riders) resulting from the utility's proposals is shown in Table 3 below.

Table 3: Bill Impacts – Change In Monthly Bill

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	$/30 days	-3.53	0.99	1.12	1.40	1.92
	%	*-2.7*	*0.8*	*0.9*	*1.1*	*1.5*
Competitive Sector Multi-Unit Residential	$/30 days	-1.74	1.01	0.89	0.99	1.51
	%	*-2.5*	*1.5*	*1.3*	*1.4*	*2.1*
General Service <50 kW	$/30 days	-5.29	2.22	2.82	4.40	4.82
	%	*-1.6*	*0.7*	*0.9*	*1.3*	*1.4*
General Service 50-999 kW	$/30 days	-442.30	262.16	49.57	87.53	84.57
	%	*-3.1*	*1.9*	*0.4*	*0.6*	*0.6*
General Service 1,000-4,999 kW	$/30 days	-4,334.08	2,782.72	408.13	720.88	696.44
	%	*-2.8*	*1.9*	*0.3*	*0.5*	*0.5*
Large Use	$/30 days	-406.96	-1,054.39	2,102.70	3,713.96	3,588.48
	%	*-0.1*	*-0.1*	*0.3*	*0.5*	*0.5*
Street Lighting	$/30 days	-7,309.35	6,962.19	3,587.48	6,323.55	6,152.69
	%	*-2.5*	*2.5*	*1.2*	*2.2*	*2.0*
Unmetered Scattered Load	$/30 days	-6.04	0.82	0.80	1.42	1.37
	%	*-9.3*	*1.4*	*1.4*	*2.4*	*2.2*

OEB Appendix 2-W
Bill Impacts

2

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 750 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.48	1	$ 37.48	$ 4.85	14.86%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%
Distribution Volumetric Rate	per kWh	$ 0.01063	750	$ 7.97	$ 0.00553	750	$ 4.15	-$ 3.83	-47.98%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	750	$ 0.31	$ 0.00095	750	$ 0.71	$ 0.41	131.71%
Sub-Total A (excluding pass through)				**$ 40.98**			**$ 44.37**	**$ 3.39**	**8.27%**
Line Losses on Cost of Power	per kWh	$ 0.0820	28	$ 2.31	$ 0.0820	28	$ 2.31	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00320	750	-$ 2.40	-$ 0.00052	750	-$ 0.39	$ 2.01	-83.75%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	750	$ 0.05	$ 0.00003	750	$ 0.02	-$ 0.03	-57.14%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.50**			**$ 46.87**	**$ 5.37**	**12.94%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	778	$ 5.91	$ 0.00796	778	$ 6.19	$ 0.29	4.87%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	778	$ 4.80	$ 0.00703	778	$ 5.47	$ 0.67	13.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.21**			**$ 58.54**	**$ 6.33**	**12.12%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	778	$ 2.49	$ 0.0032	778	$ 2.49	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	778	$ 0.23	$ 0.0003	778	$ 0.23	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	778	$ 0.31	$ 0.0004	778	$ 0.31	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	128	$ 11.99	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 116.99**			**$ 123.32**	$ 6.33	5.4%
8% Provincial Rebate		-8%		-$ 9.36	-8%		-$ 9.87	-$ 0.51	5.4%
HST		13%		$ 15.21	13%		$ 16.03	$ 0.82	5.4%
Total Bill on TOU (after Tax & Rebate)				**$ 122.84**			**$ 129.48**	$ 6.64	5.4%
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 42.17	1	$ 42.17	$ 4.69	12.51%	$ 43.54	1	$ 43.54	$ 1.37	3.25%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.51	1	$ 0.51	$ 0.51		$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.78	1	-$ 0.78	-$ 0.78		-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.83	1	-$ 0.83	-$ 0.83		-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.03	1	-$ 0.03	-$ 0.03		-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	-$ 0.28			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	-$ 0.10			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	-$ 0.03			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	-$ 0.46			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.88			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.28			1	$ -	$ -	
Distribution Volumetric Rate		750	$ -	-$ 4.15			750	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		750	$ -	-$ 0.71			750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 40.79**	**-$ 3.58**	**-8.07%**			**$ 42.16**	**$ 1.37**	**3.36%**
Line Losses on Cost of Power	$ 0.0820	22	$ 1.81	-$ 0.50	-21.54%	$ 0.0820	22	$ 1.81	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.00060	750	$ 0.45	$ 0.84	-215.38%			$ -	-$ 0.45	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00003	750	-$ 0.02	-$ 0.05	-200.00%			$ -	$ 0.02	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43.59**	**-$ 3.28**	**-7.00%**			**$ 44.53**	**$ 0.94**	**2.16%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	772	$ 6.37	$ 0.18	2.83%	$ 0.00825	772	$ 6.37	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	772	$ 5.24	-$ 0.23	-4.17%	$ 0.00679	772	$ 5.24	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 55.20**	**-$ 3.34**	**-5.70%**			**$ 56.15**	**$ 0.94**	**1.71%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	772	$ 2.47	-$ 0.02	-0.78%	$ 0.0032	772	$ 2.47	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	772	$ 0.23	-$ 0.00	-0.78%	$ 0.0003	772	$ 0.23	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	772	$ 0.31	-$ 0.00	-0.78%	$ 0.0004	772	$ 0.31	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 119.96**	-$ 3.36	-2.7%			**$ 120.90**	$ 0.94	0.8%
8% Provincial Rebate	-8%		-$ 9.60	$ 0.27	-2.7%	-8%		-$ 9.67	-$ 0.08	0.8%
HST	13%		$ 15.59	-$ 0.44	-2.7%	13%		$ 15.72	$ 0.12	0.8%
Total Bill on TOU (after Tax & Rebate)			**$ 125.96**	-$ 3.53	-2.7%			**$ 126.95**	$ 0.99	0.8%
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 44.61	1	$ 44.61	$ 1.07	2.46%	$ 46.50	1	$ 46.50	$ 1.89	4.24%	$ 48.33	1	$ 48.33	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate		750	$ -	$ -			750	$ -	$ -			750	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		750	$ -	$ -			750	$ -	$ -			750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 43.23**	**$ 1.07**	**2.54%**			**$ 45.12**	**$ 1.89**	**4.37%**			**$ 46.95**	**$ 1.83**	**4.06%**
Line Losses on Cost of Power	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%	$ 0.0820	22	$ 1.81	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 45.60**	**$ 1.07**	**2.40%**			**$ 46.93**	**$ 1.33**	**2.92%**			**$ 48.76**	**$ 1.83**	**3.90%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%	$ 0.00825	772	$ 6.37	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%	$ 0.00679	772	$ 5.24	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 57.22**	**$ 1.07**	**1.91%**			**$ 58.55**	**$ 1.33**	**2.32%**			**$ 60.38**	**$ 1.83**	**3.13%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%	$ 0.0032	772	$ 2.47	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%	$ 0.0003	772	$ 0.23	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%	$ 0.0004	772	$ 0.31	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%	$ 0.1320	135	$ 17.82	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 121.97**	$ 1.07	0.9%			**$ 123.30**	$ 1.33	1.1%			**$ 125.13**	$ 1.83	1.5%
8% Provincial Rebate	-8%		-$ 9.76	-$ 0.09	0.9%	-8%		-$ 9.86	-$ 0.11	1.1%	-8%		-$ 10.01	-$ 0.15	1.5%
HST	13%		$ 15.86	$ 0.14	0.9%	13%		$ 16.03	$ 0.17	1.1%	13%		$ 16.27	$ 0.24	1.5%
Total Bill on TOU (after Tax & Rebate)			**$ 128.07**	$ 1.12	0.9%			**$ 129.47**	$ 1.40	1.1%			**$ 131.39**	$ 1.92	1.5%
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 212 kWh ○ May 1 - October 31 ● November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.48	1	$ 37.48	$ 4.85	14.86%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%
Distribution Volumetric Rate	per kWh	$ 0.01063	212	$ 2.25	$ 0.00553	212	$ 1.17	-$ 1.08	-47.98%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	212	$ 0.09	$ 0.00095	212	$ 0.20	$ 0.11	131.71%
Sub-Total A (excluding pass through)				**$ 35.04**			**$ 40.88**	**$ 5.84**	**16.68%**
Line Losses on Cost of Power	per kWh	$ 0.0820	8	$ 0.65	$ 0.0820	8	$ 0.65	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00320	212	-$ 0.68	-$ 0.00052	212	-$ 0.11	$ 0.57	-83.75%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	212	$ 0.01	$ 0.00003	212	$ 0.01	-$ 0.01	-57.14%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 35.59**			**$ 41.99**	**$ 6.40**	**17.99%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	220	$ 1.67	$ 0.00796	220	$ 1.75	$ 0.08	4.87%
Retail Transmission Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	220	$ 1.36	$ 0.00703	220	$ 1.55	$ 0.19	13.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 38.62**			**$ 45.29**	**$ 6.67**	**17.28%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	220	$ 0.70	$ 0.0032	220	$ 0.70	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	220	$ 0.07	$ 0.0003	220	$ 0.07	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	220	$ 0.09	$ 0.0004	220	$ 0.09	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	138	$ 8.96	$ 0.0650	138	$ 8.96	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	36	$ 3.39	$ 0.0940	36	$ 3.39	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	38	$ 5.04	$ 0.1320	38	$ 5.04	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 57.11**			**$ 63.78**	**$ 6.67**	**11.7%**
8% Provincial Rebate		-8%		-$ 4.57	-8%		-$ 5.10	-$ 0.53	11.7%
HST		13%		$ 7.42	13%		$ 8.29	$ 0.87	11.7%
Total Bill on TOU (after Tax & Rebate)				**$ 59.96**			**$ 66.97**	**$ 7.01**	**11.7%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 42.17	1	$ 42.17	$ 4.69	12.51%	$ 43.54	1	$ 43.54	$ 1.37	3.25%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.51	1	$ 0.51	$ 0.51		$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.78	1	-$ 0.78	-$ 0.78		-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.83	1	-$ 0.83	-$ 0.83		-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.03	1	-$ 0.03	-$ 0.03		-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	-$ 0.28			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	-$ 0.10			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	-$ 0.03			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	-$ 0.46			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.88			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.28			1	$ -	$ -	
Distribution Volumetric Rate		212	$ -	-$ 1.17			212	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		212	$ -	-$ 0.20			212	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 40.79**	**-$ 0.09**	**-0.23%**			**$ 42.16**	**$ 1.37**	**3.36%**
Line Losses on Cost of Power	$ 0.0820	6	$ 0.51	-$ 0.14	-21.54%	$ 0.0820	6	$ 0.51	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.00060	212	$ 0.13	$ 0.24	-215.38%			$ -	-$ 0.13	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00003	212	-$ 0.01	-$ 0.01	-200.00%			$ -	$ 0.01	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 41.98**	**-$ 0.01**	**-0.02%**			**$ 43.23**	**$ 1.25**	**2.98%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	218	$ 1.80	$ 0.05	2.83%	$ 0.00825	218	$ 1.80	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	$ 0.00679	218	$ 1.48	-$ 0.06	-4.17%	$ 0.00679	218	$ 1.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.27**	**-$ 0.02**	**-0.05%**			**$ 46.52**	**$ 1.25**	**2.76%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	218	$ 0.70	-$ 0.01	-0.78%	$ 0.0032	218	$ 0.70	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	218	$ 0.07	-$ 0.00	-0.78%	$ 0.0003	218	$ 0.07	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	218	$ 0.09	-$ 0.00	-0.78%	$ 0.0004	218	$ 0.09	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%
TOU - Mid Peak	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%
TOU - On Peak	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 63.75**	**-$ 0.03**	**0.0%**			**$ 65.00**	**$ 1.25**	**2.0%**
8% Provincial Rebate	-8%		-$ 5.10	$ 0.00	0.0%	-8%		-$ 5.20	-$ 0.10	2.0%
HST	13%		$ 8.29	-$ 0.00	0.0%	13%		$ 8.45	$ 0.16	2.0%
Total Bill on TOU (after Tax & Rebate)			**$ 66.94**	**-$ 0.03**	**0.0%**			**$ 68.25**	**$ 1.31**	**2.0%**
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 44.61	1	$ 44.61	$ 1.07	2.46%	$ 46.50	1	$ 46.50	$ 1.89	4.24%	$ 48.33	1	$ 48.33	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate		212	$ -	$ -			212	$ -	$ -			212	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		212	$ -	$ -			212	$ -	$ -			212	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 43.23**	**$ 1.07**	**2.54%**			**$ 45.12**	**$ 1.89**	**4.37%**			**$ 46.95**	**$ 1.83**	**4.06%**
Line Losses on Cost of Power	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%	$ 0.0820	6	$ 0.51	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 44.30**	**$ 1.07**	**2.47%**			**$ 45.63**	**$ 1.33**	**3.00%**			**$ 47.46**	**$ 1.83**	**4.01%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%	$ 0.00825	218	$ 1.80	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%	$ 0.00679	218	$ 1.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 47.59**	**$ 1.07**	**2.30%**			**$ 48.92**	**$ 1.33**	**2.79%**			**$ 50.75**	**$ 1.83**	**3.74%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%	$ 0.0032	218	$ 0.70	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%	$ 0.0003	218	$ 0.07	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%	$ 0.0004	218	$ 0.09	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%	$ 0.0650	138	$ 8.96	$ -	0.00%
TOU - Mid Peak	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%	$ 0.0940	36	$ 3.39	$ -	0.00%
TOU - On Peak	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%	$ 0.1320	38	$ 5.04	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 66.07**	**$ 1.07**	**1.6%**			**$ 67.40**	**$ 1.33**	**2.0%**			**$ 69.23**	**$ 1.83**	**2.7%**
8% Provincial Rebate	-8%		-$ 5.29	-$ 0.09	1.6%	-8%		-$ 5.39	-$ 0.11	2.0%	-8%		-$ 5.54	-$ 0.15	2.7%
HST	13%		$ 8.59	$ 0.14	1.6%	13%		$ 8.76	$ 0.17	2.0%	13%		$ 9.00	$ 0.24	2.7%
Total Bill on TOU (after Tax & Rebate)			**$ 69.37**	**$ 1.12**	**1.6%**			**$ 70.77**	**$ 1.40**	**2.0%**			**$ 72.69**	**$ 1.92**	**2.7%**
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 650 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		2018 Current Board-Approved			2019 Current Board-Approved			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 32.63	1	$ 32.63	$ 37.48	1	$ 37.48	$ 4.85	14.86%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.48	1	-$ 0.48		1	$ -	$ 0.48	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 1.48	1	-$ 1.48		1	$ -	$ 1.48	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.10	1	$ 0.10	$ 0.10	1	$ 0.10	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.03	1	$ 0.03	$ 0.03	1	$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.46	1	$ 0.46	$ 0.46	1	$ 0.46	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.88	1	$ 0.88	$ 0.88	1	$ 0.88	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.28	1	$ 0.28	$ 0.28	1	$ 0.28	$ -	0.00%
Distribution Volumetric Rate	per kWh	$ 0.01063	650	$ 6.91	$ 0.00553	650	$ 3.59	-$ 3.32	-47.98%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00041	650	$ 0.27	$ 0.00095	650	$ 0.62	$ 0.35	131.71%
Sub-Total A (excluding pass through)				**$ 39.88**			**$ 43.72**	**$ 3.85**	**9.64%**
Line Losses on Cost of Power	per kWh	$ 0.0820	24	$ 2.00	$ 0.0820	24	$ 2.00	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00320	650	-$ 2.08	-$ 0.00052	650	-$ 0.34	$ 1.74	-83.75%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	650	$ 0.05	$ 0.00003	650	$ 0.02	-$ 0.03	-57.14%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.41**			**$ 45.97**	**$ 5.56**	**13.77%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	674	$ 5.12	$ 0.00796	674	$ 5.37	$ 0.25	4.87%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	674	$ 4.16	$ 0.00703	674	$ 4.74	$ 0.58	13.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.69**			**$ 56.08**	**$ 6.39**	**12.86%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	674	$ 2.16	$ 0.0032	674	$ 2.16	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	674	$ 0.20	$ 0.0003	674	$ 0.20	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	674	$ 0.27	$ 0.0004	674	$ 0.27	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	423	$ 27.46	$ 0.0650	423	$ 27.46	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	111	$ 10.39	$ 0.0940	111	$ 10.39	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	117	$ 15.44	$ 0.1320	117	$ 15.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	150	$ 13.35	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	**$ 0.1164**		$ -	$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 105.86**			**$ 112.25**	**$ 6.39**	**6.0%**
8% Provincial Rebate		-8%		-$ 8.47	-8%		-$ 8.98	-$ 0.51	6.0%
HST		13%		$ 13.76	13%		$ 14.59	$ 0.83	6.0%
Total Bill on TOU (after Tax & Rebate)				**$ 111.15**			**$ 117.86**	$ 6.71	6.0%
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed			Impact		2021 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	$ 42.17	1	$ 42.17	$ 4.69	12.51%	$ 43.54	1	$ 43.54	$ 1.37	3.25%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.09	1	$ 0.09	$ 0.09		$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.51	1	$ 0.51	$ 0.51		$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.28	1	$ 0.28	$ 0.28		$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.78	1	-$ 0.78	-$ 0.78		-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.12	1	-$ 0.12	-$ 0.12		-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.83	1	-$ 0.83	-$ 0.83		-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.03	1	-$ 0.03	-$ 0.03		-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	-$ 0.28			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	-$ 0.10			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	-$ 0.03			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	-$ 0.46			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.88			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.28			1	$ -	$ -	
Distribution Volumetric Rate		650	$ -	-$ 3.59			650	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		650	$ -	-$ 0.62			650	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 40.79**	**-$ 2.93**	**-6.71%**			**$ 42.16**	**$ 1.37**	**3.36%**
Line Losses on Cost of Power	$ 0.0820	19	$ 1.57	-$ 0.43	-21.54%	$ 0.0820	19	$ 1.57	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.00060	650	$ 0.39	$ 0.73	-215.38%			$ -	-$ 0.39	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00003	650	-$ 0.02	-$ 0.04	-200.00%			$ -	$ 0.02	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43.29**	**-$ 2.67**	**-5.82%**			**$ 44.29**	**$ 1.00**	**2.31%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	669	$ 5.52	$ 0.15	2.83%	$ 0.00825	669	$ 5.52	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	669	$ 4.54	-$ 0.20	-4.17%	$ 0.00679	669	$ 4.54	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 53.36**	**-$ 2.72**	**-4.85%**			**$ 54.36**	**$ 1.00**	**1.87%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	669	$ 2.14	-$ 0.02	-0.78%	$ 0.0032	669	$ 2.14	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	669	$ 0.20	-$ 0.00	-0.78%	$ 0.0003	669	$ 0.20	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	669	$ 0.27	-$ 0.00	-0.78%	$ 0.0004	669	$ 0.27	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%
TOU - Mid Peak	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%
TOU - On Peak	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 109.51**	**-$ 2.74**	**-2.4%**			**$ 110.51**	**$ 1.00**	**0.9%**
8% Provincial Rebate	-8%		-$ 8.76	$ 0.22	-2.4%	-8%		-$ 8.84	-$ 0.08	0.9%
HST	13%		$ 14.24	-$ 0.36	-2.4%	13%		$ 14.37	$ 0.13	0.9%
Total Bill on TOU (after Tax & Rebate)			**$ 114.99**	-$ 2.88	-2.4%			**$ 116.04**	$ 1.05	0.9%
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	$ 44.61	1	$ 44.61	$ 1.07	2.46%	$ 46.50	1	$ 46.50	$ 1.89	4.24%	$ 48.33	1	$ 48.33	$ 1.83	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%	$ 0.09	1	$ 0.09	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%	$ 0.51	1	$ 0.51	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%	$ 0.28	1	$ 0.28	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%	-$ 0.78	1	-$ 0.78	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%	-$ 0.12	1	-$ 0.12	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%	-$ 0.83	1	-$ 0.83	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%	-$ 0.03	1	-$ 0.03	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate		650	$ -	$ -			650	$ -	$ -			650	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		650	$ -	$ -			650	$ -	$ -			650	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 43.23**	**$ 1.07**	**2.54%**			**$ 45.12**	**$ 1.89**	**4.37%**			**$ 46.95**	**$ 1.83**	**4.06%**
Line Losses on Cost of Power	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%	$ 0.0820	19	$ 1.57	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 45.36**	**$ 1.07**	**2.42%**			**$ 46.69**	**$ 1.33**	**2.93%**			**$ 48.52**	**$ 1.83**	**3.92%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%	$ 0.00825	669	$ 5.52	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%	$ 0.00679	669	$ 4.54	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 55.43**	**$ 1.07**	**1.97%**			**$ 56.76**	**$ 1.33**	**2.40%**			**$ 58.59**	**$ 1.83**	**3.22%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%	$ 0.0032	669	$ 2.14	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%	$ 0.0003	669	$ 0.20	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%	$ 0.0004	669	$ 0.27	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%	$ 0.2500	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%	$ 0.0650	423	$ 27.46	$ -	0.00%
TOU - Mid Peak	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%	$ 0.0940	111	$ 10.39	$ -	0.00%
TOU - On Peak	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%	$ 0.1320	117	$ 15.44	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%	$ 0.0890	150	$ 13.35	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 111.58**	**$ 1.07**	**1.0%**			**$ 112.91**	**$ 1.33**	**1.2%**			**$ 114.74**	**$ 1.83**	**1.6%**
8% Provincial Rebate	-8%		-$ 8.93	-$ 0.09	1.0%	-8%		-$ 9.03	-$ 0.11	1.2%	-8%		-$ 9.18	-$ 0.15	1.6%
HST	13%		$ 14.51	$ 0.14	1.0%	13%		$ 14.68	$ 0.17	1.2%	13%		$ 14.92	$ 0.24	1.6%
Total Bill on TOU (after Tax & Rebate)			**$ 117.16**	$ 1.12	1.0%			**$ 118.56**	$ 1.40	1.2%			**$ 120.48**	$ 1.92	1.6%
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 300 **kWh** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 26.80	1	$ 26.80	$ 30.58	1	$ 30.58	$ 3.78	14.10%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.19	1	-$ 0.19		1	$ -	$ 0.19	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 0.59	1	-$ 0.59		1	$ -	$ 0.59	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.04	1	$ 0.04	$ 0.04	1	$ 0.04	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.18	1	$ 0.18	$ 0.18	1	$ 0.18	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.19	1	$ 0.19	$ 0.19	1	$ 0.19	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.09	1	$ 0.09	$ 0.09	1	$ 0.09	$ -	0.00%
Distribution Volumetric Rate	per kWh	$ 0.01627	300	$ 4.88	$ 0.00846	300	$ 2.54	-$ 2.34	-48.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00068	300	$ 0.20	$ 0.00126	300	$ 0.38	$ 0.17	85.29%
Sub-Total A (excluding pass through)				**$ 31.62**			**$ 34.01**	**$ 2.39**	**7.56%**
Line Losses on Cost of Power	per kWh	$ 0.0820	11	$ 0.92	$ 0.0820	11	$ 0.92	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00392	300	-$ 1.18	-$ 0.0005	300	-$ 0.16	$ 1.01	-86%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	300	$ 0.02	$ 0.0000	300	$ 0.01	-$ 0.01	-57%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 31.94**			**$ 35.34**	**$ 3.39**	**10.62%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	311	$ 2.36	$ 0.00796	311	$ 2.48	$ 0.12	4.87%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	311	$ 1.92	$ 0.00703	311	$ 2.19	$ 0.27	13.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 36.23**			**$ 40.00**	**$ 3.78**	**10.42%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	311	$ 1.00	$ 0.0032	311	$ 1.00	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	311	$ 0.09	$ 0.0003	311	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	311	$ 0.12	$ 0.0004	311	$ 0.12	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	195	$ 12.68	$ 0.0650	195	$ 12.68	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	51	$ 4.79	$ 0.0940	51	$ 4.79	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	54	$ 7.13	$ 0.1320	54	$ 7.13	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	300	$ 23.10	$ 0.0770	300	$ 23.10	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	0	$ -	$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 62.29**			**$ 66.06**	**$ 3.78**	**6.1%**
8% Provincial Rebate		-8%		-$ 4.98	-8%		-$ 5.29	-$ 0.30	6.1%
HST		13%		$ 8.10	13%		$ 8.59	$ 0.49	6.1%
Total Bill on TOU (after Tax & Rebate)				**$ 65.40**			**$ 69.37**	**$ 3.96**	**6.1%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 33.32	1	$ 33.32	$ 2.74	8.96%	$ 34.41	1	$ 34.41	$ 1.09	3.27%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.06	1	$ 0.06	$ 0.06		$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.34	1	$ 0.34	$ 0.34		$ 0.34	1	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.52	1	-$ 0.52	-$ 0.52		-$ 0.52	1	-$ 0.52	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.55	1	-$ 0.55	-$ 0.55		-$ 0.55	1	-$ 0.55	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.24	1	-$ 0.24	-$ 0.24		-$ 0.24	1	-$ 0.24	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	-$ 0.04			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	-$ 0.01			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	-$ 0.18			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.19			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.09			1	$ -	$ -	
Distribution Volumetric Rate		300	$ -	-$ 2.54			300	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		300	$ -	-$ 0.38			300	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 32.30**	**-$ 1.71**	**-5.02%**			**$ 33.39**	**$ 1.09**	**3.37%**
Line Losses on Cost of Power	$ 0.0820	9	$ 0.73	-$ 0.20	-21.54%	$ 0.0820	9	$ 0.73	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.00045	300	$ 0.14	$ 0.30	-183.33%			$ -	-$ 0.14	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00003	300	-$ 0.01	-$ 0.02	-200.00%			$ -	$ 0.01	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.71**	**-$ 1.63**	**-4.60%**			**$ 34.68**	**$ 0.96**	**2.86%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	309	$ 2.55	$ 0.07	2.83%	$ 0.00825	309	$ 2.55	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	309	$ 2.10	-$ 0.09	-4.17%	$ 0.00679	309	$ 2.10	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 38.36**	**-$ 1.65**	**-4.12%**			**$ 39.32**	**$ 0.96**	**2.51%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	309	$ 0.99	-$ 0.01	-0.78%	$ 0.0032	309	$ 0.99	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	309	$ 0.09	-$ 0.00	-0.78%	$ 0.0003	309	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	309	$ 0.12	-$ 0.00	-0.78%	$ 0.0004	309	$ 0.12	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%
TOU - Mid Peak	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%
TOU - On Peak	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 64.41**	**-$ 1.66**	**-2.5%**			**$ 65.37**	**$ 0.96**	**1.5%**
8% Provincial Rebate	-8%		-$ 5.15	$ 0.13	-2.5%	-8%		-$ 5.23	-$ 0.08	1.5%
HST	13%		$ 8.37	-$ 0.22	-2.5%	13%		$ 8.50	$ 0.13	1.5%
Total Bill on TOU (after Tax & Rebate)			**$ 67.63**	**-$ 1.74**	**-2.5%**			**$ 68.64**	**$ 1.01**	**1.5%**
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 35.26	1	$ 35.26	$ 0.85	2.47%	$ 36.76	1	$ 36.76	$ 1.50	4.25%	$ 38.20	1	$ 38.20	$ 1.44	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate		300	$ -	$ -			300	$ -	$ -			300	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		300	$ -	$ -			300	$ -	$ -			300	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 34.24**	**$ 0.85**	**2.55%**			**$ 35.74**	**$ 1.50**	**4.38%**			**$ 37.18**	**$ 1.44**	**4.03%**
Line Losses on Cost of Power	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%	$ 0.0820	9	$ 0.73	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 35.53**	**$ 0.85**	**2.45%**			**$ 36.47**	**$ 0.94**	**2.65%**			**$ 37.91**	**$ 1.44**	**3.95%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%	$ 0.00825	309	$ 2.55	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%	$ 0.00679	309	$ 2.10	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 40.17**	**$ 0.85**	**2.16%**			**$ 41.11**	**$ 0.94**	**2.34%**			**$ 42.55**	**$ 1.44**	**3.50%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%	$ 0.0032	309	$ 0.99	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%	$ 0.0003	309	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%	$ 0.0004	309	$ 0.12	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%	$ 0.0650	195	$ 12.68	$ -	0.00%
TOU - Mid Peak	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%	$ 0.0940	51	$ 4.79	$ -	0.00%
TOU - On Peak	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%	$ 0.1320	54	$ 7.13	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%	$ 0.0770	300	$ 23.10	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 66.22**	**$ 0.85**	**1.3%**			**$ 67.16**	**$ 0.94**	**1.4%**			**$ 68.60**	**$ 1.44**	**2.1%**
8% Provincial Rebate	-8%		-$ 5.30	-$ 0.07	1.3%	-8%		-$ 5.37	-$ 0.08	1.4%	-8%		-$ 5.49	-$ 0.12	2.1%
HST	13%		$ 8.61	$ 0.11	1.3%	13%		$ 8.73	$ 0.12	1.4%	13%		$ 8.92	$ 0.19	2.1%
Total Bill on TOU (after Tax & Rebate)			**$ 69.53**	**$ 0.89**	**1.3%**			**$ 70.52**	**$ 0.99**	**1.4%**			**$ 72.03**	**$ 1.51**	**2.1%**
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

