Toronto Hydro-Electric System Limited

EB-2018-0165

OEB Staff Compendium

Panel 3

TAB 1

TABLE 3: CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Spend ($M)					Forecasted Spend ($M)				
	2010A	2011A	2012A	2013A	2014P	2015	2016	2017	2018	2019
System Access	$44.37	$58.31	$53.15	$86.62	$76.01	$86.13	$93.54	$100.93	$90.41	$85.47
System Renewal	$215.00	$219.25	$157.25	$231.08	$286.37	$251.74	$234.99	$246.35	$260.08	$265.49
System Service	$35.32	$75.63	$38.35	$83.67	$101.34	$76.45	$69.60	$62.51	$49.54	$73.95
General Plant	$55.53	$67.71	$29.28	$33.77	$109.47	$104.63	$99.44	$28.93	$32.13	$27.88
Other CAPEX	$50.36	$24.63	$9.92	$10.52	$12.73	$12.18	$21.22	$28.65	$37.89	$49.37
Total	**$400.58**	**$445.53**	**$287.95**	**$445.66**	**$585.92**	**$531.13**	**$518.79**	**$467.36**	**$470.05**	**$502.16**
System O&M	$114.64	$111.89	$109.03	$119.84	$118.94	$128.76	-	-	-	-

/C

The following sections provide a summary of System Access, System Service, System Renewal and General Plant programs as well as System O&M expenditures. For full details and justification of the programs listed throughout these sections, see Sections E5 through E8 of the DSP. For a detailed explanation of System O&M expenditures, see Section E4.2.6.

7.1 System Access

Toronto Hydro's capital expenditures under the System Access investment category are driven by statutory, regulatory or other obligations that require Toronto Hydro to provide customers with access to the distribution system or to otherwise respond to service requests.

TABLE 4: SUMMARY OF SYSTEM ACCESS PROGRAMS

Program Index and Name		Description	Total (5 yrs)	Trigger Driver	Secondary Drivers
E5.1	**Metering**	Enable Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. This will be accomplished by testing meters, replacing damaged and obsolete meters, and upgrading the under-capacity and obsolete collector stations. Upgrading Toronto Hydro's Interval Metering MDM software will help customers manage their energy use and costs by providing them with timely access to their data.	**$81.5 M**	Mandated Service Obligations	Failure Risk

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 46:

Reference(s): Exhibit 2B, Section E2

Please provide in a single table, broken down at the level provided in the evidence (for example see table 2 and 3):

a) Approved expenditures for each year between 2015 and 2019.

b) Actual/forecast expenditures for each year between 2014 and 2019.

c) The proposed expenditures for each year between 2020 and 2024.

RESPONSE:

In Appendix A to this response, Toronto Hydro has provided the information on the basis of total capital expenditures. As explained in Exhibit 2B, Section E4.1, the OEB's envelope approval of capital related revenue requirement for the 2015-2019 CIR period did not include prescribed adjustments to the expenditure plans for specific programs or investment categories. The annual "2015 CIR (-10%)" expenditures in Appendix A were simply derived by applying a general 10% reduction to the annual capital expenditures filed in the 2015 to 2019 CIR application (EB-2014-0116).

2B-SEC-46 Appendix A: 2014-2024 Acutal/Forecast Capital Spend

$ Millions	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Test	2021 Test	2022 Test	2023 Test	2024 Test
2015 CIR Capital (-10%)	**n/a**	**478.0**	**466.9**	**420.6**	**423.0**	**451.9**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
Total Capital Spend	585.6	491.4	511.6	497.8	447.8	434.9	518.4	581.8	587.1	565.7	574.4

Table 1: Distribution Rate Base ($ millions)

Description	2008 Historical	2009 Historical	2010 Bridge	2011 Test
Gross Assets	3,645.9	3,836.8	4,055.5	4,404.2
Accumulated Depreciation	(1,942.7)	(2,069.5)	(2,205.2)	(2,376.3)
Net Assets	1,703.2	1,767.3	1,850.3	2,027.9
Working Capital	255.5	266.8	277.4	318.4
Rate Base	1,958.7	2,034.1	2,127.7	2,346.3

The gross assets balance reflects the capital expenditure programs forecasted for the Test year. The Distribution Plant, General Plant and Information Technology capital programs are described in detail in Exhibit D1, Tab 8, Schedules 1 through 8, and Exhibit D1, Tab 9, Schedules 1 through 8. The justifications for capital projects in excess of $500,000 are filed at Exhibit D1, Tab 8, Schedule 9.

The average net fixed assets included in the rate base approved in THESL's 2010 Distribution Rates Application (EB-2009-0139) was $1,867.1 million. The 2011 net plant of $2,027.9 million is $160.8 million or 8.6 percent higher than last approved. Exhibit D1, Tab 5, Schedule 1 provides a discussion of the level of THESL's distribution assets. The distribution investment over the Bridge and Test years is described in Exhibit D1, Tabs 8 and 9.

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

ORAL HEARING UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. J1.7:

Reference(s): Exhibit K1.3, page 90

To review the spreadsheet and confirm whether the Board got the numbers right or wrong and correct this chart.

RESPONSE:

Please see Appendix A for the revised numbers. Toronto Hydro confirms that all the items listed in its response to undertaking J1.2 are incorporated in Appendix A.

Undertaking J1.7

Rate Base	2020	2021	2022	2023	2024
Average PP&E NBV	$ 4,369.7	$ 4,601.9	$ 4,844.4	$ 5,128.5	$ 5,393.2
WCA	$ 222.9	$ 227.2	$ 232.0	$ 237.0	$ 243.1
Rate Base	$ 4,592.6	$ 4,829.1	$ 5,076.4	$ 5,365.5	$ 5,636.3

Revenue Requirement	2020	2021	2022	2023	2024	Total
CRR	$ 540.5	$ 579.3	$ 595.6	$ 648.1	$ 689.4	$ 3,052.8
Non-CRR	$ 230.9	$ 233.0	$ 235.1	$ 237.2	$ 239.4	$ 1,175.6
Base RR	$ 771.4	$ 812.3	$ 830.7	$ 885.3	$ 928.7	$ 4,228.4

CAPEX	2020	2021	2022	2023	2024	Total
U-IRR Net CAPEX Update	$ 521.6	$ 581.8	$ 587.1	$ 565.7	$ 574.4	$ 2,830.6
Pre-Filed Net CAPEX	$ 518.4	$ 581.8	$ 587.1	$ 565.7	$ 574.4	$ 2,827.4
Variance	$ 3.2	$ -	$ -	$ -	$ -	$ 3.2

In-Service Additions	2020	2021	2022	2023	2024	Total
U-IRR ISA Update	$ 539.9	$ 475.0	$ 587.4	$ 590.5	$ 583.6	$ 2,776.4
Pre-Filed ISA	$ 489.8	$ 483.7	$ 590.9	$ 593.0	$ 586.1	$ 2,743.5
Variance	$ 50.1	$ (8.7)	$ (3.5)	$ (2.5)	$ (2.5)	$ 32.9

Table 3: CRRVA Balance

	2015 Historical	2016 Historical	2017 Historical	2018 Bridge	2019 Bridge	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
RR impact from 10% reduction in capital spending	(7.3)	(8.7)	(10.7)	(17.7)	(24.1)	(68.6)
Capital-Related RR (Rate Order, Feb. 29, 2016 - Table 2)	430.5	456.3	506.6	549.5	583.2	2,526.0
RR impact from the application of stretch factor to capital funding[3]	-	(2.6)	(5.4)	(8.4)	(11.7)	(28.1)
Capital-Related RR in Approved 2015-2019 Rates	430.5	453.7	501.2	541.0	571.5	2,497.9
Sub-account 1508 - Externally Driven Capital Variance Account	(0.2)	(0.5)	(0.7)	(0.6)	(0.3)	(2.2)
Sub-account 1508 - Derecognition Variance Account	(12.9)	1.3	(3.9)	(10.4)	(14.8)	(40.8)
Other Adjustments[4]	(1.2)	0.6	(1.4)	(4.3)	0.2	(6.1)
Capital-Related RR in Approved Rates eligible for CRRRVA	416.2	455.1	495.3	525.6	556.6	2,448.8
Actual Historic & Forecast Bridge Capital-Related RR	413.6	449.3	481.0	503.7	543.6	2,391.2
Sub-account 1508 - CRRRVA	(2.7)	(5.8)	(14.3)	(21.9)	(13.0)	(57.6)

Note: Rounding differences may exist.

[3] Decision on Draft Rate Order, February 25, 2016, p. 3; Draft Rate Order, February 29, 2016, p. 5.
[4] 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.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 21:

Reference(s): **Exhibit 1B, Tab 4, Schedule 1, p. 8-9**

a) Please provide detailed calculations for the approved 2016-2019 capital factors (C-factors) similar to what is provided in Table 2 (Exhibit 1B / Tab 4 / Schedule 1 / p. 9).

b) Please provide the original applied for 2016-2019 C-factors from the 2015-2019 Custom IR proceeding. Please provide the detailed calculations as requested in part (a) of this question.

c) Please provide the C-factors that would have been in place during the 2016-2019 period if cost of capital had been updated in each year as follows:

    i. Updated only for the OEB-approved ROE;
    ii. Updated for OEB-approved ROE and an updated weighted average cost of debt in each year.

RESPONSE:

a) See Table 1 below for the calculation of Cn-factor approved for the period 2016-2019.

Table 1: Calculation of Cn 2016-2019 (approved version) ($ Millions)

	2015	2016	2017	2018	2019
Ratebase	3,232.0	3,575.2	3,890.2	4,075.3	4,253.8
Interest Expense	79.2	87.7	95.4	99.9	104.3
Return on Equity	120.2	133.0	144.7	151.6	158.2
Depreciation	206.02	218.8	242.2	257.7	275.0
PILs/Taxes	25.0	16.9	24.3	40.2	45.7
Capital-related RR (A)	430.5	456.3	506.6	549.5	583.2
OM&A	243.9	247.6	251.3	255.1	258.9
Revenue Offsets	- 41.3	- 41.9	- 42.5	- 43.2	- 43.8
Total RR (B)	633.1	662.0	715.4	761.4	798.3
$Cn = (A_{yx} – Ay_{(x-1)}) / B_{y(x-1)}$		4.07%	7.60%	5.99%	4.43%

b) See Table 2 for the calculation of Cn-factor from application version for the period 2016-2019.

Table 2: Calculation of Cn 2016-2019 (application version) ($ Millions)

	2015	2016	2017	2018	2019
Ratebase	3,313.5	3,683.9	3,977.9	4,199.8	4,415.2
Interest Expense	81.8	90.9	98.2	103.7	109.0
Return on Equity	123.3	137.1	148.0	156.3	164.3
Depreciation	208.2	222.0	248.2	266.7	287.2
PILs/Taxes	24.4	14.9	22.8	40.5	46.7
Capital-related RR (A)	437.8	465.0	517.3	567.2	607.3
OM&A	269.5	273.3	277.1	281.0	284.9
Revenue Offsets	- 46.1	- 46.8	- 47.4	- 48.0	- 48.7
Total RR (B)	661.2	691.5	747.0	800.1	843.5
$Cn = (A_{yx} – Ay_{(x-1)}) / B_{y(x-1)}$		4.11%	7.57%	6.68%	5.01%

c)

i) See Table 3 below for the calculation of Cn-factor if ROE is based on OEB approved annually instead of 9.3% which is approved ROE for the period 2016-2019 of Toronto Hydro's CIR.

Table 3: Calculation of Cn 2016-2019 (if ROE is OEB approved) ($ Millions)

	2015	2016	2017	2018	2019
Ratebase	3,232.0	3,575.2	3,890.2	4,075.3	4,253.8
Interest Expense	79.2	87.7	95.4	99.9	104.3
Return on Equity	120.2	131.4	136.6	146.7	152.8
Depreciation	206.0	218.8	242.2	257.7	275.0
PILs/Taxes	25.0	16.3	21.4	38.5	43.8
Capital-related RR (A)	430.5	454.2	495.6	542.8	575.8
OM&A	243.9	247.6	251.3	255.1	258.9
Revenue Offsets	- 41.3	- 41.9	- 42.5	- 43.2	- 43.8
Total RR (B)	633.1	659.9	704.4	754.7	790.9
Cn = $(A_{yx} – Ay_{(x-1)}) / B_{y(x-1)}$		3.74%	6.28%	6.70%	4.37%
ROE	9.30%	9.19%	8.78%	9.00%	8.98%

ii) See Table 4 below for the calculation of Cn-factor if ROE and debt rates are based on OEB approved and deemed for the period 2016-2019.

Table 4: Calculation of Cn 2016-2019 if ROE and Debt Rates are based on OEB approved values

	2015	2016	2017	2018	2019
Ratebase	3,232.0	3,575.2	3,890.2	4,075.3	4,253.8
Interest Expense	79.2	93.3	83.8	98.7	103.2
Return on Equity	120.2	131.4	136.6	146.7	152.8
Depreciation	206.0	218.8	242.2	257.7	275.0
PILs/Taxes	25.0	16.3	21.4	38.5	43.8
Capital-related RR (A)	430.5	459.7	484.0	541.6	574.7
OM&A	243.9	247.6	251.3	255.1	258.9
Revenue Offsets	- 41.3	- 41.9	- 42.5	- 43.2	- 43.8
Total RR (B)	633.1	665.4	692.8	753.5	789.8
Cn = $(A_{yx} – A_{y(x-1)}) / B_{y(x-1)}$		4.62%	3.65%	8.32%	4.40%

ROE	9.30%	9.19%	8.78%	9.00%	8.98%
Long-Term Debt	n/a	4.54%	3.72%	4.16%	4.13%
Short-Term Debt	n/a	1.65%	1.76%	2.29%	2.82%
Weighted Average Debt	n/a	4.35%	3.59%	4.04%	4.04%

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 23:

Reference(s): Exhibit 1B, Tab 4, Schedule 1, p. 13

a) Please provide a comparison for each year 2021-2024 (and in total for the 2020-2024 period) of the revenue requirement resulting from Toronto Hydro's proposed CPCI and resulting from a standard IRM formula (I-X). For the standard I-X calculation, use the proposals and assumptions made in the current application.

b) Please provide a comparison for each year 2016-2019 (and in total for the 2015-2019 period) of the revenue requirement resulting from Toronto Hydro's approved CPCI and resulting from a standard IRM formula (I-X). For the standard I-X calculation, use the approved I-X factors from each year.

RESPONSE:

a) Please see Table 1 below.

Table 1: Annual Revenue ($ Millions)

	2020	2021	2022	2023	2024	Total 2020-2024
Revenue based on proposed CPCI	796.8	822.8	843.0	878.8	913.3	**4,254.6**
Revenue based on I-X (where I=1.2% and X=0.3%)	796.8	804.0	811.2	818.5	825.9	**4,056.4**

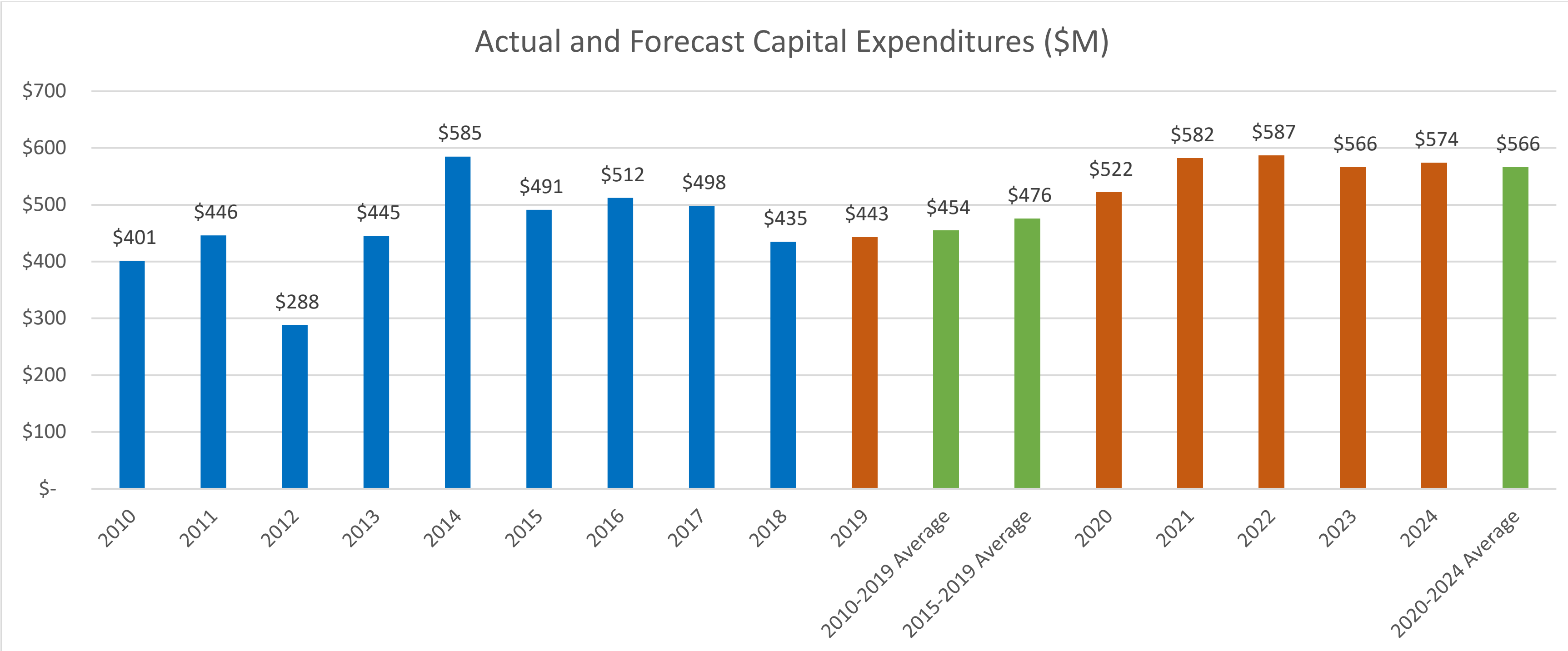
b) Please see Table 2 below.

Table 2: Annual Revenue ($ Millions)

	2015	2016	2017	2018	2019	Total 2015-2019
Revenue based on OEB approved CPCI 1	633.1	657.3	705.1	743.3	772.5	**3,511.3**
Revenue based on OEB approved I-X 2	633.1	642.6	651.0	654.9	660.7	**3,242.3**

[1] OEB approved values for CPCI: 2016 = 3.83%, 2017 = 7.26%, 2018 = 5.42%, 2019 = 3.93%

[2] OEB approved values for I: 2016 = 2.1%, 2017 = 1.9%, 2018 = 1.2%, 2019 = 1.5%.
OEB approved value for X = 0.6% (Productivity = 0.0% + Stretch = 0.6%).

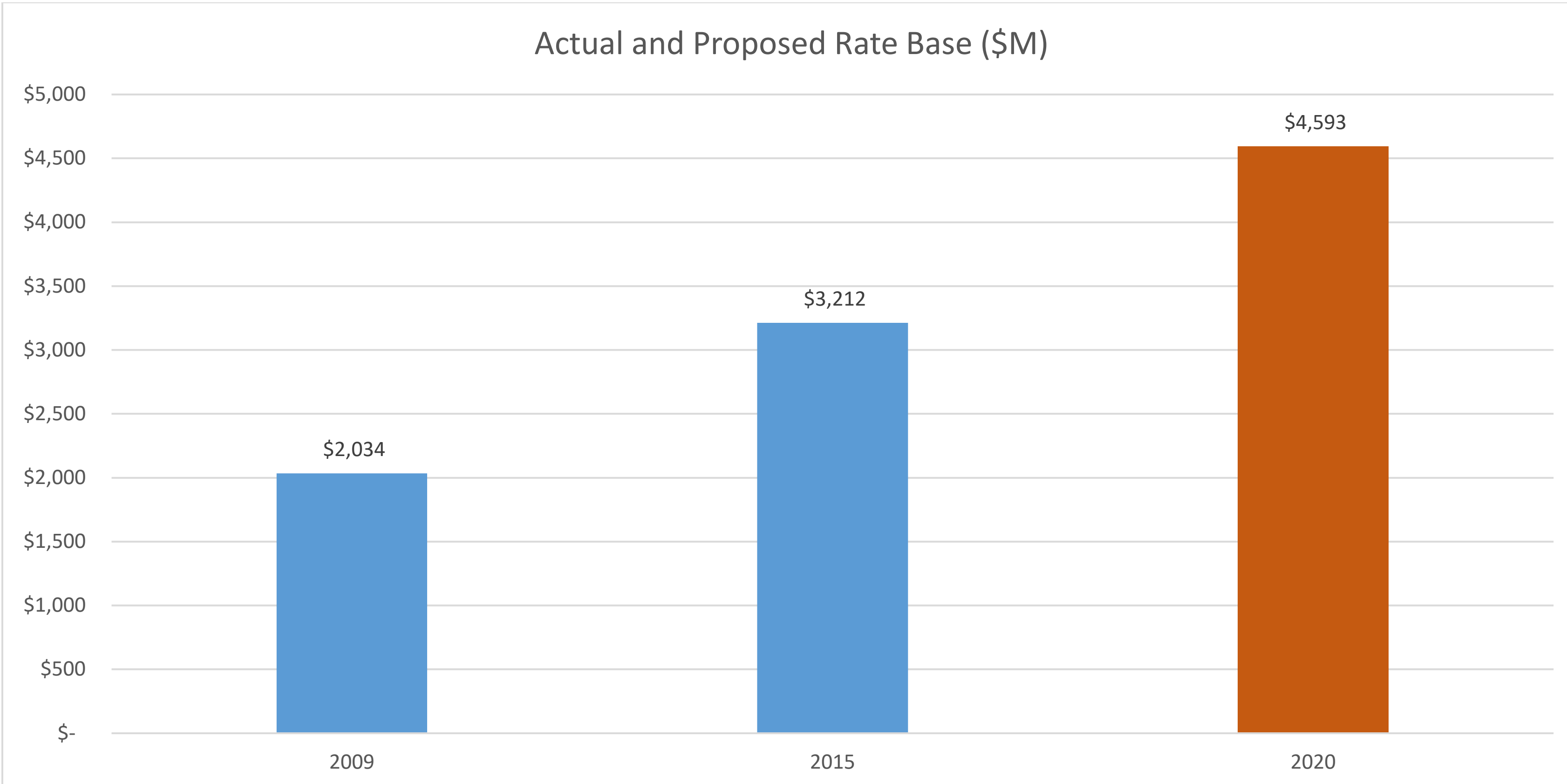


Ref:

2010-2013: EB-2014-0116 / Exhibit 2B / Schedule 00 / p. 26

2014: 2B-SEC-46 / Appendix A

2015-2024: U-Staff-168 / Appendix B / p. 8



Ref:

2009: EB-2010-0142 / Exhibit D1 / Schedule 1 / p. 2

2015: U-Staff-168 / p. 5

2020: J1.7

RATE FRAMEWORK

This schedule describes Toronto Hydro's rate framework for the 2020 to 2024 plan period. The utility's proposed rate framework continues the rate framework approved by the OEB in Toronto Hydro's 2015-2019 Rate Application.[1] The framework is aligned with OEB policy, and based on sound ratemaking principles. It has been structured in a way that includes productivity gains as part of the rate adjustment mechanism, constrains operational funding increases going forward at less than the rate of inflation, and reconciles a price-cap formula with funding requirements to address Toronto Hydro's significant, multi-year investment needs over the 2020 to 2024 period.

1. SUMMARY

Toronto Hydro's rate framework is a modification of the standard Fourth Generation Incentive Rate-Setting ("4th Generation IR") IR approach. The framework is comprehensive, covers the entirety of the application's term, and is informed by Toronto Hydro's forecasts. It is also informed by the OEB's current inflation and productivity analysis, and is aligned with Toronto Hydro's third party benchmarking of Toronto Hydro's costs. As noted, the framework is a continuation of the framework approved by the OEB in the utility's 2015-2019 Rate Application. As explained below, this includes the modifications required by the OEB in its 2015 decision, as related to the application of the stretch factor to capital and the inclusion of a growth variable to capture changes in revenue occurring due to changes in customers and loads.[2]
Year 1 is a traditional rebasing year, with costs allocated and rates set on the basis of a forecast Test Year.

[1] EB-2014-0116 Decision and Order (December 29, 2015).
[2] Ibid.

Distribution rates in Years 2 through 5 are adjusted annually by a Custom Price Cap Index ("CPCI"), as follows:

CPCI = I – X + C - g

Where,

- "**I**" is the OEB's inflation factor, determined annually;
- "**X**" is the sum of:
    - The OEB's productivity factor, as of the date of filing; and
    - Toronto Hydro's custom stretch factor;
- "**C**" provides funds incremental to "I – X" that are necessary to reconcile Toronto Hydro's capital need within a PCI framework;
- "**g**" captures revenue growth occurring due to customer and/or load changes over the forecast period, based on Toronto Hydro's forecast of loads and customers for the 2021-2024 period;

2. YEAR 1: STANDARD REBASING

The first year of the proposed rate application is a standard rebasing year, consistent with the OEB's 4th Generation IR approach. Toronto Hydro developed and has submitted in this application a forecast of its base revenue requirement for 2020. The utility developed forecasts of its costs based on its capital and operational plans for 2020. The Distribution System Plan ("DSP") and Operations, Maintenance, and Administration ("OM&A") evidence contained in Exhibits 2B and 4A, respectively, provides the details supporting these projected costs. The calculated revenue requirement resulting from these projections is detailed in the Revenue Requirement evidence filed at Exhibit 6, Tab 1.

Similarly, Toronto Hydro employed the OEB's Cost Allocation model to allocate the revenue requirement to its eight rate classes, and developed base distribution rates for each class. The standard rebasing approach maintains revenue-to-cost ratios for each class within the boundaries set out in the OEB's 2011 Review of Electricity Cost Allocation Policy.[3] For more information about Toronto Hydro's Cost Allocation and Rate Design, please refer to Exhibits 7 and 8, respectively.

In addition to base distribution rates, Toronto Hydro is applying to clear a number of Deferral and Variance accounts. Based on the values Toronto Hydro has proposed for clearance, a number of new rate riders are proposed for implementation beginning in 2020 pursuant to various clearance time frames. For more information about Toronto Hydro's proposed rate riders, please refer to Exhibit 9, Tab 3.

3. YEARS 2 TO 5: CUSTOM PRICE CAP INDEX ("CPCI")

Under 4th Generation IR, rates in the years following a rebasing year are subject to an incentive rate mechanism ("IRM"). The IRM is a formulaic approach to rate making under which distribution rates are adjusted annually using a two-component PCI:

PCI = I – X

The I-factor is intended to reflect changes to the input prices faced by the industry (i.e. inflation), while the X-factor is intended to capture changes in the productivity of the Ontario electricity distribution industry as a whole, and differences among utilities within it.

[3] EB-2010-0219, EB-2012-0383 and OEB letter issued June 12, 2015 Issuance of New Cost Allocation Policy for Street Lighting Rate Class.

In the RRFE Report, the OEB offers alternative forms of rate making "to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant."[4] The OEB notes that the CIR option in particular "will be most appropriate for distributors with significant large multi-year […] investment commitments that exceed historical levels," whereas 4th Generation IR is more suitable for utilities with "some" incremental needs.[5] The evidence at Exhibit 1B, Tab 2, Schedule 4 and the DSP at Exhibit 2B discuss Toronto Hydro's capital investment needs and, by extension, the appropriateness of the CIR option in greater detail.

A challenge for CIR applicants like Toronto Hydro is to reconcile their significantly large, multi-year investment commitments within a framework that aligns with RRFE guidance. To this end, Toronto Hydro proposes that these needs be reconciled within a CPCI framework that entrenches the OEB's inflation and productivity factors within a formulaic approach to adjusting distribution rates, with customization as set out in this evidence. The following subsections set out the approach in more detail.

3.1 Inflation and Productivity Factors

In 2013, the OEB updated its standard rate adjustment parameters following a consultation process that explicitly considered:[6]

1) The development of a more Ontario-specific inflation factor;
2) The estimation of long-run Ontario electricity distribution total factor productivity ("TFP"); and
3) The development and implementation of total cost benchmarking.

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[4] RRFE Report at page 9.
[5] RRFE Report at page 14.
[6] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013) [the "OEB Rate Setting Parameters Report"].

The OEB decided on a new methodology for the I-factor. The I-factor is based on a 30/70 weighting of labour and non-labour sub-indices and is updated annually. The labour sub-index is determined by changes in the average weekly earnings of Ontario workers, and the non-labour sub-index is determined by changes in the Canada Gross Domestic Product Implicit Price Index for final domestic demand.

Toronto Hydro proposes to use the OEB's I-factor in its CPCI. As the value for the I-factor is updated annually, Toronto Hydro will incorporate the updated value into its CPCI to appropriately adjust base distribution rates for the following year.