2

Customer Class: COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE

TOU / non-TOU: TOU

Consumption 198 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 26.80	1	$ 26.80	$ 30.58	1	$ 30.58	$ 3.78	14.10%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per 30 days	-$ 0.19	1	-$ 0.19		1	$ -	$ 0.19	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per 30 days	-$ 0.59	1	-$ 0.59		1	$ -	$ 0.59	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per 30 days	$ 0.04	1	$ 0.04	$ 0.04	1	$ 0.04	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per 30 days	$ 0.18	1	$ 0.18	$ 0.18	1	$ 0.18	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.19	1	$ 0.19	$ 0.19	1	$ 0.19	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.09	1	$ 0.09	$ 0.09	1	$ 0.09	$ -	0.00%
Distribution Volumetric Rate	per kWh	$ 0.01627	198	$ 3.22	$ 0.00846	198	$ 1.68	-$ 1.55	-48.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	$ 0.00068	198	$ 0.13	$ 0.00126	198	$ 0.25	$ 0.11	85.29%
Sub-Total A (excluding pass through)				**$ 29.89**			**$ 33.01**	**$ 3.13**	**10.47%**
Line Losses on Cost of Power	per kWh	$ 0.0820	7	$ 0.61	$ 0.0820	7	$ 0.61	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00392	198	-$ 0.78	-$ 0.0005	198	-$ 0.11	$ 0.67	-86%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	198	$ 0.01	$ 0.0000	198	$ 0.01	-$ 0.01	-57%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.29**			**$ 34.08**	**$ 3.79**	**12.51%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00759	205	$ 1.56	$ 0.00796	205	$ 1.64	$ 0.08	4.87%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00617	205	$ 1.27	$ 0.00703	205	$ 1.44	$ 0.18	13.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.12**			**$ 37.16**	**$ 4.04**	**12.21%**
Wholesale Market Service Rate - not including CBR	per kWh	$ 0.0032	205	$ 0.66	$ 0.0032	205	$ 0.66	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	per kWh	$ 0.0003	205	$ 0.06	$ 0.0003	205	$ 0.06	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	205	$ 0.08	$ 0.0004	205	$ 0.08	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	129	$ 8.37	$ 0.0650	129	$ 8.37	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	34	$ 3.16	$ 0.0940	34	$ 3.16	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	36	$ 4.70	$ 0.1320	36	$ 4.70	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	198	$ 15.25	$ 0.0770	198	$ 15.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	0	$ -	$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 50.41**			**$ 54.45**	**$ 4.04**	**8.0%**
8% Provincial Rebate		-8%		-$ 4.03	-8%		-$ 4.36	-$ 0.32	8.0%
HST		13%		$ 6.55	13%		$ 7.08	$ 0.53	8.0%
Total Bill on TOU (after Tax & Rebate)				**$ 52.93**			**$ 57.17**	**$ 4.24**	**8.0%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 33.32	1	$ 33.32	$ 2.74	8.96%	$ 34.41	1	$ 34.41	$ 1.09	3.27%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.06	1	$ 0.06	$ 0.06		$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.34	1	$ 0.34	$ 0.34		$ 0.34	1	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.52	1	-$ 0.52	-$ 0.52		-$ 0.52	1	-$ 0.52	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	-$ 0.08		-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	-$ 0.01		-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.55	1	-$ 0.55	-$ 0.55		-$ 0.55	1	-$ 0.55	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	-$ 0.02		-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.24	1	-$ 0.24	-$ 0.24		-$ 0.24	1	-$ 0.24	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	-$ 0.04			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	-$ 0.01			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	-$ 0.18			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.19			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.09			1	$ -	$ -	
Distribution Volumetric Rate		198	$ -	-$ 1.68			198	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		198	$ -	-$ 0.25			198	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 32.30**	**-$ 0.71**	**-2.16%**			**$ 33.39**	**$ 1.09**	**3.37%**
Line Losses on Cost of Power	$ 0.0820	6	$ 0.48	-$ 0.13	-21.54%	$ 0.0820	6	$ 0.48	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.00045	198	$ 0.09	$ 0.20	-183.33%			$ -	-$ 0.09	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00003	198	-$ 0.01	-$ 0.01	-200.00%			$ -	$ 0.01	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.42**	**-$ 0.66**	**-1.94%**			**$ 34.43**	**$ 1.01**	**3.01%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	204	$ 1.68	$ 0.05	2.83%	$ 0.00825	204	$ 1.68	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	204	$ 1.38	-$ 0.06	-4.17%	$ 0.00679	204	$ 1.38	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 36.49**	**-$ 0.68**	**-1.82%**			**$ 37.49**	**$ 1.01**	**2.76%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	204	$ 0.65	-$ 0.01	-0.78%	$ 0.0032	204	$ 0.65	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	204	$ 0.06	-$ 0.00	-0.78%	$ 0.0003	204	$ 0.06	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	204	$ 0.08	-$ 0.00	-0.78%	$ 0.0004	204	$ 0.08	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%
TOU - Mid Peak	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%
TOU - On Peak	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 53.77**	**-$ 0.68**	**-1.3%**			**$ 54.77**	**$ 1.01**	**1.9%**
8% Provincial Rebate	-8%		-$ 4.30	$ 0.05	-1.3%	-8%		-$ 4.38	-$ 0.08	1.9%
HST	13%		$ 6.99	-$ 0.09	-1.3%	13%		$ 7.12	$ 0.13	1.9%
Total Bill on TOU (after Tax & Rebate)			**$ 56.46**	**-$ 0.72**	**-1.3%**			**$ 57.51**	**$ 1.06**	**1.9%**
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 35.26	1	$ 35.26	$ 0.85	2.47%	$ 36.76	1	$ 36.76	$ 1.50	4.25%	$ 38.20	1	$ 38.20	$ 1.44	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%	$ 0.06	1	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%	$ 0.34	1	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%	-$ 0.52	1	-$ 0.52	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%	-$ 0.08	1	-$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%	-$ 0.01	1	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%	-$ 0.55	1	-$ 0.55	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%	-$ 0.02	1	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%	-$ 0.24	1	-$ 0.24	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate		198	$ -	$ -			198	$ -	$ -			198	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		198	$ -	$ -			198	$ -	$ -			198	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 34.24**	**$ 0.85**	**2.55%**			**$ 35.74**	**$ 1.50**	**4.38%**			**$ 37.18**	**$ 1.44**	**4.03%**
Line Losses on Cost of Power	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%	$ 0.0820	6	$ 0.48	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 35.28**	**$ 0.85**	**2.47%**			**$ 36.22**	**$ 0.94**	**2.66%**			**$ 37.66**	**$ 1.44**	**3.98%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%	$ 0.00825	204	$ 1.68	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%	$ 0.00679	204	$ 1.38	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 38.34**	**$ 0.85**	**2.27%**			**$ 39.28**	**$ 0.94**	**2.45%**			**$ 40.72**	**$ 1.44**	**3.67%**
Wholesale Market Service Rate - not including CBR	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%	$ 0.0032	204	$ 0.65	$ -	0.00%
Rural and Remote Rate Protection Charge (RRRP)	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%	$ 0.0003	204	$ 0.06	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%	$ 0.0004	204	$ 0.08	$ -	0.00%
Standard Supply Service - Administrative Charge (if applicable)	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%	$ 0.0650	129	$ 8.37	$ -	0.00%
TOU - Mid Peak	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%	$ 0.0940	34	$ 3.16	$ -	0.00%
TOU - On Peak	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%	$ 0.1320	36	$ 4.70	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%	$ 0.0770	198	$ 15.25	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 55.62**	**$ 0.85**	**1.6%**			**$ 56.56**	**$ 0.94**	**1.7%**			**$ 58.00**	**$ 1.44**	**2.5%**
8% Provincial Rebate	-8%		-$ 4.45	-$ 0.07	1.6%	-8%		-$ 4.53	-$ 0.08	1.7%	-8%		-$ 4.64	-$ 0.12	2.5%
HST	13%		$ 7.23	$ 0.11	1.6%	13%		$ 7.35	$ 0.12	1.7%	13%		$ 7.54	$ 0.19	2.5%
Total Bill on TOU (after Tax & Rebate)			**$ 58.40**	**$ 0.89**	**1.6%**			**$ 59.39**	**$ 0.99**	**1.7%**			**$ 60.90**	**$ 1.51**	**2.5%**
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,000 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 34.45	1	$ 34.45	$ 35.80	1	$ 35.80	$ 1.35	3.92%	$ 37.23	1	$ 37.23	$ 1.43	3.99%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00010	2,000	$ 0.20	$ 0.20	
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00059	2,000	$ 1.18	$ 1.18	
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per kWh									$ 0.00011	2,000	$ 0.22	$ 0.22	
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days									-$ 0.10	1	-$ 0.10	-$ 0.10	
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00091	2,000	-$ 1.82	-$ 1.82	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00015	2,000	-$ 0.30	-$ 0.30	
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00001	2,000	-$ 0.02	-$ 0.02	
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00002	2,000	-$ 0.04	-$ 0.04	
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00096	2,000	-$ 1.92	-$ 1.92	
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00004	2,000	-$ 0.08	-$ 0.08	
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00042	2,000	-$ 0.84	-$ 0.84	
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kWh									-$ 0.00004	2,000	-$ 0.08	-$ 0.08	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%		1	$ -	-$ 0.79	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%		1	$ -	-$ 0.25	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 1.55	1	$ 1.55	$ 1.55	1	$ 1.55	$ -	0.00%		1	$ -	-$ 1.55	
Distribution Volumetric Rate	per kWh	$ 0.03187	2,000	$ 63.74	$ 0.03312	2,000	$ 66.24	$ 2.50	3.92%	$ 0.03444	2,000	$ 68.88	$ 2.64	3.99%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00051	2,000	-$ 1.02		2,000	$ -	$ 1.02			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00156	2,000	-$ 3.12		2,000	$ -	$ 3.12			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00013	2,000	$ 0.26	$ 0.00013	2,000	$ 0.26	$ -	0.00%		2,000	$ -	-$ 0.26	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00003	2,000	$ 0.06	$ 0.00003	2,000	$ 0.06	$ -	0.00%		2,000	$ -	-$ 0.06	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00049	2,000	$ 0.98	$ 0.00049	2,000	$ 0.98	$ -	0.00%		2,000	$ -	-$ 0.98	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00076	2,000	$ 1.52	$ 0.00076	2,000	$ 1.52	$ -	0.00%		2,000	$ -	-$ 1.52	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00024	2,000	$ 0.48	$ 0.00024	2,000	$ 0.48	$ -	0.00%		2,000	$ -	-$ 0.48	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00019	2,000	-$ 0.38	$ 0.00020	2,000	$ 0.40	$ 0.78	-205.26%		2,000	$ -	-$ 0.40	
Sub-Total A (excluding pass through)				**$ 99.56**			**$ 108.33**	**$ 8.77**	**8.81%**			**$ 102.51**	**-$ 5.82**	**-5.37%**
Line Losses on Cost of Power	per kWh	$ 0.0820	75	$ 6.17	$ 0.0820	75	$ 6.17	$ -	0.00%	$ 0.0820	59	$ 4.84	-$ 1.33	-21.54%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00317	2,000	-$ 6.34	-$ 0.00050	2,000	-$ 1.00	$ 5.34	-84.23%	$ 0.00070	2,000	$ 1.40	$ 2.40	-240.00%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	2,000	$ 0.14	$ 0.00003	2,000	$ 0.06	-$ 0.08	-57.14%	-$ 0.00003	2,000	-$ 0.06	-$ 0.12	-200.00%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 100.09**			**$ 114.12**	**$ 14.03**	**14.02%**			**$ 109.25**	**-$ 4.87**	**-4.27%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00739	2,075	$ 15.34	$ 0.00775	2,075	$ 16.08	$ 0.75	4.87%	$ 0.00803	2,059	$ 16.53	$ 0.45	2.80%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00552	2,075	$ 11.46	$ 0.00629	2,075	$ 13.05	$ 1.60	13.95%	$ 0.00607	2,059	$ 12.50	-$ 0.55	-4.25%
Sub-Total C - Delivery (including Sub-Total B)				**$ 126.88**			**$ 143.25**	**$ 16.37**	**12.91%**			**$ 138.28**	**-$ 4.97**	**-3.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	2,075	$ 6.64	$ 0.0032	2,075	$ 6.64	$ -	0.00%	$ 0.0032	2,059	$ 6.59	-$ 0.05	-0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	2,075	$ 0.62	$ 0.0003	2,075	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ 0.00	-0.78%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	2,075	$ 0.83	$ 0.0004	2,075	$ 0.83			$ 0.0004	2,059	$ 0.82	-$ 0.01	-0.78%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	360	$ 47.52	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	1,400	$ 124.60	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 299.20**			**$ 315.57**	**$ 16.37**	**5.5%**			**$ 310.54**	**-$ 5.04**	**-1.6%**
8% Provincial Rebate		-8%		-$ 23.94	-8%		-$ 25.25	-$ 1.31	5.5%	-8%		-$ 24.84	$ 0.40	-1.6%
HST		13%		$ 38.90	13%		$ 41.02	$ 2.13	5.5%	13%		$ 40.37	-$ 0.65	-1.6%
Total Bill on TOU (after Tax & Rebate)				**$ 314.16**			**$ 331.35**	**$ 17.19**	**5.5%**			**$ 326.07**	**-$ 5.29**	**-1.6%**
Total Bill on RPP (before Taxes)				**$ 306.02**			**$ 322.39**	**$ 16.37**	**5.4%**			**$ 317.36**	**-$ 5.04**	**-1.6%**
8% Provincial Rebate		-8%		-$ 24.48	-8%		-$ 25.79	-$ 1.31	5.4%	-8%		-$ 25.39	$ 0.40	-1.6%
HST		13%		$ 39.78	13%		$ 41.91	$ 2.13	5.4%	13%		$ 41.26	-$ 0.65	-1.6%
Total Bill on RPP (after Tax & Rebate)				**$ 321.32**			**$ 338.51**	**$ 17.19**	**5.4%**			**$ 333.23**	**-$ 5.29**	**-1.6%**
Loss Factor (%)		3.76%			3.76%					2.95%				

	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 38.44	1	$ 38.44	$ 1.21	3.25%	$ 39.39	1	$ 39.39	$ 0.95	2.47%	$ 41.06	1	$ 41.06	$ 1.67	4.24%	$ 42.67	1	$ 42.67	$ 1.61	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%	$ 0.00010	2,000	$ 0.20	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.00059	2,000	$ 1.18	$ -	0.00%	$ 0.00059	2,000	$ 1.18	$ -	0.00%	$ 0.00059	2,000	$ 1.18	$ -	0.00%	$ 0.00059	2,000	$ 1.18	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%	$ 0.00011	2,000	$ 0.22	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%	-$ 0.00091	2,000	-$ 1.82	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%	-$ 0.00015	2,000	-$ 0.30	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%	-$ 0.00001	2,000	-$ 0.02	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%	-$ 0.00002	2,000	-$ 0.04	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%	-$ 0.00096	2,000	-$ 1.92	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%	-$ 0.00042	2,000	-$ 0.84	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%	-$ 0.00004	2,000	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 0.03556	2,000	$ 71.12	$ 2.24	3.25%	$ 0.03643	2,000	$ 72.86	$ 1.74	2.45%	$ 0.03797	2,000	$ 75.94	$ 3.08	4.23%	$ 0.03946	2,000	$ 78.92	$ 2.98	3.92%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 105.96**	**$ 3.45**	**3.37%**			**$ 108.65**	**$ 2.69**	**2.54%**			**$ 113.40**	**$ 4.75**	**4.37%**			**$ 117.99**	**$ 4.59**	**4.05%**
Line Losses on Cost of Power	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%	$ 0.0820	59	$ 4.84	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	-$ 1.40				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ 0.06				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 111.36**	**$ 2.11**	**1.93%**			**$ 114.05**	**$ 2.69**	**2.42%**			**$ 118.24**	**$ 4.19**	**3.67%**			**$ 122.83**	**$ 4.59**	**3.88%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%	$ 0.00803	2,059	$ 16.53	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%	$ 0.00607	2,059	$ 12.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 140.39**	**$ 2.11**	**1.53%**			**$ 143.08**	**$ 2.69**	**1.92%**			**$ 147.27**	**$ 4.19**	**2.93%**			**$ 151.86**	**$ 4.59**	**3.12%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%	$ 0.0032	2,059	$ 6.59	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%	$ 0.0003	2,059	$ 0.62	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%	$ 0.0004	2,059	$ 0.82	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%	$ 0.0940	340	$ 31.96	$ -	0.00%
TOU - On Peak	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%	$ 0.1320	360	$ 47.52	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%	$ 0.0890	1,400	$ 124.60	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 312.65**	**$ 2.11**	**0.7%**			**$ 315.34**	**$ 2.69**	**0.9%**			**$ 319.53**	**$ 4.19**	**1.3%**			**$ 324.12**	**$ 4.59**	**1.4%**
8% Provincial Rebate	-8%		-$ 25.01	-$ 0.17	0.7%	-8%		-$ 25.23	-$ 0.22	0.9%	-8%		-$ 25.56	-$ 0.34	1.3%	-8%		-$ 25.93	-$ 0.37	1.4%
HST	13%		$ 40.64	$ 0.27	0.7%	13%		$ 40.99	$ 0.35	0.9%	13%		$ 41.54	$ 0.54	1.3%	13%		$ 42.14	$ 0.60	1.4%
Total Bill on TOU (after Tax & Rebate)			**$ 328.28**	**$ 2.22**	**0.7%**			**$ 331.11**	**$ 2.82**	**0.9%**			**$ 335.51**	**$ 4.40**	**1.3%**			**$ 340.33**	**$ 4.82**	**1.4%**
Total Bill on RPP (before Taxes)			**$ 319.47**	**$ 2.11**	**0.7%**			**$ 322.16**	**$ 2.69**	**0.8%**			**$ 326.35**	**$ 4.19**	**1.3%**			**$ 330.94**	**$ 4.59**	**1.4%**
8% Provincial Rebate	-8%		-$ 25.56	-$ 0.17	0.7%	-8%		-$ 25.77	-$ 0.22	0.8%	-8%		-$ 26.11	-$ 0.34	1.3%	-8%		-$ 26.48	-$ 0.37	1.4%
HST	13%		$ 41.53	$ 0.27	0.7%	13%		$ 41.88	$ 0.35	0.8%	13%		$ 42.43	$ 0.54	1.3%	13%		$ 43.02	$ 0.60	1.4%
Total Bill on RPP (after Tax & Rebate)			**$ 335.44**	**$ 2.22**	**0.7%**			**$ 338.27**	**$ 2.82**	**0.8%**			**$ 342.67**	**$ 4.40**	**1.3%**			**$ 347.49**	**$ 4.82**	**1.4%**
Loss Factor (%)	2.95%					2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 kW SERVICE

TOU / non-TOU: TOU

Consumption 2,800 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 34.45	1	$ 34.45	$ 35.80	1	$ 35.80	$ 1.35	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh								
Rate Rider for Application of IFRS - CGAAP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh								
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kWh								
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 1.55	1	$ 1.55	$ 1.55	1	$ 1.55	$ -	0.00%
Distribution Volumetric Rate	per kWh	$ 0.03187	2,800	$ 89.24	$ 0.03312	2,800	$ 92.74	$ 3.50	3.92%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00051	2,800	-$ 1.43		2,800	$ -	$ 1.43	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00156	2,800	-$ 4.37		2,800	$ -	$ 4.37	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00013	2,800	$ 0.36	$ 0.00013	2,800	$ 0.36	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00003	2,800	$ 0.08	$ 0.00003	2,800	$ 0.08	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00049	2,800	$ 1.37	$ 0.00049	2,800	$ 1.37	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00076	2,800	$ 2.13	$ 0.00076	2,800	$ 2.13	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00024	2,800	$ 0.67	$ 0.00024	2,800	$ 0.67	$ -	0.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh	-$ 0.00019	2,800	-$ 0.53	$ 0.00020	2,800	$ 0.56	$ 1.09	-205.26%
Sub-Total A (excluding pass through)				**$ 124.57**			**$ 136.31**	**$ 11.74**	**9.42%**
Line Losses on Cost of Power	per kWh	$ 0.0820	105	$ 8.63	$ 0.0820	105	$ 8.63	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00317	2,800	-$ 8.88	-$ 0.00050	2,800	-$ 1.40	$ 7.48	-84.23%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	2,800	$ 0.20	$ 0.00003	2,800	$ 0.08	-$ 0.11	-57.14%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	per 30 days	$ 0.56	1	$ 0.56	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 125.08**			**$ 144.18**	**$ 19.10**	**15.27%**
Retail Transmissioin Rate - Network Service Rate	per kWh	$ 0.00739	2,905	$ 21.47	$ 0.00775	2,905	$ 22.52	$ 1.05	4.87%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kWh	$ 0.00552	2,905	$ 16.04	$ 0.00629	2,905	$ 18.27	$ 2.24	13.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 162.59**			**$ 184.97**	**$ 22.38**	**13.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	2,905	$ 9.30	$ 0.0032	2,905	$ 9.30	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	2,905	$ 0.87	$ 0.0003	2,905	$ 0.87	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	2,905	$ 1.16	$ 0.0004	2,905	$ 1.16		
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	1,820	$ 118.30	$ 0.0650	1,820	$ 118.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	476	$ 44.74	$ 0.0940	476	$ 44.74	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	504	$ 66.53	$ 0.1320	504	$ 66.53	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	600	$ 46.20	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	2,200	$ 195.80	$ 0.0890	2,200	$ 195.80	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 403.74**			**$ 426.12**	**$ 22.38**	**5.5%**
8% Provincial Rebate		-8%		-$ 32.30	-8%		-$ 34.09	-$ 1.79	5.5%
HST		13%		$ 52.49	13%		$ 55.40	$ 2.91	5.5%
Total Bill on TOU (after Tax & Rebate)				**$ 423.93**			**$ 447.43**	**$ 23.50**	**5.5%**
Total Bill on RPP (before Taxes)				**$ 416.17**			**$ 438.55**	**$ 22.38**	**5.4%**
8% Provincial Rebate		-8%		-$ 33.29	-8%		-$ 35.08	-$ 1.79	5.4%
HST		13%		$ 54.10	13%		$ 57.01	$ 2.91	5.4%
Total Bill on RPP (after Tax & Rebate)				**$ 436.98**			**$ 460.48**	**$ 23.50**	**5.4%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	$ 37.23	1	$ 37.23	$ 1.43	3.99%	$ 38.44	1	$ 38.44	$ 1.21	3.25%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.00010	2,800	$ 0.28	$ 0.28		$ 0.00010	2,800	$ 0.28	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.00059	2,800	$ 1.65	$ 1.65		$ 0.00059	2,800	$ 1.65	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.00011	2,800	$ 0.31	$ 0.31		$ 0.00011	2,800	$ 0.31	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.10	1	-$ 0.10	-$ 0.10		-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.00091	2,800	-$ 2.55	-$ 2.55		-$ 0.00091	2,800	-$ 2.55	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.00015	2,800	-$ 0.42	-$ 0.42		-$ 0.00015	2,800	-$ 0.42	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.00001	2,800	-$ 0.03	-$ 0.03		-$ 0.00001	2,800	-$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - CGAAP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.00002	2,800	-$ 0.06	-$ 0.06		-$ 0.00002	2,800	-$ 0.06	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.00096	2,800	-$ 2.69	-$ 2.69		-$ 0.00096	2,800	-$ 2.69	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.00004	2,800	-$ 0.11	-$ 0.11		-$ 0.00004	2,800	-$ 0.11	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.00042	2,800	-$ 1.18	-$ 1.18		-$ 0.00042	2,800	-$ 1.18	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.00004	2,800	-$ 0.11	-$ 0.11		-$ 0.00004	2,800	-$ 0.11	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.79			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.25			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	-$ 1.55			1	$ -	$ -	
Distribution Volumetric Rate	$ 0.03444	2,800	$ 96.43	$ 3.70	3.99%	$ 0.03556	2,800	$ 99.57	$ 3.14	3.25%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,800	$ -	-$ 0.36			2,800	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,800	$ -	-$ 0.08			2,800	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,800	$ -	-$ 1.37			2,800	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,800	$ -	-$ 2.13			2,800	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,800	$ -	-$ 0.67			2,800	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,800	$ -	-$ 0.56			2,800	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 128.66**	**-$ 7.64**	**-5.61%**			**$ 133.01**	**$ 4.35**	**3.38%**
Line Losses on Cost of Power	$ 0.0820	83	$ 6.77	-$ 1.86	-21.54%	$ 0.0820	83	$ 6.77	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.00070	2,800	$ 1.96	$ 3.36	-240.00%			$ -	-$ 1.96	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00003	2,800	-$ 0.08	-$ 0.17	-200.00%			$ -	$ 0.08	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%	$ 0.56	1	$ 0.56	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 137.87**	**-$ 6.31**	**-4.38%**			**$ 140.34**	**$ 2.47**	**1.79%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00803	2,883	$ 23.15	$ 0.63	2.80%	$ 0.00803	2,883	$ 23.15	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00607	2,883	$ 17.50	-$ 0.78	-4.25%	$ 0.00607	2,883	$ 17.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 178.52**	**-$ 6.46**	**-3.49%**			**$ 180.99**	**$ 2.47**	**1.38%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	2,883	$ 9.22	-$ 0.07	-0.78%	$ 0.0032	2,883	$ 9.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	2,883	$ 0.86	-$ 0.01	-0.78%	$ 0.0003	2,883	$ 0.86	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	2,883	$ 1.15	-$ 0.01	-0.78%	$ 0.0004	2,883	$ 1.15	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%
TOU - Mid Peak	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%
TOU - On Peak	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 419.58**	**-$ 6.55**	**-1.5%**			**$ 422.05**	**$ 2.47**	**0.6%**
8% Provincial Rebate	-8%		-$ 33.57	$ 0.52	-1.5%	-8%		-$ 33.76	-$ 0.20	0.6%
HST	13%		$ 54.55	-$ 0.85	-1.5%	13%		$ 54.87	$ 0.32	0.6%
Total Bill on TOU (after Tax & Rebate)			**$ 440.56**	-$ 6.87	-1.5%			**$ 443.15**	$ 2.59	0.6%
Total Bill on RPP (before Taxes)			**$ 432.01**	**-$ 6.55**	**-1.5%**			**$ 434.48**	**$ 2.47**	**0.6%**
8% Provincial Rebate	-8%		-$ 34.56	$ 0.52	-1.5%	-8%		-$ 34.76	-$ 0.20	0.6%
HST	13%		$ 56.16	-$ 0.85	-1.5%	13%		$ 56.48	$ 0.32	0.6%
Total Bill on RPP (after Tax & Rebate)			**$ 453.61**	-$ 6.87	-1.5%			**$ 456.20**	$ 2.59	0.6%
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Service Charge	$ 39.39	1	$ 39.39	$ 0.95	2.47%	$ 41.06	1	$ 41.06	$ 1.67	4.24%	$ 42.67	1	$ 42.67	$ 1.61	3.92%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%	$ 0.00010	2,800	$ 0.28	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.00059	2,800	$ 1.65	$ -	0.00%	$ 0.00059	2,800	$ 1.65	$ -	0.00%	$ 0.00059	2,800	$ 1.65	$ -	0.00%
Rate Rider for Recovery of Monthly Billing - effective until Dec. 31, 2024	$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%	$ 0.00011	2,800	$ 0.31	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%	-$ 0.10	1	-$ 0.10	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.00091	2,800	-$ 2.55	$ -	0.00%	-$ 0.00091	2,800	-$ 2.55	$ -	0.00%	-$ 0.00091	2,800	-$ 2.55	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%	-$ 0.00015	2,800	-$ 0.42	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%	-$ 0.00001	2,800	-$ 0.03	$ -	0.00%
Rate Rider for Application of IFRS - CGAAP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%	-$ 0.00002	2,800	-$ 0.06	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.00096	2,800	-$ 2.69	$ -	0.00%	-$ 0.00096	2,800	-$ 2.69	$ -	0.00%	-$ 0.00096	2,800	-$ 2.69	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.00042	2,800	-$ 1.18	$ -	0.00%	-$ 0.00042	2,800	-$ 1.18	$ -	0.00%	-$ 0.00042	2,800	-$ 1.18	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%	-$ 0.00004	2,800	-$ 0.11	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 0.03643	2,800	$ 102.00	$ 2.44	2.45%	$ 0.03797	2,800	$ 106.32	$ 4.31	4.23%	$ 0.03946	2,800	$ 110.49	$ 4.17	3.92%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,800	$ -	$ -			2,800	$ -	$ -			2,800	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 136.39**	**$ 3.39**	**2.55%**			**$ 142.38**	**$ 5.98**	**4.39%**			**$ 148.16**	**$ 5.78**	**4.06%**
Line Losses on Cost of Power	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%	$ 0.0820	83	$ 6.77	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Smart Metering Entity Charge - effective until Dec. 31, 2022	$ 0.56	1	$ 0.56	$ -	0.00%			$ -	-$ 0.56				$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 143.73**	**$ 3.39**	**2.41%**			**$ 149.15**	**$ 5.42**	**3.77%**			**$ 154.93**	**$ 5.78**	**3.88%**
Retail Transmissioin Rate - Network Service Rate	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%	$ 0.00803	2,883	$ 23.15	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%	$ 0.00607	2,883	$ 17.50	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 184.37**	**$ 3.39**	**1.87%**			**$ 189.79**	**$ 5.42**	**2.94%**			**$ 195.58**	**$ 5.78**	**3.05%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%	$ 0.0032	2,883	$ 9.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%	$ 0.0003	2,883	$ 0.86	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%	$ 0.0004	2,883	$ 1.15	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%	$ 0.0650	1,820	$ 118.30	$ -	0.00%
TOU - Mid Peak	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%	$ 0.0940	476	$ 44.74	$ -	0.00%
TOU - On Peak	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%	$ 0.1320	504	$ 66.53	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%	$ 0.0770	600	$ 46.20	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%	$ 0.0890	2,200	$ 195.80	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -		$ 0.1164		$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 425.44**	**$ 3.39**	**0.8%**			**$ 430.86**	**$ 5.42**	**1.3%**			**$ 436.64**	**$ 5.78**	**1.3%**
8% Provincial Rebate	-8%		-$ 34.03	-$ 0.27	0.8%	-8%		-$ 34.47	-$ 0.43	1.3%	-8%		-$ 34.93	-$ 0.46	1.3%
HST	13%		$ 55.31	$ 0.44	0.8%	13%		$ 56.01	$ 0.70	1.3%	13%		$ 56.76	$ 0.75	1.3%
Total Bill on TOU (after Tax & Rebate)			**$ 446.71**	$ 3.56	0.8%			**$ 452.40**	$ 5.69	1.3%			**$ 458.47**	$ 6.07	1.3%
Total Bill on RPP (before Taxes)			**$ 437.86**	**$ 3.39**	**0.8%**			**$ 443.29**	**$ 5.42**	**1.2%**			**$ 449.07**	**$ 5.78**	**1.3%**
8% Provincial Rebate	-8%		-$ 35.03	-$ 0.27	0.8%	-8%		-$ 35.46	-$ 0.43	1.2%	-8%		-$ 35.93	-$ 0.46	1.3%
HST	13%		$ 56.92	$ 0.44	0.8%	13%		$ 57.63	$ 0.70	1.2%	13%		$ 58.38	$ 0.75	1.3%
Total Bill on RPP (after Tax & Rebate)			**$ 459.76**	$ 3.56	0.8%			**$ 465.45**	$ 5.69	1.2%			**$ 471.52**	$ 6.07	1.3%
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 999 kW SERVICE