The productivity factor, one of the two X-factor components, was also updated. The productivity factor is intended to estimate the overall trend in the productivity of the electricity distribution industry in Ontario by measuring changes in TFP, defined by Pacific Economics Group ("PEG") as a "comprehensive measure of the extent to which firms convert inputs into outputs."[7]

In its report, PEG used an indexing method to estimate TFP for the Ontario distribution sector based on data from the 2002 to 2012 period.[8] This sample excluded the experience of both Toronto Hydro and Hydro One because, as a result of their large size relative to the rest of the industry, PEG determined that they were exerting a disproportionate impact on industry TFP.[9] Toronto Hydro presumes that this principle would have held if one or both had outperformed the sector on TFP.

[7] Pacific Economics Group (2013), Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario, (corrected January 24, 2014) at page 12 [the "PEG Report"].
[8] PEG suggests that a ten-year horizon is the minimum required for TFP Indexing.
[9] PEG Report, *supra* note 7 at page 4.

The result of PEG's analysis that excluded the two utilities suggested that industry TFP over that period changed at an average annual rate of -0.33 percent. That is, TFP for the sector actually declined over that period. In alignment with PEG's recommendation, the OEB ultimately adopted a zero productivity factor as a matter of policy, inclusive of an implicit stretch of 0.33 percent.

Toronto Hydro proposes to embed the OEB's productivity with its implicit incremental stretch factor unchanged within the proposed CPCI, fixed throughout the term of the ratemaking period.

3.2 Custom Stretch Factor

The second component of the X-factor is an explicit stretch factor. According to the OEB, "stretch factors promote, recognize, and reward distributors for efficiency improvements relative to the expected sector productivity trend."[10] Under the current methodology, which was updated most recently in 2013, utilities are assigned one of five stretch factors. This occurs on the basis of a comparison of the utility's total costs relative to their predicted total costs. The predicted total costs are determined using a total cost econometric model developed by PEG.[11]

As part of this application, Toronto Hydro is submitting alternative total cost benchmarking, the details of which can be found in the Power System Engineering's ("PSE") Econometric Benchmarking Report, at Exhibit 1B, Tab 4, Schedule 2 (the "PSE Report"). The alternative total cost benchmarking model prepared by PSE for Toronto Hydro is econometric in nature (similar to PEG's model) and includes an expanded data set. The results are statistically significant and relevant to the OEB's consideration of

[10] OEB Rate Setting Parameters Report, *supra* note 6 at page 18.
[11] OEB Rate Setting Parameters Report, *supra* note 6 at page 19.

Toronto Hydro's performance. The PSE Report also addresses the benchmarking comments set out in the OEB Decision in Toronto Hydro's 2015-2019 Rate Application.[12]

The PSE Report provides an appropriate and robust basis for setting Toronto Hydro's stretch factor. As noted in the PSE Report, Toronto Hydro's forecasts of its total costs are within 10 percent of its predicted total costs. Utilities within this demarcation point are assigned to Group III of the OEB's benchmarking cohorts, implying a stretch factor of 0.30 percent. Toronto Hydro therefore proposes that the stretch factor in the proposed CPCI framework be set at 0.30 percent, and fixed throughout the term of the ratemaking period.

Toronto Hydro's proposed plan and resulting revenue requirement in this CIR application reflects the results of a total cost econometric forecasting model, as envisioned in the Filing Requirements. A custom element of this CIR Application is using a PSE forecasting model in place of a PEG forecasting model.

3.3 Custom Capital Factor

The premise of the inclusion of a custom capital factor ("C-factor") is to reconcile the OEB's guidance that the CIR framework is best suited for utilities with significant, multi-year capital investment requirements as it is clear that the standard 4th Generation IR framework is not.

The proposed C-factor is designed as a rate adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro, as detailed

[12] Supra note 1 at pp.16-17.

in its DSP (Exhibit 2B). It is comprised of two sub-components that serve two primary functions:

- Reconcile Toronto Hydro's capital investment need in a price cap framework; and
- Return to ratepayers the funding already provided for capital through the standard "I – X" increase.

The first sub-component, termed "C_n", is determined as the percent change in total revenue requirement that is attributable to changes in capital-related revenue requirement – that is, depreciation, return on equity, interest and PILs/taxes. Changes in capital-related revenue requirement are based on forecast changes in average annual rate base, associated depreciation, and taxes. Tax rates and the cost of capital are maintained at their 2020 levels, consistent with the standard 4th Generation IR treatment and the OEB approved treatment in Toronto Hydro's 2015-2019 Rate Application.

The OEB approved values of C_n from the 2015-2019 Rate Application are shown in Table 1 below.[13]

Table 1: OEB Approved C_n factors for 2016-2019

2016	2017	2018	2019
4.07	7.60	5.99	4.43

For the current application, Cn for 2021-2024 is be determined on the following basis:

[13] EB-2014-0116 Draft Rate Order Update (February 29, 2016) page 6.

Table 2: Calculation of C_n ($ Millions)

Revenue Requirement Component[14]	2020	2021	2022	2023	2024
Ratebase	4,615.3	4,829.0	5,081.6	5,374.5	5,650.0
Interest Expense	100.8	105.5	111.0	117.4	123.4
Return on Equity	162.8	170.4	179.3	189.6	199.3
Depreciation	268.7	281.9	293.1	310.9	325.4
PILs/Taxes	34.7	36.5	32.7	35.7	42.2
Capital-related RR (A)	567.0	594.3	616.0	653.6	690.3
OM&A	277.5	280.0	282.5	285.1	287.6
Revenue Offsets	-47.7	-48.1	-48.5	-49.0	-49.4
Total RR (B)	796.8	826.2	850.0	889.6	928.5
$Cn = (A_{yx} – A_{y(x-1)}) / B_{y(x-1)}$		3.43%	2.63%	4.42%	4.12%

For example, in the above table, the change in forecast capital related revenue requirement from 2020 to 2021 is $27.3 million ($594.3 million minus $567.0 million). The total revenue requirement in 2020 is $796.8 million. C_n for 2020 is therefore:

$$C_n = (594.3 – 567.0) / 796.8 = \mathbf{3.43\%}.$$

The values shown in Table 2 are filed as part of the OEB's Revenue Requirement Workforms, at Exhibit 6, Tab 1, Schedules 2-6. Capital-related revenue requirement, as noted, is determined on a forecast basis. By contrast, OM&A and Revenue Offsets are assumed to increase by "I – X".

The values of C_n represent the amount by which base rates would need to be increased to fund Toronto Hydro's capital needs over the course of the rate term.

[14] Each component can be found in the Revenue Requirement Workforms filed as Exhibit 6, Tab 1, Schedule 2-6.

With the inclusion of C_n in the CPCI, Toronto Hydro would receive sufficient funding for its capital needs as presented in the DSP. However, the "I – X" increase already included in the CPCI formula does provide some degree of incremental funding for capital. Absent adjustment, the CPCI formula with just C_n would risk over-funding relative to Toronto Hydro's capital needs. This risk is removed in the CPCI through a scaling of the C_n values. Termed S_{cap}, this scaling factor is calculated in the following fashion:

$$S_{cap} = \text{(capital-related revenue requirement) / (total revenue requirement)}$$

This scaling reduces the incremental funding for capital to capture just the capital component incremental to the "I – X" already included in the CPCI. Table 3 provides the information inputs for calculating S_{cap} for 2021-2024.

Table 3: Revenue Requirement Components for Determining S_{cap}

Revenue Requirement Component	2021	2022	2023	2024
Interest	105.5	111.0	117.4	123.4
ROE	170.4	179.3	189.6	199.3
Depreciation	281.9	293.1	310.9	325.4
PILs/Taxes	36.5	32.7	35.7	42.2
Capital-related RR (A)	**594.3**	**616.0**	**653.6**	**690.3**
OM&A	280.0	282.5	285.1	287.6
Revenue Offsets	-48.1	-48.5	-49.0	-49.4
Total RR (B)	**826.2**	**850.0**	**889.6**	**928.5**
S_{cap} = A / B	**71.9%**	**72.5%**	**73.5%**	**74.3%**

In Toronto Hydro's 2015-2019 Rate Application, the scaling factor was applied to a full "I – X". However, the OEB ruled that the scaling should only apply to "I", so that the stretch factor incentive remained a component of the capital funding.[15] Toronto Hydro's proposed CPCI conforms to this finding.

3.4 Growth Factor

In its 2015 Decision, the OEB found that the inclusion of a growth variable in the CPCI was warranted to capture the change in distribution revenue that would naturally occur (in the absence of any rate changes) due to changes in billing units (customer numbers and loads) over the forecast period.[16]

Toronto Hydro has accordingly included the growth term, "g", in the CPCI. The value of the growth term is determined based on Toronto Hydro's forecast of loads and customers for the 2021-2024 period,[17] applied to 2020 proposed rates. This methodology is consistent with the OEB's approved methodology in Toronto Hydro's 2015-2019 Rate Application, and results in a g-factor value of 0.2 percent. Calculation of the g factor is shown in Table 4, below.

Table 4: Forecast Revenue at 2020 Proposed Rates ($ Millions)

	2020	2021	2022	2023	2024	Annual Average
Revenue at 2020 Rates	796.8	797.8	799.8	801.6	804.8	
Annual Growth Rate		0.1%	0.2%	0.2%	0.4%	0.2%

The above discussion sets out the variables that constitute Toronto Hydro's proposed CPCI. The resulting CPCI value for a given year would, in keeping with IRM principles, be applied to all distribution rates from the previous year to determine the following year's distribution rates.

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[15] Supra note 1 at page 18.
[16] Supra note 1.
[17] See Exhibit 3, Tab 1, Schedule 1, for Toronto Hydro's forecast of loads and customers

To summarize, the CPCI is determined in the following fashion:

$$\mathbf{CPCI = I - X + C - g, or}$$

$$\mathbf{CPCI = I - X + C_n - (S_{cap} * I) - g}$$

Where,

- "**I**" is the OEB's inflation factor, determined annually;
- "**X**" is the sum of:
  - The OEB's productivity factor of 0.0 percent; and
  - Toronto Hydro's custom stretch factor, applied to both OM&A and capital expenditures;
- "**C**" is the difference between:
  - **C_n**, a reflection of Toronto Hydro's capital investment need, and
  - **S_{cap} * I**, an offsetting adjustment required to ensure that the C-factor provides funding only in excess of what is already provided for capital through the inflation factor I;
- **"g"** is the growth factor determined by growth in distribution revenue due to changes in load and customers over the CPCI period.

Table 5, below, shows the components of the CPCI based on an assumed I-factor of 1.2 percent, the current OEB approved inflation value, the proposed stretch factor, the forecast values of C_n and S_{cap}, and the g factor, shown in Tables 1 and 2, above.

Table 5: CPCI Values Assuming an Inflation Factor of 1.2% for Each Year

CPCI Component (%)	2021	2022	2023	2024
I	1.2	1.2	1.2	1.2
X – productivity	0.0	0.0	0.0	0.0
X – custom stretch	0.3	0.3	0.3	0.3
C_n	3.43	2.63	4.42	4.12
S_{cap}	71.9	72.5	73.5	74.3
g	0.2	0.2	0.2	0.2
CPCI	**3.26**	**2.46**	**4.24**	**3.93**

For comparison purposes, the CPCI values approved by the OEB in EB-2014-0116 are shown in Table 6 below.[18]

Table 6: CPCI Values approved in EB-2014-0116

2016	2017	2018	2019
3.83	7.32	5.67	4.10

4. OFF-RAMPS AND Z-FACTOR

Toronto Hydro proposes to apply the OEB's existing policy with respect to off-ramps. The RRFE Report indicates that each rate-setting method includes a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review may be initiated. The OEB approved both a non-capital-related Earnings Sharing Mechanism and a Capital Related Revenue Requirement Variance Account in its EB-2014-0116 decision. Both of these mechanisms were established to protect ratepayers over the term of the CIR period. Toronto Hydro proposes to continue both of these mechanisms for the 2020-2024 period.

[18] EB-2014-0116 Draft Rate Order Update, February 29, 2016, page 6.

Finally, the OEB affirmed in its EB-2014-0116 decision that Z-factor relief was available to Toronto Hydro, if required, and based on the generic criteria for such applications. Toronto Hydro relies on this affirmation for the 2020-2024 period, should the need arise.

4.1 Earnings Sharing Mechanism Calculation

In its Decision and Order for Toronto Hydro's 2015-2019 CIR application, the OEB accepted the utility's proposal for a symmetrical earnings sharing mechanism ("ESM"), incorporating a 100 basis point dead band. As the OEB approved a separate Capital Related Revenue Requirement Variance Account, it approved the ESM to track the variance between the non-capital related revenue requirement embedded in rates and the actual non-capital related revenue requirement. Non-capital revenue requirement consists of OM&A expenditures and revenue offsets. Toronto Hydro determines whether to track an amount in the ESM variance account by calculating the contribution to ROE from the difference between actual and funded non-capital revenue requirement items. This calculation and determination is performed annually. / C

4.1.1 Calculation Methodology

To determine the variance in ROE resulting from non-capital related revenue requirement, Toronto Hydro uses an approach consistent with the OEB's ROE Workform – that is, ROE divided by deemed equity. Specifically, the utility calculates this as follows:

$$\frac{\text{(Actual non-capital revenue requirement)} - \text{(Funded non-capital revenue requirement)}}{\text{Actual equity on a deemed basis}}$$

The actual OM&A and revenue offset amounts included in the numerator are obtained from Toronto Hydro's RRR filing.[19] The funded amounts result from the base year approved OM&A and revenue offsets, adjusted for inflation and productivity. / C

[19] These amounts are adjusted, consistent with adjustments included the RRR ROE Workform and to make the actual results comparable to the amounts embedded in base rates.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 168:

Reference(s): **Exhibit U, Tab 2, Schedule 1, pp. 1-2, 8-9**
Exhibit U, Tab 2, Schedule 2, p. 21

<u>Preamble:</u>

Toronto Hydro provided an updated rate base summary table as follows:

	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 also provided an updated construction work in progress (CWIP) summary table as follows:

	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

Toronto Hydro stated that its 2020 rate base forecast is unchanged as the impact of rate base variances in 2018 and 2019 on the forecast net fixed asset component of 2020 rate base will be less than 1%. Toronto Hydro also proposes no changes to its 2020 in-service additions (ISAs).

In a number of places throughout the capital expenditure-related evidence update, Toronto Hydro stated that capital projects (and associated costs) have moved into the 2020-2024 period. For example, with respect to capital contributions to Hydro One for the Horner TS, Toronto Hydro stated that it deferred contributions to the 2020-2024 period.

a) Please confirm that it is Toronto Hydro's proposal to maintain the 2020 opening PP&E NBV amount of $4,270.4 million in the context that the 2019 closing PP&E NBV amount is $4,232.3 million. If so, please explain why this is appropriate.

b) Please confirm that it is Toronto Hydro's proposal to make no changes to its 2020 in-service addition (ISA) forecast ($489.8 million) (or 2021-2024 ISA forecasts) in the context that there were changes to 2018 actual ISAs and 2019 forecast ISAs (and there are a number of projects specifically referenced where changes are expected to occur during the IR term). If so, please explain why this is appropriate.

RESPONSE:

a) Toronto Hydro forecasts that its 2020 PP&E NBV amount will be within 1% of the amount originally filed. The forecast variance is caused by CWIP balances that are largely expected to be in service in 2020. As set out in Appendices A and B to this interrogatory response, Toronto Hydro is updating its 2020-2024 rate base evidence in relation to the CWIP balance.

b) As presented in Exhibit U, Tab 2, Schedule 1, page 2, Table 2, the forecasted 2019 Closing CWIP in the application update is $381.1 million, compared to the $343.5 million that was presented in Exhibit 2A, Tab 2, Schedule 1, Table 1 of the pre-filed evidence. Toronto Hydro has revised its 2020 in-service addition (ISA) forecast to reflect the impact of projects that were delayed from 2019 to 2020. ISA variance explanations for 2018-2019 are provided in response to U-Staff-170, parts (c) and (d). As a result of these deferrals, the current ISA forecast is $39 million lower than the pre-filed schedule, excluding external demand and non-rate base ISAs as shown in the table below.

Table 1: 2018-2019 ISA Variance

Category	2019 ISA Requirement	2019 Forecast	Variance
Distribution Capital Projects	390.0	375.9	(14.1)
Metering Data Collection Systems	9.5	7.0	(2.5)
Hydro One Contributions	14.7	4.0	(10.7)
IT Projects	52.4	40.7	(11.7)
Subtotal	**466.6**	**427.6**	**(39.0)**

Toronto Hydro expects to make-up the majority of this variance in 2020 from carry-over projects totalling an estimated $33.9 million in ISAs. These outstanding projects require an incremental $3.2 million in capital expenditures to be completed and placed into service in 2020, as shown in Table 2 below. The remaining ISAs variance is substantially attributed to a $4.6 million refund from Hydro One associated with the Runnymede TS circuit upgrade project. This refund resulted from the over-collection of capital contributions from Toronto Hydro. The amounts were refunded following a Capital Cost Recovery Agreement true up of the actual costs incurred in the project.

Table 2: Carryover Projects for 2020 ISA

Category	DSP Category	Capital Program	# of Projects	2020 ISA ($M)	2020 CapEx ($M)
Distribution Capital	System Service	Network Condition Monitoring and Control	2	2.3	0.4
Distribution Capital	System Renewal	Stations Renewal	5	12.6	0.5
Distribution Capital	System Renewal	Area Conversions	2	5.1	0.5
Distribution Capital	System Renewal	Underground System Renewal – Horseshoe	1	1.6	-
Distribution Capital			**10**	**21.6**	**1.4**
Metering Data Collection Systems	System Access	Metering	1	4.5	1.0
Metering Data Collection Systems			**1**	**4.5**	**1.0**
Hydro One Contributions	System Service	Stations Expansion	1	4.0	-
Hydro One Contributions			**1**	**4.0**	**-**
IT Projects	General Plant	IT/OT Systems	1	3.9	0.8
IT Projects			**1**	**3.9**	**0.8**
Subtotal			**13**	**33.9**	**3.2**
HONI Refund (Unplanned)		Stations Expansion	1	4.6	-
Total			**14**	**38.5**	**3.2**

Toronto Hydro has filed updated 2020-2024 Fixed Asset Continuity Schedules as Appendix A to this response. These schedules reflect the updated ISAs from the projects listed above, as well as other changes in the 2020-2024 period which resulted in changes in the mix of 2019 closing CWIP relative to the original pre-filed evidence.

Table 3 reflects the updated Rate Base amounts for 2020-2024 resulting from the above noted changes.

Table 3: Updated Rate Base

	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**	**4,233.4**
Closing PP&E NBV	**3,134.7**	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,232.3**	**4,506.0**
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,891.8**	**4,135.6**	**4,369.7**
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**	**4,604.9**

Table 4 below shows the updated 2020-2024 Capital Related Revenue Requirement which also captures the PILs changes resulting from Bill C-97. The overall impact is a $63.8 million reduction to the forecast 2020-2024 Capital Related Revenue Requirement compared to pre-filed evidence, $54.9 million of which is related to the PILs changes.

Table 4: Updated Revenue Requirement

	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	2020	2021	2022	2023	2024	2020-2024
ROE	162.5	170.8	179.5	189.7	199.2	**901.7**
Deemed Interest	100.6	105.7	111.1	117.4	123.3	**558.2**
Depreciation	265.5	281.5	292.3	314.0	327.1	**1,480.5**
PILS	12.8	22.2	13.6	27.9	40.5	**117.0**
Capital Related RR	**541.4**	**580.3**	**596.5**	**649.0**	**690.2**	**3,057.4**

Appendix B to this response provides revisions to other capital expenditures and rate base summary tables that are affected by the above noted changes. This includes:

- Exhibit U, Tab 2, Schedule 1, Page 4, Table 3: Gross and Net PP&E – Years Ending in December 31 ($ Millions);

- Exhibit U, Tab 2, Schedule 1, Page 7, Table 6: 2019 Bridge versus 2020 Forecast ($ Millions);
- Exhibit U, Tab 2, Schedule 1, Page 8, Table 7: Breakdown of Ending Balance of Gross Assets by Function ($ Millions);
- Exhibit U, Tab 2, Schedule 1, Appendix C: Gross Assets Breakdown by Major Plant Account – Detailed by Uniform System of Account;
- Exhibit U, Tab 4B, Schedule 1, Appendix A: Summary of Depreciation Expense;
- Exhibit U, Tab 4B, Schedule 1, Page 2, Table 3: Depreciation and Amortization Expense 2015 to 2020 ($ Millions);
- Exhibit U, Tab 2, Schedule 2, Appendix B: OEB Appendix 2-AB;
- Exhibit U, Tab 2, Schedule 2, Appendix C: OEB Appendix 2-AB (JTC1.2); and
- Exhibit U, Tab 2, Schedule 1, Page 2, Table 2: Historical, Bridge and Forecasted Construction Work In Progress ($ Millions).

Toronto Hydro has also provided an updated Appendix 2-AA (with additional variance columns) in its response to interrogatory U-VECC-71.

Toronto Hydro proposes to update the cost allocation and rates information during the draft rate order process.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2020**

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
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)	$ 247,940,281	$ 41,602,565	$ -	$ 289,542,846	($ 124,697,201)	($ 32,653,777)	$ -	($ 157,350,978)	$ 132,191,868
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 146,603,541	$ 3,545,980	$ -	$ 150,149,521	($ 16,315,310)	($ 3,719,188)	$ -	($ 20,034,497)	$ 130,115,023
47	1815	Transformer Station Equipment >50 kV	$ 38,893,291	$ 146,098	$ -	$ 39,039,389	($ 4,500,900)	($ 1,387,410)	$ -	($ 5,888,310)	$ 33,151,079
47	1820	Distribution Station Equipment <50 kV	$ 233,896,334	$ 32,875,896	($ 326,796)	$ 266,445,433	($ 46,700,148)	($ 10,856,456)	$ 95,923	($ 57,460,681)	$ 208,984,752
47	1830	Poles, Towers & Fixtures	$ 402,570,951	$ 42,684,885	($ 6,898,194)	$ 438,357,642	($ 56,695,908)	($ 11,871,898)	$ 927,888	($ 67,639,918)	$ 370,717,724
47	1835	Overhead Conductors & Devices	$ 468,238,300	$ 61,492,935	($ 2,629,678)	$ 527,101,556	($ 54,922,627)	($ 12,475,862)	$ 283,889	($ 67,114,600)	$ 459,986,957
47	1840	Underground Conduit	$ 1,306,119,180	$ 141,110,831	($ 668,559)	$ 1,446,561,452	($ 246,475,756)	($ 51,782,108)	$ 98,099	($ 298,159,766)	$ 1,148,401,686
47	1845	Underground Conductors & Devices	$ 955,851,966	$ 124,881,819	($ 5,903,043)	$ 1,074,830,742	($ 127,818,888)	($ 29,865,268)	$ 560,001	($ 157,124,156)	$ 917,706,587
47	1850	Line Transformers	$ 640,828,362	$ 102,119,136	($ 11,048,456)	$ 731,899,043	($ 122,498,051)	($ 27,962,577)	$ 1,545,228	($ 148,915,400)	$ 582,983,643
47	1855	Services (Overhead & Underground)	$ 141,412,397	$ 25,045,715	($ 398,088)	$ 166,060,024	($ 14,620,528)	($ 3,358,705)	$ 22,965	($ 17,956,268)	$ 148,103,756
47	1860	Meters	$ 105,053,832	$ 25,640,095	($ 1,022,851)	$ 129,671,076	($ 21,901,280)	($ 5,159,847)	$ 140,733	($ 26,920,394)	$ 102,750,682
47	1860	Meters (Smart Meters)	$ 138,842,990	$ 11,966,039	($ 713,141)	$ 150,095,888	($ 60,798,152)	($ 12,293,423)	$ 163,557	($ 72,928,019)	$ 77,167,870
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 240,619,777	$ 2,944,360	$ -	$ 243,564,137	($ 48,906,069)	($ 11,356,784)	$ -	($ 60,262,853)	$ 183,301,284
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 20,438,655	$ 1,053,325	$ -	$ 21,491,979	($ 11,414,206)	($ 1,886,440)	$ -	($ 13,300,646)	$ 8,191,333
50	1920	Computer Equipment - Hardware	$ 74,159,596	$ 15,123,254	$ -	$ 89,282,850	($ 50,494,297)	($ 11,199,443)	$ -	($ 61,693,740)	$ 27,589,110
10	1930	Transportation Equipment	$ 41,078,692	$ 4,604,061	$ -	$ 45,682,753	($ 27,822,725)	($ 3,150,222)	$ -	($ 30,972,947)	$ 14,709,806
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 28,881,401	$ 15,356,838	$ -	$ 44,238,240	($ 13,765,998)	($ 3,017,290)	$ -	($ 16,783,288)	$ 27,454,951
8	1945	Measurement & Testing Equipment	$ 499,679	$ 85,246	$ -	$ 584,925	($ 395,908)	($ 50,414)	$ -	($ 446,322)	$ 138,604
8	1950	Service Equipment	$ 1,387,956	$ 120,323	$ -	$ 1,508,279	($ 743,037)	($ 127,564)	$ -	($ 870,602)	$ 637,677
8	1955	Communications Equipment	$ 50,690,668	$ 1,263,248	$ -	$ 51,953,916	($ 19,759,473)	($ 4,395,505)	$ -	($ 24,154,978)	$ 27,798,938
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 223,012)	($ 34,271)	$ -	($ 257,284)	$ 13,694
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	$ 52,079,297	$ 18,811,881	($ 627,898)	$ 70,263,279	($ 14,532,254)	($ 3,652,397)	$ 67,859	($ 18,116,791)	$ 52,146,488
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 235,243,420)	($ 146,273,553)	$ 565,896	($ 380,951,077)	$ 22,047,976	$ 8,804,137	($ 28,847)	$ 30,823,265	($ 350,127,811)
N/A	1609	Capital Contributions Paid	$ 190,469,722	$ 29,784,498	$ -	$ 220,254,219	($ 17,995,699)	($ 8,256,701)	$ -	($ 26,252,400)	$ 194,001,820
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 12,323,115)	($ 676,393)	$ -	($ 12,999,508)	$ 6,748,206
		Sub-Total	**$ 5,339,480,967**	**$ 555,985,474**	**($ 29,670,808)**	**$ 5,865,795,633**	**($ 1,098,056,306)**	**($ 242,385,809)**	**$ 3,877,295**	**($ 1,336,564,821)**	**$ 4,529,230,812**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 2,730,141)	($ 5,828,584)	$ -	($ 8,558,725)	$ 34,127	$ 410,729	$ -	$ 444,856	($ 8,113,869)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 5,704,285)	($ 10,214,512)	$ -	($ 15,918,797)	$ 369,444	$ 469,291	$ -	$ 838,735	($ 15,080,062)
		Total PP&E	**$ 5,331,046,541**	**$ 539,942,378**	**($ 29,670,808)**	**$ 5,841,318,111**	**($ 1,097,652,736)**	**($ 241,505,789)**	**$ 3,877,295**	**($ 1,335,281,230)**	**$ 4,506,036,881**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 241,505,789)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 239,746,268)

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 **2021**

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
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)	$ 289,542,846	$ 37,040,209	$ -	$ 326,583,055	($ 157,350,978)	($ 35,750,756)	$ -	($ 193,101,734)	$ 133,481,321
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 150,149,521	$ 5,054,020	$ -	$ 155,203,541	($ 20,034,497)	($ 3,846,016)	$ -	($ 23,880,514)	$ 131,323,027
47	1815	Transformer Station Equipment >50 kV	$ 39,039,389	$ 117,028	$ -	$ 39,156,416	($ 5,888,310)	($ 1,429,995)	$ -	($ 7,318,304)	$ 31,838,112
47	1820	Distribution Station Equipment <50 kV	$ 266,445,433	$ 25,064,669	($ 341,165)	$ 291,168,937	($ 57,460,681)	($ 11,786,856)	$ 100,136	($ 69,147,402)	$ 222,021,535
47	1830	Poles, Towers & Fixtures	$ 438,357,642	$ 35,702,172	($ 7,314,181)	$ 466,745,633	($ 67,639,918)	($ 12,701,325)	$ 967,637	($ 79,373,607)	$ 387,372,027
47	1835	Overhead Conductors & Devices	$ 527,101,556	$ 51,007,558	($ 2,787,782)	$ 575,321,332	($ 67,114,600)	($ 13,710,100)	$ 297,886	($ 80,526,814)	$ 494,794,518
47	1840	Underground Conduit	$ 1,446,561,452	$ 112,903,055	($ 703,712)	$ 1,558,760,795	($ 298,159,766)	($ 56,331,901)	$ 102,019	($ 354,389,647)	$ 1,204,371,148
47	1845	Underground Conductors & Devices	$ 1,074,830,742	$ 104,656,787	($ 6,282,985)	$ 1,173,204,545	($ 157,124,156)	($ 32,368,162)	$ 594,838	($ 188,897,480)	$ 984,307,065
47	1850	Line Transformers	$ 731,899,043	$ 84,331,281	($ 11,603,645)	$ 804,626,678	($ 148,915,400)	($ 29,981,285)	$ 1,621,305	($ 177,275,379)	$ 627,351,299
47	1855	Services (Overhead & Underground)	$ 166,060,024	$ 20,715,062	($ 425,950)	$ 186,349,135	($ 17,956,268)	($ 3,715,367)	$ 24,571	($ 21,647,064)	$ 164,702,071
47	1860	Meters	$ 129,671,076	$ 16,187,757	($ 1,017,640)	$ 144,841,193	($ 26,920,394)	($ 5,618,339)	$ 140,016	($ 32,398,717)	$ 112,442,476
47	1860	Meters (Smart Meters)	$ 150,095,888	$ 7,996,296	($ 428,284)	$ 157,663,900	($ 72,928,019)	($ 12,056,011)	$ 98,156	($ 84,885,874)	$ 72,778,027
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 243,564,137	$ 4,470,732	$ -	$ 248,034,869	($ 60,262,853)	($ 11,386,791)	$ -	($ 71,649,644)	$ 176,385,225
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 21,491,979	$ 1,602,715	$ -	$ 23,094,695	($ 13,300,646)	($ 1,522,209)	$ -	($ 14,822,855)	$ 8,271,840
50	1920	Computer Equipment - Hardware	$ 89,282,850	$ 10,942,287	$ -	$ 100,225,137	($ 61,693,740)	($ 11,577,822)	$ -	($ 73,271,562)	$ 26,953,575
10	1930	Transportation Equipment	$ 45,682,753	$ 8,317,935	$ -	$ 54,000,688	($ 30,972,947)	($ 3,603,064)	$ -	($ 34,576,011)	$ 19,424,676
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 44,238,240	$ 19,467,406	$ -	$ 63,705,645	($ 16,783,288)	($ 3,955,827)	$ -	($ 20,739,115)	$ 42,966,530
8	1945	Measurement & Testing Equipment	$ 584,925	$ 229,524	$ -	$ 814,449	($ 446,322)	($ 40,379)	$ -	($ 486,700)	$ 327,749
8	1950	Service Equipment	$ 1,508,279	$ 248,660	$ -	$ 1,756,939	($ 870,602)	($ 130,733)	$ -	($ 1,001,335)	$ 755,604
8	1955	Communications Equipment	$ 51,953,916	$ 1,175,493	$ -	$ 53,129,409	($ 24,154,978)	($ 4,104,648)	$ -	($ 28,259,626)	$ 24,869,783
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 257,284)	($ 12,066)	$ -	($ 269,350)	$ 1,628
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	$ 70,263,279	$ 9,053,902	($ 668,673)	$ 78,648,509	($ 18,116,791)	($ 4,074,313)	$ 72,264	($ 22,118,840)	$ 56,529,668
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 380,951,077)	($ 80,356,037)	$ 579,154	($ 460,727,959)	$ 30,823,265	$ 11,560,942	($ 29,523)	$ 42,354,685	($ 418,373,275)
N/A	1609	Capital Contributions Paid	$ 220,254,219	$ 2,035,515	$ -	$ 222,289,734	($ 26,252,400)	($ 8,846,852)	$ -	($ 35,099,252)	$ 187,190,482
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 12,999,508)	($ 622,309)	$ -	($ 13,621,817)	$ 6,125,897
		Sub-Total	**$ 5,865,795,633**	**$ 477,964,027**	**($ 30,994,864)**	**$ 6,312,764,796**	**($ 1,336,564,821)**	**($ 257,612,183)**	**$ 3,989,305**	**($ 1,590,187,699)**	**$ 4,722,577,097**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 8,558,725)	($ 868,193)	$ -	($ 9,426,917)	$ 444,856	$ 642,823	$ -	$ 1,087,679	($ 8,339,239)
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	($ 15,918,797)	($ 2,121,225)	$ -	($ 18,040,021)	$ 838,735	$ 681,314	$ -	$ 1,520,049	($ 16,519,972)
		Total PP&E	**$ 5,841,318,111**	**$ 474,974,610**	**($ 30,994,864)**	**$ 6,285,297,857**	**($ 1,335,281,230)**	**($ 256,288,046)**	**$ 3,989,305**	**($ 1,587,579,972)**	**$ 4,697,717,886**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 256,288,046)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 254,528,526)

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 **2022**

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
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)	$ 326,583,055	$ 64,227,955	$ -	$ 390,811,010	($ 193,101,734)	($ 38,545,659)	$ -	($ 231,647,393)	$ 159,163,617
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 155,203,541	$ 40,378,055	$ -	$ 195,581,596	($ 23,880,514)	($ 4,350,846)	$ -	($ 28,231,360)	$ 167,350,236
47	1815	Transformer Station Equipment >50 kV	$ 39,156,416	$ 2,478,930	$ -	$ 41,635,346	($ 7,318,304)	($ 1,500,080)	$ -	($ 8,818,385)	$ 32,816,961
47	1820	Distribution Station Equipment <50 kV	$ 291,168,937	$ 26,685,246	($ 343,626)	$ 317,510,557	($ 69,147,402)	($ 12,489,301)	$ 100,860	($ 81,535,843)	$ 235,974,715
47	1830	Poles, Towers & Fixtures	$ 466,745,633	$ 34,588,526	($ 7,317,218)	$ 494,016,941	($ 79,373,607)	($ 13,442,357)	$ 974,920	($ 91,841,044)	$ 402,175,898
47	1835	Overhead Conductors & Devices	$ 575,321,332	$ 45,968,668	($ 2,789,199)	$ 618,500,800	($ 80,526,814)	($ 14,801,768)	$ 299,349	($ 95,029,233)	$ 523,471,567
47	1840	Underground Conduit	$ 1,558,760,795	$ 113,105,155	($ 706,308)	$ 1,671,159,642	($ 354,389,647)	($ 59,758,370)	$ 102,918	($ 414,045,100)	$ 1,257,114,542
47	1845	Underground Conductors & Devices	$ 1,173,204,545	$ 106,870,549	($ 6,276,298)	$ 1,273,798,796	($ 188,897,480)	($ 34,769,524)	$ 594,725	($ 223,072,279)	$ 1,050,726,517
47	1850	Line Transformers	$ 804,626,678	$ 84,455,268	($ 11,655,663)	$ 877,426,283	($ 177,275,379)	($ 31,704,069)	$ 1,629,292	($ 207,350,155)	$ 670,076,128
47	1855	Services (Overhead & Underground)	$ 186,349,135	$ 20,353,222	($ 424,454)	$ 206,277,904	($ 21,647,064)	($ 4,028,117)	$ 24,486	($ 25,650,695)	$ 180,627,208
47	1860	Meters	$ 144,841,193	$ 17,241,110	($ 1,003,870)	$ 161,078,433	($ 32,398,717)	($ 5,981,254)	$ 138,121	($ 38,241,850)	$ 122,836,582
47	1860	Meters (Smart Meters)	$ 157,663,900	$ 8,335,515	($ 260,287)	$ 165,739,128	($ 84,885,874)	($ 10,058,951)	$ 59,557	($ 94,885,267)	$ 70,853,861
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 248,034,869	$ 21,654,357	$ -	$ 269,689,225	($ 71,649,644)	($ 11,520,627)	$ -	($ 83,170,271)	$ 186,518,954
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 23,094,695	$ 7,762,883	$ -	$ 30,857,577	($ 14,822,855)	($ 1,470,022)	$ -	($ 16,292,877)	$ 14,564,701
50	1920	Computer Equipment - Hardware	$ 100,225,137	$ 13,269,836	$ -	$ 113,494,973	($ 73,271,562)	($ 10,950,953)	$ -	($ 84,222,515)	$ 29,272,458
10	1930	Transportation Equipment	$ 54,000,688	$ 7,924,120	$ -	$ 61,924,808	($ 34,576,011)	($ 4,417,573)	$ -	($ 38,993,584)	$ 22,931,223
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 63,705,645	$ 28,985,036	$ -	$ 92,690,682	($ 20,739,115)	($ 5,447,891)	$ -	($ 26,187,006)	$ 66,503,675
8	1945	Measurement & Testing Equipment	$ 814,449	$ 11,671	$ -	$ 826,120	($ 486,700)	($ 36,843)	$ -	($ 523,544)	$ 302,577
8	1950	Service Equipment	$ 1,756,939	$ 236,128	$ -	$ 1,993,067	($ 1,001,335)	($ 153,730)	$ -	($ 1,155,065)	$ 838,002
8	1955	Communications Equipment	$ 53,129,409	$ 1,180,207	$ -	$ 54,309,616	($ 28,259,626)	($ 3,324,294)	$ -	($ 31,583,920)	$ 22,725,696
8	1960	Miscellaneous Equipment	$ 270,978	$ 1,579,433	$ -	$ 1,850,410	($ 269,350)	($ 19,256)	$ -	($ 288,606)	$ 1,561,804
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	$ 78,648,509	$ 11,646,178	($ 667,846)	$ 89,626,840	($ 22,118,840)	($ 4,298,811)	$ 72,176	($ 26,345,476)	$ 63,281,364
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 460,727,959)	($ 71,719,865)	$ 597,344	($ 531,850,480)	$ 42,354,685	$ 13,732,602	($ 30,450)	$ 56,056,837	($ 475,793,643)
N/A	1609	Capital Contributions Paid	$ 222,289,734	$ 4,143,670	$ -	$ 226,433,404	($ 35,099,252)	($ 8,973,950)	$ -	($ 44,073,202)	$ 182,360,202
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 13,621,817)	($ 359,675)	$ -	($ 13,981,493)	$ 5,766,222
		Sub-Total	**$ 6,312,764,796**	**$ 591,361,853**	**($ 30,847,427)**	**$ 6,873,279,222**	**($ 1,590,187,699)**	**($ 268,671,321)**	**$ 3,965,954**	**($ 1,854,893,067)**	**$ 5,018,386,156**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 9,426,917)	($ 1,694,024)	$ -	($ 11,120,941)	$ 1,087,679	$ 748,002	$ -	$ 1,835,680	($ 9,285,261)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 18,040,021)	($ 2,219,756)	$ -	($ 20,259,777)	$ 1,520,049	$ 760,391	$ -	$ 2,280,440	($ 17,979,338)
		Total PP&E	**$ 6,285,297,857**	**$ 587,448,073**	**($ 30,847,427)**	**$ 6,841,898,504**	**($ 1,587,579,972)**	**($ 267,162,929)**	**$ 3,965,954**	**($ 1,850,776,947)**	**$ 4,991,121,557**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 267,162,929)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 265,403,409)

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 2023

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
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)	$ 390,811,010	$ 41,755,588	$ -	$ 432,566,598	($ 231,647,393)	($ 43,244,819)	$ -	($ 274,892,212)	$ 157,674,386
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 195,581,596	$ 27,700,557	$ -	$ 223,282,152	($ 28,231,360)	($ 6,059,192)	$ -	($ 34,290,551)	$ 188,991,601
47	1815	Transformer Station Equipment >50 kV	$ 41,635,346	$ 2,961,227	$ -	$ 44,596,573	($ 8,818,385)	($ 1,632,624)	$ -	($ 10,451,009)	$ 34,145,564
47	1820	Distribution Station Equipment <50 kV	$ 317,510,557	$ 26,897,223	($ 358,450)	$ 344,049,330	($ 81,535,843)	($ 13,455,228)	$ 105,205	($ 94,885,865)	$ 249,163,465
47	1830	Poles, Towers & Fixtures	$ 494,016,941	$ 35,925,013	($ 7,769,068)	$ 522,172,887	($ 91,841,044)	($ 14,251,511)	$ 1,020,341	($ 105,072,213)	$ 417,100,674
47	1835	Overhead Conductors & Devices	$ 618,500,800	$ 46,856,177	($ 2,959,674)	$ 662,397,303	($ 95,029,233)	($ 15,757,264)	$ 314,872	($ 110,471,625)	$ 551,925,678
47	1840	Underground Conduit	$ 1,671,159,642	$ 118,101,839	($ 744,311)	$ 1,788,517,171	($ 414,045,100)	($ 63,572,653)	$ 107,359	($ 477,510,394)	$ 1,311,006,776
47	1845	Underground Conductors & Devices	$ 1,273,798,796	$ 113,798,427	($ 6,689,225)	$ 1,380,907,998	($ 223,072,279)	($ 36,897,119)	$ 632,475	($ 259,336,923)	$ 1,121,571,075
47	1850	Line Transformers	$ 877,426,283	$ 88,264,338	($ 12,233,907)	$ 953,456,714	($ 207,350,155)	($ 33,692,007)	$ 1,708,443	($ 239,333,719)	$ 714,122,994
47	1855	Services (Overhead & Underground)	$ 206,277,904	$ 20,992,446	($ 454,636)	$ 226,815,713	($ 25,650,695)	($ 4,354,613)	$ 26,227	($ 29,979,081)	$ 196,836,632
47	1860	Meters	$ 161,078,433	$ 21,145,521	($ 981,543)	$ 181,242,411	($ 38,241,850)	($ 6,372,346)	$ 135,049	($ 44,479,147)	$ 136,763,264
47	1860	Meters (Smart Meters)	$ 165,739,128	$ 9,702,716	($ 116,284)	$ 175,325,560	($ 94,885,267)	($ 8,742,141)	$ 26,487	($ 103,600,921)	$ 71,724,639
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 269,689,225	$ 5,387,713	$ -	$ 275,076,939	($ 83,170,271)	($ 12,342,070)	$ -	($ 95,512,341)	$ 179,564,597
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 30,857,577	$ 1,931,444	$ -	$ 32,789,022	($ 16,292,877)	($ 1,898,451)	$ -	($ 18,191,327)	$ 14,597,694
50	1920	Computer Equipment - Hardware	$ 113,494,973	$ 14,016,313	$ -	$ 127,511,286	($ 84,222,515)	($ 12,737,643)	$ -	($ 96,960,158)	$ 30,551,128
10	1930	Transportation Equipment	$ 61,924,808	$ 8,503,841	$ -	$ 70,428,649	($ 38,993,584)	($ 5,306,497)	$ -	($ 44,300,082)	$ 26,128,567
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 92,690,682	$ 2,176,390	$ -	$ 94,867,071	($ 26,187,006)	($ 6,268,652)	$ -	($ 32,455,658)	$ 62,411,413
8	1945	Measurement & Testing Equipment	$ 826,120	$ 235	$ -	$ 826,355	($ 523,544)	($ 21,944)	$ -	($ 545,488)	$ 280,868
8	1950	Service Equipment	$ 1,993,067	$ 254,014	$ -	$ 2,247,081	($ 1,155,065)	($ 184,485)	$ -	($ 1,339,550)	$ 907,531
8	1955	Communications Equipment	$ 54,309,616	$ 1,403,601	$ -	$ 55,713,218	($ 31,583,920)	($ 2,803,611)	$ -	($ 34,387,531)	$ 21,325,686
8	1960	Miscellaneous Equipment	$ 1,850,410	$ -	$ -	$ 1,850,410	($ 288,606)	($ 226,779)	$ -	($ 515,385)	$ 1,335,026
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	$ 89,626,840	$ 12,487,400	($ 712,351)	$ 101,401,890	($ 26,345,476)	($ 4,485,953)	$ 76,983	($ 30,754,445)	$ 70,647,444
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 531,850,480)	($ 46,370,896)	$ 643,931	($ 577,577,445)	$ 56,056,837	$ 15,226,060	($ 32,825)	$ 71,250,072	($ 506,327,373)
N/A	1609	Capital Contributions Paid	$ 226,433,404	$ 38,957,642	$ -	$ 265,391,046	($ 44,073,202)	($ 9,893,999)	$ -	($ 53,967,201)	$ 211,423,845
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 13,981,493)	($ 128,056)	$ -	($ 14,109,548)	$ 5,638,166
		Sub-Total	**$ 6,873,279,222**	**$ 592,848,770**	**($ 32,375,518)**	**$ 7,433,752,475**	**($ 1,854,893,067)**	**($ 289,103,595)**	**$ 4,120,617**	**($ 2,139,876,045)**	**$ 5,293,876,430**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 11,120,941)	$ -	$ -	($ 11,120,941)	$ 1,835,680	$ 741,396	$ -	$ 2,577,076	($ 8,543,865)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 20,259,777)	($ 2,364,569)	$ -	($ 22,624,347)	$ 2,280,440	$ 843,961	$ -	$ 3,124,401	($ 19,499,946)
		Total PP&E	**$ 6,841,898,504**	**$ 590,484,201**	**($ 32,375,518)**	**$ 7,400,007,188**	**($ 1,850,776,947)**	**($ 287,518,238)**	**$ 4,120,617**	**($ 2,134,174,568)**	**$ 5,265,832,620**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 287,518,238)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 285,758,717)

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 2024

CCA Class	OEB Account	Description	Cost (Forecast) Opening Balance	Cost (Forecast) Additions	Cost (Forecast) Disposals	Cost (Forecast) Closing Balance	Accumulated Depreciation (Forecast) Opening Balance	Accumulated Depreciation (Forecast) Additions	Accumulated Depreciation (Forecast) Disposals	Accumulated Depreciation (Forecast) Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 432,566,598	$ 42,093,911	$ -	$ 474,660,509	($ 274,892,212)	($ 43,235,561)	$ -	($ 318,127,773)	$ 156,532,736
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 223,282,152	$ 29,868,364	$ -	$ 253,150,517	($ 34,290,551)	($ 7,004,320)	$ -	($ 41,294,871)	$ 211,855,646
47	1815	Transformer Station Equipment >50 kV	$ 44,596,573	$ 3,245,603	$ -	$ 47,842,175	($ 10,451,009)	($ 1,770,382)	$ -	($ 12,221,391)	$ 35,620,785
47	1820	Distribution Station Equipment <50 kV	$ 344,049,330	$ 36,813,051	($ 363,939)	$ 380,498,442	($ 94,885,865)	($ 14,380,354)	$ 106,818	($ 109,159,401)	$ 271,339,041
47	1830	Poles, Towers & Fixtures	$ 522,172,887	$ 50,051,715	($ 7,846,443)	$ 564,378,159	($ 105,072,213)	($ 15,197,585)	$ 1,028,747	($ 119,241,051)	$ 445,137,108
47	1835	Overhead Conductors & Devices	$ 662,397,303	$ 68,451,053	($ 2,991,329)	$ 727,857,027	($ 110,471,625)	($ 17,021,092)	$ 317,902	($ 127,174,815)	$ 600,682,212
47	1840	Underground Conduit	$ 1,788,517,171	$ 162,531,104	($ 753,024)	$ 1,950,295,251	($ 477,510,394)	($ 67,613,566)	$ 108,392	($ 545,015,568)	$ 1,405,279,683
47	1845	Underground Conductors & Devices	$ 1,380,907,998	$ 156,176,233	($ 6,757,459)	$ 1,530,326,772	($ 259,336,923)	($ 39,575,168)	$ 639,251	($ 298,272,840)	$ 1,232,053,932
47	1850	Line Transformers	$ 953,456,714	$ 123,778,708	($ 12,403,105)	$ 1,064,832,316	($ 239,333,719)	($ 35,404,488)	$ 1,732,472	($ 273,005,735)	$ 791,826,581
47	1855	Services (Overhead & Underground)	$ 226,815,713	$ 28,096,699	($ 458,743)	$ 254,453,669	($ 29,979,081)	($ 4,733,044)	$ 26,464	($ 34,685,660)	$ 219,768,008
47	1860	Meters	$ 181,242,411	$ 34,217,845	($ 950,656)	$ 214,509,600	($ 44,479,147)	($ 6,838,786)	$ 130,800	($ 51,187,133)	$ 163,322,467
47	1860	Meters (Smart Meters)	$ 175,325,560	$ 15,285,136	($ 13,248)	$ 190,597,448	($ 103,600,921)	($ 7,807,576)	$ 2,855	($ 111,405,642)	$ 79,191,806
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 275,076,939	$ 5,669,199	$ -	$ 280,746,138	($ 95,512,341)	($ 10,414,223)	$ -	($ 105,926,564)	$ 174,819,574
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 32,789,022	$ 2,032,354	$ -	$ 34,821,376	($ 18,191,327)	($ 2,050,626)	$ -	($ 20,241,953)	$ 14,579,423
50	1920	Computer Equipment - Hardware	$ 127,511,286	$ 14,933,709	$ -	$ 142,444,996	($ 96,960,158)	($ 13,959,747)	$ -	($ 110,919,906)	$ 31,525,090
10	1930	Transportation Equipment	$ 70,428,649	$ 8,817,216	$ -	$ 79,245,865	($ 44,300,082)	($ 6,247,699)	$ -	($ 50,547,780)	$ 28,698,084
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 94,867,071	$ 3,125,886	$ -	$ 97,992,957	($ 32,455,658)	($ 6,231,724)	$ -	($ 38,687,383)	$ 59,305,575
8	1945	Measurement & Testing Equipment	$ 826,355	$ 399	$ -	$ 826,755	($ 545,488)	($ 21,945)	$ -	($ 567,432)	$ 259,323
8	1950	Service Equipment	$ 2,247,081	$ 263,573	$ -	$ 2,510,654	($ 1,339,550)	($ 217,825)	$ -	($ 1,557,375)	$ 953,278
8	1955	Communications Equipment	$ 55,713,218	$ 1,770,353	$ -	$ 57,483,571	($ 34,387,531)	($ 2,723,621)	$ -	($ 37,111,152)	$ 20,372,418
8	1960	Miscellaneous Equipment	$ 1,850,410	$ -	$ -	$ 1,850,410	($ 515,385)	($ 226,779)	$ -	($ 742,163)	$ 1,108,247
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	$ 101,401,890	$ 15,855,126	($ 719,484)	$ 116,537,532	($ 30,754,445)	($ 4,930,266)	$ 77,754	($ 35,606,958)	$ 80,930,575
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 577,577,445)	($ 226,921,734)	$ 648,701	($ 803,850,479)	$ 71,250,072	$ 16,468,884	($ 33,068)	$ 87,685,888	($ 716,164,590)
N/A	1609	Capital Contributions Paid	$ 265,391,046	$ 9,979,192	$ -	$ 275,370,239	($ 53,967,201)	($ 10,824,439)	$ -	($ 64,791,640)	$ 210,578,599
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 14,109,548)	($ 128,056)	$ -	($ 14,237,604)	$ 5,510,110
		Sub-Total	**$ 7,433,752,475**	**$ 586,134,696**	**($ 32,608,729)**	**$ 7,987,278,441**	**($ 2,139,876,045)**	**($ 302,089,985)**	**$ 4,138,387**	**($ 2,437,827,643)**	**$ 5,549,450,798**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 11,120,941)	$ -	$ -	($ 11,120,941)	$ 2,577,076	$ 741,396	$ -	$ 3,318,472	($ 7,802,469)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 22,624,347)	($ 2,515,682)	$ -	($ 25,140,029)	$ 3,124,401	$ 932,922	$ -	$ 4,057,323	($ 21,082,705)
		Total PP&E	**$ 7,400,007,188**	**$ 583,619,014**	**($ 32,608,729)**	**$ 7,951,017,472**	**($ 2,134,174,568)**	**($ 300,415,667)**	**$ 4,138,387**	**($ 2,430,451,848)**	**$ 5,520,565,624**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 300,415,667)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 298,656,146)

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

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 4, Table 3

Table 1: 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	174.5
Other Distribution Assets	170.0	238.5	267.3	434.6	507.6	586.9
General Plant	127.7	185.2	247.5	240.1	241.4	244.3
TS Primary Above 50	5.8	6.0	36.9	37.9	38.9	39.0
Distribution System	149.9	156.8	184.5	213.5	233.9	266.4
Poles, Wires	2,172.2	2,430.6	2,663.8	2,876.9	3,132.8	3,486.9
Contributions and Grants	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(381.0)
Line Transformers	412.4	465.3	515.4	566.7	640.8	731.9
Services and Meters	262.0	290.0	321.8	344.7	385.3	445.8
Equipment	61.5	100.4	120.8	131.3	140.5	157.2
IT Assets	27.3	47.2	58.7	66.8	74.2	89.3
Gross Assets	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,841.3**
Accumulated Depreciation	(320.6)	(496.8)	(684.3)	(876.9)	(1,097.7)	(1,335.3)
Closing PP&E NBV	**3,086.2**	**3,462.6**	**3,755.8**	**4,040.6**	**4,233.4**	**4,506.0**
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**	**4,506.0**

Note: Variances due to rounding may exist

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 7, Table 6

Table 2: 2019 Bridge versus 2020 Forecast ($ Millions)

	2019 Bridge	2020 Forecast	Variance ($)	Variance (%)
Land and Buildings	171.0	174.5	3.5	2.1%
Other Distribution Assets	507.6	586.9	79.4	15.6%
General Plant	241.4	244.3	2.9	1.2%
TS Primary Above 50	38.9	39.0	0.1	0.4%
Distribution System	233.9	266.4	32.5	13.9%
Poles, Wires	3,132.8	3,486.9	354.1	11.3%
Contributions and Grants	(235.2)	(381.0)	(145.7)	61.9%
Line Transformers	640.8	731.9	91.1	14.2%
Services and Meters	385.3	445.8	60.5	15.7%
Equipment	140.5	157.2	16.7	11.9%
IT Assets	74.2	89.3	15.1	20.4%
Gross Assets	**5,331.0**	**5,841.3**	**510.3**	**9.6%**
Accumulated Depreciation	(1,097.7)	(1,335.3)	(237.6)	21.6%
Closing PP&E NBV (MIFRS)	**4,233.4**	**4,506.0**	**272.6**	**6.4%**

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 8, Table 7

Table 3: 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	39.0
Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,984.8
General Plant	354.0	482.3	599.8	683.2	741.1	817.4
Gross Fixed Assets Before CWIP	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,841.3**
CWIP	577.7	502.9	485.8	396.4	381.1	358.3
Total Including CWIP	**3,984.5**	**4,462.3**	**4,925.9**	**5,313.9**	**5,712.2**	**6,162.1**

Note: Variances due to rounding may exist

Original Reference: Exhibit U, Tab 2, Schedule 1, Appendix C

Table 4: Gross Assets Breakdown by Major Plant Account – Detailed by Uniform System of Account

	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	39.0
	Subtotal High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.0
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	150.1
1810	Leasehold Improvements	-	-	-	-	-	-
1820	Distribution Station Equipment	149.9	156.8	184.5	213.5	233.9	266.4
1830	Poles, Towers and Fixtures	311.0	339.5	362.5	380.8	402.6	438.4
1835	O/H Conductors and Devices	299.4	349.5	390.5	428.3	468.2	527.1
1840	U/G Conduit	952.0	1,051.0	1,127.9	1,205.6	1,306.1	1,446.6
1845	U/G Conductors and Devices	609.9	690.6	782.8	862.2	955.9	1,074.8
1850	Line Transformers	412.4	465.3	515.4	566.7	640.8	731.9
1855	Services	93.3	109.1	122.1	124.6	141.4	166.1
1860	Meters (includes Smart Meters)	168.7	180.9	199.7	220.1	243.9	279.8
1970	Load Management-Customer	3.0	3.0	3.0	3.0	3.0	3.0
1975	Load Management-Utility	-	-	-	-	-	-
1980	System Supervisory Equipment	25.4	28.2	33.6	39.7	46.4	54.3
1609	Capital Contributions Paid	21.7	75.6	75.6	164.2	190.5	220.3
2440	Contributed Capital	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(381.0)
	Subtotal Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,984.8
1611	Computer Software	101.6	113.6	137.0	207.9	247.9	289.5
1905	Land	17.7	17.7	17.7	17.4	17.4	17.4
1612	Land Rights	-	-	-	1.6	1.6	1.6
1908	Buildings and Fixtures	126.9	184.5	246.7	239.4	240.6	243.6
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	21.5
1920	Computer Equipment	27.3	47.2	58.7	66.8	74.2	89.3
1930	Transportation Equipment	26.6	29.9	33.7	36.1	41.1	45.7
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	35.7
1945	Measurement & Test Equipment	0.5	0.5	0.5	0.5	0.5	0.6
1950	Power Operated Equipment	0.6	0.7	0.8	1.3	1.4	1.5
1955	Communication Equipment	8.0	35.9	45.4	49.9	50.7	52.0
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	817.4
	GROSS FIXED ASSETS BEFORE CWIP	3,406.8	3,959.4	4,440.1	4,917.5	5,331.0	5,841.3
2055	Construction Work-in-Process	577.7	502.9	485.8	396.4	381.1	358.3
	TOTAL INCLUDING CWIP	3,984.5	4,462.3	4,925.9	5,313.9	5,712.2	6,199.6