TOU / non-TOU: non-TOU SPOT Class B

	180	kW
	200	kVA ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption	79,000	kWh

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 49.55	1	$ 49.55	$ 51.50	1	$ 51.50	$ 1.95	3.94%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	per 30 days								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA								
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 1.01	1	$ 1.01	$ 1.01	1	$ 1.01	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.30	1	$ 0.30	$ 0.30	1	$ 0.30	$ -	0.00%
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.	per 30 days	$ 4.64	1	$ 4.64	$ 4.64	1	$ 4.64	$ -	0.00%
Distribution Volumetric Rate	per kVA	$ 7.7987	200	$ 1,559.74	$ 8.1052	200	$ 1,621.04	$ 61.30	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0814	200	-$ 16.28		200	$ -	$ 16.28	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2512	200	-$ 50.24		200	$ -	$ 50.24	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0114	200	$ 2.28	$ 0.0114	200	$ 2.28	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0047	200	$ 0.94	$ 0.0047	200	$ 0.94	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0781	200	$ 15.62	$ 0.0781	200	$ 15.62	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1659	200	$ 33.18	$ 0.1659	200	$ 33.18	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0498	200	$ 9.96	$ 0.0498	200	$ 9.96	$ -	0.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.0912	200	$ 18.24	$ 0.1948	200	$ 38.96	$ 20.72	113.60%
Sub-Total A (excluding pass through)				**$ 1,628.94**			**$ 1,779.43**	**$ 150.49**	**9.24%**
Line Losses on Cost of Power	per kWh	$ 0.1164	2,970	$ 345.75	$ 0.1164	2,970	$ 345.75	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.7597	200	-$ 151.94	$ 0.2813	200	$ 56.26	$ 208.20	-137.03%
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5191	200	-$ 103.82	-$ 0.4734	200	-$ 94.68	$ 9.14	-8.80%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0277	200	$ 5.54	$ 0.0105	200	$ 2.10	-$ 3.44	-62.09%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112	79,000	-$ 88.48	$ 0.00068	79,000	$ 53.72	$ 142.20	-160.71%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,635.99**			**$ 2,142.58**	**$ 506.59**	**30.97%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.5690	180	$ 462.42	$ 2.6576	180	$ 478.37	$ 15.95	3.45%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0515	180	$ 369.27	$ 2.3054	180	$ 414.97	$ 45.70	12.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,467.68**			**$ 3,035.92**	**$ 568.24**	**23.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	81,970	$ 262.31	$ 0.0032	81,970	$ 262.31	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	81,970	$ 24.59	$ 0.0003	81,970	$ 24.59	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	81,970	$ 32.79	$ 0.0004	81,970	$ 32.79	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	50,560	$ 3,286.40	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	14,220	$ 1,336.68	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	14,220	$ 1,877.04	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	78,250	$ 6,964.25	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	79,000	$ 9,195.60	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 11,983.22**			**$ 12,551.46**	**$ 568.24**	**4.7%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 1,557.82	13%		$ 1,631.69	$ 73.87	4.7%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 13,541.04**			**$ 14,183.15**	**$ 642.11**	**4.7%**
Total Bill on RPP (before Taxes)				**$ 9,809.62**			**$ 10,377.86**	**$ 568.24**	**5.8%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 1,275.25	13%		$ 1,349.12	$ 73.87	5.8%
Total Bill on RPP (after Tax and Rebate)				**$ 11,084.87**			**$ 11,726.98**	**$ 642.11**	**5.8%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 52.19	1	$ 52.19	$ 0.69	1.34%	$ 53.89	1	$ 53.89	$ 1.70	3.26%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0173	200	$ 3.46	$ 3.46		$ 0.0173	200	$ 3.46	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.1030	200	$ 20.60	$ 20.60		$ 0.1030	200	$ 20.60	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	-$ 0.37		-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.1574	200	-$ 31.48	-$ 31.48		-$ 0.1574	200	-$ 31.48	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0252	200	-$ 5.04	-$ 5.04		-$ 0.0252	200	-$ 5.04	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0009	200	-$ 0.18	-$ 0.18		-$ 0.0009	200	-$ 0.18	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0033	200	-$ 0.66	-$ 0.66		-$ 0.0033	200	-$ 0.66	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1669	200	-$ 33.38	-$ 33.38		-$ 0.1669	200	-$ 33.38	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0068	200	-$ 1.36	-$ 1.36		-$ 0.0068	200	-$ 1.36	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0738	200	-$ 14.76	-$ 14.76		-$ 0.0738	200	-$ 14.76	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0404	200	-$ 8.08	-$ 8.08		-$ 0.0404	200	-$ 8.08	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.0004	200	-$ 0.08	-$ 0.08		-$ 0.0004	200	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 1.01			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 0.30			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	-$ 4.64			1	$ -	$ -	
Distribution Volumetric Rate	$ 8.37240	200	$ 1,674.48	$ 53.44	3.30%	$ 8.6453	200	$ 1,729.06	$ 54.58	3.26%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		200	$ -	-$ 2.28			200	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		200	$ -	-$ 0.94			200	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		200	$ -	-$ 15.62			200	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		200	$ -	-$ 33.18			200	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		200	$ -	-$ 9.96			200	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		200	$ -	-$ 38.96			200	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 1,655.34**	**-$ 124.09**	**-6.97%**			**$ 1,711.62**	**$ 56.28**	**3.40%**
Line Losses on Cost of Power	$ 0.1164	2,331	$ 271.27	-$ 74.48	-21.54%	$ 0.1164	2,331	$ 271.27	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.44260	200	$ 88.52	$ 32.26	57.34%			$ -	-$ 88.52	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	-$ 0.16340	200	-$ 32.68	$ 62.00	-65.48%			$ -	$ 32.68	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.01230	200	-$ 2.46	-$ 4.56	-217.14%				$ 2.46	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290	79,000	-$ 229.10	-$ 282.82	-526.47%				$ 229.10	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,750.89**	**-$ 391.69**	**-18.28%**			**$ 1,982.89**	**$ 232.00**	**13.25%**
Retail Transmissioin Rate - Network Service Rate	$ 2.7525	180	$ 495.45	$ 17.08	3.57%	$ 2.7525	180	$ 495.45	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.2259	180	$ 400.66	-$ 14.31	-3.45%	$ 2.2259	180	$ 400.66	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,647.00**	**-$ 388.92**	**-12.81%**			**$ 2,879.00**	**$ 232.00**	**8.76%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	81,331	$ 260.26	-$ 2.05	-0.78%	$ 0.0032	81,331	$ 260.26	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	81,331	$ 24.40	-$ 0.19	-0.78%	$ 0.0003	81,331	$ 24.40	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	81,331	$ 32.53	-$ 0.26	-0.78%	$ 0.0004	81,331	$ 32.53	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%
TOU - Mid Peak	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%
TOU - On Peak	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 12,160.04**	**-$ 391.42**	**-3.1%**			**$ 12,392.04**	**$ 232.00**	**1.9%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 1,580.81	-$ 50.88	-3.1%	13%		$ 1,610.97	$ 30.16	1.9%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 13,740.85**	**-$ 442.30**	**-3.1%**			**$ 14,003.01**	**$ 262.16**	**1.9%**
Total Bill on RPP (before Taxes)			**$ 9,986.44**	**-$ 391.42**	**-3.8%**			**$ 10,218.44**	**$ 232.00**	**2.3%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 1,298.24	-$ 50.88	-3.8%	13%		$ 1,328.40	$ 30.16	2.3%
Total Bill on RPP (after Tax and Rebate)			**$ 11,284.68**	**-$ 442.30**	**-3.8%**			**$ 11,546.84**	**$ 262.16**	**2.3%**
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 55.22	1	$ 55.22	$ 1.33	2.47%	$ 57.56	1	$ 57.56	$ 2.34	4.24%	$ 59.82	1	$ 59.82	$ 2.26	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0173	200	$ 3.46	$ -	0.00%	$ 0.0173	200	$ 3.46	$ -	0.00%	$ 0.0173	200	$ 3.46	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.1030	200	$ 20.60	$ -	0.00%	$ 0.1030	200	$ 20.60	$ -	0.00%	$ 0.1030	200	$ 20.60	$ -	0.00%
Rate Rider for Recovery of Stranded Meter Assets - effective until Dec. 31, 2024	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%	-$ 0.37	1	-$ 0.37	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.1574	200	-$ 31.48	$ -	0.00%	-$ 0.1574	200	-$ 31.48	$ -	0.00%	-$ 0.1574	200	-$ 31.48	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0252	200	-$ 5.04	$ -	0.00%	-$ 0.0252	200	-$ 5.04	$ -	0.00%	-$ 0.0252	200	-$ 5.04	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%	-$ 0.0009	200	-$ 0.18	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%	-$ 0.0033	200	-$ 0.66	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1669	200	-$ 33.38	$ -	0.00%	-$ 0.1669	200	-$ 33.38	$ -	0.00%	-$ 0.1669	200	-$ 33.38	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0068	200	-$ 1.36	$ -	0.00%	-$ 0.0068	200	-$ 1.36	$ -	0.00%	-$ 0.0068	200	-$ 1.36	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0738	200	-$ 14.76	$ -	0.00%	-$ 0.0738	200	-$ 14.76	$ -	0.00%	-$ 0.0738	200	-$ 14.76	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0404	200	-$ 8.08	$ -	0.00%	-$ 0.0404	200	-$ 8.08	$ -	0.00%	-$ 0.0404	200	-$ 8.08	$ -	0.00%
Rate Rider for Disposition of AR Credits - effective until Dec. 31, 2024	-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%	-$ 0.0004	200	-$ 0.08	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of Stranded Meters Assets - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 8.85800	200	$ 1,771.60	$ 42.54	2.46%	$ 9.23360	200	$ 1,846.72	$ 75.12	4.24%	$ 9.59650	200	$ 1,919.30	$ 72.58	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		200	$ -	$ -			200	$ -	$ -			200	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 1,755.49**	**$ 43.87**	**2.56%**			**$ 1,832.95**	**$ 77.46**	**4.41%**			**$ 1,907.79**	**$ 74.84**	**4.08%**
Line Losses on Cost of Power	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%	$ 0.1164	2,331	$ 271.27	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants			$ -	$ -				$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers				$ -					$ -					$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -					$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,026.76**	**$ 43.87**	**2.21%**			**$ 2,104.22**	**$ 77.46**	**3.82%**			**$ 2,179.06**	**$ 74.84**	**3.56%**
Retail Transmissioin Rate - Network Service Rate	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%	$ 2.7525	180	$ 495.45	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%	$ 2.2259	180	$ 400.66	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,922.87**	**$ 43.87**	**1.52%**			**$ 3,000.33**	**$ 77.46**	**2.65%**			**$ 3,075.17**	**$ 74.84**	**2.49%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%	$ 0.0032	81,331	$ 260.26	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%	$ 0.0003	81,331	$ 24.40	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%	$ 0.0004	81,331	$ 32.53	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%	$ 0.0650	50,560	$ 3,286.40	$ -	0.00%
TOU - Mid Peak	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%	$ 0.0940	14,220	$ 1,336.68	$ -	0.00%
TOU - On Peak	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%	$ 0.1320	14,220	$ 1,877.04	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%	$ 0.0890	78,250	$ 6,964.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%	$ 0.1164	79,000	$ 9,195.60	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 12,435.91**	**$ 43.87**	**0.4%**			**$ 12,513.37**	**$ 77.46**	**0.6%**			**$ 12,588.21**	**$ 74.84**	**0.6%**
8% Provincial Rebate	-8%			$ -		-8%			$ -		-8%			$ -	
HST	13%		$ 1,616.67	$ 5.70	0.4%	13%		$ 1,626.74	$ 10.07	0.6%	13%		$ 1,636.47	$ 9.73	0.6%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 14,052.58**	**$ 49.57**	**0.4%**			**$ 14,140.11**	**$ 87.53**	**0.6%**			**$ 14,224.68**	**$ 84.57**	**0.6%**
Total Bill on RPP (before Taxes)			**$ 10,262.31**	**$ 43.87**	**0.4%**			**$ 10,339.77**	**$ 77.46**	**0.8%**			**$ 10,414.61**	**$ 74.84**	**0.7%**
8% Provincial Rebate	-8%			$ -		-8%			$ -		-8%			$ -	
HST	13%		$ 1,334.10	$ 5.70	0.4%	13%		$ 1,344.17	$ 10.07	0.8%	13%		$ 1,353.90	$ 9.73	0.7%
Total Bill on RPP (after Tax and Rebate)			**$ 11,596.41**	**$ 49.57**	**0.4%**			**$ 11,683.94**	**$ 87.53**	**0.8%**			**$ 11,768.51**	**$ 84.57**	**0.7%**
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU SPOT Class A Non-WMP

Consumption
1,800 kW
2,000 kVA ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
900,000 kWh

		2018 Current Board-Approved			2019 Current Board-Approved			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	per 30 days	$ 946.52	1	$ 946.52	$ 983.72	1	$ 983.72	$ 37.20	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 202	per kVA								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 3	per kVA								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31,	per kVA								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 18.89	1	$ 18.89	$ 18.89	1	$ 18.89	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 5.48	1	$ 5.48	$ 5.48	1	$ 5.48	$ -	0.00%
Distribution Volumetric Rate	per kVA	$ 6.1355	2,000	$ 12,271.00	$ 6.3766	2,000	$ 12,753.20	$ 482.20	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0653	2,000	-$ 130.60		2,000	$ -	$ 130.60	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2017	2,000	-$ 403.40		2,000	$ -	$ 403.40	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0056	2,000	$ 11.20	$ 0.0056	2,000	$ 11.20	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0038	2,000	$ 7.60	$ 0.0038	2,000	$ 7.60	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0627	2,000	$ 125.40	$ 0.0627	2,000	$ 125.40	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1226	2,000	$ 245.20	$ 0.1226	2,000	$ 245.20	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0356	2,000	$ 71.20	$ 0.0356	2,000	$ 71.20	$ -	0.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effe	per kVA	$ 0.1051	2,000	$ 210.20	$ 0.1251	2,000	$ 250.20	$ 40.00	19.03%
Sub-Total A (excluding pass through)				**$ 13,378.69**			**$ 14,472.09**	**$ 1,093.40**	**8.17%**
Line Losses on Cost of Power	per kWh	$ 0.1164	33,840	$ 3,938.98	$ 0.1164	33,840	$ 3,938.98	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.8339	2,000	-$ 1,667.80	-$ 0.2186	2,000	-$ 437.20	$ 1,230.60	-73.79%
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5704	2,000	-$ 1,140.80		2,000	$ -	$ 1,140.80	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0295		$ -	$ 0.0114		$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 14,509.07**			**$ 17,973.87**	**$ 3,464.80**	**23.88%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.4821	1,800	$ 4,467.78	$ 2.5677	1,800	$ 4,621.86	$ 154.08	3.45%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0494	1,800	$ 3,688.92	$ 2.30300	1,800	$ 4,145.40	$ 456.48	12.37%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22,665.77**			**$ 26,741.13**	**$ 4,075.36**	**17.98%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	933,840	$ 2,988.29	$ 0.0032	933,840	$ 2,988.29	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	933,840	$ 280.15	$ 0.0003	933,840	$ 280.15	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004		$ -	$ 0.0004		$ -	$ -	
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	576,000	$ 37,440.00	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	162,000	$ 15,228.00	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	162,000	$ 21,384.00	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	899,250	$ 80,033.25	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	900,000	$ 104,760.00	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 130,694.46**			**$ 134,769.82**	**$ 4,075.36**	**3.1%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 16,990.28	13%		$ 17,520.08	$ 529.80	3.1%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 147,684.74**			**$ 152,289.89**	**$ 4,605.16**	**3.1%**
Total Bill on RPP (before Taxes)				**$ 106,025.46**			**$ 110,100.82**	**$ 4,075.36**	**3.8%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 13,783.31	13%		$ 14,313.11	$ 529.80	3.8%
Total Bill on RPP (after Tax and Rebate)				**$ 119,808.77**			**$ 124,413.92**	**$ 4,605.16**	**3.8%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed			Impact		2021 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	$ 944.07	1	$ 944.07	-$ 39.65	-4.03%	$ 974.85	1	$ 974.85	$ 30.78	3.26%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 202	$ 0.0130	2,000	$ 26.00	$ 26.00		$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0776	2,000	$ 155.20	$ 155.20		$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 3	-$ 0.1186	2,000	-$ 237.20	-$ 237.20		-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0190	2,000	-$ 38.00	-$ 38.00		-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	2,000	-$ 0.80	-$ 0.80		-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0025	2,000	-$ 5.00	-$ 5.00		-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31,	-$ 0.1258	2,000	-$ 251.60	-$ 251.60		-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0051	2,000	-$ 10.20	-$ 10.20		-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0557	2,000	-$ 111.40	-$ 111.40		-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0305	2,000	-$ 61.00	-$ 61.00		-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 18.89			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 5.48			1	$ -	$ -	
Distribution Volumetric Rate	$ 6.6390	2,000	$ 13,278.00	$ 524.80	4.12%	$ 6.8554	2,000	$ 13,710.80	$ 432.80	3.26%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	-$ 11.20			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	-$ 7.60			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	-$ 125.40			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	-$ 245.20			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	-$ 71.20			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effe		2,000	$ -	-$ 250.20			2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 13,688.07**	**-$ 784.02**	**-5.42%**			**$ 14,151.65**	**$ 463.58**	**3.39%**
Line Losses on Cost of Power	$ 0.1164	26,550	$ 3,090.42	-$ 848.56	-21.54%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.50370	2,000	$ 1,007.40	$ 1,444.60	-330.42%			$ -	-$ 1,007.40	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	-$ 0.18640	2,000	-$ 372.80	-$ 372.80				$ -	$ 372.80	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.01180		$ -	$ -					$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290		$ -	$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 17,413.09**	**-$ 560.78**	**-3.12%**			**$ 17,242.07**	**-$ 171.02**	**-0.98%**
Retail Transmissioin Rate - Network Service Rate	$ 2.6594	1,800	$ 4,786.92	$ 165.06	3.57%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.2236	1,800	$ 4,002.48	-$ 142.92	-3.45%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 26,202.49**	**-$ 538.64**	**-2.01%**			**$ 26,031.47**	**-$ 171.02**	**-0.65%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	926,550	$ 2,964.96	-$ 23.33	-0.78%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	926,550	$ 277.97	-$ 2.19	-0.78%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 134,205.67**	**-$ 564.15**	**-0.4%**			**$ 134,034.65**	**-$ 171.02**	**-0.1%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 17,446.74	-$ 73.34	-0.4%	13%		$ 17,424.50	-$ 22.23	-0.1%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 151,652.40**	-$ 637.49	-0.4%			**$ 151,459.15**	-$ 193.25	-0.1%
Total Bill on RPP (before Taxes)			**$ 109,536.67**	**-$ 564.15**	**-0.5%**			**$ 109,365.65**	**-$ 171.02**	**-0.2%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 14,239.77	-$ 73.34	-0.5%	13%		$ 14,217.53	-$ 22.23	-0.2%
Total Bill on RPP (after Tax and Rebate)			**$ 123,776.43**	-$ 637.49	-0.5%			**$ 123,583.18**	-$ 193.25	-0.2%
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed			Impact		2023 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	$ 998.83	1	$ 998.83	$ 23.98	2.46%	$ 1,041.18	1	$ 1,041.18	$ 42.35	4.24%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 202	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 3	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31,	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 7.02400	2,000	$ 14,048.00	$ 337.20	2.46%	$ 7.32180	2,000	$ 14,643.60	$ 595.60	4.24%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effe		2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 14,512.83**	**$ 361.18**	**2.55%**			**$ 15,150.78**	**$ 637.95**	**4.40%**
Line Losses on Cost of Power	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants			$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers				$ -					$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 17,603.25**	**$ 361.18**	**2.09%**			**$ 18,241.20**	**$ 637.95**	**3.62%**
Retail Transmissioin Rate - Network Service Rate	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 26,392.65**	**$ 361.18**	**1.39%**			**$ 27,030.60**	**$ 637.95**	**2.42%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004		$ -	$ -		$ 0.0004		$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 134,395.83**	**$ 361.18**	**0.3%**			**$ 135,033.78**	**$ 637.95**	**0.5%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 17,471.46	$ 46.95	0.3%	13%		$ 17,554.39	$ 82.93	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 151,867.28**	$ 408.13	0.3%			**$ 152,588.17**	$ 720.88	0.5%
Total Bill on RPP (before Taxes)			**$ 109,726.83**	**$ 361.18**	**0.3%**			**$ 110,364.78**	**$ 637.95**	**0.6%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 14,264.49	$ 46.95	0.3%	13%		$ 14,347.42	$ 82.93	0.6%
Total Bill on RPP (after Tax and Rebate)			**$ 123,991.31**	$ 408.13	0.3%			**$ 124,712.20**	$ 720.88	0.6%
Loss Factor (%)	2.95%					2.95%				

	2024 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge	$ 1,082.10	1	$ 1,082.10	$ 40.92	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 202	$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 3	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31,	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -	
Distribution Volumetric Rate	$ 7.6095	2,000	$ 15,219.00	$ 575.40	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effe		2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 15,767.10**	**$ 616.32**	**4.07%**
Line Losses on Cost of Power	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants			$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers				$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18,857.52**	**$ 616.32**	**3.38%**
Retail Transmissioin Rate - Network Service Rate	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 27,646.92**	**$ 616.32**	**2.28%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004		$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 135,650.10**	**$ 616.32**	**0.5%**
8% Provincial Rebate	-8%			$ -	
HST	13%		$ 17,634.51	$ 80.12	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 153,284.61**	$ 696.44	0.5%
Total Bill on RPP (before Taxes)			**$ 110,981.10**	**$ 616.32**	**0.6%**
8% Provincial Rebate	-8%			$ -	
HST	13%		$ 14,427.54	$ 80.12	0.6%
Total Bill on RPP (after Tax and Rebate)			**$ 125,408.64**	$ 696.44	0.6%
Loss Factor (%)	2.95%				

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 1,000 TO 4,999 kW SERVICE

TOU / non-TOU: non-TOU SPOT B

1,800 kW
2,000 kVA ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption 900,000 kWh

	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 946.52	1	$ 946.52	$ 983.72	1	$ 983.72	$ 37.20	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 18.89	1	$ 18.89	$ 18.89	1	$ 18.89	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 5.48	1	$ 5.48	$ 5.48	1	$ 5.48	$ -	0.00%
Distribution Volumetric Rate	per kVA	$ 6.1355	2,000	$ 12,271.00	$ 6.37660	2,000	$ 12,753.20	$ 482.20	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0653	2,000	-$ 130.60		2,000	$ -	$ 130.60	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2017	2,000	-$ 403.40		2,000	$ -	$ 403.40	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0056	2,000	$ 11.20	$ 0.0056	2,000	$ 11.20	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0038	2,000	$ 7.60	$ 0.0038	2,000	$ 7.60	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0627	2,000	$ 125.40	$ 0.0627	2,000	$ 125.40	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1226	2,000	$ 245.20	$ 0.1226	2,000	$ 245.20	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0356	2,000	$ 71.20	$ 0.0356	2,000	$ 71.20	$ -	0.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.1051	2,000	$ 210.20	$ 0.1251	2,000	$ 250.20	$ 40.00	19.03%
Sub-Total A (excluding pass through)				**$ 13,378.69**			**$ 14,472.09**	**$ 1,093.40**	**8.17%**
Line Losses on Cost of Power	per kWh	$ 0.1164	33,840	$ 3,938.98	$ 0.1164	33,840	$ 3,938.98	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.8339	2,000	-$ 1,667.80	-$ 0.2186	2,000	-$ 437.20	$ 1,230.60	-73.79%
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5704	2,000	-$ 1,140.80		2,000	$ -	$ 1,140.80	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0295	2,000	$ 59.00	$ 0.0114	2,000	$ 22.80	-$ 36.20	-61.36%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112	900,000	-$ 1,008.00	$ 0.00068	900,000	$ 612.00	$ 1,620.00	-160.71%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 13,560.07**			**$ 18,608.67**	**$ 5,048.60**	**37.23%**
Retail Transmission Rate - Network Service Rate	per kW	$ 2.4821	1,800	$ 4,467.78	$ 2.5677	1,800	$ 4,621.86	$ 154.08	3.45%
Retail Transmission Rate - Line and Transformation Connection Service Rate	per kW	$ 2.0494	1,800	$ 3,688.92	$ 2.3030	1,800	$ 4,145.40	$ 456.48	12.37%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21,716.77**			**$ 27,375.93**	**$ 5,659.16**	**26.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	933,840	$ 2,988.29	$ 0.0032	933,840	$ 2,988.29	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	933,840	$ 280.15	$ 0.0003	933,840	$ 280.15	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	933,840	$ 373.54	$ 0.0004	933,840	$ 373.54	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	576,000	$ 37,440.00	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	162,000	$ 15,228.00	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	162,000	$ 21,384.00	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	899,250	$ 80,033.25	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	900,000	$ 104,760.00	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 130,118.99**			**$ 135,778.15**	**$ 5,659.16**	**4.3%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 16,915.47	13%		$ 17,651.16	$ 735.69	4.3%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 147,034.46**			**$ 153,429.31**	**$ 6,394.85**	**4.3%**
Total Bill on RPP (before Taxes)				**$ 105,449.99**			**$ 111,109.15**	**$ 5,659.16**	**5.4%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 13,708.50	13%		$ 14,444.19	$ 735.69	5.4%
Total Bill on RPP (after Tax and Rebate)				**$ 119,158.49**			**$ 125,553.34**	**$ 6,394.85**	**5.4%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 944.07	1	$ 944.07	-$ 39.65	-4.03%	$ 974.85	1	$ 974.85	$ 30.78	3.26%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0130	2,000	$ 26.00	$ 26.00		$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0776	2,000	$ 155.20	$ 155.20		$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.1186	2,000	-$ 237.20	-$ 237.20		-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0190	2,000	-$ 38.00	-$ 38.00		-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	2,000	-$ 0.80	-$ 0.80		-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0025	2,000	-$ 5.00	-$ 5.00		-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1258	2,000	-$ 251.60	-$ 251.60		-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0051	2,000	-$ 10.20	-$ 10.20		-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0557	2,000	-$ 111.40	-$ 111.40		-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0305	2,000	-$ 61.00	-$ 61.00		-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 18.89			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 5.48			1	$ -	$ -	
Distribution Volumetric Rate	$ 6.6390	2,000	$ 13,278.00	$ 524.80	4.12%	$ 6.8554	2,000	$ 13,710.80	$ 432.80	3.26%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	-$ 11.20			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	-$ 7.60			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	-$ 125.40			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	-$ 245.20			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	-$ 71.20			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,000	$ -	-$ 250.20			2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 13,688.07**	**-$ 784.02**	**-5.42%**			**$ 14,151.65**	**$ 463.58**	**3.39%**
Line Losses on Cost of Power	$ 0.1164	26,550	$ 3,090.42	-$ 848.56	-21.54%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.50370	2,000	$ 1,007.40	$ 1,444.60	-330.42%			$ -	-$ 1,007.40	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	-$ 0.18640	2,000	-$ 372.80	-$ 372.80				$ -	$ 372.80	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.01180	2,000	-$ 23.60	-$ 46.40	-203.51%				$ 23.60	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290	900,000	-$ 2,610.00	-$ 3,222.00	-526.47%				$ 2,610.00	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 14,779.49**	**-$ 3,829.18**	**-20.58%**			**$ 17,242.07**	**$ 2,462.58**	**16.66%**
Retail Transmission Rate - Network Service Rate	$ 2.6594	1,800	$ 4,786.92	$ 165.06	3.57%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	$ 2.2236	1,800	$ 4,002.48	-$ 142.92	-3.45%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 23,568.89**	**-$ 3,807.04**	**-13.91%**			**$ 26,031.47**	**$ 2,462.58**	**10.45%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	926,550	$ 2,964.96	-$ 23.33	-0.78%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	926,550	$ 277.97	-$ 2.19	-0.78%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	926,550	$ 370.62	-$ 2.92	-0.78%	$ 0.0004	926,550	$ 370.62	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 131,942.69**	**-$ 3,835.47**	**-2.8%**			**$ 134,405.27**	**$ 2,462.58**	**1.9%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 17,152.55	-$ 498.61	-2.8%	13%		$ 17,472.68	$ 320.14	1.9%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 149,095.23**	-$ 4,334.08	-2.8%			**$ 151,877.95**	$ 2,782.72	1.9%
Total Bill on RPP (before Taxes)			**$ 107,273.69**	**-$ 3,835.47**	**-3.5%**			**$ 109,736.27**	**$ 2,462.58**	**2.3%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 13,945.58	-$ 498.61	-3.5%	13%		$ 14,265.71	$ 320.14	2.3%
Total Bill on RPP (after Tax and Rebate)			**$ 121,219.26**	-$ 4,334.08	-3.5%			**$ 124,001.98**	$ 2,782.72	2.3%
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 998.83	1	$ 998.83	$ 23.98	2.46%	$ 1,041.18	1	$ 1,041.18	$ 42.35	4.24%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0130	2,000	$ 26.00	$ -	0.00%	$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0776	2,000	$ 155.20	$ -	0.00%	$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 7.02400	2,000	$ 14,048.00	$ 337.20	2.46%	$ 7.32180	2,000	$ 14,643.60	$ 595.60	4.24%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -			2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,000	$ -	$ -			2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 14,512.83**	**$ 361.18**	**2.55%**			**$ 15,150.78**	**$ 637.95**	**4.40%**
Line Losses on Cost of Power	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants			$ -	$ -				$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers				$ -					$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 17,603.25**	**$ 361.18**	**2.09%**			**$ 18,241.20**	**$ 637.95**	**3.62%**
Retail Transmission Rate - Network Service Rate	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 26,392.65**	**$ 361.18**	**1.39%**			**$ 27,030.60**	**$ 637.95**	**2.42%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	926,550	$ 277.97	$ -	0.00%	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	926,550	$ 370.62	$ -	0.00%	$ 0.0004	926,550	$ 370.62	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 134,766.45**	**$ 361.18**	**0.3%**			**$ 135,404.40**	**$ 637.95**	**0.5%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 17,519.64	$ 46.95	0.3%	13%		$ 17,602.57	$ 82.93	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 152,286.08**	$ 408.13	0.3%			**$ 153,006.97**	$ 720.88	0.5%
Total Bill on RPP (before Taxes)			**$ 110,097.45**	**$ 361.18**	**0.3%**			**$ 110,735.40**	**$ 637.95**	**0.6%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 14,312.67	$ 46.95	0.3%	13%		$ 14,395.60	$ 82.93	0.6%
Total Bill on RPP (after Tax and Rebate)			**$ 124,410.11**	$ 408.13	0.3%			**$ 125,131.00**	$ 720.88	0.6%
Loss Factor (%)	2.95%					2.95%				

	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 1,082.10	1	$ 1,082.10	$ 40.92	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0130	2,000	$ 26.00	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0776	2,000	$ 155.20	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.1186	2,000	-$ 237.20	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0190	2,000	-$ 38.00	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0025	2,000	-$ 5.00	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1258	2,000	-$ 251.60	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0051	2,000	-$ 10.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0557	2,000	-$ 111.40	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0305	2,000	-$ 61.00	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -	
Distribution Volumetric Rate	$ 7.6095	2,000	$ 15,219.00	$ 575.40	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,000	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,000	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,000	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 15,767.10**	**$ 616.32**	**4.07%**
Line Losses on Cost of Power	$ 0.1164	26,550	$ 3,090.42	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts			$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants			$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers				$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18,857.52**	**$ 616.32**	**3.38%**
Retail Transmission Rate - Network Service Rate	$ 2.6594	1,800	$ 4,786.92	$ -	0.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	$ 2.2236	1,800	$ 4,002.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 27,646.92**	**$ 616.32**	**2.28%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	926,550	$ 2,964.96	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	926,550	$ 277.97	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	926,550	$ 370.62	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	576,000	$ 37,440.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	162,000	$ 15,228.00	$ -	0.00%
TOU - On Peak	$ 0.1320	162,000	$ 21,384.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	899,250	$ 80,033.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	900,000	$ 104,760.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 136,020.72**	**$ 616.32**	**0.5%**
8% Provincial Rebate	-8%			$ -	
HST	13%		$ 17,682.69	$ 80.12	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 153,703.41**	$ 696.44	0.5%
Total Bill on RPP (before Taxes)			**$ 111,351.72**	**$ 616.32**	**0.6%**
8% Provincial Rebate	-8%			$ -	
HST	13%		$ 14,475.72	$ 80.12	0.6%
Total Bill on RPP (after Tax and Rebate)			**$ 125,827.44**	$ 696.44	0.6%
Loss Factor (%)	2.95%				

Appendix 2-W
Bill Impacts

Customer Class: LARGE USE SERVICE

TOU / non-TOU: non-TOU | SPOT A Non-WMP

8,900	kW
9,700	kVA
4,100,000	kWh

Consumption — ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	2018 Current Board-Approved Rate ($)	2018 Volume	2018 Charge ($)	2019 Current Board-Approved Rate ($)	2019 Volume	2019 Charge ($)	Impact $ Change	Impact % Change
Service Charge	per 30 days	$ 4,178.03	1	$ 4,178.03	$ 4,342.23	1	$ 4,342.23	$ 164.20	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31,	per kVA								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of IFRS - CGAAP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 85.84	1	$ 85.84	$ 85.84	1	$ 85.84	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 25.18	1	$ 25.18	$ 25.18	1	$ 25.18	$ -	0.00%
Distribution Volumetric Rate	per kVA	$ 6.5820	9,700	$ 63,845.40	$ 6.8407	9,700	$ 66,354.79	$ 2,509.39	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.0675	9,700	-$ 654.75		9,700	$ -	$ 654.75	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 0.2084	9,700	-$ 2,021.48		9,700	$ -	$ 2,021.48	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0044	9,700	$ 42.68	$ 0.0044	9,700	$ 42.68	$ -	0.00%
Rate Rider for Disposition of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0039	9,700	$ 37.83	$ 0.0039	9,700	$ 37.83	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.0648	9,700	$ 628.56	$ 0.0648	9,700	$ 628.56	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.1382	9,700	$ 1,340.54	$ 0.1382	9,700	$ 1,340.54	$ -	0.00%
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0406	9,700	$ 393.82	$ 0.0406	9,700	$ 393.82	$ -	0.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA	$ 0.2763	9,700	$ 2,680.11	$ 0.2282	9,700	$ 2,213.54	-$ 466.57	-17.41%
Sub-Total A (excluding pass through)				**$ 70,581.76**			**$ 75,465.01**	**$ 4,883.25**	**6.92%**
Line Losses on Cost of Power	per kWh	$ 0.1164	76,670	$ 8,924.39	$ 0.1164	76,670	$ 8,924.39	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 0.8782	9,700	-$ 8,518.54	$ 0.3397	9,700	$ 3,295.09	$ 11,813.63	-138.68%
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA	-$ 0.5945	9,700	-$ 5,766.65	-$ 0.5628	9,700	-$ 5,459.16	$ 307.49	-5.33%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0032		$ -	$ 0.0095		$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kVA	-$ 0.00112		$ -	$ 0.00068		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65,220.96**			**$ 82,225.33**	**$ 17,004.37**	**26.07%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.8295	8,900	$ 25,182.55	$ 2.9271	8,900	$ 26,051.19	$ 868.64	3.45%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.2769	8,900	$ 20,264.41	$ 2.5587	8,900	$ 22,772.43	$ 2,508.02	12.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 110,667.92**			**$ 131,048.95**	**$ 20,381.03**	**18.42%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	4,176,670	$ 13,365.34	$ 0.0032	4,176,670	$ 13,365.34	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	4,176,670	$ 1,253.00	$ 0.0003	4,176,670	$ 1,253.00	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004		$ -	$ 0.0004		$ -	$ -	
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	2,624,000	$ 170,560.00	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	738,000	$ 69,372.00	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	738,000	$ 97,416.00	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	4,099,250	$ 364,833.25	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	4,100,000	$ 477,240.00	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 602,526.51**			**$ 622,907.54**	**$ 20,381.03**	**3.4%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 78,328.45	13%		$ 80,977.98	$ 2,649.53	3.4%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 680,854.96**			**$ 703,885.52**	**$ 23,030.56**	**3.4%**
Total Bill on RPP (before Taxes)				**$ 490,177.51**			**$ 510,558.54**	**$ 20,381.03**	**4.2%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 63,723.08	13%		$ 66,372.61	$ 2,649.53	4.2%
Total Bill on RPP (after Tax and Rebate)				**$ 553,900.59**			**$ 576,931.15**	**$ 23,030.56**	**4.2%**
Loss Factor (%)		1.87%			1.87%				

	2020 Proposed Rate ($)	2020 Volume	2020 Charge ($)	Impact $ Change	Impact % Change	2021 Proposed Rate ($)	2021 Volume	2021 Charge ($)	Impact $ Change	Impact % Change
Service Charge	$4,137.37	1	$ 4,137.37	-$ 204.86	-4.72%	$4,272.25	1	$ 4,272.25	$ 134.88	3.26%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31,	$ 0.0154	9,700	$ 149.38	$ 149.38		$ 0.0154	9,700	$ 149.38	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0916	9,700	$ 888.52	$ 888.52		$ 0.0916	9,700	$ 888.52	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until Dec. 31, 2024	-$ 0.1400	9,700	-$ 1,358.00	-$ 1,358.00		-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0224	9,700	-$ 217.28	-$ 217.28		-$ 0.0224	9,700	-$ 217.28	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	9,700	-$ 3.88	-$ 3.88		-$ 0.0004	9,700	-$ 3.88	$ -	0.00%
Rate Rider for Application of IFRS - CGAAP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0030	9,700	-$ 29.10	-$ 29.10		-$ 0.0030	9,700	-$ 29.10	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1484	9,700	-$ 1,439.48	-$ 1,439.48		-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0060	9,700	-$ 58.20	-$ 58.20		-$ 0.0060	9,700	-$ 58.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0657	9,700	-$ 637.29	-$ 637.29		-$ 0.0657	9,700	-$ 637.29	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0360	9,700	-$ 349.20	-$ 349.20		-$ 0.0360	9,700	-$ 349.20	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 85.84			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	-$ 25.18			1	$ -	$ -	
Distribution Volumetric Rate	$ 7.1267	9,700	$ 69,128.99	$ 2,774.20	4.18%	$ 7.3590	9,700	$ 71,382.30	$ 2,253.31	3.26%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		9,700	$ -	-$ 42.68			9,700	$ -	$ -	
Rate Rider for Disposition of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		9,700	$ -	-$ 37.83			9,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		9,700	$ -	-$ 628.56			9,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		9,700	$ -	-$ 1,340.54			9,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		9,700	$ -	-$ 393.82			9,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		9,700	$ -	-$ 2,213.54			9,700	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 70,211.83**	**-$ 5,253.18**	**-6.96%**			**$ 72,600.02**	**$ 2,388.19**	**3.40%**
Line Losses on Cost of Power	$ 0.1164	70,520	$ 8,208.53	-$ 715.86	-8.02%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.53680	9,700	$ 5,206.96	$ 1,911.87	58.02%		9,700	$ -	-$ 5,206.96	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	-$ 0.19440	9,700	-$ 1,885.68	$ 3,573.48	-65.46%		9,700	$ -	$ 1,885.68	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.00840			$ -					$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290			$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 81,741.64**	**-$ 483.69**	**-0.59%**			**$ 80,808.55**	**-$ 933.09**	**-1.14%**
Retail Transmissioin Rate - Network Service Rate	$ 3.0316	8,900	$ 26,981.24	$ 930.05	3.57%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.4705	8,900	$ 21,987.45	-$ 784.98	-3.45%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 130,710.33**	**-$ 338.62**	**-0.26%**			**$ 129,777.24**	**-$ 933.09**	**-0.71%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	4,170,520	$ 13,345.66	-$ 19.68	-0.15%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	4,170,520	$ 1,251.16	-$ 1.84	-0.15%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers			$ -	$ -				$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%
TOU - On Peak	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 622,547.40**	**-$ 360.14**	**-0.1%**			**$ 621,614.31**	**-$ 933.09**	**-0.1%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 80,931.16	-$ 46.82	-0.1%	13%		$ 80,809.86	-$ 121.30	-0.1%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 703,478.56**	**-$ 406.96**	**-0.1%**			**$ 702,424.17**	**-$ 1,054.39**	**-0.1%**
Total Bill on RPP (before Taxes)			**$ 510,198.40**	**-$ 360.14**	**-0.1%**			**$ 509,265.31**	**-$ 933.09**	**-0.2%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 66,325.79	-$ 46.82	-0.1%	13%		$ 66,204.49	-$ 121.30	-0.2%
Total Bill on RPP (after Tax and Rebate)			**$ 576,524.19**	**-$ 406.96**	**-0.1%**			**$ 575,469.80**	**-$ 1,054.39**	**-0.2%**
Loss Factor (%)	1.72%					1.72%				

	2022 Proposed Rate ($)	2022 Volume	2022 Charge ($)	Impact $ Change	Impact % Change	2023 Proposed Rate ($)	2023 Volume	2023 Charge ($)	Impact $ Change	Impact % Change	2024 Proposed Rate ($)	2024 Volume	2024 Charge ($)	Impact $ Change	Impact % Change
Service Charge	$ 4,377.35	1	$ 4,377.35	$ 105.10	2.46%	$ 4,562.95	1	$ 4,562.95	$ 185.60	4.24%	$ 4,742.27	1	$ 4,742.27	$ 179.32	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31,	$ 0.0154	9,700	$ 149.38	$ -	0.00%	$ 0.0154	9,700	$ 149.38	$ -	0.00%	$ 0.0154	9,700	$ 149.38	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.0916	9,700	$ 888.52	$ -	0.00%	$ 0.0916	9,700	$ 888.52	$ -	0.00%	$ 0.0916	9,700	$ 888.52	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - effective until Dec. 31, 2024	-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%	-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%	-$ 0.1400	9,700	-$ 1,358.00	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.0224	9,700	-$ 217.28	$ -	0.00%	-$ 0.0224	9,700	-$ 217.28	$ -	0.00%	-$ 0.0224	9,700	-$ 217.28	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%	-$ 0.0004	9,700	-$ 3.88	$ -	0.00%
Rate Rider for Application of IFRS - CGAAP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0030	9,700	-$ 29.10	$ -	0.00%	-$ 0.0030	9,700	-$ 29.10	$ -	0.00%	-$ 0.0030	9,700	-$ 29.10	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%	-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%	-$ 0.1484	9,700	-$ 1,439.48	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0060	9,700	-$ 58.20	$ -	0.00%	-$ 0.0060	9,700	-$ 58.20	$ -	0.00%	-$ 0.0060	9,700	-$ 58.20	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.0657	9,700	-$ 637.29	$ -	0.00%	-$ 0.0657	9,700	-$ 637.29	$ -	0.00%	-$ 0.0657	9,700	-$ 637.29	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.0360	9,700	-$ 349.20	$ -	0.00%	-$ 0.0360	9,700	-$ 349.20	$ -	0.00%	-$ 0.0360	9,700	-$ 349.20	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 7.5400	9,700	$ 73,138.00	$ 1,755.70	2.46%	$ 7.8597	9,700	$ 76,239.09	$ 3,101.09	4.24%	$ 8.1686	9,700	$ 79,235.42	$ 2,996.33	3.93%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 74,460.82**	**$ 1,860.80**	**2.56%**			**$ 77,747.51**	**$ 3,286.69**	**4.41%**			**$ 80,923.16**	**$ 3,175.65**	**4.08%**
Line Losses on Cost of Power	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%	$ 0.1164	70,520	$ 8,208.53	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants		9,700	$ -	$ -			9,700	$ -	$ -			9,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers				$ -					$ -					$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -					$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 82,669.35**	**$ 1,860.80**	**2.30%**			**$ 85,956.04**	**$ 3,286.69**	**3.98%**			**$ 89,131.69**	**$ 3,175.65**	**3.69%**
Retail Transmissioin Rate - Network Service Rate	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%	$ 3.0316	8,900	$ 26,981.24	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%	$ 2.4705	8,900	$ 21,987.45	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 131,638.04**	**$ 1,860.80**	**1.43%**			**$ 134,924.73**	**$ 3,286.69**	**2.50%**			**$ 138,100.38**	**$ 3,175.65**	**2.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%	$ 0.0032	4,170,520	$ 13,345.66	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%	$ 0.0003	4,170,520	$ 1,251.16	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers			$ -	$ -				$ -	$ -				$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%	$ 0.0650	2,624,000	$ 170,560.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%	$ 0.0940	738,000	$ 69,372.00	$ -	0.00%
TOU - On Peak	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%	$ 0.1320	738,000	$ 97,416.00	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%	$ 0.0890	4,099,250	$ 364,833.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%	$ 0.1164	4,100,000	$ 477,240.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 623,475.11**	**$ 1,860.80**	**0.3%**			**$ 626,761.80**	**$ 3,286.69**	**0.5%**			**$ 629,937.45**	**$ 3,175.65**	**0.5%**
8% Provincial Rebate	-8%			$ -		-8%			$ -		-8%			$ -	
HST	13%		$ 81,051.76	$ 241.90	0.3%	13%		$ 81,479.03	$ 427.27	0.5%	13%		$ 81,891.87	$ 412.83	0.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 704,526.87**	**$ 2,102.70**	0.3%			**$ 708,240.83**	**$ 3,713.96**	0.5%			**$ 711,829.32**	**$ 3,588.48**	0.5%
Total Bill on RPP (before Taxes)			**$ 511,126.11**	**$ 1,860.80**	**0.4%**			**$ 514,412.80**	**$ 3,286.69**	**0.6%**			**$ 517,588.45**	**$ 3,175.65**	**0.6%**
8% Provincial Rebate	-8%			$ -		-8%			$ -		-8%			$ -	
HST	13%		$ 66,446.39	$ 241.90	0.4%	13%		$ 66,873.66	$ 427.27	0.6%	13%		$ 67,286.50	$ 412.83	0.6%
Total Bill on RPP (after Tax and Rebate)			**$ 577,572.50**	**$ 2,102.70**	0.4%			**$ 581,286.46**	**$ 3,713.96**	0.6%			**$ 584,874.95**	**$ 3,588.48**	0.6%
Loss Factor (%)	1.72%					1.72%					1.72%				

Appendix 2-W
Bill Impacts

Customer Class: **STREET LIGHTING SERVICE**

TOU / non-TOU:	non-TOU	16,000	Devices
	SPOT CLASS B	2,700	kW
		2,700	kVA ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
	Consumption	955,000	kWh

	Charge Unit	2018 Current Board-Approved			2019 Current Board-Approved			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge (per device)	per device per 30 days	$ 1.55	16,000	$ 24,800.00	$ 1.61	16,000	$ 25,760.00	$ 960.00	3.87%
Distribution Volumetric Rate	per kVA	$ 34.4231	2,700	$ 92,942.37	$ 35.7759	2,700	$ 96,594.93	$ 3,652.56	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kVA								
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kVA								
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kVA	-$ 0.5347	2,700	-$ 1,443.69		2,700	$ -	$ 1,443.69	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kVA	-$ 1.6506	2,700	-$ 4,456.62		2,700	$ -	$ 4,456.62	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kVA	$ 0.0741	2,700	$ 200.07	$ 0.0741	2,700	$ 200.07	$ -	0.00%
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kVA	$ 0.0312	2,700	$ 84.24	$ 0.0312	2,700	$ 84.24	$ -	0.00%
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kVA	$ 0.5133	2,700	$ 1,385.91	$ 0.5133	2,700	$ 1,385.91	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kVA		2,700	$ -		2,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kVA	$ 0.0478	2,700	$ 129.06	$ 0.0478	2,700	$ 129.06	$ -	0.00%
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kVA		2,700	$ -		2,700	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 113,641.34**			**$ 124,154.21**	**$ 10,512.87**	**9.25%**
Line Losses on Cost of Power	per kWh	$ 0.1164	35,908	$ 4,179.69	$ 0.1164	35,908	$ 4,179.69	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	per kVA	-$ 1.0860	2,700	-$ 2,932.20	-$ 0.1687	2,700	-$ 455.49	$ 2,476.71	-84.47%
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants	per kVA		2,700	$ -		2,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kVA	$ 0.0236	2,700	$ 63.72	$ 0.0092	2,700	$ 24.84	-$ 38.88	-61.02%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112	955,000	-$ 1,069.60	$ 0.00068	955,000	$ 649.40	$ 1,719.00	-160.71%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 113,882.95**			**$ 128,552.65**	**$ 14,669.70**	**12.88%**
Retail Transmissioin Rate - Network Service Rate	per kW	$ 2.2849	2,700	$ 6,169.23	$ 2.3638	2,700	$ 6,382.26	$ 213.03	3.45%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	per kW	$ 2.4461	2,700	$ 6,604.47	$ 2.7488	2,700	$ 7,421.76	$ 817.29	12.37%
Sub-Total C - Delivery (including Sub-Total B)				**$ 126,656.65**			**$ 142,356.67**	**$ 15,700.02**	**12.40%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	990,908	$ 3,170.91	$ 0.0032	990,908	$ 3,170.91	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	990,908	$ 297.27	$ 0.0003	990,908	$ 297.27	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	990,908	$ 396.36	$ 0.0004	990,908	$ 396.36	$ -	0.00%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	611,200	$ 39,728.00	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	171,900	$ 16,158.60	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	171,900	$ 22,690.80	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	954,250	$ 84,928.25	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164	955,000	$ 111,162.00	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)				**$ 241,683.44**			**$ 257,383.46**	**$ 15,700.02**	**6.5%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 31,418.85	13%		$ 33,459.85	$ 2,041.00	6.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)				**$ 273,102.29**			**$ 290,843.31**	**$ 17,741.02**	**6.5%**
Total Bill on RPP (before Taxes)				**$ 215,507.44**			**$ 231,207.46**	**$ 15,700.02**	**7.3%**
8% Provincial Rebate		-8%			-8%				
HST		13%		$ 28,015.97	13%		$ 30,056.97	$ 2,041.00	7.3%
Total Bill on RPP (after Tax and Rebate)				**$ 243,523.41**			**$ 261,264.43**	**$ 17,741.02**	**7.3%**
Loss Factor (%)		3.76%			3.76%				

	2020 Proposed			Impact		2021 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge (per device)	$ 1.66	16,000	$ 26,560.00	$ 800.00	3.11%	$ 1.71	16,000	$ 27,360.00	$ 800.00	3.01%
Distribution Volumetric Rate	$ 36.9560	2,700	$ 99,781.20	$ 3,186.27	3.30%	$ 38.1608	2,700	$ 103,034.16	$ 3,252.96	3.26%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0968	2,700	$ 261.36	$ 261.36		$ 0.0968	2,700	$ 261.36	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.5764	2,700	$ 1,556.28	$ 1,556.28		$ 0.5764	2,700	$ 1,556.28	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.8812	2,700	-$ 2,379.24	-$ 2,379.24		-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.1412	2,700	-$ 381.24	-$ 381.24		-$ 0.1412	2,700	-$ 381.24	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0088	2,700	-$ 23.76	-$ 23.76		-$ 0.0088	2,700	-$ 23.76	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0187	2,700	-$ 50.49	-$ 50.49		-$ 0.0187	2,700	-$ 50.49	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.9343	2,700	-$ 2,522.61	-$ 2,522.61		-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0380	2,700	-$ 102.60	-$ 102.60		-$ 0.0380	2,700	-$ 102.60	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.4134	2,700	-$ 1,116.18	-$ 1,116.18		-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.2264	2,700	-$ 611.28	-$ 611.28		-$ 0.2264	2,700	-$ 611.28	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,700	$ -	-$ 200.07			2,700	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,700	$ -	-$ 84.24			2,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,700	$ -	-$ 1,385.91			2,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,700	$ -	-$ 129.06			2,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,700	$ -	$ -			2,700	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 120,971.44**	**-$ 3,182.77**	**-2.56%**			**$ 125,024.40**	**$ 4,052.96**	**3.35%**
Line Losses on Cost of Power	$ 0.1164	28,173	$ 3,279.28	-$ 900.41	-21.54%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts	$ 0.25620	2,700	$ 691.74	$ 1,147.23	-251.87%		2,700	$ -	-$ 691.74	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants		2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	-$ 0.01130	2,700	-$ 30.51	-$ 55.35	-222.83%		2,700		$ 30.51	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	-$ 0.00290	955,000	-$ 2,769.50	-$ 3,418.90	-526.47%		955,000		$ 2,769.50	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 122,142.45**	**-$ 6,410.20**	**-4.99%**			**$ 128,303.68**	**$ 6,161.23**	**5.04%**
Retail Transmissioin Rate - Network Service Rate	$ 2.4481	2,700	$ 6,609.87	$ 227.61	3.57%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.6541	2,700	$ 7,166.07	-$ 255.69	-3.45%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 135,918.39**	**-$ 6,438.28**	**-4.52%**			**$ 142,079.62**	**$ 6,161.23**	**4.53%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	983,173	$ 3,146.15	-$ 24.75	-0.78%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	983,173	$ 294.95	-$ 2.32	-0.78%	$ 0.0003	983,173	$ 294.95	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	983,173	$ 393.27	-$ 3.09	-0.78%	$ 0.0004	983,173	$ 393.27	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%
TOU - On Peak	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 250,915.01**	**-$ 6,468.45**	**-2.5%**			**$ 257,076.24**	**$ 6,161.23**	**2.5%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 32,618.95	-$ 840.90	-2.5%	13%		$ 33,419.91	$ 800.96	2.5%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 283,533.96**	**-$ 7,309.35**	**-2.5%**			**$ 290,496.15**	**$ 6,962.19**	**2.5%**
Total Bill on RPP (before Taxes)			**$ 224,739.01**	**-$ 6,468.45**	**-2.8%**			**$ 230,900.24**	**$ 6,161.23**	**2.7%**
8% Provincial Rebate	-8%			$ -		-8%			$ -	
HST	13%		$ 29,216.07	-$ 840.90	-2.8%	13%		$ 30,017.03	$ 800.96	2.7%
Total Bill on RPP (after Tax and Rebate)			**$ 253,955.08**	**-$ 7,309.35**	**-2.8%**			**$ 260,917.27**	**$ 6,962.19**	**2.7%**
Loss Factor (%)	2.95%					2.95%				