Original Reference: Exhibit U, Tab 4B, Schedule 1, Appendix A

Table 5: Summary of Depreciation Expense

		2020 MIFRS		
OEB	**Description**	**Depreciation Expense**	**Derecognition**	**Total Depreciation Expense**
1611	Computer Software (Formally known as Account 1925)	$ 32,653,777	$ -	$ 32,653,777
1612	Land Rights	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -
1808	Buildings	$ 3,719,188	$ -	$ 3,719,188
1815	Transformer Station Equipment >50 kV	$ 1,387,410	$ -	$ 1,387,410
1820	Distribution Station Equipment <50 kV	$ 10,856,456	$ 230,873	$ 11,087,329
1830	Poles, Towers & Fixtures	$ 11,871,898	$ 5,970,306	$ 17,842,204
1835	Overhead Conductors & Devices	$ 12,475,862	$ 2,345,789	$ 14,821,651
1840	Underground Conduit	$ 51,782,108	$ 570,460	$ 52,352,569
1845	Underground Conductors & Devices	$ 29,865,268	$ 5,343,042	$ 35,208,310
1850	Line Transformers	$ 27,962,577	$ 9,503,228	$ 37,465,805
1855	Services (Overhead & Underground)	$ 3,358,705	$ 375,123	$ 3,733,828
1860	Meters	$ 17,453,270	$ 1,431,703	$ 18,884,973
1905	Land	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,356,784	$ -	$ 11,356,784
1910	Leasehold Improvements	$ -	$ -	$ -
1915	Office Furniture & Equipment	$ 1,886,440	$ -	$ 1,886,440
1920	Computer Equipment - Hardware	$ 11,199,443	$ -	$ 11,199,443
1930	Transportation Equipment	$ 3,150,222	$ -	$ 3,150,222
1935	Stores Equipment	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 3,017,290	$ -	$ 3,017,290
1945	Measurement & Testing Equipment	$ 50,414	$ -	$ 50,414
1950	Power Operated Equipment	$ 127,564	$ -	$ 127,564
1955	Communications Equipment	$ 4,395,505	$ -	$ 4,395,505
1960	Miscellaneous Equipment	$ 34,271	$ -	$ 34,271
1970	Load Management Controls Customer Premises	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 3,652,397	$ 560,039	$ 4,212,436
2440	Contributions & Grants	($ 8,804,137)	($ 537,050)	($ 9,341,186)
1609	Capital Contributions Paid	$ 8,256,701	$ -	$ 8,256,701
2005	Property Under Capital Leases	$ 676,393	$ -	$ 676,393
	Sub-Total	$ 242,385,809	$ 25,793,513	$ 268,179,322
	Less Socialized Renewable Energy Generation Investments (input as negative)	($ 410,729)	$ -	($ 410,729)
	Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 469,291)	$ -	($ 469,291)
	Total	$ 241,505,789	$ 25,793,513	$ 267,299,302

Less: Fully Allocated Depreciation			
Transportation	($ 1,759,521)		($ 1,759,521)
Net Depreciation	**$ 239,746,268**	**$ 25,793,513**	**$ 265,539,781**

Original Reference: Exhibit U, Tab 4B, Schedule 1, Page 2, Table 3

Table 6: Depreciation and Amortization Expense 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Updated Bridge	2020 Updated Forecast
Depreciation and Amortization Expense	166.0	179.1	192.5	205.3	223.6	239.7

Original Reference: Exhibit U, Tab 2, Schedule 2, Appendix B

Table 7:
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%	92.8	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%	307.6	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%	34.6	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%	79.6	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%	521.6	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%	508.8	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
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.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Original Reference: Exhibit U, Tab 2, Schedule 2, Appendix C

Table 8:
OEB Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

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	Bridge	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%	161.4	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%	307.6	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%	58.9	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%	79.6	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%	614.5	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%	521.6	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				

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
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.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 2, Table 2

Table 9: 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	381.1
Additions (CAPEX)	490.6	508.4	496.6	434.9	425.3	517.2
Deductions (In Service Additions)	(435.3)	(584.3)	(520.3)	(524.4)	(440.6)	(539.9)
Other	0.3	1.1	6.5	0.0	-	-
Closing CWIP	577.7	502.9	485.8	396.4	381.1	358.3

ORAL HEARING UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. J1.8:

Reference(s): Exhibit K1.3, page 92

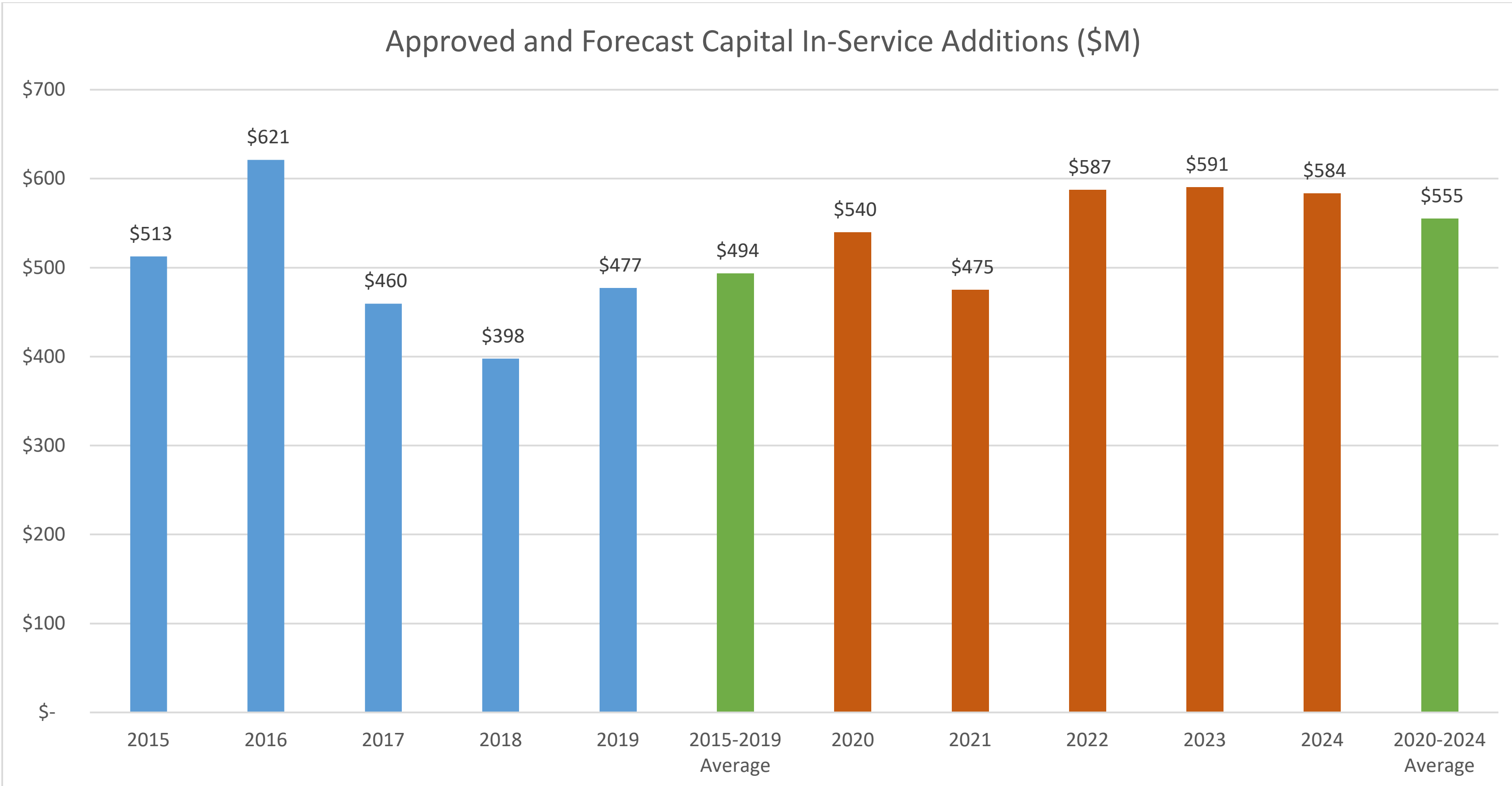
To review the spreadsheet and confirm whether the Board got the numbers right or wrong and correct this chart.

RESPONSE:

Please refer to Appendix A to this response for the revised values. Toronto Hydro confirms that all the items listed in Table 1 of its response to undertaking J1.2 are incorporated in Appendix A.

Undertaking J1.8

Revenue Requirement	2020	2021	2022	2023	2024	Total
CRR	$ 540.46	$ 579.30	$ 595.57	$ 648.13	$ 689.36	$ 3,052.83
Non-CRR	$ 230.93	$ 233.01	$ 235.10	$ 237.22	$ 239.35	$ 1,175.61
Base RR	$ 771.39	$ 812.31	$ 830.67	$ 885.35	$ 928.72	$ 4,228.44
I		1.20%	1.20%	1.20%	1.20%	
X		0.30%	0.30%	0.30%	0.30%	
Cn		5.03%	2.00%	6.33%	4.66%	
Scap		71.32%	71.70%	73.21%	74.23%	
G		0.20%	0.20%	0.20%	0.20%	
CPCI		4.88%	1.84%	6.15%	4.47%	
Revenue Requirement recovered in rates		$ 809.03	$ 823.93	$ 874.60	$ 913.66	



Ref:

2015-2019: Exhibit U / Tab 2 / Schedule 1 / Appendix A

2020-2024: J1.7

	Ref:	TH 2015-2019 CIR (Funded) 2015	2016	2017	2018	2019	5 yr Total / Average	TH 2020-2024 CIR (Proposed) 2020	2021	2022	2023	2024	5 yr Total / Average	Test Year 2015 vs 2020 Change (%)	Proportional Change (%)	Term 2015-2019 vs Term 2020-2024 Change (%)	Proportional Change (%)
Rate Base	1	$ 3,232.00	$ 3,575.20	$ 3,890.20	$ 4,075.30	$ 4,253.80		$ 4,592.60	$ 4,829.10	$ 5,076.40	$ 5,365.50	$ 5,636.30					
Approved/Proposed CRR	2	$ 430.50	$ 456.30	$ 506.60	$ 549.50	$ 583.20	$ 2,526.10	$ 540.50	$ 579.30	$ 595.60	$ 648.10	$ 689.40	$ 3,052.90				
Stretch Factor Reduction to CRR	3		$ (2.60)	$ (5.40)	$ (8.40)	$ (11.70)	$ (28.10)		$ (1.62)	$ (3.36)	$ (5.15)	$ (7.09)	$ (17.22)				
Funded/Proposed Funded CRR	4	$ 430.50	$ 453.70	$ 501.20	$ 541.00	$ 571.50	$ 2,497.90	$ 540.50	$ 577.68	$ 592.24	$ 642.95	$ 682.31	$ 3,035.68				
Approved/Proposed Depreciation	5	$ 206.02	$ 218.80	$ 242.20	$ 257.70	$ 275.00	$ 1,199.72	$ 265.50	$ 281.50	$ 292.30	$ 314.00	$ 327.10	$ 1,480.40				
Stretch Factor Reduction to Depreciation	6		$ (1.24)	$ (2.55)	$ (4.00)	$ (5.55)	$ (13.34)		$ (0.80)	$ (1.64)	$ (2.52)	$ (3.46)	$ (8.42)				
Funded/Proposed Funded Depreciation	7	$ 206.02	$ 217.56	$ 239.65	$ 253.70	$ 269.45	$ 1,186.38	$ 265.50	$ 280.70	$ 290.66	$ 311.48	$ 323.64	$ 1,471.98				
Funded/Proposed Funded RR	8	$ 633.10	$ 657.30	$ 705.10	$ 743.30	$ 772.50	$ 3,511.30	$ 771.40	$ 809.03	$ 823.93	$ 874.60	$ 913.66	$ 4,192.62				
Approved/Proposed Net Capex	9	$ 478.00	$ 466.90	$ 420.60	$ 423.00	$ 451.90	$ 2,240.40	$ 521.60	$ 581.80	$ 587.10	$ 565.70	$ 574.40	$ 2,830.60				
Net Capex / Rate Base	10	14.79%	13.06%	10.81%	10.38%	10.62%	11.93%	11.36%	12.05%	11.57%	10.54%	10.19%	11.14%	-3.43%	-23.21%	-0.79%	-6.64%
Funded Depreciation / Net Capex	11	43.10%	46.60%	56.98%	59.98%	59.63%	52.95%	50.90%	48.25%	49.51%	55.06%	56.34%	52.00%	7.80%	18.10%	-0.95%	-1.80%
Annual Net Capex Growth			-2.32%	-9.92%	0.57%	6.83%			11.54%	0.91%	-3.65%	1.54%					
Rate Base Growth (Term)	12						31.62%						22.73%			-8.89%	-28.12%

		TH 2015-2019 IRM (Alternative) 2015	2016	2017	2018	2019	5 yr Total / Average	TH 2020-2024 IRM (Alternative) 2020	2021	2022	2023	2024	5 yr Total / Average
Rate Base	13	$ 3,232.00						$ 4,592.60					
Funded CRR	14	$ 430.50	$ 436.96	$ 442.64	$ 445.29	$ 449.30	$ 2,204.69	$ 540.50	$ 545.36	$ 550.27	$ 555.23	$ 560.22	$ 2,751.58
Funded Depreciation	15	$ 206.02	$ 209.11	$ 211.83	$ 213.10	$ 215.02	$ 1,055.08	$ 265.50	$ 267.89	$ 270.30	$ 272.73	$ 275.19	$ 1,351.61
Funded RR	16	$ 633.10	$ 642.60	$ 651.00	$ 654.90	$ 660.70	$ 3,242.30	$ 771.40	$ 778.34	$ 785.35	$ 792.42	$ 799.55	$ 3,927.05
Proposed Net CAPEX	17	$ 478.00	$ 466.90	$ 420.60	$ 423.00	$ 451.90	$ 2,240.40	$ 521.60	$ 581.80	$ 587.10	$ 565.70	$ 574.40	$ 2,830.60
Net CAPEX / Average Rate Base	18	14.79%						11.36%					
Funded Depreciation / Net CAPEX	19	43.10%	44.79%	50.36%	50.38%	47.58%	47.09%	50.90%	46.04%	46.04%	48.21%	47.91%	47.75%

		TH 2015-2019 CIR (Funded) vs IRM (Alternative) Shortfall ($/%)	Proportional Shortfall (%)	TH 2020-2024 CIR (Proposed) vs IRM (Alternative) Shortfall ($/%)	Proportional Shortfall (%)	Term 2015-2019 vs Term 2020-2024 Change in Proportional Shortfall (%)	Relative Change in Proportional Shortfall (%)
CRR Funding	20	**$ 293.21**	**11.74%**	**$ 284.10**	**9.36%**	**-2.38%**	**-20.27%**
Depreciation Funding	21	**$ 131.31**	**11.07%**	**$ 120.37**	**8.18%**	**-2.89%**	**-26.11%**
RR Funding	22	**$ 269.00**	**7.66%**	**$ 265.57**	**6.33%**	**-1.33%**	**-17.32%**
Term Funded Depreciation / Net CAPEX	23	**5.86%**	**11.07%**	**4.25%**	**8.18%**	**-2.89%**	**-26.11%**

Notes/References:

1 2015-2019 CIR: 1B-Staff-21(a)
2020-2024 CIR: J1.7
2 2015-2019 CIR: Ex. 9 / T1 / S1 / p.12/ L3
2020-2024 CIR: J1.7
3 2015-2019 CIR: Ex. 9 / T1 / S1 / p.12/ L4
2020-2024 CIR: Line 4*0.3% Stretch + Prior Year
4 Line 4 + Line 5
5 2015-2019 CIR: 1B-Staff-21(a)
2020-2024 CIR: U-Staff-168
6 2015-2019 CIR: Line 7*0.6% Stretch + Previous Year
2020-2024 CIR: Line 7*0.3% Stretch + Previous Year
7 Line 7 + Line 8
8 2015-2019 CIR: 1B-Staff-23 (b)
2020-2024 CIR: J1.8
9 2015-2019 CIR: 2B-Staff-75 (Adx. A, 2015-2019 CIR Filing - 10%)
2020-2024 CIR: J1.7
10 2015-2019 CIR: Line 11 / Line 3
2020-2024 CIR: Line 11 / Line 3
2015 vs 2020 Change (%): K12-D12
2015 vs 2020 Proportional Change (%): R12/D12
Term 2015-2019 vs Term 2020-2024 Change (%): P12-I12
Term 2015-2019 vs Term 2020-2024 Proportional Change (%): T12/I12
11 2015-2019 CIR: Line 9 / Line 11
2020-2024 CIR: Line 9 / Line 11
2015 vs 2020 Change (%): K13-D13
2015 vs 2020 Proportional Change (%): R13/D13
Term 2015-2019 vs Term 2020-2024 Change (%): P13-I13
Term 2015-2019 vs Term 2020-2024 Proportional Change (%): T13/I13
12 2015-2019 CIR: (H3-D3)/D3
2020-2024 CIR: (O3-K3)/K3
Term 2015-2019 vs Term 2020-2024 Change (%): P15-I15
Term 2015-2019 vs Term 2020-2024 Proportional Change (%): T15/I15
13 2015-2019 IRM: 1B-Staff-21(a)
2020-2024 IRM: Ex. J1.7
14 2015-2019 IRM: Ex. 9 / T1 / S1 / L5 - 2015 then escalated for I-X (Note 24 - Table 1)
2020-2024 IRM: J1.7 - 2020 then escalated for I-X (Note 24 - Table 1)
15 2015-2019 IRM: 1B-Staff-21(a) - 2015 then escalated for I-X (Note 24 - Table 1)
2020-2024 IRM: U-Staff-168 - 2020 then escalated for I-X (Note 24 - Table 1)
16 2015-2019 IRM: 1B-Staff-23(b)
2020-2024 IRM: J1.8 - 2020 then escalated for I-X (Note 24 - Table 1)
17 2015-2019 IRM: 2B-Staff-75 (Adx. A, 2015-2019 CIR Filing - 10%)
2020-2024 IRM: J1.7
18 Line 23 / Line 19
19 Line 21 / Line 23
20 2015-2019 CIR vs IRM Shortfall: (I20-I6)*-1
2015-2019 CIR vs IRM Proportional Shortfall: I29/I6
2020-2024 CIR vs IRM Shortfall: (P20-P6)*-1
2024-2024 CIR vs IRM Proportional Shortfall: P29/P6
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Change in Proportional Shortfall: Q29-J29
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Relative Change in Proportional Shortfall: R29/J29
21 2015-2019 CIR vs IRM Shortfall: (I21-9)*-1
2015-2019 CIR vs IRM Proportional Shortfall: I30/I9
2020-2024 CIR vs IRM Shortfall: (P21-P9)*-1
2024-2024 CIR vs IRM Proportional Shortfall: P30/P9
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Change in Proportional Shortfall: Q30-J30
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Relative Change in Proportional Shortfall: R30/J30
22 2015-2019 CIR vs IRM Shortfall: (I22-I10)*-1
2015-2019 CIR vs IRM Proportional Shortfall: I31/I10
2020-2024 CIR vs IRM Shortfall: (P22-P10)*-1
2024-2024 CIR vs IRM Proportional Shortfall: P31/P10
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Change in Proportional Shortfall: Q31-J31
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Relative Change in Proportional Shortfall: R31/J31
23 2015-2019 CIR vs IRM Shortfall: (I25-I13)*-1
2015-2019 CIR vs IRM Proportional Shortfall: I32/I13
2020-2024 CIR vs IRM Shortfall: (P25-P13)*-1
2024-2024 CIR vs IRM Proportional Shortfall: P32/P13
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Change in Proportional Shortfall: Q32-J32
Term 2015-2019 (IRM vs CIR) vs Term 2020-2024 (IRM vs CIR) Relative Change in Proportional Shortfall: R32/J32

24 Table 1 - I-X Calculations:

	Inflation	TH Stretch	I-X
2015	1.01600	0.006	1.0100
2016	1.02100	0.006	1.0150
2017	1.01900	0.006	1.0130
2018	1.01200	0.006	1.0060
2019	1.01500	0.006	1.0090
2020	1.01200	0.003	1.0090
2020A	1.01200	0.006	1.0060

Ontario Energy Board

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

this Report is an important step in the continued evolution of electricity regulation in Ontario.

In developing the policies set out in this Report, the Board has been informed by, and has benefitted greatly from, extensive consultation and dialogue with stakeholders representing a broad range of interests and perspectives. The materials generated for and through this consultation provide useful background and context for the issues discussed in this Report, as well as a detailed record of stakeholder comments on those issues. Many of these materials are listed in Appendix A, and all are readily available on the Board's website.

The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

4 Performance Measurement and Continuous Improvement

The renewed regulatory framework is a comprehensive performance-based approach to regulation that promotes the achievement of performance outcomes that will benefit existing and future customers. The framework will align customer and utility interests, continue to support the achievement of important public policy objectives, and place a greater focus on delivering value for money.

The achievement of the performance outcomes will be supported by specific measures and targets and annual reporting. Distributor performance will be compared year over year, both to prior performance and to the performance of other distributors. To facilitate performance monitoring and distributor benchmarking, the Board will use a scorecard approach to link directly to the performance outcomes.

Under the renewed regulatory framework a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, which in turn can lead to reduced costs for customers.

4.1 Monitoring Distributor Performance

Under the rate-setting approach described in Chapter 2, the Board will be setting rates under longer-term plans and allowing distributors to select the rate-setting method that best meets their needs and circumstances. Distributors will be required to undertake longer-term integrated planning that captures all categories of network planning, including those reflecting regional needs, as discussed in Chapter 3.

The Board has standards and measures for performance in place today;[19] however, the Board needs to assess whether these continue to be appropriate in light of the performance outcomes defined by the Board and the new rate setting methods. The Board also needs to consider the consequences that might flow from performance that does not meet the standards.

Benchmarking will become increasingly important, as comparison among distributors is one means of analyzing whether a given distributor is as efficient as possible.

Stakeholder Views

There was general stakeholder support for meaningful, empirically-based standards, performance measures and regulatory mechanisms, provided that the implementation costs do not outweigh the value for customers. Desirable characteristics that were identified included: focus on what customers value; promoting alignment of distributor and customer interests; and ability to accommodate differences within the distribution sector.

Stakeholder suggestions for objectives to underpin the development of distributor customer service and cost performance standards and measures included furthering market development; revealing infrastructure investment planning effectiveness or cost performance; facilitating price transparency for customers; and improving existing customer service standards.

A number of stakeholders acknowledged the cost performance incentives that are inherent in incentive regulation. Caution was expressed about implementing direct financial incentives until Board-approved measures are in place. Stakeholders were divided on process incentives; some were supportive of streamlined regulatory processes for high-performing distributors while others were opposed to limits being

[19] These are identified in the *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors.*

placed on the review of applications based on the quality of evidence or the applicant's past performance.

The Board's Conclusions

Performance Outcomes and the Electricity Distributor Scorecard

The Board is establishing performance outcomes that it expects distributors to achieve in four distinct areas:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board concludes that a scorecard will be used to monitor individual distributor performance and to compare performance across the distribution sector. The scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons, which are critical to the Board's rate-setting approach under the renewed regulatory framework. Distributors will be required to report their progress against the scorecard on an annual basis.

Ontario Energy Board **Commission de l'énergie de l'Ontario**

EB-2013-0416/EB-2014-0247

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR APPROVAL OF DISTRIBUTION RATES FOR 2015 TO 2019

DECISION
March 12, 2015

- Overall lack of consistency and comparability with incentive rate-setting particularly with regard to the specification and use of a custom index approach to rate-setting that includes explicit, externally imposed improvement incentives.

In its May 30, 2014 evidence update, Hydro One provided eight outcomes by which to measure its five year plan. The company agreed to report annually on these outcomes, including the results achieved and actual amounts spent on the programs. Many parties submitted that additional reporting, for example, on actual capital spending and the results of the smart grid program, was necessary.

Parties submitted that the inadequacies of the application should be addressed by the OEB through either denial of the five year application (i.e. set rates for only one or two years) or substantive adjustments to the five year plan such as using 2015 as a base year and setting rates for 2016 – 2019 through an index.

Findings

The OEB has concluded, for the reasons set out below, that Hydro One's application is insufficient as a Custom IR application under RRFE and has determined that it will deny approval of the proposed five-year plan. Instead the OEB will approve rates for a three-year period based on the evidence provided. This change from what was applied for by Hydro One is due to a number of shortcomings with Hydro One's proposed approach. The OEB is directing Hydro One to address those shortcomings, set out below, over the next three years in preparation for the next rates application.

3.1 Inconsistency with outcome-based regulation

Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service.

Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies. Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation.

The OEB finds that Hydro One's proposed plan is deficient in this regard, as it includes limited prospects for continuous improvement, lacks any externally imposed improvement incentives, includes limited cost and productivity benchmarking support, and fails to demonstrate value to customers commensurate with the forecasted spending.

3.2 Lack of externally imposed incentives

The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.

The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year in a form illustrating trends in a transparent fashion.

It is not sufficient to embed savings in cost forecasts. As already noted, the OEB's Custom IR is an incentive rate-setting approach designed to drive efficiencies. Benefits from explicit, objectively determined productivity and efficiency adjustments such as stretch factors include mimicking competitive market conditions, sharing anticipated savings with ratepayers “up front”, and facilitating a more outcome-based approach to regulation.

As already noted, traditional cost of service review will continue to entail detailed input cost assessments. However, Custom IR proceedings are intended to be framed more like performance inquiries resulting in multi-year outcome commitments and measures that facilitate year-over-year performance assessment. The productivity and efficiency elements allow the OEB to move away from detailed input cost assessment and focus more on utility performance. These factors provide utilities with strong incentives to continually seek efficiencies and share expected savings with ratepayers “up front” avoiding “after the fact” regulatory scrutiny.

3.3 Weak benchmarking evidence

The RRFE policy articulates the importance the OEB places on benchmarking. Benchmarking evidence, whether it compares a utility’s performance to itself year-over-year, or to other utilities, is a critical input to the OEB’s assessment of utility performance.

Benchmarking, when used in combination with specific cost drivers and other sources of utility performance information, allows for an overall assessment of a utility’s cost and outcome performance.

A majority of parties were critical of the lack of benchmarking in Hydro One’s plan. Hydro One described eight benchmarking or similar studies it had undertaken. The OEB agrees with the submissions of OEB staff and the majority of the intervenors that the studies provided in this proceeding by Hydro One, lack:

1) a top-down perspective of what the appropriate level of costs should be; and

2) measures of Hydro One’s cost performance against other comparable utilities.

IRM Design for Toronto Hydro-Electric System

May 22, 2019 (revised)

Mark Newton Lowry, Ph.D.
President

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5. Other Plan Design Issues

The other provisions of the IRM proposed by Toronto Hydro are in some respects uncontroversial. We have noted that the plan is similar to Custom IR plans the Board has previously approved for the Company and other distributors. Some provisions are also consistent with other Board decisions. We are nonetheless concerned about some features of the Company's proposal.

The proposed ratemaking treatment of capital is our chief concern. The C factor would ensure that the Company recovers its projected/proposed capital cost less a perfunctory stretch factor markdown. Any cumulative capex underspend would be returned to the ratepayer. Externally-driven capex such as that due to highway construction would be addressed by a variance account. Hence, capital revenue would chiefly be established on a cost of service basis.

Despite the proposed clawback of capex underspends, Toronto Hydro would still have some incentive to exaggerate capex needs since exaggerations strengthen the case for a C Factor and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Toronto Hydro's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted. Toronto Hydro would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company somehow managed to change the timing of its capex so that the $I - X + g$ escalation was compensatory it would obtain no supplemental revenue.

The full clawback of capex underspends and the variance account treatment of externally driven capex would greatly reduce the Company's incentive to contain capex. Incentives to contain capex and OM&A expenses would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce OM&A costs.

Another problem with the proposal is that while customers must fully compensate Toronto Hydro for expected capital revenue *shortfalls* when capex is high, for reasons beyond its control the Company need not reduce its capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Slow capital cost growth in the future may very well occur, and not just because of good capital cost management. For example, depreciation of recent and prospective surge capex will tend to slow capital cost growth in the future. Customers therefore would never receive the full benefit of the industry's multifactor productivity trend, even in the long run and even when it is achievable.

A related problem is that most of the capex addressed by the C factor and the externally-driven capex variance account would be conventional distributor capex that is similar in kind to that incurred by distributors in past and future productivity research samples used to calibrate X factors.[42] Utilities can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, Toronto Hydro's weak incentive to contain capex, and the Company's incentive to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[43] This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals greatly complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB staff and stakeholders are often hard-pressed to effectively challenge distributor capex proposals. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements without making the same investment that the British and Australian regulators have made in the capability for appraising and ruling on capex proposals.[44]

The substantial compensation for full funding of capital revenue shortfalls that has been permitted by the OEB under Custom IR may be more remunerative than that available under the incremental capital modules ("ICMs") in 4th GIRM. ICMs, after all, feature a materiality threshold including a 10% deadband before funding projected capital revenue shortfalls. These thresholds are rationalized on the grounds of reducing regulatory cost. This encourages distributors to choose Custom IR instead of the 4th GIRM. Some distributors may have chosen Custom IR, with its weaker performance

[42] Toronto Hydro would not, however, be compensated during the plan for unexpected capex overruns.