	2022 Proposed			Impact		2023 Proposed			Impact		2024 Proposed			Impact	
	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change	Rate ($)	Volume	Charge ($)	$ Change	% Change
Service Charge (per device)	$ 1.75	16,000	$ 28,000.00	$ 640.00	2.34%	$ 1.82	16,000	$ 29,120.00	$ 1,120.00	4.00%	$ 1.89	16,000	$ 30,240.00	$ 1,120.00	3.85%
Distribution Volumetric Rate	$ 39.0996	2,700	$ 105,568.92	$ 2,534.76	2.46%	$ 40.7574	2,700	$ 110,044.98	$ 4,476.06	4.24%	$ 42.3592	2,700	$ 114,369.84	$ 4,324.86	3.93%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.0968	2,700	$ 261.36	$ -	0.00%	$ 0.0968	2,700	$ 261.36	$ -	0.00%	$ 0.0968	2,700	$ 261.36	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.5764	2,700	$ 1,556.28	$ -	0.00%	$ 0.5764	2,700	$ 1,556.28	$ -	0.00%	$ 0.5764	2,700	$ 1,556.28	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%	-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%	-$ 0.8812	2,700	-$ 2,379.24	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.1412	2,700	-$ 381.24	$ -	0.00%	-$ 0.1412	2,700	-$ 381.24	$ -	0.00%	-$ 0.1412	2,700	-$ 381.24	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%	-$ 0.0088	2,700	-$ 23.76	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%	-$ 0.0187	2,700	-$ 50.49	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%	-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%	-$ 0.9343	2,700	-$ 2,522.61	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.0380	2,700	-$ 102.60	$ -	0.00%	-$ 0.0380	2,700	-$ 102.60	$ -	0.00%	-$ 0.0380	2,700	-$ 102.60	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%	-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%	-$ 0.4134	2,700	-$ 1,116.18	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.2264	2,700	-$ 611.28	$ -	0.00%	-$ 0.2264	2,700	-$ 611.28	$ -	0.00%	-$ 0.2264	2,700	-$ 611.28	$ -	0.00%
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 128,199.16**	**$ 3,174.76**	**2.54%**			**$ 133,795.22**	**$ 5,596.06**	**4.37%**			**$ 139,240.08**	**$ 5,444.86**	**4.07%**
Line Losses on Cost of Power	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%	$ 0.1164	28,173	$ 3,279.28	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants		2,700	$ -	$ -			2,700	$ -	$ -			2,700	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers		2,700		$ -			2,700		$ -			2,700		$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers		955,000		$ -			955,000		$ -			955,000		$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 131,478.44**	**$ 3,174.76**	**2.47%**			**$ 137,074.50**	**$ 5,596.06**	**4.26%**			**$ 142,519.36**	**$ 5,444.86**	**3.97%**
Retail Transmissioin Rate - Network Service Rate	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%	$ 2.4481	2,700	$ 6,609.87	$ -	0.00%
Retail Transmissioin Rate - Line and Transformation Connection Service Rate	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%	$ 2.6541	2,700	$ 7,166.07	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 145,254.38**	**$ 3,174.76**	**2.23%**			**$ 150,850.44**	**$ 5,596.06**	**3.85%**			**$ 156,295.30**	**$ 5,444.86**	**3.61%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%	$ 0.0032	983,173	$ 3,146.15	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%	$ 0.0003	983,173	$ 294.95	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%	$ 0.0004	983,173	$ 393.27	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%	$ 0.0650	611,200	$ 39,728.00	$ -	0.00%
TOU - Mid Peak	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%	$ 0.0940	171,900	$ 16,158.60	$ -	0.00%
TOU - On Peak	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%	$ 0.1320	171,900	$ 22,690.80	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%	$ 0.0770	750	$ 57.75	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%	$ 0.0890	954,250	$ 84,928.25	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -		$ 0.1164	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%	$ 0.1164	955,000	$ 111,162.00	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price (before Taxes)			**$ 260,251.00**	**$ 3,174.76**	**1.2%**			**$ 265,847.06**	**$ 5,596.06**	**2.2%**			**$ 271,291.92**	**$ 5,444.86**	**2.0%**
8% Provincial Rebate	-8%			$ -		-8%			$ -		-8%			$ -	
HST	13%		$ 33,832.63	$ 412.72	1.2%	13%		$ 34,560.12	$ 727.49	2.2%	13%		$ 35,267.95	$ 707.83	2.0%
Total Bill on Average IESO Wholesale Market Price (after Tax and Rebate)			**$ 294,083.63**	**$ 3,587.48**	**1.2%**			**$ 300,407.18**	**$ 6,323.55**	**2.2%**			**$ 306,559.87**	**$ 6,152.69**	**2.0%**
Total Bill on RPP (before Taxes)			**$ 234,075.00**	**$ 3,174.76**	**1.4%**			**$ 239,671.06**	**$ 5,596.06**	**2.4%**			**$ 245,115.92**	**$ 5,444.86**	**2.3%**
8% Provincial Rebate	-8%			$ -		-8%			$ -		-8%			$ -	
HST	13%		$ 30,429.75	$ 412.72	1.4%	13%		$ 31,157.24	$ 727.49	2.4%	13%		$ 31,865.07	$ 707.83	2.3%
Total Bill on RPP (after Tax and Rebate)			**$ 264,504.75**	**$ 3,587.48**	**1.4%**			**$ 270,828.30**	**$ 6,323.55**	**2.4%**			**$ 276,980.99**	**$ 6,152.69**	**2.3%**
Loss Factor (%)	2.95%					2.95%					2.95%				

Appendix 2-W
Bill Impacts

Customer Class: UNMETERED SCATTERED LOAD SERVICE

TOU / non-TOU: non-TOU — RPP

1 Connection

Consumption 285 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge	Charge Unit	2018 Current Board-Approved Rate ($)	Volume	Charge ($)	2019 Current Board-Approved Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2020 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	per 30 days	$ 6.87	1	$ 6.87	$ 7.14	1	$ 7.14	$ 0.27	3.93%	$ 6.43	1	$ 6.43	-$ 0.71	-9.94%
Connection Charge (per connection)	per connection per 30 days	$ 0.71	1	$ 0.71	$ 0.74	1	$ 0.74	$ 0.03	4.23%	$ 0.67	1	$ 0.67	-$ 0.07	-9.46%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	per kWh									$ 0.00020	285	$ 0.06	$ 0.06	
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	per kWh									$ 0.00121	285	$ 0.34	$ 0.34	
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	per kWh									-$ 0.00185	285	-$ 0.53	-$ 0.53	
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	per kWh									-$ 0.00030	285	-$ 0.09	-$ 0.09	
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	per kWh									-$ 0.00002	285	-$ 0.01	-$ 0.01	
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	per kWh									-$ 0.00004	285	-$ 0.01	-$ 0.01	
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00196	285	-$ 0.56	-$ 0.56	
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	per kWh									-$ 0.00008	285	-$ 0.02	-$ 0.02	
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	per kWh									-$ 0.00087	285	-$ 0.25	-$ 0.25	
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	per kWh									-$ 0.00047	285	-$ 0.13	-$ 0.13	
Rate Rider for Recovery of 2015 Foregone Revenue (per connection) - effective until Dec. 31, 2019	per connection per 30 days	$ 0.02	1	$ 0.02	$ 0.02	1	$ 0.02	$ -	0.00%		1	$ -	-$ 0.02	
Rate Rider for Recovery of 2016 Foregone Revenue (per connection) - effective until Dec. 31, 2019	per connection per 30 days	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%		1	$ -	-$ 0.01	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.16	1	$ 0.16	$ 0.16	1	$ 0.16	$ -	0.00%		1	$ -	-$ 0.16	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per 30 days	$ 0.05	1	$ 0.05	$ 0.05	1	$ 0.05	$ -	0.00%		1	$ -	-$ 0.05	
Distribution Volumetric Rate	per kWh	$ 0.08632	285	$ 24.60	$ 0.08971	285	$ 25.57	$ 0.97	3.93%	$ 0.08073	285	$ 23.01	-$ 2.56	-10.01%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00203	285	$ 0.58	$ 0.00203	285	$ 0.58	$ -	0.00%		285	$ -	-$ 0.58	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.	per kWh	$ 0.00062	285	$ 0.18	$ 0.00062	285	$ 0.18	$ -	0.00%		285	$ -	-$ 0.18	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018	per kWh	-$ 0.00096	285	-$ 0.27		285	$ -	$ 0.27			285	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.	per kWh	-$ 0.00296	285	-$ 0.84		285	$ -	$ 0.84			285	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.	per kWh	$ 0.00029	285	$ 0.08	$ 0.00029	285	$ 0.08	$ -	0.00%		285	$ -	-$ 0.08	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.	per kWh	$ 0.00006	285	$ 0.02	$ 0.00006	285	$ 0.02	$ -	0.00%		285	$ -	-$ 0.02	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.	per kWh	$ 0.00092	285	$ 0.26	$ 0.00092	285	$ 0.26	$ -	0.00%		285	$ -	-$ 0.26	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.	per kWh		285	$ -		285	$ -	$ -			285	$ -	$ -	
Sub-Total A (excluding pass through)				**$ 32.42**			**$ 34.80**	**$ 2.38**	**7.35%**			**$ 28.92**	**-$ 5.89**	**-16.92%**
Line Losses on Cost of Power	per kWh	$ 0.0770	11	$ 0.83	$ 0.0770	11	$ 0.83	$ -	0.00%	$ 0.0770	8	$ 0.65	-$ 0.18	-21.54%
Rate Rider for Disposition of Deferral/Variance Accounts	per kWh	-$ 0.00316	285	-$ 0.90	-$ 0.00049	285	-$ 0.14	$ 0.76	-84.49%	$ 0.00073	285	$ 0.21	$ 0.35	-248.98%
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers	per kWh	$ 0.00007	285	$ 0.02	$ 0.00003	285	$ 0.01	-$ 0.01	-57.14%	-$ 0.00003	285	-$ 0.01	-$ 0.02	-200.00%
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers	per kWh	-$ 0.00112		$ -	$ 0.00068		$ -	$ -		-$ 0.00290			$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.37**			**$ 35.50**	**$ 3.13**	**9.68%**			**$ 29.76**	**-$ 5.73**	**-16.16%**
RTSR - Network	per kWh	$ 0.00460	296	$ 1.36	$ 0.00482	296	$ 1.43	$ 0.07	4.78%	$ 0.00500	293	$ 1.47	$ 0.04	2.92%
RTSR - Line and Transformation Connection	per kWh	$ 0.00390	296	$ 1.15	$ 0.00444	296	$ 1.31	$ 0.16	13.85%	$ 0.00429	293	$ 1.26	-$ 0.05	-4.13%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.88**			**$ 38.24**	**$ 3.36**	**9.63%**			**$ 32.49**	**-$ 5.75**	**-15.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0032	296	$ 0.95	$ 0.0032	296	$ 0.95	$ -	0.00%	$ 0.0032	293	$ 0.94	-$ 0.01	-0.78%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0003	296	$ 0.09	$ 0.0003	296	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	-$ 0.00	-0.78%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	per kWh	$ 0.0004	296	$ 0.12	$ 0.0004	296	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	-$ 0.00	-0.78%
Standard Supply Service Charge	per 30 days	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0650	185	$ 12.04	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.0940	48	$ 4.55	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1320	51	$ 6.77	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0770	285	$ 21.95	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0890	-	$ -	$ 0.0890	-	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	per kWh	$ 0.1164		$ -	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	per kWh	$ 0.1164		$ -	$ 0.1164	-	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 58.23**			**$ 61.59**	**$ 3.36**	**5.8%**			**$ 55.83**	**-$ 5.76**	**-9.3%**
8% Provincial Rebate		-8%		-$ 4.66	-8%		-$ 4.93	-$ 0.27	5.8%	-8%		-$ 4.47	$ 0.46	-9.3%
HST		13%		$ 7.57	13%		$ 8.01	$ 0.44	5.8%	13%		$ 7.26	-$ 0.75	-9.3%
Total Bill on RPP (after Tax and Rebate)				**$ 61.14**			**$ 64.66**	**$ 3.53**	**5.8%**			**$ 58.62**	**-$ 6.04**	**-9.3%**
Loss Factor (%)		3.76%			3.76%					2.95%				

Charge	2021 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2022 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 6.64	1	$ 6.64	$ 0.21	3.27%	$ 6.80	1	$ 6.80	$ 0.16	2.41%
Connection Charge (per connection)	$ 0.69	1	$ 0.69	$ 0.02	2.99%	$ 0.71	1	$ 0.71	$ 0.02	2.90%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.00020	285	$ 0.06	$ -	0.00%	$ 0.00020	285	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.00121	285	$ 0.34	$ -	0.00%	$ 0.00121	285	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.00185	285	-$ 0.53	$ -	0.00%	-$ 0.00185	285	-$ 0.53	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.00030	285	-$ 0.09	$ -	0.00%	-$ 0.00030	285	-$ 0.09	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.00196	285	-$ 0.56	$ -	0.00%	-$ 0.00196	285	-$ 0.56	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.00008	285	-$ 0.02	$ -	0.00%	-$ 0.00008	285	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.00087	285	-$ 0.25	$ -	0.00%	-$ 0.00087	285	-$ 0.25	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.00047	285	-$ 0.13	$ -	0.00%	-$ 0.00047	285	-$ 0.13	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue (per connection) - effective until Dec. 31, 2019		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue (per connection) - effective until Dec. 31, 2019		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 0.08336	285	$ 23.76	$ 0.75	3.26%	$ 0.08541	285	$ 24.34	$ 0.58	2.46%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		285	$ -	$ -			285	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 29.90**	**$ 0.98**	**3.39%**			**$ 30.66**	**$ 0.76**	**2.56%**
Line Losses on Cost of Power	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts		285	$ -	-$ 0.21			285	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers		285	$ -	$ 0.01			285	$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 30.54**	**$ 0.78**	**2.62%**			**$ 31.31**	**$ 0.76**	**2.50%**
RTSR - Network	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%
RTSR - Line and Transformation Connection	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 33.27**	**$ 0.78**	**2.40%**			**$ 34.03**	**$ 0.76**	**2.30%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%
TOU - Mid Peak	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%
TOU - On Peak	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on RPP (before Taxes)			**$ 56.61**	**$ 0.78**	**1.4%**			**$ 57.37**	**$ 0.76**	**1.4%**
8% Provincial Rebate	-8%		-$ 4.53	-$ 0.06	1.4%	-8%		-$ 4.59	-$ 0.06	1.4%
HST	13%		$ 7.36	$ 0.10	1.4%	13%		$ 7.46	$ 0.10	1.4%
Total Bill on RPP (after Tax and Rebate)			**$ 59.44**	**$ 0.82**	**1.4%**			**$ 60.24**	**$ 0.80**	**1.4%**
Loss Factor (%)	2.95%					2.95%				

Charge	2023 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change	2024 Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Service Charge	$ 7.09	1	$ 7.09	$ 0.29	4.26%	$ 7.37	1	$ 7.37	$ 0.28	3.95%
Connection Charge (per connection)	$ 0.74	1	$ 0.74	$ 0.03	4.23%	$ 0.77	1	$ 0.77	$ 0.03	4.05%
Rate Rider for Disposition of Other Post Employment Benefit - Cash vs. Accrual - effective until Dec. 31, 2024	$ 0.00020	285	$ 0.06	$ -	0.00%	$ 0.00020	285	$ 0.06	$ -	0.00%
Rate Rider for Recovery of the Impact for USGAAP - Actuarial Loss on OPEB - effective until Dec. 31, 2024	$ 0.00121	285	$ 0.34	$ -	0.00%	$ 0.00121	285	$ 0.34	$ -	0.00%
Rate Rider for Application of Operations Center Consolidation Plan Sharing Variance - efffective until Dec. 31, 2024	-$ 0.00185	285	-$ 0.53	$ -	0.00%	-$ 0.00185	285	-$ 0.53	$ -	0.00%
Rate Rider for Recovery of the Deferred Gain on Disposal of Property - effective until Dec. 31, 2024	-$ 0.00030	285	-$ 0.09	$ -	0.00%	-$ 0.00030	285	-$ 0.09	$ -	0.00%
Rate Rider for Recovery of Wireless Pole Attachment Revenue - effective until Dec. 31, 2024	-$ 0.00002	285	-$ 0.01	$ -	0.00%	-$ 0.00002	285	-$ 0.01	$ -	0.00%
Rate Rider for Application of IFRS - CGAPP Property Plant and Equipment - effective until Dec. 31, 2024	-$ 0.00004	285	-$ 0.01	$ -	0.00%	-$ 0.00004	285	-$ 0.01	$ -	0.00%
Rate Rider for Recovery of Capital Related Revenue Requirement Variance Account - effective until Dec. 31, 2024	-$ 0.00196	285	-$ 0.56	$ -	0.00%	-$ 0.00196	285	-$ 0.56	$ -	0.00%
Rate Rider for Recovery of External Driven Capital - effective until Dec. 31, 2024	-$ 0.00008	285	-$ 0.02	$ -	0.00%	-$ 0.00008	285	-$ 0.02	$ -	0.00%
Rate Rider for Application of Derecognition Variance Account - effective until Dec. 31, 2024	-$ 0.00087	285	-$ 0.25	$ -	0.00%	-$ 0.00087	285	-$ 0.25	$ -	0.00%
Rate Rider for Application of Excess Expansion Deposits - effective until Dec. 31, 2024	-$ 0.00047	285	-$ 0.13	$ -	0.00%	-$ 0.00047	285	-$ 0.13	$ -	0.00%
Rate Rider for Recovery of 2015 Foregone Revenue (per connection) - effective until Dec. 31, 2019		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue (per connection) - effective until Dec. 31, 2019		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 0.08903	285	$ 25.37	$ 1.03	4.24%	$ 0.09253	285	$ 26.37	$ 1.00	3.93%
Rate Rider for Recovery of 2015 Foregone Revenue - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of 2016 Foregone Revenue - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Post Employment Benefit - Tax Savings - effective until Dec. 31, 2018		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of Operations Center Consolidation Plan Sharing - effective until Dec. 31, 2018.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of the Gain on the Sale of Named Properties - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Recovery of Hydro One Capital Contributions Variance - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Application of IFRS - 2014 Derecognition - effective until Dec. 31, 2019.		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until Dec. 31, 2018.		285	$ -	$ -			285	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 32.01**	**$ 1.35**	**4.41%**			**$ 33.32**	**$ 1.31**	**4.08%**
Line Losses on Cost of Power	$ 0.0770	8	$ 0.65	$ -	0.00%	$ 0.0770	8	$ 0.65	$ -	0.00%
Rate Rider for Disposition of Deferral/Variance Accounts		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers		285	$ -	$ -			285	$ -	$ -	
Rate Rider for Disposition of Global Adjustment Account Applicable only for Non-RPP Customers				$ -					$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 32.66**	**$ 1.35**	**4.32%**			**$ 33.97**	**$ 1.31**	**4.00%**
RTSR - Network	$ 0.00500	293	$ 1.47	$ -	0.00%	$ 0.00500	293	$ 1.47	$ -	0.00%
RTSR - Line and Transformation Connection	$ 0.00429	293	$ 1.26	$ -	0.00%	$ 0.00429	293	$ 1.26	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 35.39**	**$ 1.35**	**3.97%**			**$ 36.69**	**$ 1.31**	**3.70%**
Wholesale Market Service Charge (WMSC)	$ 0.0032	293	$ 0.94	$ -	0.00%	$ 0.0032	293	$ 0.94	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	293	$ 0.09	$ -	0.00%	$ 0.0003	293	$ 0.09	$ -	0.00%
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$ 0.0004	293	$ 0.12	$ -	0.00%	$ 0.0004	293	$ 0.12	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ -	0.00%	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	185	$ 12.04	$ -	0.00%	$ 0.0650	185	$ 12.04	$ -	0.00%
TOU - Mid Peak	$ 0.0940	48	$ 4.55	$ -	0.00%	$ 0.0940	48	$ 4.55	$ -	0.00%
TOU - On Peak	$ 0.1320	51	$ 6.77	$ -	0.00%	$ 0.1320	51	$ 6.77	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0770	285	$ 21.95	$ -	0.00%	$ 0.0770	285	$ 21.95	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0890	0	$ -	$ -		$ 0.0890	0	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1164	0	$ -	$ -		$ 0.1164	0	$ -	$ -	
Total Bill on RPP (before Taxes)			**$ 58.72**	**$ 1.35**	**2.4%**			**$ 60.03**	**$ 1.31**	**2.2%**
8% Provincial Rebate	-8%		-$ 4.70	-$ 0.11	2.4%	-8%		-$ 4.80	-$ 0.10	2.2%
HST	13%		$ 7.63	$ 0.18	2.4%	13%		$ 7.80	$ 0.17	2.2%
Total Bill on RPP (after Tax and Rebate)			**$ 61.66**	**$ 1.42**	**2.4%**			**$ 63.03**	**$ 1.37**	**2.2%**
Loss Factor (%)	2.95%					2.95%				

DEFERRAL AND VARIANCE ACCOUNTS VARIANCE ANALYSIS

1. SUMMARY OF DVA BALANCES

Exhibit 9, Tab 1 includes detailed information about Toronto Hydro's Deferral and Variance Accounts (DVA). This schedule provides an updated summary of the Group 1 and Group 2 DVA balances, including the 2018 actuals and updated 2019 forecasts. The information is supported by the following appendices: DVA Continuity Schedule (Appendix A); GA Analysis Workform (Appendix B); Account 1595 Workform (Appendix C); Group 1 DVA Rate Rider Model (Appendix D); Group 2 DVA Rate Rider Model (Appendix E) and Energy Sales and Cost of Power (Appendix F). This schedule also includes an updated 2018 Earnings Sharing Mechanism calculation (Table 18).

Table 1: Summary of DVA Balances – Group 1 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	2017 Balances approved for clearance (including CC)	Projected Interest for 2019	2018 Balances requesting for clearance
LV Variance Account	0.7	0.0	0.4	0.0	0.3
RSVA – Wholesale Market Service Charges	(29.4)	(0.6)	(25.8)	(0.1)	(4.3)
Variance WMS – Sub-account CBR Class B	0.0	0.0	0.6	0.0	(0.6)
RSVA – Retail Transmission Network Charge	17.0	0.3	8.3	0.2	9.2
RSVA – Retail Transmission Connection Charge	25.7	0.3	8.5	0.4	17.9
RSVA – Power	(8.8)	(0.2)	(3.4)	(0.1)	(5.6)
RSVA – Global Adjustment	(17.3)	0.5	6.9	(0.5)	(24.3)
Total Retail Settlement Variance Account ("RSVA")	**(12.1)**	**0.3**	**(4.5)**	**(0.1)**	**(7.4)**
Smart Meter Entity Charges	(0.8)	(0.0)	(0.1)	(0.0)	(0.7)
Total Group 1 Balances	**(12.9)**	**0.3**	**(4.6)**	**(0.2)**	**(8.2)**

Note: Rounding differences may exist.

1 **Table 2: Summary of DVA Balances – Group 2 Accounts ($ Millions)**

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	Balances as of Dec 31, 2018	2017 Balances approved for clearance (incl. CC)	2019 Forecast Principal Activity	2019 Forecast Carrying Charges	Balances for clearance as at Dec 31, 2019
Stranded Meter Costs	3.3	0.3	**3.6**	-	(4.7)	(0.3)	**(1.4)**
IFRS-USGAAP Transitional PP&E[1] Amounts	5.7	-	**5.7**	-	(7.3)	-	**(1.6)**
LRAM Variance Account ("LRAMVA")	27.9	0.5	**28.4**	(12.3)	-	-	**-**
Impact for USGAAP Deferral	48.1	-	**48.1**	-	-	-	**48.1**
Capital Related Revenue Requirement Variance Account ("CRRRVA")	(52.8)	(0.9)	**(53.7)**	-	(22.8)	(1.4)	**(77.9)**
Externally Driven Capital Variance Account ("EDCVA")	(2.3)	(0.0)	**(2.3)**	-	(0.8)	(0.1)	**(3.2)**
.Derecognition	(21.0)	(0.8)	**(21.8)**	-	(12.1)	(0.6)	**(34.5)**
Wireless Attachments	(0.5)	(0.0)	**(0.5)**	-	(0.1)	(0.0)	**(0.6)**
Monthly Billing	7.4	0.2	**7.5**	-	4.1	0.2	**11.8**
Operating Centers Consolidation Program ("OCCP")	(52.8)	(0.5)	**(53.3)**	-	(19.1)	(1.1)	**(73.5)**
Other Post-Employment Benefits ("OPEB") Cash vs Accrual	5.5	-	**5.5**	-	2.6	-	**8.1**
Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(4.3)	-	**(4.3)**	-	(2.0)	-	**(6.3)**
Total	**(35.8)**	**(1.2)**	**(37.1)**	**(12.3)**	**(62.2)**	**(3.3)**	**(131.0)**

Note: Rounding differences may exist.

[1] International Financial Reporting Standards ("IFRS"); United States Generally Accepted Accounting Principles ("USGAAP"); Property, plant and equipment ("PP&E").

2. CARRYING CHARGES

Carrying charges have been applied to specific accounts using the OEB's Prescribed Interest Rates. For the periods up to 2019 Q2, the rates are as determined by the OEB. For the periods 2019 Q3 through Q4, the 2019 Q2 rate has been applied as a forecast. Toronto Hydro proposes to update these rates for the actual approved rates at the time of clearance of these accounts.

Table 3: Interest on Carrying Charges

OEB Interest Rates Applied Calculation of Carrying Charges			
Quarter	Annual %	Quarter	Annual %
Q1 2014	1.47%	Q1 2017	1.10%
Q2 2014	1.47%	Q2 2017	1.10%
Q3 2014	1.47%	Q3 2017	1.10%
Q4 2014	1.47%	Q4 2017	1.50%
Q1 2015	1.47%	Q1 2018	1.50%
Q2 2015	1.10%	Q2 2018	1.89%
Q3 2015	1.10%	Q3 2018	1.89%
Q4 2015	1.10%	Q4 2018	2.17%
Q1 2016	1.10%	Q1 2019	2.45%
Q2 2016	1.10%	Q2 2019	2.18%
Q3 2016	1.10%	Q3 2019	2.18%
Q4 2016	1.10%	Q4 2019	2.18%

3. DISPOSITION OF ACCOUNTS

The balances of the accounts have been updated for 2018 actuals as reflected in the audited financial statements for the year ending December 31, 2018. The sections that follow explain the material changes to the account balances based on the 2018 financials.

3.1 Account 1555 – Stranded Meters

There were no material changes to this account in 2018.

3.2 Account 1575 – IFRS USGAAP Transitional PP&E Amounts

There were no material changes to this account in 2018.

3.3 Account 1508 – Other Regulatory Assets, Subaccount – Impact for USGAAP Deferral Account

Toronto Hydro's actuary performed a full actuarial valuation of the OPEB plans for the year-ending December 31, 2018 (Exhibit U, Tab 4A, Schedule 3, Appendix C). The change in the balance of this account reflects the recognition of a $37.2 million actuarial gain on the OPEB obligation. The actuarial gain arose from updates to the actuarial assumptions (e.g. membership data, claim costs, and discount rate) and plan experience.

3.4 Account 1508 – Other Regulatory Assets, Subaccount – CRRRVA

The balance for clearance in this account has been updated from $57.6 million to $75.6 million credit (refund) to customers. The difference is related to lower than forecasted in-service additions in 2018 associated with distribution assets, the timing of the Copeland TS project, the ERP project, and Hydro One Networks Incorporated ("Hydro One") capital contributions.