[43] Proposed programs that raise capex and reduce OM&A expenses merit close examination. An example is the proposition to reduce backyard overhead facilities.

[44] Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IRM proceedings. This view is supported by independent engineering and benchmarking research.

incentives and higher regulatory cost, even though efficient and compensatory operation under 4th GIRM was feasible.

In pondering this quandary, the following remarks of the OEB in its decision approving Toronto Hydro's last Custom IR plan resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[45]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors.

The Alberta Utilities Commission ("AUC") faced a similar challenge following an unhappy experience with capital cost trackers in their first-generation IRMs for provincial gas and electricity distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second generation IRMs. Based on the record, the AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts.[46] Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

Informed by our research and testimony for a party to that proceeding, as well as by our familiarity with Custom IR, we believe that the following alternatives to Toronto Hydro's proposed ratemaking treatment of capital merit consideration.

- An obvious candidate for a different approach is that chosen by the OEB in the recent Hydro One Dx decision.[47] A special stretch factor would apply only to the calculation of the C factor. A variant on this theme is to calculate the C factor using the (typically slower) productivity growth trend of capital, while the X factor for OM&A revenue could reflect the

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[45] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

[46] PEG is not recommending this ratemaking treatment for Toronto Hydro.

[47] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019.

Pacific Economics Group Research, LLC

(typically faster) productivity trend of OM&A. This would reduce the need for C factors and make escalation of OM&A revenue more reflective of industry OM&A cost trends. Unfortunately, there is no conclusive research available to the panel in this proceeding on OM&A and capital productivity trends of power distributors.

- The C factor could alternatively, like ICMs, be subject to materiality thresholds and dead zones. For example, a company would not be eligible for a C factor unless its capital cost growth exceeded growth in capital revenue by a certain percent. A percentage of the underfunding would not be eligible for supplemental funding. Dead zones could also be added to the materiality thresholds for externally-driven capex.
- The X factor could be raised, in this and the Company's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Toronto Hydro's capex containment incentives.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Toronto Hydro's capex containment incentives. The IRMs for the Fortis companies in British Columbia track the cost of all older capital.
- Eligibility of capex for supplemental C factor revenue could be scaled back. For example, capex in the last year of the plan term could be declared ineligible for supplemental revenue because this involves only one year of underfunding.
- The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IRM proceeding.
- Toronto Hydro could be permitted to keep a share of the value of capex underspends. This would strengthen the Company's incentive to contain capex but also its incentive to exaggerate its capex needs.

If the OEB is prepared to deviate from Toronto Hydro's proposed C factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans has many advantages. This could be done in such a manner that the *first* A% of unfunded capital cost (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the ICMs used in 4^{th} GIRM. For example, if proposed capital cost exceeded the materiality threshold, a possibly lower set percentage of *all* unfunded capital cost could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capital cost *at the margin*. The kind of adjustment to the C factor formula that the Board approved in the Hydro One distribution IRM proceeding has less incentive impact.

already provided for within the 2015 base OM&A.[14] The 2015 OM&A has been updated on that basis. The resulting 2015 OM&A amount is $243.9M.

4. TAXES AND PAYMENTS-IN-LIEU OF TAXES ("PILS")

The DRO Decision required that PILs amounts be recalculated to ensure that the effects of the findings in the DRO Decision flow through to PILs.[15] Toronto Hydro has made the updates to its DRO and recalculated PILs as prescribed. The recalculation results in an immaterial PILs decrease of $7,000 in 2015. The result reflects a decrease to Working Capital arising from the OM&A update described above.[16]

5. 10% CAPITAL EXPENDITURE FUNDING REDUCTION

Toronto Hydro has applied the 10% reduction to capital expenditures, not the C-Factor, as clarified by the DRO Decision. Table 1, below, reflects this:

Table 1 – Approved Capital Expenditure Amounts

CAPEX	**2015**	**2016**	**2017**	**2018**	**2019**
APPLICATION	$531.1	$518.8	$467.4	$470.1	$502.2
10% reduction	($53.1)	($51.9)	($46.7)	($47.0)	($50.2)
TOTAL	$478.0	$466.9	$420.6	$423.0	$451.9

[14] EB-2014-0116, Toronto Hydro-Electric System Limited Decision on Draft Rate Order (February 25, 2016) at p. 5.
[15] EB-2014-0116, Toronto Hydro-Electric System Limited Decision on Draft Rate Order (February 25, 2016) at p. 6.
[16] Specifically, the denial of adjustments to the base OM&A for CIR Application costs and the transfer of street lighting assets.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC4.6:

Reference(s): 8-Staff-149, Appendix A

With reference to 8-Staff-149, Appendix A, subtotal a amounts for 2010-2024, to add year-over-year subtotal a changes on a dollar and percentage basis, and also the subtotal a changes over each five-year period that is captured between 2010 and 2024.

RESPONSE:

Please see Appendix A attached.

APPENDIX A: 2010-2024 Sub-total A Amounts

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Average Annual Increase		
										Expected	Proposed	Proposed	Proposed	Proposed	Proposed	2010-14	2015-19	2020-24
Residential - 750 kWh																		
i Sub-Total A including Rate Riders	31.26	30.60	30.57	31.74	32.18	30.25	36.81	39.23	40.98	43.63	41.31	42.68	43.75	45.64	47.47			
annual change - $	3.31	-0.66	-0.03	1.17	0.44	-1.93	6.56	2.42	1.75	2.65	-2.32	1.37	1.07	1.89	1.83	0.85	2.29	0.77
annual change - %	11.8%	-2.1%	-0.1%	3.8%	1.4%	-6.0%	21.7%	6.6%	4.5%	6.5%	-5.3%	3.3%	2.5%	4.3%	4.0%	2.9%	6.3%	1.7%
ii Sub-Total A excluding Rate Riders	30.04	29.65	29.65	29.84	30.17	30.17	36.88	39.03	40.60	41.60	42.14	43.51	44.58	46.47	48.30			
annual change - $	2.45	-0.39	0.00	0.19	0.33	0.00	6.71	2.15	1.57	1.00	0.54	1.37	1.07	1.89	1.83	0.52	2.29	1.34
annual change - %	8.9%	-1.3%	0.0%	0.6%	1.1%	0.0%	22.2%	5.8%	4.0%	2.5%	1.3%	3.3%	2.5%	4.2%	3.9%	1.8%	6.6%	3.0%
Competitive Sector Multi-Unit Residential - 300 kWh[1]																		
i Sub-Total A including Rate Riders	-	-	-	26.63	26.26	25.20	27.36	29.63	31.62	33.61	32.72	33.81	34.66	36.16	37.61			
annual change - $					-0.37	-1.06	2.16	2.27	1.99	1.99	-0.89	1.09	0.85	1.50	1.45	-0.37	1.47	0.80
annual change - %					-1.4%	-4.0%	8.6%	8.3%	6.7%	6.3%	-2.6%	3.3%	2.5%	4.3%	4.0%	#VALUE!	5.1%	2.3%
ii Sub-Total A excluding Rate Riders	-	-	-	24.93	25.20	25.20	27.70	29.89	31.68	33.10	33.40	34.49	35.34	36.84	38.29			
annual change - $					0.27	0.00	2.50	2.19	1.79	1.42	0.30	1.09	0.85	1.50	1.45	0.27	1.58	1.04
annual change - %					1.1%	0.0%	9.9%	7.9%	6.0%	4.5%	0.9%	3.3%	2.5%	4.2%	3.9%	#VALUE!	5.6%	3.0%
General Service < 50 kW - 2,000 kWh																		
i Sub-Total A including Rate Riders	70.78	70.61	70.61	73.45	82.90	76.26	94.64	101.93	99.56	107.87	103.25	106.70	109.38	114.12	118.71			
annual change - $	9.50	-0.17	0.00	2.84	9.45	-6.64	18.38	7.29	-2.37	8.31	-4.62	3.45	2.68	4.74	4.59	4.32	4.99	2.17
annual change - %	15.5%	-0.2%	0.0%	4.0%	12.9%	-8.0%	24.1%	7.7%	-2.3%	8.3%	-4.3%	3.3%	2.5%	4.3%	4.0%	6.2%	5.4%	1.9%
ii Sub-Total A excluding Rate Riders	69.70	69.24	69.24	69.89	70.66	70.66	86.83	93.14	98.19	101.98	105.65	109.10	111.78	116.52	121.11			
annual change - $	8.76	-0.46	0.00	0.65	0.77	0.00	16.17	6.31	5.05	3.79	3.67	3.45	2.68	4.74	4.59	1.94	6.26	3.83
annual change - %	14.4%	-0.7%	0.0%	0.9%	1.1%	0.0%	22.9%	7.3%	5.4%	3.9%	3.6%	3.3%	2.5%	4.2%	3.9%	3.0%	7.6%	3.5%
General Service 50-999 kW - 200 kVA																		
i Sub-Total A including Rate Riders	1,156.75	1,164.63	1,163.73	1,213.89	1,257.53	1,197.40	1,453.46	1,564.60	1,628.94	1,739.17	1,679.30	1,735.56	1,779.41	1,856.83	1,931.63			
annual change - $	93.37	7.88	-0.90	50.16	43.64	-60.13	256.06	111.14	64.34	110.23	-59.87	56.26	43.85	77.42	74.80	38.83	96.33	38.49
annual change - %	8.8%	0.7%	-0.1%	4.3%	3.6%	-4.8%	21.4%	7.6%	4.1%	6.8%	-3.4%	3.4%	2.5%	4.4%	4.0%	3.4%	6.7%	2.1%
ii Sub-Total A excluding Rate Riders	1,152.29	1,154.68	1,154.68	1,165.80	1,178.61	1,178.61	1,423.22	1,526.54	1,609.29	1,671.24	1,725.73	1,781.99	1,825.84	1,903.26	1,978.06			
annual change - $	89.42	2.39	0.00	11.12	12.81	0.00	244.61	103.32	82.75	61.95	54.49	56.26	43.85	77.42	74.80	23.15	98.53	61.36
annual change - %	8.4%	0.2%	0.0%	1.0%	1.1%	0.0%	20.8%	7.3%	5.4%	3.8%	3.3%	3.3%	2.5%	4.2%	3.9%	2.1%	7.2%	3.4%
General Service 1,000-4,999 kW - 2,000 kVA																		
i Sub-Total A including Rate Riders	8,789.08	9,963.73	9,656.35	10,072.37	10,191.31	9,784.48	11,483.66	12,555.43	13,378.69	14,211.33	13,816.49	14,278.14	14,637.83	15,273.21	15,887.16			
annual change - $	-466.75	1174.65	-307.38	416.02	118.94	-406.83	1699.18	1071.77	823.26	832.64	-394.84	461.65	359.69	635.38	613.95	187.10	804.00	335.17
annual change - %	-5.0%	13.4%	-3.1%	4.3%	1.2%	-4.0%	17.4%	9.3%	6.6%	6.2%	-2.8%	3.3%	2.5%	4.3%	4.0%	1.9%	6.9%	2.3%
ii Sub-Total A excluding Rate Riders	8,747.40	9,585.86	9,585.86	9,678.06	9,784.48	9,784.48	11,689.49	12,538.06	13,217.52	13,726.36	14,163.09	14,624.74	14,984.43	15,619.81	16,233.76			
annual change - $	-603.95	838.46	0.00	92.20	106.42	0.00	1905.01	848.57	679.46	508.84	436.73	461.65	359.69	635.38	613.95	86.63	788.38	501.48
annual change - %	-6.5%	9.6%	0.0%	1.0%	1.1%	0.0%	19.5%	7.3%	5.4%	3.8%	3.2%	3.3%	2.5%	4.2%	3.9%	0.9%	7.0%	3.4%
Large Use - 9,700 kVA																		
i Sub-Total A including Rate Riders	44,687.52	50,904.48	49,298.23	51,478.37	52,088.26	50,007.83	59,065.92	65,062.02	70,581.76	73,196.71	71,187.04	73,570.07	75,426.75	78,705.26	81,872.75			
annual change - $	4258.54	6216.96	-1606.25	2180.14	609.89	-2080.43	9058.09	5996.10	5519.74	2614.95	-2009.67	2383.03	1856.68	3278.51	3167.49	2,331.86	4,221.69	1,735.21
annual change - %	10.5%	13.9%	-3.2%	4.4%	1.2%	-4.0%	18.1%	10.2%	8.5%	3.7%	-2.7%	3.3%	2.5%	4.3%	4.0%	5.2%	7.0%	2.3%
ii Sub-Total A excluding Rate Riders	44,440.46	48,992.93	48,992.93	49,464.19	50,007.83	50,007.83	60,158.67	64,526.14	68,023.43	70,642.26	73,087.27	75,470.30	77,326.98	80,605.49	83,772.98			
annual change - $	3633.86	4552.47	0.00	471.26	543.64	0.00	10150.84	4367.47	3497.29	2618.83	2445.01	2383.03	1856.68	3278.51	3167.49	1,840.25	4,126.89	2,626.14
annual change - %	8.9%	10.2%	0.0%	1.0%	1.1%	0.0%	20.3%	7.3%	5.4%	3.8%	3.5%	3.3%	2.5%	4.2%	3.9%	4.2%	7.2%	3.5%
Street lighting - 2,700 kVA																		
i Sub-Total A including Rate Riders	114,725.63	113,109.30	98,996.96	103,202.80	104,358.29	100,284.27	99,151.07	107,582.88	113,641.34	124,079.96	122,806.09	126,857.16	130,030.30	135,623.93	141,066.36			
annual change - $	47138.76	-1616.33	-14112.34	4205.84	1155.49	-4074.02	-1133.20	8431.81	6058.46	10438.62	-1273.87	4051.07	3173.14	5593.63	5442.43	7,354.28	3,944.33	3,397.28
annual change - %	69.7%	-1.4%	-12.5%	4.2%	1.1%	-3.9%	-1.1%	8.5%	5.6%	9.2%	-1.0%	3.3%	2.5%	4.3%	4.0%	9.1%	3.5%	2.6%
ii Sub-Total A excluding Rate Riders	100,005.63	98,356.96	98,356.96	99,262.97	100,284.27	100,284.27	104,116.37	111,683.91	117,742.37	122,280.68	126,287.20	130,338.27	133,511.41	139,105.04	144,547.47			
annual change - $	32418.76	-1648.67	0.00	906.01	1021.30	0.00	3832.10	7567.54	6058.46	4538.31	4006.52	4051.07	3173.14	5593.63	5442.43	6,539.48	4,399.28	4,453.36
annual change - %	48.0%	-1.6%	0.0%	0.9%	1.0%	0.0%	3.8%	7.3%	5.4%	3.9%	3.3%	3.2%	2.4%	4.2%	3.9%	8.2%	4.0%	3.4%
USL - 285 kWh																		
i Sub-Total A including Rate Riders	24.00	23.50	22.72	23.79	24.07	23.1	28.55	30.77	32.42	34.77	33.82	34.95	35.83	37.38	38.87			
annual change - $	8.82	-0.50	-0.78	1.07	0.28	-0.97	5.45	2.22	1.65	2.35	-0.95	1.13	0.88	1.55	1.49	1.78	2.14	0.82
annual change - %	58.1%	-2.1%	-3.3%	4.7%	1.2%	-4.0%	23.6%	7.8%	5.4%	7.2%	-2.7%	3.3%	2.5%	4.3%	4.0%	9.7%	7.6%	2.3%
ii Sub-Total A excluding Rate Riders	22.78	22.63	22.63	22.84	23.10	23.10	28.46	30.53	32.18	33.42	34.58	35.71	36.59	38.14	39.63			
annual change - $	7.11	-0.15	0.00	0.21	0.26	0.00	5.36	2.07	1.65	1.24	1.16	1.13	0.88	1.55	1.49	1.49	2.06	1.24
annual change - %	45.4%	-0.7%	0.0%	0.9%	1.1%	0.0%	23.2%	7.3%	5.4%	3.9%	3.5%	3.3%	2.5%	4.2%	3.9%	8.1%	7.7%	3.5%

Note 1: Competitive Sector Multi-Unit Residential rates were first approved as part of 2013 Toronto Hydro Decision and Order (EB-2012-0064)

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.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 188:

Reference(s): Exhibit U, Tab 4B, Schedule 2

Preamble:

The Government of Canada's 2018 Fall Economic Statement was tabled on November 21, 2018.

It proposes the following measures for certain eligible property acquired after November 20, 2018:

- Accelerated Investment Incentive – Providing an enhanced first-year allowance for certain eligible property that is subject to the Capital Cost Allowance (CCA) rules. In general, the incentive will be made up of two elements:
    - applying the prescribed CCA rate for a class to up to one-and-a-half times the net addition to the class for the year
    - suspending the existing CCA half-year rule (and equivalent rules for Canadian vessels and class 13 property).

- Full Expensing for Manufacturers and Processors – Allowing businesses to immediately write off the full cost of machinery and equipment used for the manufacturing or processing of goods (class 53).

- Full Expensing for Clean Energy Investments – Allowing businesses to immediately write off the full cost of specified clean energy equipment (classes 43.1 and 43.2).

The Federal Government's 2019 Budget, announced on March 19, 2019, confirmed the Government's intention to proceed with the above proposals.

a) Please confirm whether Toronto Hydro has reflected the impact of the new accelerated CCA rules in its Corporate Tax / PILs calculations for 2020-2024 that are currently on the record of this proceeding.

b) If the accelerated CCA is not reflected within Toronto Hydro's 2020-2024 PILs calculations, please explain why. Please also provide updated detailed PILs calculations and supporting CCA tables for the period 2020-2024 that reflect the new accelerated CCA rules.

c) As the accelerated CCA rules are effective November 20, 2018, please advise whether Toronto Hydro prepared its 2018 corporate tax return using these new CCA rules. If not, please explain why.

d) In the context that the approved 2018 and 2019 rates were underpinned by the old CCA rules, please explain how Toronto Hydro is planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the difference between the PILs amounts included in rates for those years and the PILS amounts that would have been included in rates had they been based on the new accelerated CCA rules.

e) Please provide the calculations for 2018 and 2019 revenue requirement impact had the PILs for those years been calculated using the new accelerated CCA rules.

f) If Toronto Hydro is not planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the change in CCA rules, please explain why such an approach is appropriate.

RESPONSE:

a) Toronto Hydro has not reflected the impact of the new accelerated CCA rules in its 2020-2024 PILs calculations that are currently on the record of this proceeding.

b) Bill C-97, Budget Implementation Act, 2019, No. 1, which proposes to implement the accelerated CCA rules, received first reading in the House of Commons on April 8, 2019. Toronto Hydro had not completed the assessment of the tax consequences of the new rules in time for the submission of the updated application evidence on April 30, 2019.

Please see Appendix A for the estimated updated PILs requirement calculations and supporting CCA tables for the 2019-2024 period that reflect Toronto Hydro's current understanding of the new accelerated CCA rules. These estimates are based on assumptions that may materially change as the legislation is finalized and as new information becomes known and is assessed. The PILs affected by this tax policy change consequently affect the capital-related revenue requirement. As a result, any variance between forecast and actuals in 2018-2019 would flow into the 2015-2019 CRRRVA; any variance between forecast and actuals in 2020-2024 would flow into the 2020-2024 CRRRVA.

Bill C-97 requires the identification of acquisition dates for costs incurred after November 20, 2018 and available for use prior to 2028 in order to qualify for accelerated CCA. This leads to planning complexities in order to estimate the costs that will qualify under the new draft rules.

c) If Bill C-97 is enacted, Toronto Hydro intends to reflect the resulting tax consequences in its corporate tax return for 2018. Toronto Hydro is currently preparing its 2018 corporate tax return which is expected to be filed by June 30, 2019.

d) Toronto Hydro proposes to make ratepayers whole by recording the PILs differences resulting from the new draft tax legislation for 2018 and 2019 in its 2015-2019 CRRRVA. The company has proposed to dispose of its 2019 forecasted CRRRVA account balance in 2020 rates with a true-up in 2021 rates that reflects the variances between the amount disposed in 2020 and 2019 audited financials. Were the CRRRVA not in place, these differences would be credited to customers through Account 1592.

e) Within the time available to produce interrogatory responses, Toronto Hydro could not generate detailed, revised calculations of revenue requirement, cost allocation, rates, and bill impacts that flow through the effects of these changes as they apply to 2018 and 2019.

See Table 1 for the estimated change in PILs resulting from the change in draft tax legislation. These amounts may materially change as the legislation is finalized and as new information become known and is assessed.

The change in tax rules only affects the determination of PILs. Consequently, this does not cause Toronto Hydro to change its operational plans and related costs or values (i.e. OM&A, shared services, capital expenditures, depreciation and fixed assets) provided in evidence.

The estimated change to annual revenue requirement resulting from the new draft tax legislation is expected to be similar to the estimated change in PILs amounts. While Toronto Hydro expects items other than the PILs component of revenue requirement to change (e.g. reduction to PILs used to determine working capital allowance), the resulting annual amounts are not expected to be material.

Table 1: PILs (Grossed-up) ($ Millions)

		2019 Bridge	2020 Test	2021 Test	2022 Test	2023 Test	2024 Test
Current PILs forecast in evidence	(a)	22.1	34.7	36.5	32.7	35.7	42.2
Estimated Updated PILs following existing CCA rule (see Appendix B)	(b)	22.3	29.2	33.5	31.4	35.8	42.0
Estimated decrease in Updated PILs following new accelerated CCA rules	(c)	(10.5)	(16.4)	(11.3)	(17.8)	(7.9)	(1.5)
Estimated Updated PILs following new accelerated CCA rules (See Appendix A)	(d) = (b) + (c)	11.8	12.8	22.2	13.6	27.9	40.5
Estimated change due to new accelerated CCA rules	(d) - (a)	(10.3)	(21.9)	(14.3)	(19.1)	(7.8)	(1.7)

The accelerated investment incentive provides Canadian businesses an opportunity to claim additional CCA for eligible capital investment in the first year of eligibility resulting in reduced tax expense. Eligible property must be acquired after November 20, 2018 and must be available for use before 2028 in order to qualify. A phase-out will begin for property that becomes available for use after 2023, and eliminated completely for assets ready to be put into use after 2027. As a result, not all capital expenditures within this period will be eligible.

The enhanced first-year deduction does not alter the total CCA over the lifetime of the asset; the higher deduction taken in the first year is eventually offset by lower deductions in subsequent years.[1] That is, the incentive results in a tax timing difference – less tax paid (and lesser rates) in the earlier years of the asset lives and more tax paid (and greater rates) in the later years.

f) Not applicable; Toronto Hydro proposes to keep ratepayers whole. Please see Toronto Hydro's response to part (d).

[1] Between 2025 and the end of the depreciable lives of eligible assets, the CCA deduction will be lower (and PILs consequently greater) than it would have been if the draft tax legislation did not exist. As a result, the lower CCA over this period will offset the greater CCA available between 2018 and 2024.

Excluding PILs	TH 2015-2019 CIR (Funded) 2015	2016	2017	2018	2019	5 yr Total / Average		TH 2020-2024 CIR (Proposed) 2020	2021	2022	2023	2024	5 yr Total / Average	Ref:
Approved/Proposed CRR	$ 430.50	$ 456.30	$ 506.60	$ 549.50	$ 583.20	$ 2,526.10		$ 540.50	$ 579.30	$ 595.60	$ 648.10	$ 689.40	$ 3,052.90	J1.7
Approved/Proposed CRR (excl PILs)	$ 405.50	$ 439.40	$ 482.30	$ 509.30	$ 537.50	$ 2,374.00		$ 527.70	$ 557.10	$ 582.00	$ 620.20	$ 648.90	$ 2,935.90	
Stretch Factor Reduction to CRR (excl PILs)		$ (2.43)	$ (5.07)	$ (7.96)	$ (11.02)	$ (26.48)			$ (1.58)	$ (3.25)	$ (5.00)	$ (6.86)	$ (16.70)	
Funded/Proposed Funded CRR (excl PILs)	$ 405.50	$ 436.97	$ 477.23	$ 501.34	$ 526.48	$ 2,347.52	Ref: 1B-Staff-21	$ 527.70	$ 555.52	$ 578.75	$ 615.20	$ 642.04	$ 2,919.20	
Approved/Proposed PILs	$ 25.00	$ 16.90	$ 24.30	$ 40.20	$ 45.70	$ 152.10		$ 12.80	$ 22.20	$ 13.60	$ 27.90	$ 40.50	$ 117.00	U-Staff-168 / Table 4
Stretch Factor Reduction to PILs		$ (0.15)	$ (0.25)	$ (0.40)	$ (0.64)	$ (1.44)			$ (0.04)	$ (0.11)	$ (0.15)	$ (0.23)	$ (0.52)	
Funded/Proposed Funded PILs	$ 25.00	$ 16.75	$ 24.05	$ 39.80	$ 45.06	$ 150.66		$ 12.80	$ 22.16	$ 13.50	$ 27.75	$ 40.27	$ 116.48	

	TH 2015-2019 IRM (Alternative) 2015	2016	2017	2018	2019	5 yr Total / Average	TH 2020-2024 IRM (Alternative) 2020	2021	2022	2023	2024	5 yr Total / Average
Funded CRR (exl PILS)	$ 405.50	$ 411.58	$ 416.93	$ 419.43	$ 423.21	$ 2,076.66	$ 527.70	$ 532.45	$ 537.24	$ 542.08	$ 546.96	$ 2,686.42
Funded PILs	$ 25.00	$ 25.38	$ 25.70	$ 25.86	$ 26.09	$ 128.03	$ 12.80	$ 12.92	$ 13.03	$ 13.15	$ 13.27	$ 65.16

	TH 2015-2019 CIR (Funded) vs IRM (Alternative)		TH 2020-2024 CIR (Proposed) vs IRM (Alternative)		Term 2015-2019 vs Term 2020-2024	
	Shortfall ($/%)	Proportional Shortfall (%)	Shortfall ($/%)	Proportional Shortfall (%)	Change in Proportional Shortfall (%)	Relative Change in Proportional Shortfall (%)
CRR Funding (Exl PILS)	$ 270.86	11.54%	$ 232.78	7.97%	-3.56%	-30.89%
PILs Funding	$ 22.63	15.02%	$ 51.32	44.06%		

Table 1 - I-X Calculations:

	Inflation	TH Stretch	I-X
2015	1.01600	0.006	1.0100
2016	1.02100	0.006	1.0150
2017	1.01900	0.006	1.0130
2018	1.01200	0.006	1.0060
2019	1.01500	0.006	1.0090
2020	1.01200	0.003	1.0090
2020A	1.01200	0.006	1.0060

Ontario

Report of the OEB

EB-2014-0219

New Policy Options for the Funding of Capital Investments: Supplemental Report

January 22, 2016

surveyed.[4] Ofgem in the United Kingdom provides for no depreciation expense to be recovered in the year that assets enter service, but provides for full year recovery in subsequent years. No jurisdiction surveyed allows the full amount of depreciation and return in the test year for assets that enter service in that year.

3.2 Incentive Rate-setting Years

In the traditional environment of annual cost of service rate applications, the use of the half-year rule or a more detailed variation does not pose an issue for subsequent years following the inclusion of an asset into rate base for the first time. The rate base and the revenue requirement are updated every year; assets that receive half-year (or partial-year) treatment in the year that they enter service receive full-year treatment in subsequent years.

The nature of economic regulation, particularly rate-setting, has evolved. Since the 1980s, performance-based regulation (PBR)/incentive regulation mechanisms (IRM) have evolved as an alternative to more traditional cost of service regulation. PBR/IRM can provide for any form of regulatory oversight that may be a better representation of the market forces that discipline the performance of firms in competitive markets.

With the OEB's performance based incentive rate-setting methodology, rates are no longer established on an annual cost of service approach. As a result, the half-year rule, or similar treatment, continues during the IR years. During the IR years, depreciation expense is the return of originally invested capital that is available for re-investment in the replacement assets when the original assets reach end-of-life. On that theoretical basis, a utility can invest in future capital with no adverse impact on financial metrics. However, the theoretical approach does not consider inflation or growth in electricity demand and growth in number of customers.

KPMG undertook various analyses to assess the impact of the half-year rule under the OEB rate setting approach of a cost of service review followed by four years of IR adjustments. KPMG compared the OEB approach against annual cost of service applications, where the utility was held whole through the annual update of the rate base and revenue requirement, and also against the scenario of cost of service and IR with full-year depreciation.

[4] However, in most cases, it appears to the OEB that the approach adopted has been so long institutionalized that the justification for the approach is long forgotten. Nor does there appear to be questions of the appropriateness of the approach persisting during non-rebasing periods and whether it raises concerns of sufficiency or deficiency of recoveries.

Toronto Hydro	2020	2021	2022	2023	2024	Total	Average	Ref:
Net CAPEX	$ 521.60	$ 581.80	$ 587.10	$ 565.70	$ 574.40	$ 2,830.60	$ 566.12	J1.7
Net ISA	$ 539.90	$ 475.00	$ 587.40	$ 590.50	$ 583.60	$ 2,776.40	$ 555.28	J1.7
Variance	-3.51%	18.36%	-0.05%	-4.38%	-1.60%	1.91%	1.91%	

Toronto Hydro	2020	2021	2022	2023	2024	Total	Ref:
CIR Proposed Funded Depreciation	$ 265.50	$ 280.70	$ 290.66	$ 311.48	$ 323.64	$ 1,471.98	U-Staff-168 / Table 4 (net of stretch)
IRM Funded Depreciation	$ 265.50	$ 267.89	$ 270.30	$ 272.73	$ 275.19	$ 1,351.61	U-Staff-168 / Table 4 (esclated for I-X)
Net ISA	$ 539.90	$ 475.00	$ 587.40	$ 590.50	$ 583.60	$ 2,776.40	J1.7
CIR Proposed Funded Depreciation / Net ISA	49.18%	59.10%	49.48%	52.75%	55.46%	53.02%	
IRM Funded Depreciation / Net ISA	49.18%	56.40%	46.02%	46.19%	47.15%	48.68%	

Ontario LDCs	2015	2016	2017	2018	Total	Ref:
Actual Depreciation	$ 863.85	$ 925.46	$ 946.04	$ 997.89	$ 3,733.23	RRR Data - Staff Panel 1 Compendium / p. 136
Actual Gross ISA	$ 2,237.82	$ 2,149.21	$ 2,129.76	$ 2,097.15	$ 8,613.94	
Actual Net ISA	$ 1,956.22	$ 1,895.92	$ 1,885.91	$ 1,848.78	$ 7,586.82	
Actual Depreciation / Actual Gross ISA					43.34%	
Actual Depreciation / Actual Net ISA					49.21%	

Utility	2015 Gross	2015 CC	2015 Net	2015 Depr	2016 Gross	2016 CC	2016 Net	2016 Depr	2017 Gross	2017 CC	2017 Net	2017 Depr	2018 Gross	2018 CC	2018 Net	2018 Depr
Alectra Utilities Corporation	$ 364,268,455	$ 47,506,346	$ 316,762,109	$ 113,106,491	$ 281,306,153	$ 48,905,031	$ 232,401,122	$ 122,083,435	$ 319,754,362	$ 65,651,383	$ 254,102,979	$ 113,975,594	$ 294,858,527	$ 62,381,505	$ 232,477,022	$ 129,483,639
Algoma Power Inc.	$ 10,888,963	$ 157,118	$ 10,731,845	$ 3,136,802	$ 8,580,000	$ -	$ 8,580,000	$ 3,326,205	$ 7,472,000	$ 137,000	$ 7,335,000	$ 3,438,399	$ 9,510,000	$ 69,000	$ 9,441,000	$ 3,600,160
Atikokan Hydro Inc.	$ 268,667	$ 19,966	$ 248,701	$ 180,844	$ 359,099	$ 19,209	$ 339,890	$ 189,853	$ 260,787	$ -	$ 260,787	$ 192,622	$ 716,351	$ -	$ 716,351	$ 205,391
Bluewater Power Distribution Corporation	$ 7,641,889	$ 360,407	$ 7,281,482	$ 4,554,631	$ 7,898,911	$ 272,609	$ 7,626,302	$ 4,135,676	$ 7,707,327	$ -	$ 7,707,327	$ 4,042,541	$ 9,241,677	$ -	$ 9,241,677	$ 3,834,546
Brantford Power Inc.	$ 4,502,042	$ 308,810	$ 4,193,232	$ 3,004,084	$ 4,630,910	$ 494,077	$ 4,136,833	$ 3,153,797	$ 4,357,574	$ 524,289	$ 3,833,285	$ 3,168,628	$ 4,322,647	$ 813,883	$ 3,508,764	$ 3,116,154
Burlington Hydro Inc.	$ 10,253,246	$ 1,950,451	$ 8,302,795	$ 4,973,073	$ 11,716,382	$ 4,410,445	$ 7,305,937	$ 5,255,671	$ 13,264,151	$ 4,681,623	$ 8,582,529	$ 5,562,540	$ 13,483,193	$ 3,151,665	$ 10,331,528	$ 5,927,266
Canadian Niagara Power Inc.	$ 9,293,758	$ 1,264,311	$ 8,029,447	$ 4,175,124	$ 10,470,000	$ 1,370,000	$ 9,100,000	$ 4,271,027	$ 10,493,000	$ 1,327,000	$ 9,166,000	$ 4,506,021	$ 17,371,000	$ 1,812,000	$ 15,559,000	$ 4,443,841
Centre Wellington Hydro Ltd.	$ 1,884,001	$ 13,625	$ 1,870,376	$ 543,004	$ 2,181,292	$ 48,495	$ 2,132,797	$ 548,179	$ 1,501,988	$ 284,435	$ 1,217,553	$ 562,972	$ 1,453,404	$ 258,315	$ 1,195,089	$ 574,190
Chapleau Public Utilities Corporation	$ 101,175	$ -	$ 101,175	$ 50,827	$ 36,284	$ -	$ 36,284	$ 52,874	$ 56,756	$ -	$ 56,756	$ 49,114	$ 512,765	$ -	$ 512,765	$ 107,640
EPCOR Electricity Distribution Ontario Inc. (Collus Powerstream)	$ 2,443,137	$ 745,573	$ 1,697,564	$ 742,598	$ 3,765,684	$ 1,739,589	$ 2,026,095	$ 845,096	$ 3,469,137	$ 527,957	$ 2,941,180	$ 944,462	$ 2,952,067	$ 904,892	$ 2,047,176	$ 1,008,075
Cooperative Hydro Embrun Inc.	$ 369,452	$ 82,004	$ 287,448	$ 118,183	$ 465,096	$ 6,450	$ 458,646	$ 124,120	$ 1,750,905	$ 75,885	$ 1,675,020	$ 145,310	$ 227,281	$ 60,245	$ 167,036	$ 163,632
E.L.K. Energy Inc.	$ 1,080,986	$ 267,274	$ 813,713	$ 364,814	$ 560,406	$ 438,399	$ 122,007	$ 343,271	$ 815,789	$ 242,709	$ 573,080	$ 347,372	$ 1,105,038	$ 172,754	$ 932,284	$ 366,333
Energy Plus Inc. (Brant + Cambridge)	$ 15,859,310	$ 4,496,481	$ 11,362,829	$ 6,042,661	$ 16,043,120	$ 2,763,059	$ 13,280,062	$ 6,114,161	$ 18,873,629	$ 3,212,372	$ 15,661,257	$ 5,912,459	$ 14,222,941	$ 5,262,706	$ 8,960,235	$ 5,745,054
Entegrus Powerlines Inc.	$ 9,347,691	$ 290,288	$ 9,057,403	$ 3,789,326	$ 9,393,902	$ 846,286	$ 8,547,616	$ 3,846,009	$ 10,212,278	$ 549,095	$ 9,663,183	$ 3,964,230	$ 12,166,321	$ 1,454,213	$ 10,712,108	$ 5,644,237
ENWIN Utilities Ltd.	$ 22,631,448	$ 5,036,747	$ 17,594,701	$ 9,831,922	$ 18,697,650	$ 1,069,571	$ 17,628,079	$ 10,501,504	$ 16,024,514	$ 2,315,399	$ 13,709,115	$ 11,469,873	$ 20,041,827	$ 2,325,435	$ 17,716,392	$ 11,878,593
ERTH Power Corporation (Erie Thames)	$ 5,928,082	$ 667,719	$ 5,260,364	$ 1,525,419	$ 4,385,303	$ 587,128	$ 3,798,175	$ 1,712,622	$ 3,874,526	$ 892,192	$ 2,982,334	$ 1,931,170	$ 4,455,228	$ 1,152,910	$ 3,302,317	$ 1,958,311
Espanola Regional Hydro Distribution Corporation	$ 244,019	$ -	$ 244,019	$ 96,039	$ 426,403	$ -	$ 426,403	$ 129,660	$ 641,889	$ -	$ 641,889	$ 144,902	$ 479,403	$ -	$ 479,403	$ 151,428
Essex Powerlines Corporation	$ 6,672,825	$ 1,448,183	$ 5,224,642	$ 2,537,950	$ 4,879,788	$ 931,021	$ 3,948,767	$ 1,493,988	$ 6,373,189	$ 921,652	$ 5,451,536	$ 2,173,960	$ 6,383,352	$ 1,167,137	$ 5,216,215	$ 2,038,972
Festival Hydro Inc.	$ 3,156,899	$ 170,827	$ 2,986,072	$ 2,428,856	$ 2,438,323	$ 206,585	$ 2,231,738	$ 2,156,996	$ 2,908,329	$ 369,219	$ 2,539,110	$ 2,264,309	$ 3,761,249	$ 585,407	$ 3,175,842	$ 2,388,518
Fort Frances Power Corporation	$ 200,667	$ -	$ 200,667	$ 217,683	$ 392,772	$ -	$ 392,772	$ 210,483	$ 641,863	$ -	$ 641,863	$ 318,110	$ 511,691	$ -	$ 511,691	$ 329,410
Greater Sudbury Hydro Inc.	$ 8,891,797	$ 1,327,041	$ 7,564,756	$ 3,844,521	$ 8,626,092	$ 915,758	$ 7,710,334	$ 3,685,266	$ 9,491,829	$ 707,218	$ 8,784,611	$ 3,666,463	$ 10,886,000	$ 1,214,036	$ 9,671,964	$ 3,843,665
Grimsby Power Incorporated	$ 10,291,335	$ 1,228,744	$ 9,062,590	$ 794,526	$ 1,398,920	$ 304,022	$ 1,094,898	$ 1,081,719	$ 2,147,523	$ 723,784	$ 1,423,739	$ 1,108,916	$ 1,866,440	$ 363,406	$ 1,503,034	$ 1,120,220
Guelph Hydro Electric Systems Inc.	$ 13,947,373	$ 5,139,636	$ 8,807,737	$ 4,892,433	$ 17,025,784	$ 3,065,993	$ 13,959,791	$ 5,645,805	$ 14,785,381	$ 1,305,661	$ 13,479,720	$ 5,963,945	$ 12,397,374	$ 4,936,780	$ 7,460,594	$ 6,212,742
Halton Hills Hydro Inc.	$ 8,295,868	$ 2,271,997	$ 6,023,871	$ 1,780,440	$ 8,312,782	$ 654,903	$ 7,657,879	$ 1,795,856	$ 9,883,110	$ 1,482,936	$ 8,400,174	$ 1,950,940	$ 8,507,661	$ 979,445	$ 7,528,216	$ 2,053,294
Hearst Power Distribution Company Limited	$ 188,878	$ 2,609	$ 186,269	$ 344,309	$ 147,424	$ 29,251	$ 118,173	$ 94,346	$ 166,897	$ 13,751	$ 153,146	$ 100,725	$ 278,156	$ 29,510	$ 248,646	$ 124,014
Hydro 2000 Inc.	$ 36,025	$ -	$ 36,025	$ 51,899	$ 26,335	$ -	$ 26,335	$ 52,237	$ 45,376	$ -	$ 45,376	$ 47,324	$ 44,997	$ 3,750	$ 41,247	$ 45,712
Hydro Hawkesbury Inc.	$ 612,706	$ 93,493	$ 519,213	$ 188,834	$ 1,513,998	$ 17,741	$ 1,496,257	$ 194,087	$ 983,217	$ 49,138	$ 934,078	$ 225,270	$ 218,486	$ 59,897	$ 158,590	$ 263,204
Hydro One Networks Inc.	$ 828,346,491	$ 85,771,343	$ 742,575,148	$ 364,748,322	$ 721,111,668	$ 55,740,572	$ 664,975,416	$ 375,051,162	$ 744,465,071	$ 55,055,191	$ 689,409,880	$ 388,008,854	$ 691,819,864	$ 51,882,608	$ 639,937,256	$ 397,485,263
Hydro Ottawa Limited	$ 147,267,262	$ 24,928,647	$ 122,338,615	$ 37,990,760	$ 103,176,348	$ 21,578,316	$ 81,598,032	$ 40,097,278	$ 122,692,101	$ 24,998,607	$ 97,693,494	$ 41,682,623	$ 122,854,180	$ 22,598,352	$ 100,255,828	$ 45,984,835
Innpower Corporation	$ 19,803,244	$ 2,188,564	$ 17,614,680	$ 1,879,151	$ 6,882,669	$ 2,265,141	$ 4,617,528	$ 2,348,783	$ 4,460,324	$ 966,418	$ 3,493,906	$ 2,363,240	$ 5,426,267	$ 1,358,814	$ 4,067,453	$ 2,503,452
Synergy North Corporation – Kenora Rate District	$ 643,008	$ 83,037	$ 559,971	$ 569,016	$ 640,560	$ 38,966	$ 601,594	$ 678,946	$ 589,140	$ 43,418	$ 545,722	$ 637,871	$ 629,080	$ -	$ 629,080	$ 653,653
Kingston Hydro Corporation	$ 3,206,337	$ 96,296	$ 3,110,041	$ 1,690,705	$ 5,834,543	$ 592,672	$ 5,241,871	$ (1,600,252)	$ 8,172,029	$ 4,666,656	$ 3,505,373	$ 2,095,293	$ 5,289,056	$ 1,400,024	$ 3,889,032	$ 2,193,987
Kitchener-Wilmot Hydro Inc.	$ 21,918,728	$ 9,593,246	$ 12,325,482	$ 2,349,311	$ 24,286,420	$ 8,950,517	$ 15,335,903	$ 8,710,983	$ 22,408,879	$ 6,242,858	$ 16,166,021	$ 8,565,130	$ 21,257,307	$ 4,696,647	$ 16,560,661	$ 9,116,473
Lakefront Utilities Inc.	$ 1,829,242	$ 58,465	$ 1,770,776	$ 1,121,030	$ 3,079,543	$ 80,316	$ 2,999,226	$ 1,178,282	$ 2,562,505	$ 202,427	$ 2,360,078	$ 1,184,544	$ 1,548,781	$ 358,852	$ 1,189,929	$ 1,091,129
Lakeland Power Distribution Ltd.	$ 3,088,920	$ 194,049	$ 2,894,871	$ 1,200,180	$ 2,502,246	$ 551,703	$ 1,950,543	$ 1,349,997	$ 2,345,613	$ 365,698	$ 1,979,915	$ 1,414,343	$ 2,440,139	$ 347,817	$ 2,092,322	$ 1,453,186
London Hydro Inc.	$ 33,025,844	$ 3,788,551	$ 29,237,293	$ 16,858,883	$ 35,609,719	$ 3,313,477	$ 32,296,242	$ 17,771,936	$ 32,522,017	$ 5,205,870	$ 27,316,147	$ 17,350,372	$ 48,041,965	$ 4,795,268	$ 43,246,697	$ 17,881,259
Midland Power Utility Corporation (now Newmarket Tay)	$ 629,276	$ 36,084	$ 593,193	$ 644,006	$ 763,589	$ 60,073	$ 703,516	$ 816,330	$ 1,376,632	$ 110,794	$ 1,265,838	$ 796,446	$ -	$ -	$ -	$
Milton Hydro Distribution Inc.	$ 15,617,439	$ 1,823,780	$ 13,793,659	$ 2,761,704	$ 11,320,875	$ 3,333,020	$ 7,987,855	$ 3,301,468	$ 8,924,115	$ 2,879,515	$ 6,044,600	$ 3,482,059	$ 11,224,369	$ 2,920,318	$ 8,304,051	$ 3,761,991
Newmarket-Tay Power Distribution Ltd.	$ 14,686,360	$ 1,826,732	$ 12,859,628	$ 2,904,007	$ 9,949,992	$ 6,438,453	$ 3,511,539	$ 3,068,914	$ 6,191,846	$ 1,405,507	$ 4,786,339	$ 3,598,756	$ 3,257,127	$ 869,125	$ 2,388,002	$ 5,747,249
Niagara Peninsula Energy Inc.	$ 14,979,925	$ 5,600,233	$ 9,379,692	$ 6,099,694	$ 15,426,432	$ 4,031,451	$ 11,394,981	$ 6,462,385	$ 14,933,017	$ 2,180,761	$ 12,752,256	$ 6,937,287	$ 14,985,908	$ 2,240,998	$ 12,744,910	$ 7,449,739
Niagara-on-the-Lake Hydro Inc.	$ 1,713,213	$ 600,722	$ 1,112,491	$ 775,384	$ 2,828,580	$ 1,603,277	$ 1,225,303	$ 741,925	$ 1,622,011	$ 319,954	$ 1,302,058	$ 717,757	$ 3,282,575	$ 723,766	$ 2,558,809	$ 726,405
North Bay Hydro Distribution Limited	$ 6,896,610	$ 703,198	$ 6,193,413	$ 1,693,086	$ 5,570,545	$ 352,323	$ 5,218,222	$ 926,479	$ 6,191,840	$ 728,037	$ 5,463,803	$ 1,833,811	$ 6,940,048	$ 558,617	$ 6,381,431	$ 2,854,199
Northern Ontario Wires Inc.	$ 424,755	$ 123,412	$ 301,343	$ 368,228	$ 692,947	$ 23,550	$ 669,397	$ 380,214	$ 810,159	$ 8,321	$ 801,838	$ 414,285	$ 845,234	$ -	$ 845,234	$ 420,378
Oakville Hydro Electricity Distribution Inc.	$ 15,777,343	$ 5,082,947	$ 10,694,396	$ 8,545,048	$ 20,301,606	$ 9,686,384	$ 10,615,222	$ 8,984,647	$ 17,886,851	$ 5,040,755	$ 12,846,096	$ 9,156,545	$ 22,655,649	$ 5,599,139	$ 17,056,510	$ 9,123,190
Orangeville Hydro Limited	$ 1,293,107	$ 200,284	$ 1,092,823	$ 667,675	$ 1,940,991	$ 395,789	$ 1,545,202	$ 651,574	$ 2,551,610	$ 633,962	$ 1,917,648	$ 687,935	$ 1,778,360	$ 205,712	$ 1,572,648	$ 713,571
Orillia Power Distribution Corporation	$ 2,239,251	$ 134,720	$ 2,104,531	$ 1,121,075	$ 5,606,188	$ 396,371	$ 5,209,817	$ (246,829)	$ 3,572,280	$ 349,120	$ 3,223,160	$ 1,183,380	$ 2,262,041	$ 171,780	$ 2,090,261	$ 1,222,768
Oshawa PUC Networks Inc.	$ 15,178,835	$ 3,324,147	$ 11,854,688	$ 3,797,997	$ 10,425,039	$ 1,084,859	$ 9,340,180	$ 4,437,246	$ 9,083,922	$ 1,226,128	$ 7,857,794	$ 4,362,249	$ 16,868,642	$ 3,911,288	$ 12,957,354	$ 4,981,587
Ottawa River Power Corporation	$ 959,680	$ 179,612	$ 780,068	$ 765,290	$ 1,201,956	$ 96,899	$ 1,105,056	$ 1,503,773	$ 1,692,123	$ 263,533	$ 1,428,590	$ 717,910	$ 1,582,652	$ 136,450	$ 1,446,202	$ 900,205
Peterborough Distribution Incorporated	$ 7,704,000	$ 2,203,000	$ 5,501,000	$ 2,874,800	$ 5,766,000	$ 1,838,000	$ 3,928,000	$ 3,423,805	$ 5,847,000	$ 1,745,000	$ 4,102,000	$ 3,585,437	$ 5,124,000	$ 648,000	$ 4,476,000	$ 3,455,256
PUC Distribution Inc.	$ 6,710,692	$ 454,801	$ 6,255,891	$ 3,888,942	$ 5,988,626	$ 450,272	$ 5,538,354	$ 4,089,742	$ 6,352,193	$ 1,136,727	$ 5,215,467	$ 3,666,323	$ 5,575,711	$ 431,033	$ 5,144,679	$ 3,781,554
Renfrew Hydro Inc.	$ 510,990	$ 18,266	$ 492,724	$ 222,240	$ 437,215	$ 32,772	$ 404,442	$ 270,394	$ 558,903	$ 10,457	$ 548,446	$ 328,560	$ 984,506	$ 31,873	$ 952,632	$ 126,844
Rideau St. Lawrence Distribution Inc.	$ 598,917	$ 5,200	$ 593,717	$ 306,218	$ 480,494	$ 98,590	$ 381,904	$ 364,321	$ 1,201,654	$ 101,073	$ 1,100,581	$ 427,050	$ 558,128	$ 63,487	$ 494,642	$ 407,195
Sioux Lookout Hydro Inc.	$ 300,614	$ 40,513	$ 260,101	$ 210,722	$ 330,619	$ 29,696	$ 300,923	$ 217,627	$ 585,165	$ 115,657	$ 469,508	$ 223,701	$ 646,956	$ 80,920	$ 566,037	$ 244,833
St. Thomas Energy Inc. (now Entegrus)	$ 2,514,762	$ 355,700	$ 2,159,062	$ 1,148,681	$ 2,554,843	$ 608,283	$ 1,946,560	$ 1,254,621	$ 2,645,990	$ 813,088	$ 1,832,902	$ 1,311,590	$ -	$ -	$ -	$ -
Synergy North Corporation – Thunder Bay Rate District	$ 11,735,209	$ 1,984,671	$ 9,750,538	$ 3,228,843	$ 12,182,464	$ 2,737,839	$ 9,444,625	$ 3,385,685	$ 11,256,399	$ 973,179	$ 10,283,220	$ 3,544,405	$ 11,948,111	$ 1,243,211	$ 10,704,900	$ 3,600,977
Tillsonburg Hydro Inc.	$ 591,806	$ 336,487	$ 255,319	$ 325,196	$ 840,760	$ 81,140	$ 759,619	$ 327,997	$ 1,696,551	$ 458,663	$ 1,237,888	$ 364,128	$ 1,724,289	$ 95,802	$ 1,628,487	$ 419,420
Toronto Hydro-Electric System Limited	$ 465,402,574	$ 30,083,801	$ 435,318,773	$ 192,329,429	$ 617,138,762	$ 32,842,749	$ 584,296,013	$ 225,905,945	$ 548,964,114	$ 28,704,350	$ 520,259,764	$ 228,284,811	$ 563,606,573	$ 39,248,789	$ 524,357,783	$ 241,845,269
Veridian Connections Inc.	$ 27,411,798	$ 6,239,695	$ 21,172,103	$ 11,161,147	$ 31,520,006	$ 7,369,144	$ 24,150,862	$ 11,349,987	$ 26,811,166	$ 3,340,859	$ 23,470,307	$ 12,002,916	$ 29,421,418	$ 6,344,749	$ 23,076,670	$ 12,567,912
Wasaga Distribution Inc.	$ 1,040,957	$ 521,208	$ 519,749	$ 621,402	$ 1,473,765	$ 587,159	$ 886,606	$ 542,441	$ 1,737,291	$ 415,754	$ 1,321,537	$ 565,019	$ 1,422,849	$ 135,478	$ 1,287,371	$ 591,332
Waterloo North Hydro Inc.	$ 20,238,920	$ 7,373,641	$ 12,865,279	$ 8,510,773	$ 32,161,079	$ 12,636,204	$ 19,524,875	$ 8,271,633	$ 20,470,098	$ 4,578,501	$ 15,891,597	$ 8,643,425	$ 19,537,430	$ 2,968,930	$ 16,568,500	$ 8,973,807
Welland Hydro-Electric System Corp.	$ 2,506,400	$ 421,827	$ 2,084,573	$ 1,304,212	$ 3,128,400	$ 207,254	$ 2,921,146	$ 1,365,712	$ 2,332,938	$ 36,017	$ 2,296,921	$ 1,429,127	$ 2,186,056	$ 170,518	$ 2,015,538	$ 1,491,768
Wellington North Power Inc.	$ 817,661	$ -	$ 817,661	$ 346,404	$ 1,545,545	$ -	$ 1,545,545	$ 365,478	$ 744,253	$ -	$ 744,253	$ 407,729	$ 501,091	$ -	$ 501,091	$ 424,389
ERTH Power Corporation - West Coast Huron rate zone	$ 1,057,149	$ 46,777	$ 1,010,372	$ 257,196	$ 1,228,091	$ 122,777	$ 1,105,314	$ 279,897	$ 850,390	$ 241,529	$ 608,861	$ 340,018	$ 774,627	$ 89,552	$ 685,075	$ 382,620
Westario Power Inc.	$ 4,112,933	$ 148,625	$ 3,964,308	$ 1,653,966	$ 5,740,396	$ 584,438	$ 5,155,958	$ 1,638,686	$ 4,901,467	$ 497,727	$ 4,403,740	$ 1,886,263	$ 5,789,860	$ 415,354	$ 5,374,506	$ 1,926,937
Whitby Hydro Electric Corporation	$ 15,742,522	$ 10,178,882	$ 5,563,640	$ 3,588,586	$ 11,862,259	$ 2,961,787	$ 8,900,472	$ 2,742,165	$ 9,790,126	$ 1,795,019	$ 7,995,107	$ 3,659,835	$ 10,385,977	$ 2,470,429	$ 7,915,548	$ 4,756,936
SUM TOTAL	**$ 2,237,823,469**	**$ 281,600,814**	**$ 1,956,222,655**	**$ 863,846,600**	**$ 2,149,210,590**	**$ 252,897,853**	**$ 1,895,917,057**	**$ 925,455,322**	**$ 2,129,757,110**	**$ 243,851,828**	**$ 1,885,905,282**	**$ 946,039,197**	**$ 2,097,151,905**	**$ 248,372,590**	**$ 1,848,779,315**	**$ 997,889,808**

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**
VOLUME:	**2**	
DATE:	**June 28, 2019**	
BEFORE:	**Lynne Anderson**	**Presiding Member**
	Michael Janigan	**Member**
	Susan Frank	**Member**

-- the depreciation and amortization expense we see here doesn't match the numbers that we pulled from the RRRs, and that is true even if you include the derecognition expense, which is on the next page.

And we simply wanted to ask the panel in charge of depreciation why that might be. It may be something that you need to undertake? I also want to be clear, we are not suggesting anything has been done improperly here. This is not to say the RRRs were wrong or this number is wrong or anything. We assume there is a reason why those numbers don't match, and we just, we were curious as to what that might be. Again, my guess is that is probably more appropriate for an undertaking, but if you happen to know off the top of your head, that's fine too.

MR. MUNDENCHIRA: Mr. Millar, so on page 136, the depreciation that you see is depreciation as presented in IFRS, where we show the depreciation on gross capital assets.

So any amortization on capital contributions in IFRS, it does not get presented under regular depreciation. It goes towards other income.

However, on page 137, we have presented depreciation, including amortization of capital contributions, because for rate-making purposes we do need to account for capital contributions in the depreciation piece of that calculation, if that helps. So derecognition is included in page 136.

MR. MILLAR: Okay.

L1.INTERROGATORY SEC-13

Reference: Exhibit M1 [p. 66]

Please provide an example of how a materiality threshold and dead zone for capital could be added to Toronto Hydro's proposal, and what the impact would be of doing so.

Response to SEC-13: The following response was provided by PEG.

Toronto Hydro proposes to receive, through a C factor term in its price cap index ("PCI"), supplemental revenue for the shortfall between its proposed capital revenue requirement and the growth in revenue which would otherwise result from growth in the PCI and billing determinants. Assuming a 0.45% stretch factor, the capital revenue requirement in index year 1 would, for example, effectively be

$$RK_1 = CK_o \times [1 + (I - X - g) + g] + [CK_1 - CK_0 \times (1 + I)] \quad [1a]$$

$$= CK_o \times (1 + I - X) + [CK_1 - CK_0 \times (1 + I)] \quad [1b]$$

$$= CK_1 - 0.0045 \times CK_0. \quad [1c]$$

Here

RK = Allowed capital revenue

CK = Capital revenue requirement

I = growth in the PCI inflation measure

X = productivity factor (including stretch)

g = growth in billing determinants (assumed for simplicity to equal forecasted growth)

The cost saving from any cumulative net capex underspend would be returned to customers in full. The depreciated cost of any capex overspends would potentially be eligible for recovery in future rebasings. The OEB granted Hydro One Networks Inc. Distribution this ratemaking treatment of capex overspends in EB-2017-0049.

PEG has criticized Toronto Hydro's proposed C Factor approach on various grounds. We believe that it would weaken capex containment incentives since (a) there would be dollar for dollar recovery of any approved capital cost that exceeds $CK_0 \times (1 + I)$, (b) the cost savings from capex underspends would be returned, (c) some portion of overspends might be recoverable and (d) incentives to contain OM&A expenses are stronger. Regulatory cost would be higher, and exaggerated capex requirements and strategic "bunching" of capex to bolster supplemental revenue would be encouraged. Customers would be denied the benefits of industry productivity growth, even in the long run and even if it is achievable. PEG has also expressed concern that a more favorable ratemaking treatment of capex in Custom IR than in 4GIRM can encourage utilities to embrace Custom IR, with its many disadvantages.