Table 4: CRRRVA Balance ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Updated Total	Original Total
Proposed Capital-Related RR, 2015-2019 CIR (1B-T2-S3-P10, Table 3)	437.8	465.0	517.3	567.2	607.3	2,594.6	2,594.6
RR impact from 10% reduction in capital spending	(7.3)	(8.7)	(10.7)	(17.7)	(24.1)	(68.6)	(68.6)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Updated Total	Original Total
Capital-Related RR (Rate Order, Feb. 29, 2016 - Table 2)	430.5	456.3	506.6	549.5	583.2	2,526.0	2,526.0
RR impact from the application of stretch factor to capital funding[2]	-	(2.6)	(5.4)	(8.4)	(11.7)	(28.1)	(28.1)
Capital-Related RR in Approved 2015-2019 Rates	430.5	453.7	501.2	541.0	571.5	2,497.9	2,497.9
Sub-account 1508 - Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)
Sub-account 1508 - Derecognition Variance Account	(12.9)	1.3	(3.9)	(5.5)	(12.1)	(33.1)	(40.8)
Other Adjustments[3]	(1.2)	0.6	(1.4)	(0.7)	3.5	0.8	(6.1)
Capital-Related RR in Approved Rates eligible for CRRRVA	416.2	455.1	495.3	533.9	562.1	2,462.5	2,448.8
Actual Historic & Forecast Bridge Capital-Related RR	413.6	449.3	481.0	503.9	539.3	2,387.1	2,391.2
Sub-account 1508 – CRRRVA	**(2.7)**	**(5.8)**	**(14.3)**	**(30.0)**	**(22.8)**	**(75.6)**	**(57.6)**
CRRRVA – carrying charges	(0.0)	(0.1)	(0.2)	(0.6)	(1.4)	(2.3)	(1.8)
Total	**(2.7)**	**(5.9)**	**(14.5)**	**(30.6)**	**(24.2)**	**(77.9)**	**(59.4)**

Note: Rounding differences may exist.

[2] Decision on Draft Rate Order, February 25, 2016, p. 3; Draft Rate Order, February 29, 2016, p. 5.
[3] These adjustments are primarily to account for variances in opening 2015 rate base and disposals. As is the case for Externally Driven Capital and Derecognition, these capital-related variances are outside the OEB-approved scope of the CRRRVA.

3.5 Account 1508 – Other Regulatory Assets, Subaccount – Externally Driven Capital Variance Account

The balance for clearance in this account has been updated from $2.2 million to $3.1 million credit (refund) to customers. The difference is driven by lower in-service additions amount in 2018. The tables below set out the actual/forecast versus approved expenditures and revenue requirement for 2015-2019.

Table 5: Externally Driven Capital Expenditures (2015-2019) ($ Millions)

Year	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Total Project Cost	3.8	9.0	12.5	24.2	21.2	70.7	72.0
Customer Contributions	1.6	6.4	9.9	18.3	12.9	49.1	48.7
Toronto Hydro Cost	2.2	2.6	2.6	5.9	8.3	21.6	23.2
Approved Capital Spend	4.0	4.0	4.0	4.0	4.0	20.0	20.0
Variance	(1.8)	(1.4)	(1.4)	1.9	4.3	1.6	3.2

Note: Rounding differences may exist.

Table 6: Externally Driven Capital Revenue Requirement (2015-2019) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Approved Externally Driven Capital ISA	4.0	4.0	4.0	4.0	4.0	20.0	20.0
Actual and Bridge Externally Driven Capital ISA	0.2	0.1	2.4	0.1	10.1	12.9	18.2
Variance	(3.8)	(3.9)	(1.6)	(3.9)	6.1	(7.1)	(1.8)
Revenue requirement impact	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)
Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Externally Driven Capital Variance Account – carrying charges	-	-	-	(0.0)	(0.1)	(0.1)	(0.1)
Total	**(0.2)**	**(0.5)**	**(0.7)**	**(0.9)**	**(0.9)**	**(3.2)**	**(2.3)**

Note: Rounding differences may exist.

Revenue Requirement Calculation	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Rate Base	(1.9)	(5.6)	(8.1)	(10.6)	(9.2)		
Return on equity	(0.1)	(0.2)	(0.3)	(0.4)	(0.3)	(1.3)	(1.0)
Interest	-	(0.1)	(0.2)	(0.3)	(0.2)	(0.8)	(0.6)
Depreciation	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(1.1)	(0.7)
PILs	-	-	-	-	-	-	0.1
Revenue Requirement	(0.2)	(0.5)	(0.7)	(0.9)	(0.8)	(3.1)	(2.2)

Note: Rounding differences may exist.

3.6 Account 1508 – Other Regulatory Assets, Subaccount – Derecognition

The balance for clearance in this account has been updated from $42.1 million to $34.5 million credit (refund) to customers. The difference is driven by higher derecognition in 2018 for distribution assets and for software as a result of implementing the new ERP system. Toronto Hydro updated the 2019 forecast based on a four year average of derecognition expense as opposed to using a three year average.

Table 7: Derecognition ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Losses on derecognition included in approved rates	33.9	26.6	28.0	29.4	32.6	150.5	150.5

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Actual and forecast losses on derecognition	24.1	27.0	24.5	24.5	22.4	122.5	116.5
Variance	(9.8)	0.4	(3.5)	(4.9)	(10.2)	(28.0)	(34.0)
PILs	(3.4)	0.2	(1.2)	(1.7)	(3.6)	(9.8)	(11.9)
Capital revenue requirement	0.4	0.7	0.7	1.1	1.7	4.7	5.1
Derecognition variance account	(12.8)	1.3	(4.0)	(5.5)	(12.1)	(33.1)	(40.8)
Derecognition variance account – carrying charges	(0.1)	(0.1)	(0.2)	(0.4)	(0.6)	(1.4)	(1.3)
Total	**(12.9)**	**1.2**	**(4.2)**	**(5.9)**	**(12.7)**	**(34.5)**	**(42.1)**

Note: Rounding differences may exist.

Capital revenue requirement calculation	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Rate Base	4.9	9.6	11.1	15.2	22.8		
Return on equity	0.2	0.4	0.4	0.6	0.8	2.4	2.6
Interest expense	0.1	0.2	0.2	0.4	0.6	1.4	1.6
PILs	0.1	0.1	0.1	0.2	0.3	0.8	0.9
Capital revenue requirement	0.4	0.7	0.7	1.1	1.7	4.7	5.1

Note: Rounding differences may exist.

3.7 Account 1508 – Other Regulatory Assets, Subaccount – Wireless Attachments

There were no material changes to this account in 2018.

3.8 Account 1508 – Other Regulatory Assets, Subaccount – Monthly Billing

There were no material changes to this account in 2018.

3.9 Account 1508 – Other Regulatory Assets, Subaccount – OCCP

The balance for clearance in this account has been updated from $71.2 million to $73.5 million credit (refund) to customers. The change is a result of updated carrying charges and updated total 2018 disposition amounts.

Table 12: OCCP ($ Millions)

	Original OCCP Variance Account			Total Update
	5800 Yonge	28 Underwriters	Total	
Net gain, net of tax	98.6	6.0	104.6	104.6
Tax Savings after gross-up	35.5	2.1	37.6	37.6
Actual net gain before carrying charges	**134.1**	**8.1**	**142.2**	**142.2**
Carrying Charges			1.5	1.7
Total net gain for clearance			**143.7**	**143.9**
Forecasted total disposition up to 2018	(60.4)	(12.1)	(72.5)	(70.4)
OCCP balance for clearing			**71.2**	**73.5**

3.10 Account 1508 – Other Regulatory Assets, Subaccount – OPEB Cash vs Accrual

The balance in this account has been updated from $8.9 million to $8.1 million. The change in is the result of the updated 2018 cash payments (to reflect actual payments incurred) and updated 2019 forecasted payments based on the most recent actuarial valuation (Exhibit U, Tab 4A, Schedule 3, Appendix C), in addition to an immaterial update to the forecasted OPEB costs.

Table 13: Cash versus Accrual Variance ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Forecasted OPEB costs (OM&A programs)	10.2	10.4	10.6	10.6	10.6	52.4	53.1
Estimated Capital Depreciation Collected for OPEB	2.2	2.4	2.6	2.8	3.0	13.0	13.0
Amount collected through rates (A)	12.4	12.8	13.2	13.4	13.6	65.4	66.1
Less: Cash payments (B)	9.1	10.8	10.9	10.9	8.9	50.6	50.0
Difference (C) = (A) – (B)	3.3	2.0	2.3	2.5	4.7	14.8	16.1
OpEx/Capex split (D)	56.2%	57.4%	55.0%	55.1%	55.2%		
Cash versus accrual variance (C) x (D)	1.8	1.1	1.3	1.3	2.6	8.1	8.9

Note: Rounding differences may exist.

3.11 Account 1533 – Renewable Generation Connection Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment Variances

The balance in this account has been updated from $5.1 million to $6.5 million. The change is due to lower than expected in-service additions in 2018.

Table 14: Provincially Funded Renewable Eligible Investment Variance Account ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
Approved Revenue Requirement	0.3	0.9	1.5	2.1	2.6	7.4	7.4
Actual/Forecast Revenue Requirement	-	-	0.1	0.1	0.6	0.8	2.2
Variance Account Balance	(0.3)	(0.9)	(1.4)	(2.0)	(2.0)	(6.6)	(5.2)

Note: Rounding differences may exist.

3.12 New Deferral Account Requested: Excess Expansion Deposits

The balance in this account has been updated from $5.5 million to $8.0 million as a result of excess expansion deposits realized in 2018.

Table 15: Excess Expansion Deposits ($ Millions)

	Principal Balance as at Dec 31	Carrying Charge Balance	Total Balances as at Dec 31
2016	4.0	0.1	4.1
2017	5.1	0.2	5.3
2018 Updated	7.5	0.4	7.9
2019 Updated	7.5	0.5	8.0
2019 Original	5.1	0.4	5.5

4. TORONTO HYDRO SEEKS CLEARANCE OF GROUP 1 ACCOUNTS

Toronto Hydro requests disposition of the Group 1 DVA account balances, including RSVAs and SME charges. The GA Workform at Appendix B and the Account 1595 Workform at Appendix C support the request.

5. SUMMARY OF PROPOSED DVA DISPOSITIONS

Table 16: Summary of Proposed Dispositions for Group 1 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	2017 Balances approved for clearance (including CC)	Projected Interest for 2019	2018 Balances requesting for clearance
Group 1 Accounts					
LV Variance Account	0.7	0.0	0.4	0.0	0.3
RSVA – Wholesale Market Service Charges	(29.4)	(0.6)	(25.8)	(0.1)	(4.3)
Variance WMS – Sub-account CBR Class B	0.0	0.0	0.6	0.0	(0.6)

	Principal Balance as of Dec 31, 2018	Carrying Charge Balance as of Dec 31, 2018	2017 Balances approved for clearance (including CC)	Projected Interest for 2019	2018 Balances requesting for clearance
RSVA – Retail Transmission Network Charge	17.0	0.3	8.3	0.2	9.2
RSVA – Retail Transmission Connection Charge	25.7	0.3	8.5	0.4	17.9
RSVA – Power	(8.8)	(0.2)	(3.4)	(0.1)	(5.6)
RSVA – Global Adjustment	(17.3)	0.5	6.9	(0.5)	(24.3)
Total Retail Settlement Variance Account ("RSVA")	**(12.1)**	**0.3**	**(4.5)**	**(0.1)**	**(7.4)**
Smart Meter Entity Charges	(0.8)	(0.0)	(0.1)	(0.0)	(0.7)
Total Group 1 Balances	**(12.9)**	**0.3**	**(4.6)**	**(0.2)**	**(8.2)**

Table 17: Summary of Proposed Dispositions for Group 2 Accounts ($ Millions)

	Original			Updated		
	Principal Balance	Carrying Charges up to Dec 31, 2019	Balances for clearance as at Dec 31, 2019	Principal Balance	Carrying Charges up to Dec 31, 2019	Balances for clearance as at Dec 31, 2019
Stranded Meter Costs	(1.4)	—	(1.4)	(1.4)	—	(1.4)
IFRS-USGAAP Transitional PP&E Amounts	(1.6)	—	(1.6)	(1.6)	—	(1.6)
Impact for USGAAP Deferral	85.3	—	85.3	48.1	—	48.1
CRRRVA	(57.6)	(1.8)	(59.4)	(75.6)	(2.3)	(77.9)
Externally Driven Capital	(2.2)	(0.1)	(2.3)	(3.1)	(0.1)	(3.2)
Derecognition	(40.8)	(1.3)	(42.1)	(33.1)	(1.4)	(34.5)
Wireless Attachments	(0.6)	(0.0)	(0.6)	(0.6)	(0.0)	(0.6)
Monthly Billing	11.5	0.3	11.8	11.5	0.4	11.8
OCCP	(69.7)	(1.5)	(71.2)	(71.8)	(1.7)	(73.5)
OPEB Cash vs Accrual	8.9	—	8.9	8.1	—	8.1
Excess Expansion Deposits	(5.1)	(0.4)	(5.5)	(7.5)	(0.5)	(8.0)
Total Balance	**(73.3)**	**(4.8)**	**(78.1)**	**(127.0)**	**(5.6)**	**(132.6)**

6. RATE RIDERS

Appendices D and E explain how the rate riders were calculated for each of the proposed clearances. The balances have been allocated to the rate classes in accordance with the OEB's EDDVAR Report (EB-2008-0046). Toronto Hydro applied the structure and logic of the DVA Workform but modified the calculations of rate riders found in the DVA Workform as necessary to take into account the utility's specific requests.

7. 2018 EARNINGS SHARING MECHANISM ("ESM") CALCULATION

Toronto Hydro's 2018 ESM calculation is shown in the Table 18 below. The utility did not surpass the ESM threshold in 2018.

1 **Table 18: 2015-2018 ESM Calculations[4] ($ Millions)**

		2015	2016	2017	2018
OM&A [a]	*A*	244.0	246.6	250.6	262.9
Revenue Offsets [a]	*B*	- 39.9	- 50.2	- 51.7	-52.8
Unadjusted non-capital revenue requirement ("Non-CRRR")	*C=A+B*	**204.1**	**196.4**	**198.9**	**210.2**
RRR Adjustments [b]					
Depreciation expense related to non-regulated assets (renewable energy investment)	*D*	-	-	- 0.0	-0.1
Non-recoverable expenses – donations and meals	*E*	- 0.4	- 0.4	- 0.6	-0.8
Subtotal	*F=C+D+E*	**203.7**	**196.1**	**198.2**	**209.2**
Adjustments for items not included in rates					
Amortization of 2014 balance in DVA account 1575 – IFRS USGAAP Transitional PP&E Amounts [c]	*G*	-	5.2	6.6	6.7
Amortization of capital contributions (deferred revenue) [d]	*H*	2.2	3.8	4.7	5.3
Actual non-CRRR items for ESM purposes	*I=F+G+H*	**206.0**	**205.1**	**209.5**	**221.2**
Less: non-CRRR embedded in rates [e,f]	*J*	**202.7**	**205.7**	**208.3**	**209.6**
Non-CRRR difference	*K=I-J*	3.3	- 0.6	1.2	11.6
Deemed equity portion of actual rate base [g]	*L*	1,285.2	1,420.1	1,540.4	1649.5
Non-CRRR difference	*M=K/L*	0.26%	- 0.04%	0.08%	0.70%
ESM threshold	*N*	1.00%	1.00%	1.00%	1.00%
ESM test result	*M compared to N*	Within threshold	Within threshold	Within threshold	Within threshold

Rounding variances may exist.
[a] Source: RRR 2.1.7 - trial balance.
[b] Source: RRR 2.1.5.6 - Appendices 1 and 2.
[c] Source: RRR 2.1.7 - trial balance account 4310, reported as revenue offsets.
[d] Source: RRR 2.1.7 - trial balance account 4245, reported as revenue offsets.
[e] EB-2014-0116, Decision and Order (29th Dec, 2015), page 49
f 2015 non-CRRR is from EB-2014-0116, Draft Rate Order Update (29th Feb, 2016), Table 2, Page 6. To determine 2016 and 2017 amount, I (2.1% and 1.9%) and X (0.6% and 0.6%) was applied to the previous year amount.
[g] Source: RRR 2.1.5.6 - ROE Summary.

[4] Source: Toronto Hydro's annual RRR submissions.

Ontario Energy Board

2019 Deferral/Variance Account Workform

version 1.0

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

2019 Deferral/Variance Account Workform

Instructions

Tab	Tab Details	Step	Instructions
2 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.	1	Complete the DVA continuity schedule. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2018 rate application, DVA balances as at December 31, 2016 were approved for disposition, start the continuity schedule from 2016 by entering the closing 2015 balances in the Adjustments column under 2015. For all Account 1595 sub-accounts, complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2017 regardless of whether the account is being requested for disposition in the current application. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2015) would have information starting in 2015, when the relevant balances approved for disposition were first transferred into Account 1595 (2015). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year.
		2a	If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (e.g. last disposition was for 2015 balances in the 2017 rate application, current balance requested for disposition accumulated from 2016 to 2017), check off the checkbox in cell BS13. If the checkbox is not checked off, then proceed to tabs 3 to 7 and complete the tabs accordingly. If the checkbox is checked off, tab 6 relating to Class A customer consumption will be generated, see step 7 to 10 below for further details. If the checkbox in step 2a is checked off, another checkbox will pop up to the right of the previous checkbox. If you had any Class A customers at any point during the period that the Account 1580, sub-account CBR Class B balance accumulated (e.g. 2016, 2017 or 2016 & 2017), check off the checkbox. If the checkbox is not checked off, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account 1580 WMS, as a part of the general DVA rate rider. If the checkbox is checked off, then tab 6.2 will be generated. This tab will calculate the billing determinants applicable to Account 1580 sub-account CBR Class B, using information inputted in tab 6. See step 12 below for further details. The CBR Class B balance will be allocated in tab 6.2a and the rate rider will be calculated in tab 7.
		2b	Enter the number of utility-specific 1508 sub-accounts that are approved for the utility in the textbox in cell B71. The DVA continuity schedule will generate the number of utility-specific 1508 sub-accounts starting in row 51. Input the name and the balances of the sub-account(s) starting in row 51. If a utility does not have utility-specific 1508 sub-accounts, the generic 1508 sub-account Other will still be listed in the DVA continuity schedule. Check off the "check to dispose of account" checkbox in column BT for sub-accounts requested for disposition.
3. Appendix A	This tab shows the year end balance variances between the continuity schedule	3	Provide an explanation for the variances identified.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.	4	Complete the billing determinants table. Note that columns O and P are generated when a utility indicates they have Class A customers in tab 2a. Information in these columns are populated based on data from tab 6
5 - Allocating Def-Var Balances	This tab allocates the DVA balance (except for CBR Class B if Class A customers exist).	5	Review the allocated balances to ensure the allocation is appropriate. Note that the allocations for Account 1589, Account 1580, sub-account CBR Class B will be determined after tabs 6 to 6.2a have been completed.

Ontario Energy Board

2019 Deferral/Variance Account Workform

Instructions

Tab	Tab Details	Step	Instructions
6 - Class A Data Consumption	This is a new tab that is to be completed if there were any Class A customers at any point during the period the GA balance CBR Class B balance accumulated. The tab also considers Class A/B transition customers. The data on this tab is used for the purposes of determining the GA rate rider, CBR Class B rate rider (if applicable), as well as customer specific GA and CBR Class B charges for transition customers (if applicable).	6	This tab is generated when the utility checks in tab 2a. that they have Class A customers during the period that the GA balance accumulated. Under #1, enter the year for which the Account 1589 GA balance was last disposed.
		7	Under #2a, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accumulated. If no, proceed to #3b in step 9. If yes, #2b and tab 6.1a. will be generated. Proceed to #2b. Under #2b, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR Class B balance accumulated. If no, proceed to #3a in step 8. If yes, tab 6.2a. will be generated. Proceed to #3a in step 8.
		8	Under #3a, enter the number of transition customers during the period the Account 1589 GA balance accumulated. A table will be generated based on the number of customers. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and the customer class during the half year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition customers in tabs 6.1a. and 6.2a., respectively. Each transition customer identified in tab 6, table 3a will be assigned a customer number and the number will correspond to the same transition customers populated in tabs 6.1a. and 6.2a. The data in tab 6 will also be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
		9	Under #3b, enter the number of customers who were Class A customers during the entire period since the year the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B during the period). A table will be generated based on the number of customers. Complete the table accordingly for each Class A customer identified. This data will be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
6.1a. - GA Allocation	This tab has been revised. It allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers who contributed to the GA balance but are now Class A customers and former Class A customers who are now Class B customers contributing to the GA balance).	10	This tab is generated when the utility indicates that they have transition customers in tab 6, #2a during the period when the GA balance accumulated. In row 20, enter the total Class B consumption which equals to Non-RPP consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the GA balance to transition customers in the bottom table. All transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B GA rate rider as calculated in tab 7.
6.2 - CBR	This is a new tab that calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.	11	This tab is generated when the utility checks in tab 2a. that they have Class A customers during the period that Account 1580, sub-account CBR Class B balance accumulated. The rest of the information in the tab is auto-populated and will be used in the calculation of the CBR Class B rate rider calculated in tab 6.
6.2a - CBR_B Allocation	This is a new tab that allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers who contributed to the balance but are now Class A customers and former Class A customers who are now Class B contributing to the balance).	12	This tab is generated when the utility indicates that they have transition customers in tab 6, #2b during the period where the CBR Class B balance accumulated. In B16 select the year when the balance in CBR Class B was last disposed. In row 20, enter the total Class B consumption which equals to total consumption less WMP consumption and consumption for Class A customers (who were Class A for eiher partial or full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the CBR Class B balance to transition customers in the bottom table. Note that the transition customers for GA may be different than the transition customers for CBR Class B as this would depend on the period in which the GA and CBR Class B balances accumulated. Any transition customer who is allocated a specific CBR Class B amount is not to be charged the general CBR Class B rate rider.
7 - Calculation of Def-Var RR	This tab calculates all the applicable DVA rate riders.	13	Enter the proposed rate rider recovery period if different than the default 12 month period. For each rate class of each rate rider, select whether the rate rider is to be calculated on a kWh, kW or number of customers basis. The rest of the information in the tab is auto-populated and the rate riders are calculated accordingly .

Ontario Energy Board

Deferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2017, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

		2012									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts											
LV Variance Account	1550					$0					$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[9]	1580					$0					$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584					$0					$0
RSVA - Retail Transmission Connection Charge	1586					$0					$0
RSVA - Power (excluding Global Adjustment)[12]	1588					$0					$0
RSVA - Global Adjustment [12]	1589					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

		2013									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551					$0	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588	$0				$0	$0				$0
RSVA - Global Adjustment [12]	1589	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB

Ontario Energy Board

eferral/Variance Account

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
Group 1 Accounts											
LV Variance Account	1550	$0	$1,680,006			$1,680,006	$0	$48,585			$48,585
Smart Metering Entity Charge Variance Account	1551	$0	$230,907			$230,907	$0	$10,096			$10,096
RSVA - Wholesale Market Service Charge[9]	1580	$0	-$104,177,755			-$104,177,755	$0	-$4,243,265			-$4,243,265
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0	$60,297,064			$60,297,064	$0	$1,969,184			$1,969,184
RSVA - Retail Transmission Connection Charge	1586	$0	$28,085,714			$28,085,714	$0	$981,663			$981,663
RSVA - Power (excluding Global Adjustment)[12]	1588	$0	-$18,770,687			-$18,770,687	$0	$0			$0
RSVA - Global Adjustment [12]	1589	$0	$85,657,811			$85,657,811	$0	$2,633,307			$2,633,307
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	-$363,600			-$363,600	$0	-$318,137			-$318,137
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	-$2,483,823			-$2,483,823	$0	$1,563,823			$1,563,823
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$109,729			$109,729	$0	-$261,355			-$261,355
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$95,890			$95,890	$0	-$55,626			-$55,626
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$50,361,255	$0	$0	$50,361,255	$0	$2,328,275	$0	$0	$2,328,275
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	-$35,296,556	$0	$0	-$35,296,556	$0	-$305,032	$0	$0	-$305,032
RSVA - Global Adjustment 12	**1589**	$0	$85,657,811	$0	$0	$85,657,811	$0	$2,633,307	$0	$0	$2,633,307

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15
Group 1 Accounts											
LV Variance Account	1550	$1,680,006	$447,453			$2,127,459	$48,585	$22,355			$70,940
Smart Metering Entity Charge Variance Account	1551	$230,907	-$103,295			$127,611	$10,096	$2,861			$12,957
RSVA - Wholesale Market Service Charge[9]	1580	-$104,177,755	-$53,058,389			-$157,236,144	-$4,243,265	-$1,397,797			-$5,641,062
Variance WMS – Sub-account CBR Class A[9]	1580		$554,306			$554,306	$0	$1,757			$1,757
Variance WMS – Sub-account CBR Class B[9]	1580		$5,967,910			$5,967,910	$0	$19,743			$19,743
RSVA - Retail Transmission Network Charge	1584	$60,297,064	$6,453,241			$66,750,305	$1,969,184	$753,147			$2,722,331
RSVA - Retail Transmission Connection Charge	1586	$28,085,714	$7,451,237			$35,536,950	$981,663	$375,400			$1,357,063
RSVA - Power (excluding Global Adjustment)[12]	1588	-$18,770,687	-$3,662,931			-$22,433,618	$0	-$261,729			-$261,729
RSVA - Global Adjustment [12]	1589	$85,657,811	$8,710,805			$94,368,616	$2,633,307	$1,177,873			$3,811,180
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600	$0			-$363,600	-$318,137	-$48,826			-$366,963
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823	$0			-$2,483,823	$1,563,823	$17,095			$1,580,918
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729	$0			$109,729	-$261,355	$1,308			-$260,047
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$55,626	$1,139			-$54,487
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$50,361,255	-$27,239,665	$0	$0	$23,121,590	$2,328,275	$664,326	$0	$0	$2,992,600
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$35,296,556	-$35,950,470	$0	$0	-$71,247,026	-$305,032	-$513,547	$0	$0	-$818,579
RSVA - Global Adjustment 12	**1589**	$85,657,811	$8,710,805	$0	$0	$94,368,616	$2,633,307	$1,177,873	$0	$0	$3,811,180

For all OEB-Approved dispositions, please ensure that the disposition an balances are to have a positive figure and credit balance are to have a n

Ontario Energy Board

eferral/Variance Account

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

2016

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 1 Accounts											
LV Variance Account	1550	$2,127,459	$312,025	$1,192,584		$1,246,899	$70,940	$15,001	$64,774		$21,166
Smart Metering Entity Charge Variance Account	1551	$127,611	-$379,776	$435,919		-$688,084	$12,957	$14,090	$16,147		$10,900
RSVA - Wholesale Market Service Charge[9]	1580	-$157,236,144	-$26,035,861			-$183,272,005	-$5,641,062	-$1,776,861			-$7,417,923
Variance WMS – Sub-account CBR Class A[9]	1580	$554,306		$554,306		$0	$1,757		$1,757		$0
Variance WMS – Sub-account CBR Class B[9]	1580	$5,967,910	$1,535,334			$7,503,244	$19,743	$14,282	$19,743		$14,282
RSVA - Retail Transmission Network Charge	1584	$66,750,305	-$16,414,401			$50,335,904	$2,722,331	$664,278			$3,386,608
RSVA - Retail Transmission Connection Charge	1586	$35,536,950	-$29,949,890			$5,587,061	$1,357,063	$271,369			$1,628,432
RSVA - Power (excluding Global Adjustment)[12]	1588	-$22,433,618	-$4,099,996		-$804,747	-$27,338,361	-$261,729	-$265,904			-$527,633
RSVA - Global Adjustment [12]	1589	$94,368,616	-$14,088,418		$804,747	$81,084,945	$3,811,180	$1,131,533			$4,942,712
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-$363,600		-$363,600		$0	-$366,963	-$26,599	-$393,562		-$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-$2,483,823		-$2,483,823		-$0	$1,580,918	-$66,708	$1,514,210		-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	$109,729		$109,729		-$0	-$260,047	-$12,853	-$272,900		$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$95,890				$95,890	-$54,487	$966			-$53,521
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$8,704,230	-$45,304,160		$54,008,390	$0	-$28,061	-$131,074		$103,013
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$23,121,590	-$80,416,753	-$45,859,045	$0	-$11,436,118	$2,992,600	-$65,468	$819,096	$0	$2,108,037
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$71,247,026	-$66,328,336	-$45,859,045	-$804,747	-$92,521,064	-$818,579	-$1,197,000	$819,096	$0	-$2,834,676
RSVA - Global Adjustment 12	**1589**	$94,368,616	-$14,088,418	$0	$804,747	$81,084,945	$3,811,180	$1,131,533	$0	$0	$4,942,712

2017

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 1 Accounts											
LV Variance Account	1550	$1,246,899	$394,328	$934,874		$706,353	$21,166	$6,808	$19,906		$8,068
Smart Metering Entity Charge Variance Account	1551	-$688,084	-$113,182	-$308,308		-$492,958	$10,900	-$15,080	-$7,181		$3,001
RSVA - Wholesale Market Service Charge[9]	1580	-$183,272,005	-$25,199,715	-$157,236,144		-$51,235,576	-$7,417,923	-$555,630	-$7,370,570		-$602,984
Variance WMS – Sub-account CBR Class A[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580	$7,503,244	$524,231	$5,967,910		$2,059,564	$14,282	$20,888	$85,385		-$50,215
RSVA - Retail Transmission Network Charge	1584	$50,335,904	$8,096,178	$66,750,305		-$8,318,223	$3,386,608	-$83,173	$3,456,545		-$153,109
RSVA - Retail Transmission Connection Charge	1586	$5,587,061	$8,333,125	$35,536,950		-$21,616,765	$1,628,432	-$278,307	$1,747,948		-$397,823
RSVA - Power (excluding Global Adjustment)[12]	1588	-$27,338,361	-$3,337,116	-$22,433,618		-$8,241,858	-$527,633	-$93,593	-$508,477		-$112,749
RSVA - Global Adjustment [12]	1589	$81,084,945	$56,920,194	$94,368,616	-$50,366,169	-$6,729,646	$4,942,712	$274,057	$4,812,604	-$127,586	$276,580
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0				$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-$0				-$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	-$0				-$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$95,890		$95,890		-$0	-$53,521		-$53,433		-$88
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$54,008,390	-$13,829,257			$40,179,133	$103,013	-$18,718		-$993,537	-$909,242
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$2,791,740			$2,791,740	$0	$142,065			$142,065
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$11,436,118	$34,580,526	$23,676,474	-$50,366,169	-$50,898,236	$2,108,037	-$600,683	$2,182,727	-$1,121,123	-$1,796,497
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$92,521,064	-$22,339,668	-$70,692,141	$0	-$44,168,591	-$2,834,676	-$874,740	-$2,629,877	-$993,537	-$2,073,076
RSVA - Global Adjustment 12	**1589**	$81,084,945	$56,920,194	$94,368,616	-$50,366,169	-$6,729,646	$4,942,712	$274,057	$4,812,604	-$127,586	$276,580

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

Ontario Energy Board

eferral/Variance Account

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

		2018										2019			
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-18**	**Transactions(1) Debit / (Credit) during 2018**	**OEB-Approved Disposition during 2018**	**Principal Adjustments(2) during 2018**	**Closing Principal Balance as of Dec-31-18**	**Opening Interest Amounts as of Jan-1-18**	**Interest Jan-1 to Dec-31-18**	**OEB-Approved Disposition during 2018**	**Interest Adjustments(2) during 2018**	**Closing Interest Amounts as of Dec-31-18**	**Principal Disposition during 2019 - instructed by OEB**	**Interest Disposition during 2019 - instructed by OEB**	**Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019**	**Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019**
Group 1 Accounts															
LV Variance Account	1550	$706,353	$320,000	$312,025	$0	$714,328	$8,068	$10,579	$5,861	$0	$12,787	$394,328	$9,276	$320,000	$3,511
Smart Metering Entity Charge Variance Account	1551	-$492,958	-$727,042	-$379,776	$0	-$840,224	$3,001	-$1,169	$13,241	$0	-$11,409	-$113,182	-$19,076	-$727,042	$7,667
RSVA - Wholesale Market Service Charge[9]	1580	-$51,235,576	-$4,206,092	-$26,035,862	$0	-$29,405,806	-$602,984	-$497,277	-$498,414	$0	-$601,847	-$25,199,715	-$556,274	-$4,206,092	-$45,573
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$2,059,564	-$570,685	$1,535,334	$0	-$46,455	-$50,215	$6,908	-$52,680	$0	$9,373	$524,231	$11,862	-$570,686	-$2,489
RSVA - Retail Transmission Network Charge	1584	-$8,318,223	$8,947,315	-$16,414,402	$0	$17,043,495	-$153,109	$200,783	-$205,715	$0	$253,388	$8,096,178	$197,730	$8,947,316	$55,658
RSVA - Retail Transmission Connection Charge	1586	-$21,616,765	$17,363,768	-$29,949,890	$0	$25,696,892	-$397,823	$277,670	-$446,320	$0	$326,167	$8,333,125	$197,868	$17,363,768	$128,299
RSVA - Power (excluding Global Adjustment)[12]	1588	-$8,241,858	-$5,431,100	-$4,904,742	$0	-$8,768,216	-$112,749	-$152,662	-$98,572	$0	-$166,840	-$3,337,116	-$73,995	-$5,431,100	-$92,845
RSVA - Global Adjustment [12]	1589	-$6,729,646	-$23,898,524	-$13,283,671	$0	-$17,344,499	$276,580	$274,390	$57,211	$0	$493,759	$6,554,025	$341,438	-$23,898,523	$152,321
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	$0	$0	$0	$0	-$0	$0	$0	$0	-$0	$0	$0	$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-$0	$0	$0	$0	-$0	-$0	$0	$0	$0	-$0	$0	$0	-$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	-$0	$0	$0	$0	-$0	$0	$0	$0	$0	$0	$0	$0	-$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	-$0	$0	$0	$0	-$0	-$88	$0	$0	$0	-$88	$0	$0	-$0	-$88
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$40,179,133	-$14,888,043	$0	$0	$25,291,090	-$909,242	-$91,080	$0	$0	-$1,000,322	$0	$0	$25,291,090	-$1,000,322
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$2,791,740	-$2,695,385	$0	$0	$96,355	$142,065	-$35,114	$0	$0	$106,951	$0	$0	$96,355	$106,951
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	-$6,348,433	$0	$0	-$6,348,433	$0	-$711,779	$0	$0	-$711,779	$0	$0	-$6,348,433	-$711,779
Not to be disposed of until a year after rate rider has expired and that balanc															
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$50,898,236	-$32,134,222	-$89,120,985	$0	$6,088,526	-$1,796,497	-$718,751	-$1,225,388	$0	-$1,289,859	-$4,748,127	$108,829	$10,836,653	-$1,398,688
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$44,168,591	-$8,235,698	-$75,837,313	$0	$23,433,025	-$2,073,076	-$993,140	-$1,282,599	$0	-$1,783,618	-$11,302,151	-$232,609	$34,735,176	-$1,551,009
RSVA - Global Adjustment 12	**1589**	-$6,729,646	-$23,898,524	-$13,283,671	$0	-$17,344,499	$276,580	$274,390	$57,211	$0	$493,759	$6,554,025	$341,438	-$23,898,523	$152,321

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

Ontario Energy Board

)eferral/Variance Account

If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2017), check off the checkbox ☐

If you had Class A customer(s) during this period, Tab 6 will be generated and applicants must complete the information pertaining to Class A customers.

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustn example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

Account Descriptions	Account Number	Projected Interest on Dec-31-18 Balances: Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)	Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)	Total Interest		Total Claim	2.1.7 RRR: As of Dec 31-18	Variance RRR vs. 2018 Balance (Principal + Interest)
Group 1 Accounts								
LV Variance Account	1550	$7,192	$0	$10,703		$330,703.40	$727,114	-$1
Smart Metering Entity Charge Variance Account	1551	-$18,884	$0	-$11,217		-$738,258.55	-$851,633	-$0
RSVA - Wholesale Market Service Charge[9]	1580	-$94,532	$0	-$140,105		-$4,346,196.35	-$30,093,038	-$85,385
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0		$0.00	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	-$12,826	$0	-$15,316		-$586,001.52	$48,303	$85,385
RSVA - Retail Transmission Network Charge	1584	$201,091	$0	$256,749		$9,204,065.53	$17,296,882	-$0
RSVA - Retail Transmission Connection Charge	1586	$390,251	$0	$518,550		$17,882,317.91	$26,023,060	-$0
RSVA - Power (excluding Global Adjustment)[12]	1588	-$122,064	$0	-$214,909		-$5,646,008.99	-$8,935,056	$0
RSVA - Global Adjustment [12]	1589	-$537,119	$0	-$384,799		-$24,283,321.89	-$16,850,741	-$1
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	$0	-$0		$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$0	$0	-$0		$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$0	$0	-$88	☐ Check to Dispose of Account	$0.00	$0	$88
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0	-$1,000,322	☐ Check to Dispose of Account	$0.00	$24,290,768	$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$0	$106,951	☐ Check to Dispose of Account	$0.00	$203,308	$1
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	$0	-$711,779	☐ Check to Dispose of Account	$0.00	-$7,060,210	$2
Not to be disposed of until a year after rate rider has expired and that balance								
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$186,892	$0	-$1,585,580		-$8,182,700	$4,798,757	$89
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$350,227	$0	-$1,200,781		$16,100,621.45	$21,649,498	$90
RSVA - Global Adjustment 12	**1589**	-$537,119	$0	-$384,799	☐ Check to Dispose of Account	-$24,283,321.89	-$16,850,741	-$1

For all OEB-Approved dispositions, please ensure that the disposition an balances are to have a positive figure and credit balance are to have a n

Account Descriptions	Account Number	2012 Opening Principal Amounts as of Jan-1-12	2012 Transactions(1) Debit / (Credit) during 2012	2012 OEB-Approved Disposition during 2012	2012 Principal Adjustments(2) during 2012	2012 Closing Principal Balance as of Dec-31-12	2012 Opening Interest Amounts as of Jan-1-12	2012 Interest Jan-1 to Dec-31-12	2012 OEB-Approved Disposition during 2012	2012 Interest Adjustments(1) during 2012	2012 Closing Interest Amounts as of Dec-31-12	2013 Opening Principal Amounts as of Jan-1-13	2013 Transactions(1) Debit / (Credit) during 2013	2013 OEB-Approved Disposition during 2013	2013 Principal Adjustments(2) during 2013	2013 Closing Principal Balance as of Dec-31-13	2013 Opening Interest Amounts as of Jan-1-13	2013 Interest Jan-1 to Dec-31-13	2013 OEB-Approved Disposition during 2013	2013 Interest Adjustments(2) during 2013	2013 Closing Interest Amounts as of Dec-31-13
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508		$61,499,000			$61,499,000					$0	$61,499,000	-$22,718,000			$38,781,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518					$0					$0	$0				$0	$0				$0
Misc. Deferred Debits	1525					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548					$0					$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567					$0					$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572					$0					$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574					$0					$0	$0				$0	$0				$0
RSVA - One-time	1582					$0					$0	$0				$0	$0				$0
Other Deferred Credits	2425					$0					$0	$0				$0	$0				$0
Group 2 Sub-Total			$61,499,000	$0	$0	$61,499,000	$0	$0	$0	$0	$0	$61,499,000	-$22,718,000	$0	$0	$38,781,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				-$2,314,616	-$2,314,616				-$83,852	-$83,852	-$2,314,616				-$2,314,616	-$83,852	-$34,020			-$117,872
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				-$1,100,000	-$1,100,000				-$34,148	-$34,148	-$1,100,000				-$1,100,000	-$34,148	-$16,169			-$50,317
LRAM Variance Account[11]	**1568**					$0					$0	$0				$0	$0				$0
Total including Account 1568		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000	$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
Renewable Generation Connection Capital Deferral A	1531					$0					$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532					$0					$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533					$0					$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534					$0					$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535					$0					$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555				$59,226,643	$59,226,643					$0	$59,226,643	-$59,226,643			$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555				-$27,078,565	-$27,078,565				$350,269	$350,269	-$27,078,565	$27,078,565			$0	$350,269	-$350,269			$0
Smart Meter Capital and Recovery Offset Variance -	1555				$0	$0					$0	$0	$16,876,471		-$1,085,160	$15,791,311	$0				$0
Smart Meter OM&A Variance[4]	1556				$22,925,549	$22,925,549					$0	$22,925,549	-$22,925,549			$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557																				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0						$0			$30,506,428	$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576											$0				$0					

		2014										2015									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-14**	**Transactions(1) Debit / (Credit) during 2014**	**OEB-Approved Disposition during 2014**	**Principal Adjustments(2) during 2014**	**Closing Principal Balance as of Dec-31-14**	**Opening Interest Amounts as of Jan-1-14**	**Interest Jan-1 to Dec-31-14**	**OEB-Approved Disposition during 2014**	**Interest Adjustments(2) during 2014**	**Closing Interest Amounts as of Dec-31-14**	**Opening Principal Amounts as of Jan-1-15**	**Transactions(1) Debit / (Credit) during 2015**	**OEB-Approved Disposition during 2015**	**Principal Adjustments(2) during 2015**	**Closing Principal Balance as of Dec-31-15**	**Opening Interest Amounts as of Jan-1-15**	**Interest Jan-1 to Dec-31-15**	**OEB-Approved Disposition during 2015**	**Interest Adjustments(2) during 2015**	**Closing Interest Amounts as of Dec-31-15**
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$38,781,000	$48,551,000			$87,332,000	$0				$0	$87,332,000	-$6,142,424			$81,189,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0	$0	-$2,679,349			-$2,679,349	$0	-$13,714			-$13,714
Other Regulatory Assets - Sub-Account - EIP	1508	$0	$0			$0	$0				$0	$0	-$155,757			-$155,757	$0	$0			$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	$0			$0	$0				$0	$0	-$12,913,378			-$12,913,378	$0	-$41,430			-$41,430
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0	-$112,142			-$112,142	$0	-$738			-$738	-$112,142	-$100,000			-$212,142	-$738	-$1,780			-$2,518
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0	$0	$339,784			$339,784	$0	$0			$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0	$0	-$5,844,028			-$5,844,028	$0	-$66,137			-$66,137
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0	$0	$1,840,000			$1,840,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$38,781,000	$48,438,858	$0	$0	$87,219,858	$0	-$738	$0	$0	-$738	$87,219,858	-$25,655,152	$0	$0	$61,564,705	-$738	-$123,061	$0	$0	-$123,799
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$117,872	-$34,020			-$151,892	-$2,314,616				-$2,314,616	-$151,892	-$27,603			-$179,495
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$50,317	-$16,170			-$66,487	-$1,100,000				-$1,100,000	-$66,487	-$13,114			-$79,601
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0	$0	$9,112,988			$9,112,988	$0	$216,135			$216,135
Total including Account 1568		$35,366,384	$48,438,858	$0	$0	$83,805,241	-$168,189	-$50,928	$0	$0	-$219,117	$83,805,241	-$16,542,164	$0	$0	$67,263,077	-$219,117	$52,357	$0	$0	-$166,760
Renewable Generation Connection Capital Deferral /	1531	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$15,791,311			-$1,387,244	$14,404,067	$0				$0	$14,404,067				$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557											$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428				$30,506,428						$30,506,428			-$1,558,360	$28,948,068					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0						$0				$0					

2016

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$81,189,576	-$21,022,000			$60,167,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$2,679,349	-$5,791,209			-$8,470,558	-$13,714	-$54,531			-$68,245
Other Regulatory Assets - Sub-Account - EIP	1508	-$155,757	-$472,141			-$627,897	$0	-$1,154			-$1,154
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$12,913,378	$1,290,093			-$11,623,285	-$41,430	-$169,801			-$211,231
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$212,142	-$100,016			-$312,158	-$2,518	-$2,815			-$5,333
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$339,784	$1,653,589			$1,993,373	$0	$7,871			$7,871
Other Regulatory Assets - Sub-Account - OCCP	1508	-$5,844,028	$14,486,588			$8,642,560	-$66,137	-$11,273			-$77,409
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$1,840,000	$1,131,000			$2,971,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$61,564,705	-$8,824,096	$0	$0	$52,740,609	-$123,799	-$231,702	$0	$0	-$355,502
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616		-$2,314,616		$0	-$179,495	-$4,244	-$183,739		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000		-$1,100,000		$0	-$79,601	-$2,017	-$81,619		$2
LRAM Variance Account[11]	**1568**	$9,112,988	$4,319,627	$3,452,615	$1,278,369	$11,258,369	$216,135	$109,612	$131,074		$194,673
Total including Account 1568		$67,263,077	-$4,504,470	$37,999	$1,278,369	$63,998,978	-$166,760	-$128,351	-$134,285	$0	-$160,827
Renewable Generation Connection Capital Deferral A	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	$0	-$1,026,599			-$1,026,599	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$14,404,067	-$3,102,224			$11,301,843	$0	$110,022			$110,022
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$28,948,068	-$9,933,709			$19,014,359					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

2017

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$60,167,576	$25,093,000			$85,260,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$8,470,558	-$14,277,069			-$22,747,626	-$68,245	-$208,682			-$276,927
Other Regulatory Assets - Sub-Account - EIP	1508	-$627,897	-$698,387			-$1,326,285	-$1,154	-$3,252			-$4,406
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$11,623,285	-$3,870,968			-$15,494,253	-$211,231	-$192,636			-$403,867
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$312,158	-$100,000			-$412,158	-$5,333	-$4,396			-$9,729
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$1,993,373	$2,024,793			$4,018,166	$7,871	$37,270			$45,142
Other Regulatory Assets - Sub-Account - OCCP	1508	$8,642,560	$18,394,134			$27,036,693	-$77,409	$212,645			$135,235
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$2,971,000	$1,300,000			$4,271,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$52,740,609	$27,865,503	$0	$0	$80,606,113	-$355,502	-$159,051	$0	$0	-$514,552
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2
LRAM Variance Account[11]	**1568**	$11,258,369	$9,612,739	$4,810,834		$16,060,274	$194,673	$156,370	$139,236		$211,807
Total including Account 1568		$63,998,978	$37,478,243	$4,810,834	$0	$96,666,387	-$160,827	-$2,680	$139,236	$0	-$302,743
Renewable Generation Connection Capital Deferral A	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	-$1,026,599	-$1,400,410			-$2,427,009	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$11,301,843	-$3,985,516			$7,316,327	$110,022	$109,435			$219,457
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$19,014,359	-$6,583,043			$12,431,316					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

Account Descriptions	Account Number	2018 Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	Forecast 2019 Forecast Principal Amount - 2019	Forecast Interest Amount - 2019	Closing Principal Balance - Including Forecast 2019	Closing Interest Balance - Including Forecast 2019	2019 Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 2 Accounts																			
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$85,260,576	-$37,157,000			$48,103,576	$0				$0			$48,103,576	$0			$48,103,576	$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$22,747,626	-$30,124,132			-$52,871,758	-$276,927	-$630,950			-$907,877	-$22,772,218	-$228,813	-$75,643,977	-$1,136,691			-$75,643,977	-$1,136,691
Other Regulatory Assets - Sub-Account - EIP	1508	-$1,326,285	-$918,437			-$2,244,722	-$4,406	-$30,653			-$35,059	-$833,163	-$6,811	-$3,077,885	-$41,870			-$3,077,885	-$41,870
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$15,494,253	-$5,487,866			-$20,982,120	-$403,867	-$383,862			-$787,730	-$12,135,667	-$121,938	-$33,117,786	-$909,668			-$33,117,786	-$909,668
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$412,158	-$100,000			-$512,158	-$9,729	-$8,376			-$18,105	-$100,000	-$11,412	-$612,158	-$29,517			-$612,158	-$29,517
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$4,018,166	$3,332,692			$7,350,858	$45,142	$105,434			$150,576	$4,143,047	$41,629	$11,493,905	$192,205			$11,493,905	$192,205
Other Regulatory Assets - Sub-Account - OCCP	1508	$27,036,693	-$79,824,824			-$52,788,130	$135,235	-$634,606			-$499,371	-$19,060,013	$0	-$71,848,144	-$499,371			-$71,848,144	-$499,371
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$4,271,000	$1,182,000			$5,453,000	$0	$0			$0	$2,627,000	$0	$8,080,000	$0			$8,080,000	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0			$0	$0			$0	$0
Misc. Deferred Debits	1525	$0				$0	$0				$0			$0	$0			$0	$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0			$0	$0			$0	$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0			$0	$0			$0	$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0			$0	$0			$0	$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0			$0	$0			$0	$0
RSVA - One-time	1582	$0				$0	$0				$0			$0	$0			$0	$0
Other Deferred Credits	2425	$0				$0	$0				$0			$0	$0			$0	$0
Group 2 Sub-Total		$80,606,113	-$149,097,567	$0	$0	-$68,491,454	-$514,552	-$1,583,015	$0	$0	-$2,097,567	-$48,131,014	-$327,346	-$116,622,468	-$2,424,913	$0	$0	-$116,622,468	-$2,424,913
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0			$0	$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2			$0	$2			$0	$2
LRAM Variance Account[11]	**1568**	$16,060,274	$18,290,141	$6,447,545		$27,902,870	$211,807	$410,304	$121,812		$500,299			$27,902,870	$500,299	$12,048,215	$295,181	$15,854,655	$205,118
Total including Account 1568		$96,666,387	-$130,807,426	$6,447,545	$0	-$40,588,584	-$302,743	-$1,172,710	$121,812	$0	-$1,597,265	-$48,131,014	-$327,346	-$88,719,599	-$1,924,611	$12,048,215	$295,181	-$100,767,814	-$2,219,792
Renewable Generation Connection Capital Deferral /	1531	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection Funding Adder D	1533	-$2,427,009	-$1,873,867			-$4,300,876	$0				$0	-$2,236,158.79		-$6,537,035	$0			-$6,537,035	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$7,316,327	-$4,029,308			$3,287,019	$219,457	$98,856			$318,313	-$4,674,263	-$318,313	-$1,387,244	$0			-$1,387,244	$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0			$0	$0			$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0			$0	$0			$0	$0
														$0	$0				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$12,431,316	- 6,740,859.89			$5,690,456	$0				$0	-$7,248,817		-$1,558,360	$0			-$1,558,360	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				$0			$0	$0			$0	$0

		Projected Interest on Dec-31-18 Balances					2.1.7 RRR	
Account Descriptions	Account Number	Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)	Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)	Total Interest		Total Claim	As of Dec 31-18	Variance RRR vs. 2018 Balance (Principal + Interest)
Group 2 Accounts								
Other Regulatory Assets - Sub-Account - Deferred IF	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Incrementa	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508			$0	Check to Dispose of Account	$48,103,576.00	$48,103,576	-$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$1,188,293		-$2,324,983	Check to Dispose of Account	-$77,968,960.17	-$53,779,636	-$0
Other Regulatory Assets - Sub-Account - EIP	1508	-$50,450		-$92,320	Check to Dispose of Account	-$3,170,205.06	-$2,279,781	-$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$471,573		-$1,381,241	Check to Dispose of Account	-$34,499,027.38	-$21,769,849	-$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$850		-$28,667	Check to Dispose of Account	-$640,825.32	-$530,264	-$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$165,211		$357,415	Check to Dispose of Account	$11,851,320.65	$7,501,434	$1
Other Regulatory Assets - Sub-Account - OCCP	1508	-$1,186,413		-$1,685,784	Check to Dispose of Account	-$73,533,927.94	-$53,287,501	$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$0	$0	Check to Dispose of Account	$8,080,000.00	$5,453,000	$0
Retail Cost Variance Account - Retail	1518			$0	Check to Dispose of Account	$0.00		$0
Misc. Deferred Debits	1525			$0	Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$0		$0.00		$0
Board-Approved CDM Variance Account	1567			$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0		$0.00		$0
RSVA - One-time	1582			$0		$0.00		$0
Other Deferred Credits	2425			$0	Check to Dispose of Account	$0.00		$0
Group 2 Sub-Total		-$2,730,668	$0	-$5,155,581		-$121,778,049.22	-$70,589,021	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0		$0.00		-$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$2		$2.17		-$2
LRAM Variance Account[11]	**1568**			$205,118		$0.00	$28,403,169	-$0
Total including Account 1568		-$2,730,668	$0	-$4,950,460		-$121,778,047	-$42,185,852	-$2
Renewable Generation Connection Capital Deferral /	1531			$0		$0.00		$0
Renewable Generation Connection OM&A Deferral A	1532			$0		$0.00		$0
Renewable Generation Connection Funding Adder D	1533			$0		-$6,537,035.00	-$4,300,876	$0
Smart Grid Capital Deferral Account	1534			$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0	Check to Dispose of Account	-$1,387,243.88	$3,605,333	$0
Smart Meter OM&A Variance[4]	1556			$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[10]	1557			$0		$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0	Check to Dispose of Account	-$1,558,360.02	5,690,456.49	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			$0	Check to Dispose of Account	$0.00		$0

Ontario Energy Board

2019 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2017 Balance (Principal + Interest)	Explanation
3	RSVA - Wholesale Market Service Charge9	1580	$ (85,384.86)	The 2017 approved disposition for CBR class B interest of $85,385 was recorded as part of RSVA - WMS Charge (primary account) for the RRR 2.1.7 Trial Balance. For the purposes of this continuity, the interest component has been reported in the Sub-account CBR class B line. The amount corresponds to the interest approved in EB-2016-0254. See offsetting amount below in the Sub-account CBR Class B.
3.2	Variance WMS – Sub-account CBR Class B9	1580	$ 85,385.39	See above.

Ontario Energy Board

GA Analysis Workform

Version 1.0

Account 1589 Global Adjustment (GA) Analysis Workform

Input cells
Drop down cells

Utility Name TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Note 1 **Year(s) Requested for Disposition** **2018**

Note 7 **Summary of GA (if multiple years requested for disposition)**

Year	Annual Net Change in Expected GA Balance from GA Analysis (cell K51)	Net Change in Principal Balance in the GL (cell C62)	Reconciling Items (sum of cells C63 to C75)	Adjusted Net Change in Principal Balance in the GL (cell C76)	Unresolved Difference	$ Consumption at Actual Rate Paid (cell J51)	Unresolved Difference as % of Expected GA Payments to IESO
2014	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2015	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2016	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2017	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2018	-$ 17,118,545	-$ 23,898,524	$ 11,149,436	-$ 12,749,088	$ 4,369,457	$ 833,670,695	0.5%
Cumulative Balance	**-$ 17,118,545**	**-$ 23,898,524**	**$ 11,149,436**	**-$ 12,749,088**	**$ 4,369,457**	**$ 833,670,695**	**N/A**

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2018		
Total Metered excluding WMP	C = A+B	24,466,430,392	kWh	100%
RPP	A	10,416,743,189	kWh	42.6%
Non RPP	B = D+E	14,049,687,203	kWh	57.4%
Non-RPP Class A	D	5,208,597,011	kWh	21.3%
Non-RPP Class B*	E	8,841,090,192	kWh	36.1%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below.
The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month

Note 4 **Analysis of Expected GA Amount**

Year 2018

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	849,734,205	850,744,627	842,429,225	841,418,803	0.08777	$ 73,851,328	0.06736	$ 56,677,971	-$ 17,173,358
February	799,751,814	842,429,225	705,359,910	662,682,499	0.07333	$ 48,594,508	0.08167	$ 54,121,280	$ 5,526,772
March	739,653,450	705,359,910	756,475,470	790,769,009	0.07877	$ 62,288,875	0.09481	$ 74,972,810	$ 12,683,935
April	767,838,600	756,475,470	761,171,140	772,534,270	0.09810	$ 75,785,612	0.09959	$ 76,936,688	$ 1,151,076
May	727,410,928	761,171,140	738,400,175	704,639,964	0.09392	$ 66,179,785	0.10793	$ 76,051,791	$ 9,872,006
June	782,233,924	738,400,175	735,320,321	779,154,070	0.13336	$ 103,907,987	0.11896	$ 92,688,168	-$ 11,219,819
July	781,663,293	735,320,321	861,017,528	907,360,500	0.08502	$ 77,143,790	0.07737	$ 70,202,482	-$ 6,941,308
August	822,933,360	861,017,528	868,275,307	830,191,139	0.07790	$ 64,671,890	0.07490	$ 62,181,316	-$ 2,490,573
September	802,911,438	868,275,307	785,460,234	720,096,365	0.08424	$ 60,660,918	0.08584	$ 61,813,072	$ 1,152,154
October	782,253,575	785,460,234	674,331,062	671,124,404	0.08921	$ 59,871,008	0.12059	$ 80,930,892	$ 21,059,884
November	682,530,587	674,331,062	699,869,426	708,068,951	0.12235	$ 86,632,236	0.09855	$ 69,780,195	-$ 16,852,041
December	692,616,487	699,869,426	781,348,434	774,095,495	0.09198	$ 71,201,304	0.07404	$ 57,314,030	-$ 13,887,273
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**9,231,531,663**	**9,278,854,426**	**9,209,458,233**	**9,162,135,470**		**$ 850,789,240**		**$ 833,670,695**	**-$ 17,118,545**

Calculated Loss Factor **1.0363**

Note 5 **Reconciling Items**

	Item	Amount	Explanation
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		(23,898,524)	
1a	True-up of GA Charges based on Actual Non-RPP Volumes - prior year	-	Not applicable as Toronto Hydro ("TH") records the true-up RPP settlement amounts with the IESO on a quarterly basis. The RPP amounts for 2018 are based on the actual IESO invoices received.
1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year	-	Not applicable as Toronto Hydro ("TH") records the true-up RPP settlement amounts with the IESO on a quarterly basis. The RPP amounts for 2018 are based on the actual IESO invoices received.
2a	Remove prior year end unbilled to actual revenue differences	(1,595,003)	
2b	Add current year end unbilled to actual revenue differences	3,079,023	
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers	-	Not applicable.
3b	Add difference between current year accrual/forecast to actual from long term load transfers	-	Not applicable.
4	Remove GA balances pertaining to Class A customers	3,542,616	Due to timing differences between Class A GA charges from the IESO and billings to Class A customers, $3.5M was included in the 2017 RSVA account pertaining to Class A Customers, which reversed in 2018. There is no Class A GA RSVA pertaining to 2018 activity.
5	Significant prior period billing adjustments recorded in current year	-	Not applicable.
6	Differences in GA IESO posted rate and rate charged on IESO invoice	-	Not applicable.
7	Differences in actual system losses and billed TLFs	6,122,800	
8	Others as justified by distributor		
9			
Note 6	**Adjusted Net Change in Principal Balance in the GL**	(12,749,088)	
	Net Change in Expected GA Balance in the Year Per Analysis	(17,118,545)	
	Unresolved Difference	4,369,457	
	Unresolved Difference as % of Expected GA Payments to IESO	0.52%	

Ontario Energy Board

1595 Analysis Workform

Version 1.0

Account 1595 Analysis Workform

Input cells	
Drop down cells	

Utility Name TORONTO HYDRO-ELECTRIC SYSTEM LIMITED **Utility name must be selected**

1595 Rate Years Requested for Disposition

- ☐ **2012**
- ☐ **2013**
- ☐ **2014**
- ☐ **2015**
- ☑ **2016**

Ontario Energy Board

1595 Analysis Workform

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/Returned	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$65,881,308	-$2,489,641	-$68,370,949	-$70,894,315	$2,523,366	-$234,170	**$2,289,197**	**-3.7%**
Account 1589 - Global Adjustment		$94,368,616	$4,812,604	$99,181,220	$102,688,259	-$3,507,039	$426,282	**-$3,080,757**	**-3.5%**
Total Group 1 and Group 2 Balances		$28,487,308	$2,322,963	$30,810,271	$31,793,944	-$983,673	$192,113	**-$791,560**	**-3.2%**

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Additional Notes and Comments

This is for 1595 2017 balances, tab name cannot be changed (not an option to be selected on Information Sheet). Balances approved per Decision and Rate Order EB-2016-0254 including LRAM.