The EB-2017-0049 decision also included a reform of the C factor mechanism that merits consideration for Toronto Hydro's new plan. The total capital cost eligible for supplemental revenue was reduced by a further stretch factor that we denote by "S". The value of S was set at 0.15%. Assuming once again a 0.45% stretch factor, the capital revenue requirement in index year 1 would effectively then be

$$RK_1 = CK_o \times (1 + I - X - g + g) + [CK_1 - CK_1 \times (1 + I + S)] \quad [2a]$$

$$= CK_1 - (X+S) \times CK_0 \quad [2b]$$

$$= CK_1 - 0.0060 \times CK_0. \quad [2c]$$

PEG acknowledges that the $0.0060 \times CK_0$ term in [2c] (and the $0.0045 \times CK_0$ term in [1c]) both provide a materiality threshold and dead zone for capital revenue. Our concern is that the threshold and dead zone are not ideal.

- We believe that 0.0060 does not establish parity with the materiality threshold for supplemental capital revenue in 4GIRM. One problem is that the effective capital revenue markdown depends on the base productivity trend, which is 0. In contrast, the 10% deadband factor for the ACM/ICM in 4GIRM is not linked to the base productivity trend. Our preliminary research on this issue, which is more complicated than it first appears,[1] suggests that an S factor of around **0.6%** would achieve rough parity between the Custom IR and ACM/ICM markdowns.[2] A substantially more exact estimate of a parity value for S is beyond the scope of this project, as is PEG's assessment of the ideal materiality threshold and dead zone for supplemental capital funding.
- A straightforward way to sidestep this calculation is to abandon the current C factor mechanism and to instead use the current ACM/ICM mechanism to determine the capex that is eligible for supplemental revenue. Alternatively, the ACM/ICM mechanism might be used to determine incremental capex eligible for supplemental revenue, which would then be used to determine the C-factor for the rate adjustment in each year. This might require some adjustments to the C-factor formula to maintain parity with the ACM/ICM.
- Even if parity was established between Custom IR and 4GIRM markdowns, the

[1] The complexity arises as one is trying to balance considerations of performance incentives, regulatory cost, and fairness to customers with the legitimate need of some utilities for capital spending surges.

[2] Our analysis identified the value of the supplemental stretch factor "S" that would cause the C-factor to yield a similar outcome to the ACM/ICM materiality threshold given some mathematical simplifications and the capital cost data that Toronto Hydro has used in its C-factor proposal.

markdowns would likely not be enough to address all of our concerns (noted above) about supplemental capital revenue. Determination of a more optimal markdown is also beyond the scope of this project.

- Neither the C factor nor the 4GIRM approach strengthen incentives to contain *incremental* capex once the materiality threshold is exceeded. The following alternative approach to calculating the C factor has better incentive properties than [2a-c].

$$RK_1 = CK_0 \times (1 + I - X - g + g) - [CK_1 \times (1\text{-}S)] - CK_0 \times (1 + I)\} \quad [3a]$$

$$= CK_1 \times (1\text{-}S) - CK_0 \times X \quad [3b]$$

Another way to incentivize containment of incremental capex is to permit the Company to keep a share (say 10%) of any cumulative CRRRVA balance at the end of the next plan. An analogous share of capital cost overruns could, similarly, be ineligible for supplemental revenue at the end of the plan. The OEB took a step in the direction of sharing variances with the approval of Hydro One Networks' Capital In-Service Additions Variance Account, which only requires refunds when capital spending is 98% or less of the OEB's approved amount. Actual additions are compared to the amounts approved by the OEB in each year, and the account will be cleared at the end of the Custom IR plan.

TAB 2

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 77:

Reference(s): **Exhibit U, Tab 3, Schedule 1, p. 2;**
3-VECC-21;
Technical Conference Transcript, Day 4, p. 111

a) At the Technical Conference, THESL was uncertain as to the extent to which it would be "updating" its load forecast models. For purposes of the Update did THESL: i) re-valuate each of its load forecast models (per VECC 21 a)) in terms of what were the appropriate explanatory variables to use, including the testing of variables not used in the original models or ii) simply re-estimate the models using the same variables as in the original models?

b) Please provide a schedule that sets out the "weather normal" HDD and CDD values as used in the original load forecast and those used in the Update.

c) Please provide a schedule that sets out the historical and forecast unemployment rates and GDP values as used in the original load forecast and the Update.

RESPONSE:

a) Toronto Hydro revaluated all models for the Load Forecast update using up-to-date information. Different input variables were retested to determine the best fit based on statistics and professional evaluation. As noted in Exhibit U, Tab 3, Schedule 1, page 2, lines 13-17, all model specifications remained unchanged except for the GS

1000-4999 kW class, where the unemployment rate variable was dropped.

b) The historical and forecast values for all driver variables, including HDD, CDD, unemployment and GDP, as appropriate, are provided in Appendix F of Exhibit U, Tab 3, Schedule 1, for both the original and updated load forecasts.

c) See part b.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**

VOLUME:	**Technical Conference**
DATE:	**February 22, 2019**

was it just the gentleman on the phone?

MR. RITCHIE: I have one question.

MR. MILLAR: Okay. We're trying to keep things peppy, as we're getting near the end of Staff's time. But please go ahead.

EXAMINATION BY MR. RITCHIE:

MR. RITCHIE: No problem. I am basically just wanting to talk about the load forecasting, and really there's only one IR I want to follow up on -- I guess probably with you, Mr. Seal -- and it would be 3-Staff-104.

MR. SEAL: I have that.

MR. RITCHIE: Okay. And this is really about the concept of the auto-correlation that is exhibited in all of your models.

Now, first as a starting point, when I looked at the regression statistics which are shown in your evidence in Exhibit 3, tab 1, schedule 1, appendix A 2 -- we don't really need to bring it up -- most of your models are based on a historical data series of 186 observations. And again, your forecast period right now is 84 observations, which is basically seven years, two bridge years and the five-year custom IR period, correct?

MR. SEAL: That sounds correct.

MR. RITCHIE: And the forecast period is really about 45 percent of the length of the historical data range. So you actually are predicting out a fairly long period from -- you know, relative to the history. You would agree with that?

MR. SEAL: I would agree that we are forecasting out to the end of 2024, correct.

MR. RITCHIE: Yes, and that's, you know, that's as it is, you know, because you've got a custom IR period in that.

So when I was looking at your models and at the regression statistics, and looking at the top of page 2 of this IR response -- actually, I guess the top of page 3. Sorry, I was just -- and again:

> "Furthermore, from a forecasting perspective, the presence of auto-correlation in the model residual values does not indicate any bias in the forecast values."

Now, that's true if the auto correlation is not indicative of missing variables, or other model specification that could be there. Wouldn't that be correct?

MR. SEAL: I am maybe a little far removed from my econometrics training to know that specifically or not. I think in the interrogatory response with respect to this particular item, we have indicated why the Durbin Watson statistics we look at when we do the load forecast, and only one of them.

MR. RITCHIE: Correct. But again, you have tried your model, you know, these are your estimates right now. But, you know, you do see serial correlation in all of the models, you know, per the preamble that I put with the table of the Durbin Watson stats.

But then continuing on that, you say:

"But only suggests that prediction variances may be larger than otherwise."

And I guess that would be sort of consistent with the idea that with serial correlation the OLS estimates of the coefficients and even of the forecasts are not necessarily the best linear, unbiased estimates, to use the technical, statistical, or econometric term.

MR. SEAL: I think that would be the technical definition, yes.

MR. RITCHIE: Okay. And then in the B part of the interrogatory, you talk about the concern with the auto-regressive model approach in terms of the variances -- or the confidence interval reliability of the predictions sort of getting wider as you -- the further out you forecast. Correct?

MR. SEAL: My concern with AR models generally and based on my experience in doing forecasting and forecasting using different types of modelling techniques is that AR models, auto-regressive models, do tend to be more problematic, especially in the longer-term forecast, because they are exactly relying on the forecasted values themselves as an explanatory variable in the forecasting periods. So my experience has been that they have been problematic from that perspective.

MR. RITCHIE: But even for your ordinary least squares approach that you have used when you are forecasting values you also have to forecast some of the other explanatory variables. And again, we don't -- we don't know the future, so you don't have a full accuracy or full certainty of those future values.

MR. SEAL: I accept that. They are forecasting of the independent variables. However, when you have auto-regressive models, typically the emphasis or the coefficient that's placed on the auto-regressive term is quite high and creates a large dependence on that particular variable. That's why, again, I am generally suspect of AR models, especially for longer-term forecasting.

MR. RITCHIE: Okay, and also even with the OLS, the coefficients themselves are estimates, and there is a confidence interval. So I guess what the concern I see you also saying about the AR is almost what we call a -- I call it a trumpet horn, sort of as the further out you go the wider the confidence interval looks?

MR. SEAL: I would accept that, yes.

MR. RITCHIE: Why doesn't that also apply in terms of the forecasts that you are doing here? You don't necessarily know all of the future values for -- you're estimating the future values and you also have the uncertainty of the model coefficients?

MR. SEAL: And I certainly accept that the confidence interval will grow larger through the forecast period, even in my models. What I am saying is that my experience with AR models are that they are not -- the predictive value of those models is less in the longer-term type forecasting.

TAB 3

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

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.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 78:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 2-3;**
Exhibit U, Tab 3, Schedule 1, Appendix B and Appendix D

a) Are the 2018-2020 planned CDM results (per Appendix B) comparable (in terms of definition) to the values set out in Appendix D, Tables 1-7?
   i) If yes, please reconcile the savings values shown in Table 7 for program years 2019 and 2020 with the total savings shown in Appendix B for the same years
   ii) If no, please provide a schedule that reconciles the savings values shown in Table 7 for program years 2019 and 2020 with the total savings shown in Appendix B for the same years and that explains the sources of the differences.

b) What is the source/basis for the non-verified 2018 CDM results?

c) Please provide a schedule that compares by customer class the non-verified 2018 CDM results (per Appendix D, Tables 1-6) with the 2018 planned results as set out in the THESL's latest CDM Plan (Appendix B). In doing so, please adjust the results as set out in the CDM Plan (as required) so that they are comparable, in terms of definition, with the unverified CDM results as shown in Tables 1-6 of Appendix D and explain the basis/reasons for the adjustments.

d) How does THESL deliver each of the CDM programs set out in its CDM plan – as submitted to the IESO (i.e., does it use third party contractors and/or other contracts with third parties)?

e) With respect to the 2019-2020 CDM programs set out in Appendix B, please indicate which ones THESL already has third-party contracts in place to deliver and outline whether or not there are any penalties for terminating the contracts.

RESPONSE:

a)

i) The 2018-2020 planned CDM results (per Appendix B) are not comparable to the values set out in Appendix D, Tables 1-7 because the values provided by the IESO in the originally filed Appendix B as part of the Application Update were incorrect. Please refer to a corrected version of Exhibit U, Tab 3, Schedule 1, Appendix B, appended to this response. The corrected Appendix B is the source of the 2018-2020 data for Appendix D.

ii) Please refer to Table 1 for a reconciliation between the savings values in Table 7 and the update to Appendix B.

Table 1: Reconciliation between the savings values shown in Table 7 for program years 2019 and 2020 and the total savings in Appendix B

	CDM Load Forecast (MWh) (Appendix D)	Persistence Removed (MWh)	CDM Load Forecast (Persistence from Previous Years Removed)	Net-to-Gross Ratios	CDM Planned Savings (Net MWh) (Appendix B)
2019	1,034,023	726,232	307,791	88%	269,609
2020	1,483,703	1,046,450	437,253	87%	381,414

b) Toronto Hydro tracks all project completions and savings results per program and uses them as the basis for the estimated 2018 savings. This includes adjustments for net to gross ratios based on historical values.

c) Please refer to Table 2 for a schedule that compares the non-verified 2018 CDM results (Appendix D) with the total savings in the corrected Appendix B.

Table 2: Comparison between the non-verified 2018 CDM results (per Appendix D, Tables 1-6) with the total savings in Appendix B

	CDM Load Forecast (MWh) (Appendix D)	Persistence Removed (MWh)	CDM Load Forecast (Persistence from Previous Years Removed)	Net-to-Gross Ratios	CDM Planned Savings (Net MWh) (Appendix B)
Residential	201,939	149,145	52,794	115%	60,912
CSMUR	8,898	6,410	2,488	120%	2,982
GS<50 kW	56,196	17,945	38,251	91%	34,773
GS50 -999 kW	302,606	146,150	156,456	86%	134,818
GS1,000 – 4,999 kW	100,405	39,247	61,158	84%	51,524
LU	56,187	23,554	32,633	84%	27,513
Total	**726,232**	**382,450**	**343,782**	**91%**	**312,521**

d) Toronto Hydro delivers all of the programs noted in its CDM plan while using third parties to support varying portions of the work depending on the requirements of the program and to supplement the skill of the Toronto Hydro CDM team. For example, for direct install programs Toronto Hydro contracts the installation of the work to a contractor due to the specialized work involved.

e) In accordance with the OEB rules requiring accounting separation between CDM costs and rate regulated distribution costs, Toronto Hydro ratepayers are insulated from any costs or penalties associated with CDM contract termination that are not recovered from the IESO.

Toronto Hydro-Hydro Electric System Limited
EB-2018-0165
Interrogatory Responses
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Appendix A
FILED: June 11, 2019
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Toronto Hydro-Hydro Electric System Limited
EB-2018-0165
Exhibit U
Tab 3
Schedule 1
Appendix B
UPDATED: June 11, 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: Residential	Low-income	Small business	Commercial (including	Agriculture	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 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	$101,902	251	$589,927	2,063	$1,407,090	9,604	$843,810	10,627	$807,212	10,000	$515,146	5,000	$4,265,087	37,545
	SAVE ON ENERGY BUSINESS REFRIGERATION INCENTIVE PROGRAM			01-Sep-2016			Yes	Yes		Yes		$0	0	$0	0	$974,837	3,481	$2,002,425	8,695	$1,333,283	4,986	$1,325,886	4,945	$5,636,430	21,729
	SAVE ON ENERGY COUPON PROGRAM			01-Jul-2015	Yes	Yes						$2,198,647	15,589	$6,325,639	84,732	$16,876,770	154,798	$11,246,773	57,485	$2,319,530	10,000	$1,211,169	4,104	$40,178,528	277,560
	SAVE ON ENERGY ENERGY MANAGER PROGRAM			01-Jul-2015						Yes	Yes	$13,666	0	$710,398	15,534	$1,975,785	6,776	$2,366,450	3,941	$2,409,850	4,022	$2,164,050	3,561	$9,640,199	29,665
	Save on Energy Energy Performance Program for Multi-Site Customers			01-Jan-2015				Yes		Yes	Yes	$0	0	$0	0	$0	1,725	$194,000	0	$194,000	0	$194,000	0	$582,000	1,725
	SAVE ON ENERGY EXISTING BUILDING COMMISSIONING PROGRAM			01-Feb-2016				Yes		Yes	Yes	$0	0	$539,587	730	$374,486	788	$239,661	1,910	$106,086	0	$109,269	0	$1,369,089	3,428
	SAVE ON ENERGY HEATING & COOLING PROGRAM			01-Jul-2015	Yes	Yes						$2,535,528	4,023	$4,444,112	9,408	$4,650,863	7,328	$3,901,906	4,067	$2,720,318	3,000	$2,043,949	2,163	$20,296,676	29,990
	SAVE ON ENERGY HIGH PERFORMANCE NEW CONSTRUCTION PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$122,493	77	$1,604,652	8,929	$3,797,751	2,610	$2,029,841	3,111	$2,436,056	4,000	$1,962,732	2,964	$11,953,525	21,691
	SAVE ON ENERGY HOME ASSISTANCE PROGRAM			01-Sep-2015		Yes						$2,220	283	$1,119,803	1,171	$1,094,833	774	$196,222	302	$3,249,977	5,000	$3,314,981	5,100	$8,978,036	12,605
	SAVE ON ENERGY MONITORING & TARGETING PROGRAM			01-May-2016						Yes	Yes	$0	0	$0	0	$3,995	0	$20,000	0	$20,000	0	$20,000	0	$63,995	0
	SAVE ON ENERGY NEW CONSTRUCTION PROGRAM			01-Jul-2015	Yes							$456	39	$54,294	237	$232,341	236	$441,084	491	$443,689	500	$529,859	787	$1,701,723	2,291
	SAVE ON ENERGY PROCESS & SYSTEMS UPGRADES PROGRAM			01-Jul-2015				Yes		Yes	Yes	$32,086	0	$426,596	18,831	$2,020,513	2,544	$4,571,778	18,090	$5,136,078	21,060	$30,748,416	155,790	$42,935,467	216,315
	SAVE ON ENERGY RETROFIT PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$3,244,135	39,246	$26,507,778	213,504	$28,216,341	146,419	$31,465,524	182,017	$31,217,416	180,000	$30,579,363	175,000	$151,230,557	936,983
	SAVE ON ENERGY SMALL BUSINESS LIGHTING PROGRAM			01-Jul-2015			Yes					$1,385	0	$166,782	69	$1,581,395	5,306	$2,465,191	8,305	$1,910,606	6,000	$1,447,998	4,077	$7,573,357	23,178
	SAVE ON ENERGY SMART THERMOSTAT PROGRAM			01-Jan-2015	Yes	Yes						$0	0	$0	0	$0	0	$441,789	0	$0	0	$0	0	$441,789	0
		ADAPTIVE THERMOSTAT LOCAL PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$26,672	0	$477,696	0	$380,388	755	$379,099	750	$384,984	750	$1,648,838	750
		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	370	$0	0	$0	0	$0	0	$0	0	$0	370
		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	9	$0	0	$0	0	$0	0	$0	0	$0	9
		MURB In-Suite Direct Install Lighting Program		01-Jan-2018								$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	2,864	$191,927	0	$502,285	1,459	$662,347	6,541	$633,130	5,422	$1,989,688	16,287
		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	29,319
		PUMPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$100,075	988	$2,112,372	15,569	$0	0	$0	0	$0	0	$2,212,447	0
		RTUSAVER		01-Jan-2017		Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$69,316		$2,068,149	3,297	$1,903,332	3,000	$1,903,332	3,000	$5,944,129	9,297
		SOCIAL BENCHMARKING LOCAL PROGRAM		01-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$4,078,842	10,476	$2,586,817	0	$2,586,817	0	$2,586,817	0	$11,839,293	10,476
		SWIMMING POOL EFFICIENCY LOCAL PROGRAM		01-Apr-2017	Yes							$0	0	$0	0	$271,149	1,402	$419,626	778	$411,598	750	$411,598	750	$1,513,971	3,680
		TRUCKLOAD EVENT PILOT PROGRAM		01-Sep-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	3,296	$498,428	0	$0	0	$0	0	$0	0	$498,428	3,296
		Toronto Hydro – Enbridge Joint Low-Income Program LDC Innovation Fund Pilot Program		30-Jan-2017		Yes						$0	0	$0	0	$0	373	$0	0	$0	0	$0	0	$0	373
		WHOLE HOME PILOT		30-Jan-2017	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$0	1,132	$51,600	0	$51,600	0	$51,600	0	$154,800	1,132
		EnerNOC Conservation Fund Pilot Program		01-Jan-2015				Yes		Yes	Yes	$0	199	$0	0	$0	0	$0	0	$0	0	$0	0	$0	0
		Loblaw P4P Conservation Fund Pilot Program		01-Jan-2015				Yes		Yes	Yes	$0	2,469	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	2,469
		Strategic Energy Group Conservation Fund Pilot Program		01-Jan-2015				Yes		Yes	Yes	$0	2,577	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0
FCR TOTAL												8,252,518	65,421	42,616,315	363,882	70,906,730	371,342	71,423,919	312,521	64,283,619	269,609	85,732,016	381,414	343,215,117	1,706,407
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	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)*	Appliance Retirement Initiative												316												0
	Coupon Initiative												2,536												2,516
	Bi-Annual Retailer Event Initiative												4,243												4,097
	HVAC Incentives Initiative												3,399												3,399
	Residential New Construction and Major Renovation Initiative												0												0
	Energy Audit Initiative												7,005												7,005
	Efficiency: Equipment Replacement Incentive Initiative												160,765												160,879
	Direct Install Lighting and Water Heating Initiative												6,891												7,189
	New Construction and Major Renovation Initiative												25,472												25,461
	Existing Building Commissioning Incentive Initiative												522												243
	Process and Systems Upgrades Initiatives - Project Incentive Initiative												5,327												5,327
	Process and Systems Upgrades Initiatives - Energy Manager Initiative												8,403												5,013
	Low Income Initiative												1,680												1,248
	Program Enabled Savings												311												311
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	226,869											0.0	222,687
TARGET GAP TOTAL																								$0	
CDM PLAN TOTAL												$8,252,518	292,289.6	$42,616,315	363,881.9	$70,906,730	371,341.9	$71,423,919	312,521.1	$64,283,619	269,609.3	$85,732,016	381,414.5	$343,215,117	1,929,095
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

Load Forecast Energy Impacts

Line No.	A	B	C	D	E	F	G	H
				D=B+C		F=D+E		H=FxG
	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
1	2020 CDM Forecast	801,974	(778,251)	23,723.65	3,857.28	27,581	101.6%	28,027
2	2021 CDM Forecast	814,023	(778,251)	35,772.39	3,084.97	38,857	100.8%	39,167
3	2022 CDM Forecast	826,072	(778,251)	47,821.12	2,312.67	50,134	100.3%	50,307
4	2023 CDM Forecast	838,121	(778,251)	59,869.85	1,540.37	61,410	100.1%	61,447
5	2024 CDM Forecast	850,169	(778,251)	71,918.59	768.06	72,687	99.9%	72,587
6								
	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
7	2020 CDM Forecast	17,218	(14,417)	2,801	689.16	3,490	103.4%	3,607
8	2021 CDM Forecast	18,888	(14,417)	4,471	649.83	5,121	103.0%	5,272
9	2022 CDM Forecast	20,558	(14,417)	6,141	610.51	6,752	102.8%	6,938
10	2023 CDM Forecast	22,228	(14,417)	7,811	571.18	8,382	102.6%	8,603
11	2024 CDM Forecast	23,898	(14,417)	9,481	531.86	10,013	102.5%	10,268
12								
	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
13	2020 CDM Forecast	528,267	(486,659)	41,608	12,031.48	53,639	91.04%	48,831
14	2021 CDM Forecast	553,672	(486,659)	67,013	11,552.84	78,566	90.99%	71,485
15	2022 CDM Forecast	578,837	(486,659)	92,178	10,878.44	103,057	90.96%	93,741
16	2023 CDM Forecast	604,002	(486,659)	117,343	9,168.00	126,511	90.94%	115,053
17	2024 CDM Forecast	629,166	(486,659)	142,507	5,925.19	148,433	90.93%	134,971
18								
	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
19	2020 CDM Forecast	1,405,151	(1,158,734)	246,416	75,548.50	321,965	81.8%	263,251
20	2021 CDM Forecast	1,550,567	(1,158,734)	391,832	61,072.88	452,905	83.1%	376,145
21	2022 CDM Forecast	1,681,723	(1,158,734)	522,988	60,591.48	583,580	83.8%	488,829
22	2023 CDM Forecast	1,812,878	(1,158,734)	654,144	59,977.68	714,122	84.2%	601,390
23	2024 CDM Forecast	1,944,034	(1,158,734)	785,300	52,270.07	837,570	84.6%	708,471
24								
	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
25	2020 CDM Forecast	754,394	(656,924)	97,470	31,711.48	129,181	86.3%	111,523
26	2021 CDM Forecast	816,091	(656,924)	159,167	26,125.77	185,293	86.4%	160,098
27	2022 CDM Forecast	872,326	(656,924)	215,402	25,898.94	241,301	86.4%	208,583
28	2023 CDM Forecast	928,560	(656,924)	271,636	25,659.37	297,296	86.5%	257,057
29	2024 CDM Forecast	984,795	(656,924)	327,871	22,674.29	350,546	86.5%	303,173
30								
	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
31	2020 CDM Forecast	620,763	(492,700)	128,063	78,627.05	206,690	93.5%	193,202
32	2021 CDM Forecast	723,296	(492,700)	230,597	20,064.37	250,661	91.9%	230,317
33	2022 CDM Forecast	767,721	(492,700)	275,022	19,349.74	294,372	90.8%	267,155
34	2023 CDM Forecast	812,146	(492,700)	319,447	18,566.71	338,013	89.9%	304,019
35	2024 CDM Forecast	856,571	(492,700)	363,872	15,668.07	379,540	89.1%	338,284
36								
	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
37	2020 CDM Forecast	4,127,767	(3,587,685)	540,082	202,464.95	742,547	87.3%	648,442
38	2021 CDM Forecast	4,476,538	(3,587,685)	888,853	122,550.66	1,011,404	87.3%	882,484
39	2022 CDM Forecast	4,747,237	(3,587,685)	1,159,552	119,641.78	1,279,194	87.2%	1,115,553
40	2023 CDM Forecast	5,017,936	(3,587,685)	1,430,251	115,483.30	1,545,734	87.2%	1,347,569
41	2024 CDM Forecast	5,288,634	(3,587,685)	1,700,950	97,837.54	1,798,787	87.2%	1,567,754

LRAM Energy Impact Breakdown

Line No.	I	J	K	L	M	N	O	P
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
1	2020 CDM Forecast	16,124.48	11,902.91					**28,027.39**
2	2021 CDM Forecast	16,124.48	11,139.95	11,902.91				**39,167.34**
3	2022 CDM Forecast	16,124.48	11,139.95	11,139.95	11,902.91			**50,307.29**
4	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	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**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
7	2020 CDM Forecast	1,902.17	1,705.22					**3,607.39**
8	2021 CDM Forecast	1,902.17	1,665.07	1,705.22				**5,272.46**
9	2022 CDM Forecast	1,902.17	1,665.07	1,665.07	1,705.22			**6,937.52**
10	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	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**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
13	2020 CDM Forecast	25,510.01	23,320.56					**48,830.57**
14	2021 CDM Forecast	25,297.89	23,316.03	22,870.66				**71,484.58**
15	2022 CDM Forecast	24,832.18	23,171.66	22,866.13	22,870.66			**93,740.63**
16	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	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**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
19	2020 CDM Forecast	123,574.57	139,676.61					**263,251.18**
20	2021 CDM Forecast	123,524.77	139,546.31	113,073.61				**376,144.68**
21	2022 CDM Forecast	123,306.51	139,505.70	112,943.30	113,073.61			**488,829.12**
22	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	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.	I	J	K	L	M	N	O	P
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
25	2020 CDM Forecast	52,651.63	58,871.66					**111,523.30**
26	2021 CDM Forecast	52,629.42	58,787.22	48,681.23				**160,097.87**
27	2022 CDM Forecast	52,537.65	58,767.74	48,596.79	48,681.23			**208,583.42**
28	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	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**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
31	2020 CDM Forecast	47,264.88	145,937.49					**193,202.37**
32	2021 CDM Forecast	47,179.99	145,603.50	37,533.93				**230,317.42**
33	2022 CDM Forecast	46,892.76	145,528.48	37,199.94	37,533.93			**267,155.11**
34	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	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**
	MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	***Total***
37	2020 CDM Forecast	267,027.75	381,414.46					**648,442.20**
38	2021 CDM Forecast	266,658.72	380,058.08	235,767.55				**882,484.35**
39	2022 CDM Forecast	265,595.74	379,778.60	234,411.18	235,767.55			**1,115,553.07**
40	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	252,422.10	377,877.96	233,143.81	234,131.70	234,411.18	235,767.55	**1,567,754.30**

MWh

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								
	Load Forecast Demand Impacts								LRAM Demand Impact Breakdown							
	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**

MW

TAB 4

	Principal Balance as of Dec 31, 2017	Carrying Charge Balance as of Dec 31, 2017	Balances as of Dec 31, 2017
IFRS-USGAAP Transitional PP&E[1] Amounts	12.4	—	12.4
LRAM Variance Account (“LRAMVA”)	16.1	0.2	16.3
Impact for USGAAP Deferral	85.3	—	85.3
Capital Related Revenue Requirement Variance Account (“CRRRVA”)	(22.7)	(0.3)	(23.0)
Externally Driven Capital Variance Account (“EDCVA”)	(1.3)	0.0	(1.3)
Derecognition	(15.5)	(0.4)	(15.9)
Wireless Attachments	(0.4)	0.0	(0.4)
Monthly Billing	4.0	0.1	4.1
Operating Centers Consolidation Program (“OCCP”)	27.1	0.1	27.2
Other Post-Employment Benefits (“OPEB”) Cash vs Accrual	4.2	—	4.2
Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(2.4)	—	(2.4)
Total Balance	**110.4**	**1.4**	**111.8**

1.1 Group 1 Accounts

RSVA: Accounts include the following OEB Accounts:

- 1580 – Wholesale Market Service Charges ($RSVA_{WMS}$)
- 1584 – Retail Transmission Network Charge ($RSVA_{NW}$)
- 1586 – Retail Transmission Connection Charge ($RSVA_{CN}$)
- 1588 – Power ($RSVA_{Power}$)
- 1589 – Global Adjustment ($RSVA_{GA}$)

[1] International Financial Reporting Standards (“IFRS”); United States Generally Accepted Accounting Principles (“USGAAP”); Property, plant and equipment (“PP&E”).