Billing Determinants

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.
Used 2020 Load Forecast

			A		B		C		D=A-C		E			F =B-C-E (deduct E if applicable)
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kVA**	**Metered kWh for Non-RPP Customers [5] (excluding WMP)**	**Metered kVA for Non-RPP Customers[5] (excluding WMP)**	**Metered kWh for Wholesale Market Participants (WMP)**	**Metered kVA for Wholesale Market Participants (WMP)**	**Total Metered kWh less WMP consumption *(if applicable)***	**Total Metered kVA less WMP consumption (if applicable)**	**Total Metered 2018 kWh for Class A Customers that were Class A for the entire period the GA balance accumulated**	**Total Metered 2018 kWh for Customers that Transitioned Between Class A and B during the period the GA balance accumulated**		**Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	615,118	4,531,218,421	-	120,867,876		-	-	4,531,218,421	-	-	-	**4,531,218,421**	120,867,876
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CL	kWh	85,852	297,763,685	-	1,256,022		-	-	297,763,685	-	-	-	**297,763,685**	1,256,022
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICAT	kWh	71,599	2,299,006,608	-	340,748,367		-	-	2,299,006,608	-	-	-	**2,299,006,608**	340,748,367
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	10,417	9,659,470,299	24,899,004	6,675,659,664	17,765,688	51,161,050	107,338	9,608,309,249	24,791,665	172,242,450	171,190,992	**9,264,875,806**	6,332,226,222
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICAT	kVA	430	4,595,446,119	10,406,674	4,411,896,455	10,021,029	430,714	14,192	4,595,015,405	10,392,482	2,849,579,357	801,154,480	**944,281,567**	761,162,617
LARGE USE SERVICE CLASSIFICATION	kVA	38	2,164,924,150	4,600,360	1,908,284,149	4,126,573	275,445,723	503,078	1,889,478,427	4,097,281	1,678,111,033	29,403,915	**181,963,479**	200,769,201
STANDBY POWER SERVICE CLASSIFICATION	kVA		-	-			-	-	-	-	-	-	**-**	-
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	825	40,588,612	-	118,578		-	-	40,588,612	-	-	-	**40,588,612**	118,578
STREET LIGHTING SERVICE CLASSIFICATION	kVA	1	116,219,746	326,300	116,219,746	326,300	-	-	116,219,746	326,300	-	-	**116,219,746**	116,219,746
Total		**784,280**	**23,704,637,639**	**40,232,337**	**13,575,050,857**	**32,239,590**	**327,037,487**	**624,609**	**23,377,600,153**	**39,607,728**	**4,699,932,841**	**1,001,749,388**	**17,675,917,924**	**7,873,368,628**

[1] Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

[3] Input the allocation as determined in the LRAMVA model. The associated rate riders will be calculated in the EDDVAR model.

[5] If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are not

Allocation of Balances

		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	LARGE USE SERVICE CLASSIFICATION	STANDBY POWER SERVICE CLASSIFICATION	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION
LV Variance Account	1550	330,703	kWh	63,215	4,154	32,073	134,759	64,111	30,203	0	566	1,621
Smart Metering Entity Charge Variance Account	1551	(738,259)	# of Customers	(587,800)	(82,039)	(68,419)	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(4,346,196)	kWh	(842,412)	(55,358)	(427,415)	(1,786,308)	(854,272)	(351,278)	0	(7,546)	(21,607)
RSVA - Retail Transmission Network Charge	1584	9,204,066	kWh	1,759,387	115,616	892,661	3,750,591	1,784,325	840,599	0	15,760	45,126
RSVA - Retail Transmission Connection Charge	1586	17,882,318	kWh	3,418,263	224,627	1,734,326	7,286,917	3,466,715	1,633,177	0	30,619	87,674
RSVA - Power (excluding Global Adjustment)	1588	(5,646,009)	kWh	(1,094,351)	(71,914)	(555,241)	(2,320,538)	(1,109,759)	(456,335)	0	(9,803)	(28,069)
RSVA - Global Adjustment	1589	(22,861,166)	Non-RPP kWh	(350,953)	(3,647)	(989,399)	(18,386,294)	(2,210,117)	(582,955)	0	(344)	(337,456)
Total of Group 1 Accounts (excluding 1589)		**16,686,623**		**2,716,302**	**135,086**	**1,607,985**	**7,065,421**	**3,351,120**	**1,696,366**	**0**	**29,597**	**84,746**
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(570,202)**	**kWh**	**(146,171)**	**(9,605)**	**(74,163)**	**(298,873)**	**(30,461)**	**(5,870)**	**0**	**(1,309)**	**(3,749)**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**26,678,828**		**4,653,065**	**262,358**	**2,590,641**	**11,172,267**	**5,315,152**	**2,503,979**	**0**	**46,945**	**134,421**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(9,992,205)**		**(1,936,763)**	**(127,272)**	**(982,656)**	**(4,106,846)**	**(1,964,031)**	**(807,613)**	**0**	**(17,349)**	**(49,675)**
Balance of Account 1589 Allocated to Non-WMPs		**(22,861,166)**		**(350,953)**	**(3,647)**	**(989,399)**	**(18,386,294)**	**(2,210,117)**	**(582,955)**	**0**	**(344)**	**(337,456)**

Class A Consumption Data

1	**Please enter the Year the Account 1589 GA Balance was Last Disposed.**	2017	**(e.g. If in the 2018 EDR process, you received approval to dispose the GA variance account balance as at December 31, 2016, enter 2016.)**
2a	**Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from year after the balance was last disposed to 2017)?**	Yes	**(e.g. If you received approval to dispose the GA account balance as at December 31, 2016, the period the GA accumulated would be 2017.)**
2b	**Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1580, sub-account CBR Class B balance accumulated (i.e. from year after the balance was last disposed to 2017).**	Yes	**(e.g. If the CBR Class B balance was last disposed as at December 31, 2016, the period the CBR Class B variance accumulated would be 2017.)**
3a	**Enter the number of transition customers you had during the period the Account 1589 GA balance accumulated.**	127	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class		2018 January to June	2018 July to December
Customer 1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICAT	kWh	15,237,254	10,750,334
		kVA	37,162	31,849
		Class A/B	A	B
Customer 2	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICAT	kWh	70,146,308	75,057,096
		kVA	198,802	199,630
		Class A/B	B	A
Customer 3	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIF	kWh	68,119,407	65,561,674
		kVA	199,249	193,805
		Class A/B	A	B
Customer 4	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIF	kWh	329,125,988	338,347,412
		kVA	698,099	733,007
		Class A/B	B	A
Customer 5	LARGE USE SERVICE CLASSIFICATION	kWh	14,205,212	15,198,704
		kVA	41,746	41,028
		Class A/B	B	A

3b	**Enter the number of customers who were Class A during the entire period since the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B).**	278

Class A Customers - Billing Determinants by Customer

Customer	Rate Class		2018
Customer A1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICAT	kWh	172,242,450
		kVA	419,165
Customer A2	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIF	kWh	2,849,579,357
		kVA	6,029,167
Customer A3	LARGE USE SERVICE CLASSIFICATION	kWh	1,678,111,033
		kVA	3,329,196

GA Allocation

This tab allocates the GA balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current GA balance. The tables below calculates specific amounts for each transition customer. The general GA rate rider to non-RPP customers is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year of the Account 1589 GA Balance Last Disposed	**2017**

Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2018	
Total Class B Consumption for Years During Balance Accumulation (Non-RPP Consumption LESS WMP Consumption and Consumption for Class A customers who were Class A for partial and full year)	A	8,363,158,143	8,363,158,143	
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515	
Transition Customers' Portion of Total Consumption	C=B/A	**5.86%**	**7,873,368,628**	-

Allocation of Total GA Balance $

Total GA Balance	D	-$ 24,283,322
Transition Customers Portion of GA Balance	E=C*D	-$ 1,422,156
GA Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 22,861,166

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers**	**Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers in 2017**	**% of kWh**	**Customer Specific GA Allocation During the Period They Were a Class B customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 31,215	-$ 2,601
Customer 2		70,146,308	70,146,308	14.32%	-$ 203,677	-$ 16,973
Customer 3		65,561,674	65,561,674	13.39%	-$ 190,365	-$ 15,864
Customer 4		329,125,988	329,125,988	67.20%	-$ 955,652	-$ 79,638
Customer 5		14,205,212	14,205,212	2.90%	-$ 41,246	-$ 3,437
TOTAL		**489,789,515**	**489,789,515**	**100.00%**	**-$ 1,422,156**	**-$ 118,513**

CBR B Allocation

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each transition customer. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Please enter the Year the Account 1580 CBR Class B was Last Disposed.	2017	**(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

Allocation of total Consumption (kWh) between Class B and Class A/B Transition Customers

		Total	2017
Total Class B Consumption for Years During Balance Accumulation (Total Consumption Less WMP Consumption and Consumption for Class A who were Class A for the full year)	A	18,165,707,440	18,165,707,440
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515
Transition Customers' Portion of Total Consumption	C=B/A	2.70%	17,675,917,924

-

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	D	-$ 586,002
Transition Customers Portion of CBR Class B Balance	E=D*C	-$ 15,800
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 570,202

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers**	**Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers in 2018**	**% of kWh**	**Customer Specific CBR Class B Allocation During the Period They Were a Class B Customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 347	-$ 29
Customer 2		70,146,308	70,146,308	14.32%	-$ 2,263	-$ 189
Customer 3		65,561,674	65,561,674	13.39%	-$ 2,115	-$ 176
Customer 4		329,125,988	329,125,988	67.20%	-$ 10,617	-$ 885
Customer 5		14,205,212	14,205,212	2.90%	-$ 458	-$ 38
Total		**489,789,515**	**489,789,515**	100.00%	**-$ 15,800**	**-$ 1,317**

CBR B

The purpose of this tab is to calculate the billing determinants for CBR rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1580, sub-account CBR Class B balance accumulated.

The Year the Account 1580 CBR Class B was Last Disposed. 2017 **(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

	Total Metered 2018 Consumption Minus WMP		Total Metered 2018 Consumption for Class A customers that were Class A for the entire period CBR Class B balance accumulated		Total Metered 2018 Consumption for Customers that Transitioned Between Class A and B during the period CBR Class B balance accumulated		Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		% of total kWh
	kWh	kVA	kWh	kVA	kWh	kVA	kWh	kVA	
RESIDENTIAL SERVICE CLASSIFICATION	4,531,218,421	-	0	0	0	0	4,531,218,421	-	26%
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICAT	297,763,685	-	0	0	0	0	297,763,685	-	2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	2,299,006,608	-	0	0	0	0	2,299,006,608	-	13%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	9,608,309,249	24,791,665	172,242,450	419,165	171,190,992	467,443	9,264,875,806	23,905,058	52%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	4,595,015,405	10,392,482	2,849,579,357	6,029,167	801,154,480	1,824,160	944,281,567	2,539,155	5%
LARGE USE SERVICE CLASSIFICATION	1,889,478,427	4,097,281	1,678,111,033	3,329,196	29,403,915	82,773	181,963,479	685,312	1%
STANDBY POWER SERVICE CLASSIFICATION	-	-	0	0	0	0	-	-	0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	40,588,612	-	0	0	0	0	40,588,612	-	0%
STREET LIGHTING SERVICE CLASSIFICATION	116,219,746	326,300	0	0	0	0	116,219,746	326,300	1%
Total	23,377,600,153	39,607,728	4,699,932,841	9,777,527	1,001,749,388	2,374,376	17,675,917,924	27,455,825	100%

Rate Rider Calculations

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	Units	kVA / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	ROUNDED Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ 2,716,302	**0.00060**	0.00060	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	297,763,685	$ 135,086	**0.00045**	0.00045	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ 1,607,985	**0.00070**	0.00070	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,899,004	$ 11,172,267	**0.44256**	0.44260	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,406,674	$ 5,315,152	**0.50375**	0.50370	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,600,360	$ 2,503,979	**0.53684**	0.53680	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ 29,597	**0.00073**	0.00073	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ 84,746	**0.25616**	0.25620	$/kVA
Total			**$ 23,565,113**			

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance - Non-WMP	Rate Rider for Deferral/Variance Accounts for Non-WMP	ROUNDED Rate Rider for Deferral/Variance Accounts for Non-WMP	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ -	**-**	-	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	297,763,685	$ -	**-**	-	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ -	**-**	-	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,791,665	-$ 4,106,846	**- 0.16339**	- 0.16340	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,392,482	-$ 1,964,031	**- 0.18640**	- 0.18640	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,097,281	-$ 807,613	**- 0.19441**	- 0.19440	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ -	**-**	-	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ -	**-**	-	$/kVA
Total			**-$ 6,878,490**			

Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP calculated separately in the table above. For all rate classes without WMP customers, balances in Accounts 1580 and 1588 are included in Deferral/Variance Account Rate Riders calculated in the first table above and disposed through a combined Deferral/Variance Account and Rate Rider.

Rate Rider Calculation for Account 1580, sub-account CBR Class B

1580, Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B	ROUNDED Rate Rider for Sub-account 1580 CBR Class B	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	-$ 146,171	**- 0.00003**	- 0.00003	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	297,763,685	-$ 9,605	**- 0.00003**	- 0.00003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	-$ 74,163	**- 0.00003**	- 0.00003	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	23,905,058	-$ 298,873	**- 0.01233**	- 0.01230	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	2,539,155	-$ 30,461	**- 0.01183**	- 0.01180	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	685,312	-$ 5,870	**- 0.00845**	- 0.00840	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	-$ 1,309	**- 0.00003**	- 0.00003	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	-$ 3,749	**- 0.01133**	- 0.01130	$/kVA
Total			**-$ 570,202**			

Rate rider calculated separately only if Class A customers exist during the period the balance accumulated

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment	ROUNDED Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	120,867,876	-$ 350,953	**- 0.00290**	- 0.00290	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATIO	kWh	1,256,022	-$ 3,647	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	340,748,367	-$ 989,399	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	6,332,226,222	-$ 18,386,294	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kWh	761,162,617	-$ 2,210,117	**- 0.00290**	- 0.00290	$/kWh
LARGE USE SERVICE CLASSIFICATION	kWh	200,769,201	-$ 582,955	**- 0.00290**	- 0.00290	$/kWh
STANDBY POWER SERVICE CLASSIFICATION	kWh	-	$ -	**-**	-	$/kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	118,578	-$ 344	**- 0.00290**	- 0.00290	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	116,219,746	-$ 337,456	**- 0.00290**	- 0.00290	$/kWh
Total			**-$ 22,861,166**			

Group 2 Rate Riders Development

% to split by Class	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
Allocators										
2016 kWh	100.0%	20.0%	0.9%	9.6%	40.6%	19.4%	8.8%	0.5%	0.2%	0.0%
2017 Distribution Revenue	100.0%	39.7%	3.7%	14.2%	27.0%	8.5%	4.4%	2.0%	0.5%	0.0%
2020 Revenue Offsets	100.0%	49.2%	4.0%	20.4%	18.3%	3.5%	1.5%	2.3%	0.8%	0.0%
2009/10 Reg Assets Allocation	100.0%	18.2%	0.7%	8.2%	42.4%	19.6%	10.2%	0.5%	0.2%	0.0%
2013 Non-RPP kWh	100.0%	2.1%	0.0%	2.4%	48.3%	31.0%	15.4%	0.8%	0.0%	0.0%
LRAMVA	100.0%	7.2%	0.3%	29.8%	48.2%	7.3%	7.3%	0.0%	0.0%	0.0%
2013 SM Entity Rider Recovery	100.0%	85.2%	5.2%	9.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Stranded Meters	100.0%	51.4%	0.0%	31.8%	16.8%	0.0%	0.0%	0.0%	0.0%	0.0%
2020 kWh forecast	100.0%	19.4%	1.3%	9.8%	41.1%	19.7%	8.1%	0.5%	0.2%	0.0%
Monthly Billing Conversion	100.0%	89.6%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Distribution Revenue GS>50 kW	100.0%	0.0%	0.0%	0.0%	63.6%	20.0%	10.5%	4.7%	1.2%	0.0%
AR Credits	100.0%	83.5%	0.0%	15.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Other Allocators 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other Allocators 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other Allocators 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other Allocators 8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other Allocators 9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

	RA Balance by Class	Allocators (Drop Down)	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
1	Stranded Meters	Stranded Meters	- 1,387,244	- 713,195	-	- 441,086	- 232,962	-	-	-	-	-
2	Wireless pole attachments Rev	2020 Revenue Offsets	- 640,825	- 315,551	- 25,503	- 130,871	- 117,301	- 22,483	- 9,513	- 14,612	- 4,992	-
3	Impact for USGAAP (Actuarial loss on OPEB)	2017 Distribution Revenue	48,103,576	19,087,915	1,783,829	6,806,795	12,996,819	4,093,974	2,135,323	953,529	245,391	-
4	IFRS-CGAAP PP&E	2017 Distribution Revenue	- 1,558,360	- 618,371	- 57,789	- 220,512	- 421,044	- 132,628	- 69,176	- 30,890	- 7,950	-
5	CRRRVA	2017 Distribution Revenue	- 77,968,960	- 30,938,757	- 2,891,330	- 11,032,834	- 21,065,970	- 6,635,741	- 3,461,051	- 1,545,533	- 397,744	-
6	Monthly Billing	Monthly Billing Conversion	11,851,321	10,624,432	-	1,226,889	-	-	-	-	-	-
8	External Driven Capital	2017 Distribution Revenue	- 3,170,205	- 1,257,965	- 117,561	- 448,593	- 856,539	- 269,808	- 140,726	- 62,841	- 16,172	-
9	OPEB cash vs accrual	2017 Distribution Revenue	8,080,000	3,206,214	299,631	1,143,343	2,183,087	687,668	358,672	160,165	41,219	-
10	Derecognition	2017 Distribution Revenue	- 34,499,027	- 13,689,512	- 1,279,331	- 4,881,712	- 9,321,087	- 2,936,125	- 1,531,416	- 683,854	- 175,990	-
11	Deferred Gain on disposals	2017 Distribution Revenue	- 11,780,824	- 4,674,733	- 436,869	- 1,667,021	- 3,182,991	- 1,002,636	- 522,952	- 233,524	- 60,098	-
12	Operations Consolidation Plan Sharing Variance	2017 Distribution Revenue	- 73,533,928	- 29,178,898	- 2,726,866	- 10,405,264	- 19,867,695	- 6,258,287	- 3,264,180	- 1,457,620	- 375,119	-
13	Excess Expansion Deposits	Distribution Revenue GS>50 kW	- 8,021,484	-	-	-	- 5,104,215	- 1,607,818	- 838,601	- 374,478	- 96,372	-
14	AR Credits	AR Credits	- 3,407,868	- 2,844,480	-	- 510,430	- 52,044	- 415	-	-	- 499	-
	Total		- 147,933,830	- 51,312,902	- 5,451,788	- 20,561,296	- 45,041,941	- 14,084,299	- 7,343,619	- 3,289,659	- 848,326	

Note: This table lists all forecasted regulatory account balances proposed for clearance by THESL over the 2020-2024 period ($147.9M). The summary of amounts proposed for disposition in Tables 16 and 17, Exhibit X_T9_S01 excludes disposition of amounts described in Exhibit 8, Tab 1, Schedule 1, section 4.7. The continuity schedule (Exhibit X-T9-S01 App A) lists only the regulatory accounts previously approved by the OEB for tracking.

	Load / Customers / Devices / Connections Forecast	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	2020 Forecast Dist Billing Determinants (Jan - Dec)										
	kVA	40,232,337	NA	NA	NA	24,899,004	10,406,674	4,600,360	326,300	NA	-
	kWh	23,377,600,153	4,531,218,421	297,763,685	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	-
	Number of Customers	784,280	615,118	85,852	71,599	10,417	430	38	1	-	825
	Devices/Connections	177,454	NA	NA	NA	NA	NA	NA	165,274	12,180	-

	Rate Riders	RR Pass-through or not	Proposed Recovery Period (years)	Amount	Allocators	Rate Rider Start Year	Rate Rider End Year	Billing Unit	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Volumetric Rate Riders																
1	Stranded Meters	Not Pass-through	5.00	- 1,387,244	Stranded Meters	2020	2024	Customers [1]	- 0.02	-	- 0.10	- 0.37	-	-	-	-	-
2	Wireless pole attachments Rev	Not Pass-through	5.00	- 640,825	2020 Revenue Offsets	2020	2024	Cust.+ Usage [1]	- 0.01	-	- 0.00001	- 0.00090	- 0.00040	- 0.00040	- 0.00880	- 0.00002	-
3	Impact for USGAAP (Actuarial loss on OPEB)	Not Pass-through	5.00	48,103,576	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	0.51	0.34	0.00059	0.10300	0.07760	0.09160	0.57640	0.00121	-
4	IFRS-CGAAP PP&E	Not Pass-through	5.00	- 1,558,360	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.02	- 0.01	- 0.00002	- 0.00330	- 0.00250	- 0.00300	- 0.01870	- 0.00004	-
5	CRRRVA	Not Pass-through	5.00	- 77,968,960	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.83	- 0.55	- 0.00096	- 0.16690	- 0.12580	- 0.14840	- 0.93430	- 0.00196	-
6	Monthly Billing	Not Pass-through	5.00	11,851,321	Monthly Billing Convers	2020	2024	Cust.+ Usage [1]	0.28	-	0.00011	-	-	-	-	-	-
8	External Driven Capital	Not Pass-through	5.00	- 3,170,205	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.03	- 0.02	- 0.00004	- 0.00680	- 0.00510	- 0.00600	- 0.03800	- 0.00008	-
9	OPEB cash vs accrual	Not Pass-through	5.00	8,080,000	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	0.09	0.06	0.00010	0.01730	0.01300	0.01540	0.09680	0.00020	-
10	Derecognition	Not Pass-through	5.00	- 34,499,027	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.37	- 0.24	- 0.00042	- 0.07380	- 0.05570	- 0.06570	- 0.41340	- 0.00087	-
11	Deferred Gain on disposals	Not Pass-through	5.00	- 11,780,824	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.12	- 0.08	- 0.00015	- 0.02520	- 0.01900	- 0.02240	- 0.14120	- 0.00030	-
12	Operations Consolidation Plan Sharing Variance	Not Pass-through	5.00	- 73,533,928	2017 Distribution Reven	2020	2024	Cust.+ Usage [1]	- 0.78	- 0.52	- 0.00091	- 0.15740	- 0.11860	- 0.14000	- 0.88120	- 0.00185	-
13	Excess Expansion Deposits	Not Pass-through	5.00	- 8,021,484	Distribution Revenue GS	2020	2024	Cust.+ Usage [1]	-	-	-	- 0.04040	- 0.03050	- 0.03600	- 0.22640	- 0.00047	-
14	AR Credits	Not Pass-through	5.00	- 3,407,868	AR Credits	2020	2024	Cust.+ Usage [1]	- 0.08	-	- 0.00004	- 0.00040	-	-	-	-	-

[1] "Customers" means Residential, GS < 50 kW and GS 50 to 999 kW rates recovery are based on $/cust/30 days
[1] "Cust.+Usage" means Residential and CSMUR rates recovery are based on $/cust/30 days and all other Rate classes recovery are based on $/kWh or $/kVA or $/Device or $/Connection

December 31, 2018 - Reconciliation of Sale of Electricity and Cost of Power Expense
Filing Requirement 2.9 - Deferral and Variance Accounts

The sale of electricity and cost of power expense have been reconciled to the Audited Financial Statements and the net profit is zero as shown in the tables below.

The IESO Global Adjustment charge is pro-rated into the RPP and Non-RPP portions.

Table 1: Sale of Electricity and Cost of Power Expense

SALE OF ELECTRICITY		
USofA		**Dec 31 2018 RRR ($,000's)**
4006	Residential Energy Sales	-461,396
4010	Commercial Energy Sales	-1,481,102
4020	Energy Sales to Large Users	-171,949
4025	Street Lighting Energy Sales	-7,015
4035	General Energy Sales	-231,515
4050	Revenue Adjustment	-1,609
4062	Billed WMS	-93,145
4066	Billed NW	-156,050
4068	Billed CN	-126,607
4075	Billed - LV	0
4076	Billed Smart Metering Entity Charge	-5,620
	Total Sale of Electricity Revenue	**-2,736,007**
	Board filing 2.1.13 Sale of Electricity	**-2,736,007**
COST OF POWER EXPENSE		
USofA		**Dec 31 2018 RRR ($,000's)**
4705	Power Purchased	1,225,222
4707	Charges - Global Adjustment	1,129,362
4708	Charges-WMS	93,145
4714	Charges-NW	156,050
4716	Charges-CN	126,607
4750	Charges - LV	0
4751	Charges Smart Metering Entity Chg	5,620
	Total Cost of Power Expense	**2,736,007**
	Board filing 2.1.13 Cost of Power Expense	**2,736,007**

December 31, 2018 - Sale of Electricity and Cost of Power Expense
THESL Audited Financial Statements (AFS) Mapped to USofA Accounts
Filing Requirement 2.9 - Deferral and Variance Accounts

The sale of electricity and cost of power expense have been reconciled to the Audited Financial Statements and the net profit is zero as shown in the tables below.
reconciled to the RRR filed Sale of electricity and Cost of power expense OEB accounts.

Table 2: USofA Balances Mapped and Reconciled to the AFS - Sale of Electricity and Cost of Power Expense - Year ended December 31, 2018

	THESL Consolidated Audited 2018	Less: Net Movement adjustment	Adjusted THESL Consolidated Audited 2017	Dec 31 2018 RRR	Difference	Notes
	($,000s)	($,000s)	($,000s)	($,000s)	($,000s)	
	(1)	(2)	(3)=(1)-(2)	(4)	(5)=(3)-(4)	
Sale of electricity	-2,704,128	-84,473	-2,619,655	**-2,736,007**	116,352	**1**
Cost of power expense	2,646,286	26,631	2,619,655	**2,736,007**	-116,352	**2**

Note 1: "Sale of electricity" difference of $116,352: Adjusted AFS balance of ($2,704,128) versus RRR balance of ($2,736,007), as follows:	**($,000s)**
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.	110,732
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge":	5,620
	116,352

Note 2: "Cost of power expense" difference of ($116,352): Adjusted AFS balance of $2,646,286 versus RRR balance of $2,736,007, as follows:	**($,000s)**
a. For RRR reporting, the Global Adjustment (GA) modifier is presented gross in Energy sales as it should keep THESL financially whole/neutral for THESL's billing to customers who qualified for the GA credit. For AFS, the GA modifier is netted with Energy purchases per the new IFRS 15, which requires Energy sales to be recorded at the price customer pays.	-110,732
b. Smart Metering Entity charge: As per AFS GAAP, THESL books the Smart Metering entity revenue and charge on a net basis, while for RRR it is booked on a gross basis, in the prescribed regulatory accounts 4076 "Billed Smart Metering Entity Charge" and 4751 "Charges Smart Metering Entity Charge"	-5,620
	-116,352