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)

Ontario Energy Board | Commission de l'énergie de l'Ontario

SEPTEMBER 14, 2017

Report of the Ontario Energy Board

Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs

EB-2015-0040

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pensions and OPEBs (i.e. typically the effective date of the rate order of its next cost-based application).

C. Interest Rate

Carrying charges on the new tracking account will be assessed on the monthly opening account balance at the OEB's prescribed Construction Work In Progress (CWIP) rate. Several different interest rate options were considered in this consultation ranging from the low end of the OEB's prescribed rate for deferral and variance accounts (currently at 1.1%) to a utility's weighted average cost of capital (WACC), which may be in the 6.5% range for most utilities. The OEB views the prescribed CWIP rate (currently at 2.53%) as establishing a balance between the longer term nature of financial loans and investments required to support pension and OPEB costs, and the shorter term nature of the time required for a utility to dispose of any carrying charges on the differential between the accrual and cash amounts (typically five years).

The OEB is of the view that ideally, the CWIP rate (representing more of a mid-term rate) could apply for amounts expensed, while a utility's WACC could apply for amounts that a utility may capitalize. However, this approach may not provide sufficient incremental value to justify the added complexity of tracking amounts that are capitalized separately from those that are expensed. Utilities are instead expected to track the gross cost flowing from their actuarial valuations. For utilities that do experience a material impact due to the capitalization of a significant portion of pensions and OPEBs, parties in the applicable rates proceedings may propose an enhanced methodology for determining the account balance and the appropriate carrying charge to be applied.

D. Accounting Frameworks

As noted in the KPMG report, a utility's accounting framework would affect the level of accrual expense a utility recognizes for its pension and OPEBs. This is partially due to the difference in the accounting treatment of actuarial gains and losses, which are the gains and losses that arise from experience adjustments and changes in actuarial assumptions. Under United States Generally Accepted Accounting Principles, a utility can choose to recognize these gains and losses immediately in net income, or initially in Other Comprehensive Income (OCI) and then amortize them into net income over time. Under International Financial Reporting Standards (IFRS), a utility must recognize all actuarial gains and losses in OCI, but these amounts are never amortized into net income. Under Accounting Standards for Private Enterprises, all actuarial gains and losses are immediately recognized in net income. As the pension and OPEBs accrual amount that is recovered in rates is derived from the accounting expense recognized in net income, utilities who are recovering their pension and OPEB costs on an accrual basis under IFRS will not be able to dispose of any amounts pertaining to actuarial gains and losses because they will never form part of net income.

The OEB recognizes that this issue may not affect a large number of utilities because most utilities under IFRS participate in the OMERS pension plan, where the accrual expense equals the employer contributions made to the plan. Furthermore, for those utilities with OPEB plans, their OPEB expense and any actuarial gains and losses may not be significant relative to other costs incurred by these utilities. For some utilities, the OEB has already approved the use of a deferral account to capture the cumulative actuarial gains or losses in post-retirement benefits.

As at the date of this Report, one utility with this deferral account has had the account approved for disposition.[7] Utilities may propose disposition of the account in future cost-based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time.

This matter was not the focus of this consultation and therefore, the OEB has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS. The OEB will consider the potential need for further analysis and guidance on this matter in due course.

E. Set-Aside Mechanism

Solvency of the pension and OPEB plans of Ontario utilities is important: will the money be there to provide the promised benefits to future retirees? The OEB is not the regulator responsible for ensuring solvency of pension plans. In Ontario, the PBA legislates the solvency requirements for defined benefit pension plans and, in particular, requires that a registered defined benefit pension plan must be fully funded (the assets of the plan are adequate to cover its liabilities). The funding status of a plan is determined by a triennial actuarial valuation. If the valuation identifies a funding shortfall (liabilities greater than assets), then the PBA requires that the employer make special payments in addition to the employer’s usual contributions to the plan, over a specified period of time in order to fund this shortfall. In addition, due partially to the funding requirements of pension plans, it is likely that neither the accrual nor cash (funding contribution) method will consistently produce a higher cost. The direction of the variance would generally be expected to reverse over time (see Appendix A: example of

[7] Four of the seven utilities with this deferral account have had the opportunity to request disposition of this account but three utilities have proposed to defer disposition.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 193:

Reference(s): **Exhibit U, Tab 9, Schedule 1, p. 4**
Exhibit U, Tab 4A, Schedule 3, Appendix C
Exhibit 9, Tab 1, Schedule 1, pp. 7-10
EB-2015-0049, Report of the Ontario Energy Board on Regulatory Treatment of Pension and OPEB Costs

Preamble:

Account 1508 Other Regulatory Asset – Sub-account – Impact for US GAAP Deferral tracks the actuarial gains and losses related to Toronto Hydro's OPEBs, which the utility is required to report in Other Comprehensive Income for financial reporting purposes, and are never amortized into profit or loss. In approving such DVA accounts, the OEB expected that amounts accumulated within these accounts would off-set over time and therefore would likely never require disposition. However, as part of the Report of the Ontario Energy Board on Regulatory Treatment of Pension and OPEB costs (dated September 14, 2017), the OEB stated that utilities may propose disposition of balances tracked in this account if the amounts do not substantively offset over-time.

As part of the original evidence filed in this proceeding, Toronto Hydro was seeking recovery of the balance in this account on the basis that changes in the underlying actuarial assumptions, in particular, changes in the discount rate, are not expected to substantially offset the actuarial loss incurred to date. Toronto Hydro proceeded to provide extensive analysis to support their claim (Exhibit 9 / Tab 1 / Schedule 1 / pp. 7-10).

Toronto Hydro submitted an updated actuarial valuation for the period 2019-2024 as part of the application update. The valuation resulted in an actuarial gain of $37.2 million that reduced the balance in account 1508 Other Regulatory Asset – Sub-account – Impact for US GAAP Deferral from the $85.3 million filed as part of the original evidence in this proceeding to $48.1 million as at December 31, 2018.

a) The updated valuation and resulting actuarial gain contradicts the statements made by Toronto Hydro in its original evidence filed in support of its disposition of this account balance. Specifically, the changes in the underlying actuarial assumptions in the most recent actuarial valuation has resulted in an almost 50% reduction in the account balance compared to the original evidence. In this context, please explain whether Toronto Hydro still believes that the balance in account 1508 Other Regulatory Asset – Sub-account – Impact for US GAAP Deferral will not offset over time.

RESPONSE:

a) In its original evidence, Toronto Hydro projected the discount rate used as at December 31, 2017 to increase by 50 basis points and remain stable over the following seven years. If materialized, and if all other actuarial assumptions remained unchanged, the account balance as at December 31, 2017 was projected to reduce by approximately $23.4 million.[1] In its response to interrogatory 9-Staff-152, Toronto Hydro noted that it cannot make reasonable predictions on future changes to mortality rates, demographics, and health cost trend rate. The change in valuation as at December 31, 2018, which also resulted in a reduction to the account balance from

[1] Exhibit 9, Tab 1, Schedule 1, page 9.

the preceding year, accounted for updates to the discount rate and other actuarial variables.

In addition to the discount rate forecast, Toronto Hydro's analysis of the historical account balance trend informs Toronto Hydro's proposal. Please see Table 1 for the continuity of fiscal year end balances and annual changes to the deferral account balances.

Table 1: Deferral Account Balances and Changes ($ Millions)

Year	Balance	Balance Change
2010	30.1	n/a
2011	64.8	34.7
2012	61.5	-3.3
2013	38.8	-22.7
2014	87.3	48.5
2015	81.2	-6.1
2016	60.2	-21.0
2017	85.3	25.1
2018	48.1	-37.2
Average	**61.9**	**2.0**
Total	**n/a**	**+18.0**

Although the valuation in 2018 resulted in an actuarial gain and a reduction to the account balance, the movement has been volatile and the balance increased by $18.0 million or 60 percent since 2010. Net actuarial losses contributed to $32.8 million of this increase.[2] Over the same period, the account balance has not fallen below $30.1 million and has had a $61.9 million balance (on average), with an increasing trend.

[2] See 9-Staff-152 (d) for the drivers of changes to the deferred account balance.

In its report on OPEBs dated September 14, 2017,[3] the OEB stated that, *"[f]or some utilities, the OEB has already approved the use of a deferral account to capture the cumulative actuarial gains or losses in post-retirement benefits. Utilities may propose disposition of the account in future cost-based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time. This matter was not the focus of this consultation and therefore, the OEB has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS. The OEB will consider the potential need for further analysis and guidance on this matter in due course."*

In its report to the OEB dated May 2, 2016,[4] KPMG stated that *"[r]easonable OPEB costs should be included in customer rates in time periods as close to the time periods to which they relate as is reasonable while recognizing the need for rate stability and predictability."*

Given the significant and sustained account balance, Toronto Hydro is seeking approval to clear the portion of the 2018 balance over the 2020-2024 period based on the average remaining service life of its employees ("EARSL method"). As presented in JTC 4.10, this would result in a clearance of approximately $17.2 million, or $3.44 million annually, over the five-year period ending 2024.

Toronto Hydro proposes that the 2018 balance, less approximately $17.2 million noted above, continue in the deferral account ("residual 2018 balance"). The residual 2018 balance is approximately $30.9 million.

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[3] Report of the OEB – Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040), page 13.
[4] KPMG Report to the Ontario Energy Board on Pension and Other Post-Employment Benefit Costs, May 2, 2016, page 88.

Toronto Hydro proposes that future actuarial gains and losses be added to the residual 2018 balance, and that the resulting cumulative balance of these amounts be the subject of future applications, as applicable, also in accordance with the EARSL method.

The EARSL method is consistent with the approach described by KPMG in its OPEB report to the OEB[5] in which it stated: *"If the accounting framework that is used by a utility does not periodically reclassify to net income the component of OPEB costs that is recorded in OCI, consideration should be given to whether a utility should be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the OPEB plan."*

Toronto Hydro notes that a regulatory deferral balance can only be recognized if it is determined that it is probable that future revenue in an amount at least equal to the deferred cost will be recovered in rates. It is probable that Toronto Hydro will not be able to continue to recognize this balance in its external financial statements if there is no acceptance by its regulator for the subsequent inclusion of this deferred balance in its rates, resulting in an impairment of the balance.

[5] Report on Pension and Other Post-Employment Benefit Costs, May 2, 2016.

As per the OEB's APH Frequently Asked Questions, Toronto Hydro needs to bring forward the trued-up account balance for OEB's review in a subsequent rate setting proceeding.

The actual IFRS USGAAP Transitional PP&E amount was $28.9 million. The amount proposed for clearing is a $1.6 million credit (refund) to customers.

4.3 Account 1508 – Other Regulatory Assets, Subaccount – Impact for USGAAP Deferral Account

The amount proposed for clearing is an $85.3 million debit (recovery) from customers. This account captures the impact of the change in the accounting for OPEB as a result of transition to a different accounting framework.

In its EB 2012-0079 Decision and Order issued on June 7, 2012, the OEB approved the use of account 1508 to capture the difference related to OPEB costs arising from transition from Canadian Generally Accepted Accounting Principles ("GAAP") to United States GAAP ("US GAAP") on January 1, 2012. In its EB 2014-0116 Decision and Order issued on December 29, 2015, the OEB accepted Toronto Hydro's request to continue to use this deferral account to capture accounting differences related to OPEB costs arising from its transition from US GAAP to International Financial Reporting Standards ("IFRS") on January 1, 2015. The differences related mainly to changes in the accounting treatment of actuarial gains and losses arising from updated actuarial assumptions and experience adjustments recognized in other comprehensive income, but never amortized into profit or loss under IFRS.

No carrying charges were applied to the balance in this account.

On September 14, 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs (EB-2015-0040), stating that utilities may propose disposition of this particular account if the gains and losses that are tracked in this account do not substantially offset over time. Toronto Hydro is seeking recovery of this balance in the current application as changes in the underlying actuarial assumptions, in particular changes in discount rate, are not expected to substantially offset the actuarial loss incurred to date. The discount rate that Toronto Hydro uses is based on the yield of high quality corporate bonds that result in a similar cash flow pattern to the OPEB plans. For Toronto Hydro, the average plan duration is approximately 16.7 years based on the valuation as at January 1, 2016. Toronto Hydro's actuaries expect the Government of Canada bond rates to remain stable with no significant changes for the foreseeable future.

Historically, the Canadian Institute of Actuaries ("CIA") Fiera Capital rate has followed the same trend as the 30-year Government Bond Yield.

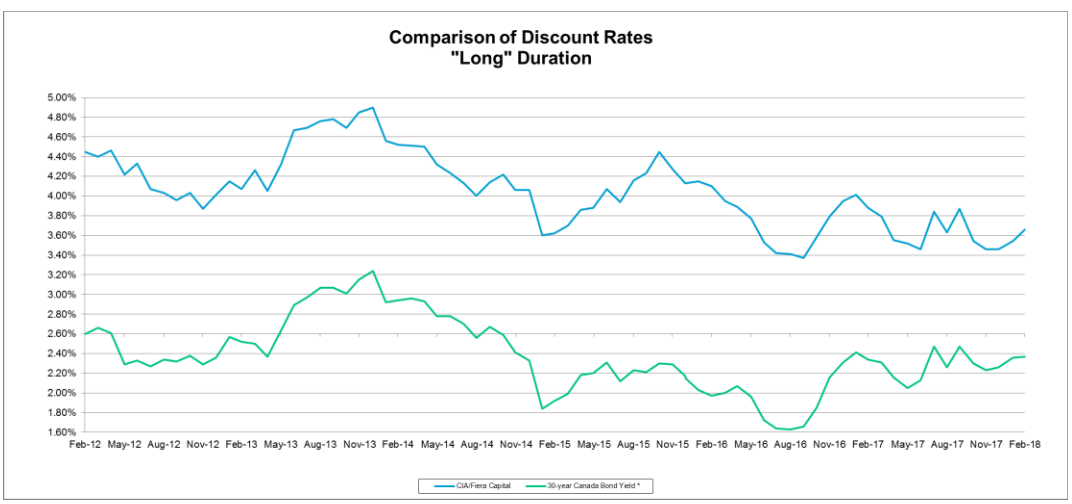

Figure 1: Historical discount rates

Based on the current projected 30-year Government bond rate, Toronto Hydro does not expect significant changes to the discount rate that would substantially offset the actuarial loss incurred to date. The discount rate used as at December 31, 2017 was 3.5 percent. Based on the projected 30-year Government bond rate and applying the average spread between the 30-year Government bond rate and the CIA Fiera rate, the projected discount rate is expected to increase and remain stable at 4.0 percent over the next seven years. As at December 31, 2017, Toronto Hydro's actuary estimated that a 1 percent increase in the discount rate would reduce the obligation by $46.8 million, with a corresponding reduction of the balance in this account by $46.8 million. Keeping all other assumptions constant, a 50 basis points ("bps") increase to 4.0 percent would offset the current actuarial loss ($85.3 million as at December 31, 2017) by an estimated $23.4 million. As such, the increase in discount rate will not substantially offset over time.

Figure 2: Projected Discount rate (2018-2024)

As at December 31, 2017, the balance in this account was $85.3 million debit (recovery) from customers. Toronto Hydro is proposing to clear this balance over five years. Although Toronto Hydro has proposed the disposition of the balances accumulated in /C this account, the OPEB plans will continue to experience actuarial gains or losses as a /C result of changes in actuarial assumptions in the future. Therefore, the utility requests /C the continuance of this account to record these expected changes. /C

4.4 Account 1508 – Other Regulatory Assets, Subaccount – CRRRVA

The balance in the Capital-Related Revenue Requirement Variance Account, all of which is proposed for clearance, is a $59.4 million credit (refund) to customers. The account balance reflects the variance between the cumulative 2015 to 2019 capital related revenue requirement included in rates and the actual capital in-service additions ("ISA") related revenue requirement over the same period. Balances in the CRRRVA include carrying charges and exclude balances that are captured in the Externally Driven Capital and Derecognition variance accounts.

The CRRRVA was approved by the OEB to protect ratepayers in the event Toronto Hydro's actual revenue requirement related to capital was less than the amount funded in the approved revenue requirement for the rate period. The utility forecasts actual capital related revenue requirement will be lower; as a result, there is a credit to customers. There are two reasons for the variance.

First, $36.8 million of the variance is due to a decision by Toronto Hydro to not spend that money funded through approved rates. Toronto Hydro discovered a discrepancy in the estimated useful life used to calculate the depreciation for meters in the 2015-2019 CIR forecast. The forecasted depreciation for meters was based on an estimated useful

TAB 5

Finally, the OEB affirmed in its EB-2014-0116 decision that Z-factor relief was available to Toronto Hydro, if required, and based on the generic criteria for such applications. Toronto Hydro relies on this affirmation for the 2020-2024 period, should the need arise.

4.1 Earnings Sharing Mechanism Calculation

In its Decision and Order for Toronto Hydro's 2015-2019 CIR application, the OEB accepted the utility's proposal for a symmetrical earnings sharing mechanism ("ESM"), incorporating a 100 basis point dead band. As the OEB approved a separate Capital Related Revenue Requirement Variance Account, it approved the ESM to track the variance between the non-capital related revenue requirement embedded in rates and the actual non-capital related revenue requirement. Non-capital revenue requirement consists of OM&A expenditures and revenue offsets. Toronto Hydro determines whether to track an amount in the ESM variance account by calculating the contribution to ROE from the difference between actual and funded non-capital revenue requirement items. This calculation and determination is performed annually. / C

4.1.1 Calculation Methodology

To determine the variance in ROE resulting from non-capital related revenue requirement, Toronto Hydro uses an approach consistent with the OEB's ROE Workform – that is, ROE divided by deemed equity. Specifically, the utility calculates this as follows:

$$\frac{\text{(Actual non-capital revenue requirement)} - \text{(Funded non-capital revenue requirement)}}{\text{Actual equity on a deemed basis}}$$

The actual OM&A and revenue offset amounts included in the numerator are obtained from Toronto Hydro's RRR filing.[19] The funded amounts result from the base year approved OM&A and revenue offsets, adjusted for inflation and productivity. / C

[19] These amounts are adjusted, consistent with adjustments included the RRR ROE Workform and to make the actual results comparable to the amounts embedded in base rates.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 24:

Reference(s): **EB-2017-0077, Decision and Rate Order, p. 7**
Updated Exhibit 1B, Tab 4, Schedule 1, p. 14-15

Preamble:

In its Decision and Order, dated December 14, 2017, in Toronto Hydro's 2018 rates proceeding, the OEB states that it "encourages Toronto Hydro to review the methodology for calculating the earnings sharing with OEB staff in advance of the filing of the next Custom IR or rebasing application at which time the variance account will be reviewed for disposition" (EB-2017-0077 / Decision and Rate Order / p. 7).

a) Please advise whether Toronto Hydro reviewed its methodology for calculating earnings sharing with OEB staff in advance of its current filing. If not, please explain.

RESPONSE:

a) In 2017 and 2018, Toronto Hydro followed the OEB-established process for rates update proceedings and believes it satisfactorily responded to the interrogatories from OEB staff regarding earnings sharing. [1] As a result, Toronto Hydro did not further engage OEB staff to review the earnings sharing calculation. All information provided to, or discussed with, OEB staff is available in Exhibit 1B, Tab 4, Schedule 1 starting on page 14.

[1] EB-2017-0077 and EB-2018-0071.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 25:

Reference(s): **Updated Exhibit 1B, Tab 4, Schedule 1, pp. 14-15**

Preamble:

Toronto Hydro provided the methodology it uses for calculating earnings sharing during the 2015-2019 period as follows.

$$\frac{\text{(Actual non-capital revenue requirement)} - \text{(Funded non-capital revenue requirement)}}{\text{Actual equity on a deemed basis}}$$

a) Please provide the earnings sharing calculations based on Toronto Hydro's methodology for each year 2015-2017. Please provide and explain in detail all adjustments that are made in the calculation (Exhibit 1B / Tab 4 / Schedule 1 / p. 15 / Footnote 19).

b) Please advise whether actual equity on a deemed basis means the deemed equity portion of actual rate base.

c) Please advise whether Toronto Hydro agrees that the methodology it uses for calculating the earnings sharing amount is essentially a true-up of OM&A costs and revenue offsets between the amounts approved in rates and actual (subject to a ROE-related threshold to determine whether earnings sharing is required). Specifically, please confirm that actual revenues are not considered as part of the earnings sharing calculation.

d) Please provide Toronto Hydro's understanding of the operation of the earnings sharing mechanism in terms of the following:

   i) Is earnings sharing symmetrical (e.g. if Toronto Hydro overspends OM&A on an actual basis relative to the amount approved for recovery in rates, and the earnings sharing threshold is met, does Toronto Hydro collect that amount from ratepayers)?

   ii) Is earnings sharing cumulative (i.e. do the over and under-earning amounts net against each other over the entire 2015-2019 period)?

e) As part of the current proceeding, is it Toronto Hydro's intent to seek final approval of the earning sharing amounts for 2015-2018 (with the 2019 balance subject to review in the 2021 rates proceeding)? Alternatively, does Toronto Hydro believe that it already has final approval of the 2015-2017 earnings sharing amounts? Please discuss what requests Toronto Hydro is making as part of the current proceeding.

f) Please provide alternative earnings sharing calculations for 2015-2017 based on the following methodology and provide Toronto Hydro's position on the suggested approach.

$$\frac{\text{(Actual non-capital revenue)} - \text{(Funded non-capital revenue requirement)}}{\text{Actual equity on a deemed basis}}$$

For calculating the actual non-capital revenue amount,

   i) apply the approved S_{cap} in the relevant year to total base distribution revenues (with any adjustments that Toronto Hydro believes are necessary);

ii) subtract the amount from part (i) from the total base distribution revenues;

iii) add the residual amount (which OEB staff believes could be considered a reasonable proxy for the actual non-capital base distribution revenues) from part (ii) to the revenue offset amount.

The remainder of the calculation is unchanged from Toronto Hydro's proposed approach.

g) Please provide alternative earnings sharing calculations for 2015-2017 based on a methodology that compares the utility net income amount to the deemed equity portion of actual rate base. Please make any necessary adjustments to back-out amounts that are non-utility or are otherwise encumbered in deferral and variance accounts (DVAs) (which are subject to separate dispositions) in order to avoid double counting.

RESPONSE:

a) Toronto Hydro's calculation of the earnings sharing mechanism ("ESM") for 2015-2017 follows.

Table 1: 2015-2017 ESM Calculations[1] ($ Millions)

		2015	2016	2017
OM&A [a]	*A*	244.0	246.6	250.6
Revenue Offsets [a]	*B*	- 39.9	- 50.2	- 51.7
Unadjusted non-capital revenue requirement ("Non-CRRR")	*C=A+B*	**204.1**	**196.4**	**198.9**
RRR Adjustments [b]				
Depreciation expense related to non-regulated assets (renewable energy investment)	*D*	-	-	- 0.0
Non-recoverable expenses – donations and meals	*E*	- 0.4	- 0.4	- 0.6
Subtotal	*F=C+D+E*	**203.7**	**196.1**	**198.2**
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
Amortization of capital contributions (deferred revenue) [d]	*H*	2.2	3.8	4.7
Actual non-CRRR items for ESM purposes	*I=F+G+H*	**206.0**	**205.1**	**209.5**
Less: non-CRRR embedded in rates [e,f]	*J*	**202.7**	**205.7**	**208.3**
Non-CRRR difference	*K=I-J*	3.3	- 0.6	1.2
Deemed equity portion of actual rate base [g]	*L*	1,285.2	1,420.1	1,540.4
Non-CRRR difference	*M=K/L*	0.26%	- 0.04%	0.08%
ESM threshold	*N*	1.00%	1.00%	1.00%
ESM test result	*M compared to N*	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.

b) Confirmed.

[1] Source: Toronto Hydro's annual RRR submissions.

c) Toronto Hydro's earnings sharing methodology (as described in part a) is essentially a true-up of OM&A costs and revenue offsets between the: (i) amounts approved in base rates; and (ii) comparable actuals. Actual amounts from Toronto Hydro's RRR submissions are adjusted for items which do not form approved base rates. The resulting difference is subject to the ROE-related threshold to determine whether earnings sharing is required.

Actual distribution revenue, as reported in the RRR, is not considered in Toronto Hydro's earnings sharing calculation, although actual reported OM&A and revenue offsets are.

d) Toronto Hydro's understanding of the operation of the ESM follows.
   i) The account is symmetrical.[2]
   ii) The account is not cumulative.[3]

e) In each of Toronto Hydro's annual rate updates during the 2015-2019 rate cycle, the ESM has been a live issue. In each proceeding, Toronto Hydro has produced the annual ESM calculation. It has been Toronto Hydro's expectation that if the ESM threshold had been surpassed in any given year, that the OEB would order the resulting ESM disposition at that time.

In the event that the 2018 ESM threshold is surpassed, those financial results and the resulting disposition are subject to review in this proceeding (following finalization and filing of Toronto Hydro's 2018 financial results). In the event that the 2019 ESM

[2] EB-2014-0116 Decision and Order dated December 29, 2015, section 3.2, page 49.
[3] Handbook to Electricity Distributor and Transmitter Consolidations, Section - Earning Sharing Mechanism (ESM), page 16 of the handbook.

threshold is surpassed (following finalization and filing of Toronto Hydro's 2019 financial results in its first rate updates thereafter, namely the 2021 rate update proceeding), Toronto Hydro expects that the OEB would order disposition in relation to 2019.

f) The 2015-2017 calculations, based on Toronto Hydro's understanding of the alternative approach, are provided below in Table 2.

Toronto Hydro believes that reported distribution revenue should not form part of Toronto Hydro's earning sharing calculation since it (i) results from approved rates which are based on forecasted OM&A and revenue offsets, (ii) includes items not embedded in approved rates for the 2015-2019 CIR term and is not comparable to non-CRRR embedded in rates, and (iii) has errors in logic.

- The approach entails double-counting of revenue offsets;
- The alternative approach uses projected S_{cap} (not actual S_{cap}) applied to actual revenues to determine a proxy for actual OM&A and revenue offsets, rather than actual amounts which are available from RRR filings;
- Reported distribution revenue includes accounting recognition of revenues in the CIR term for DVA balances prior to the CIR term (i.e. "out-of-period" amounts) and amounts excluded for determining base distribution rates (e.g. donations); and
- Reported revenue includes effects of unplanned weather and other forecasting differences, which are already considered as part of the ROE threshold test

1 **Table 2: ESM calculation based on the alternative methodology ($ Millions)**

		2015	2016	2017
Distribution revenue [a]	*A*	612.4	696.5	679.2
Adjustments for rate rider revenues and out of period items (See Table 3)	*B*	- 14.1	- 38.8	12.8
Distribution revenue, adjusted (base revenue)	*C=A+B*	598.3	657.7	691.9
Projected S_{cap} [b]	*D*	68.9%	70.8%	72.2%
Derived capital related revenue	*E=C*D*	412.2	465.7	499.6
Distribution revenue, adjusted (base revenue)	*F=C*	598.3	657.7	691.9
Less: derived capital related revenue	*G=E*	412.2	465.7	499.6
Derived non-CRRR	*H=F-G*	186.1	192.0	192.4
Add: revenue offsets per RRR	*I*	39.9	50.2	51.7
Derived non-CRRR plus revenue offsets	*J=H+I*	226.0	242.2	244.1
Less: funded non-CRRR	*K*	202.7	205.7	208.3
Non-CRRR approved vs Non-CRRR actual	*L=J-K*	23.3	36.5	35.8
Deemed equity portion of actual rate base	*M*	1,285.2	1,420.1	1,540.4
Non-CRRR difference	*N=L/M*	-1.82%	-2.57%	-2.32%
ESM threshold	*O*	1.00%	1.00%	1.00%
ESM test result	*N compared to O*	Not within threshold	Not within threshold	Not within threshold
$ Impact (Recovery/(Credit) from/ to the customers)	*P=[M*(N-O)]/2*	*5.2*	*11.2*	*10.2*

Rounding variances may exist.

[a] RRR 2.1.7 - trial balance account 4080 (distribution revenue).

[b] EB-2014-0116, Draft Rate Order Update, Filed 2016, Feb 29, Page 6, Table 3. Toronto Hydro notes that these values are based on values projected in 2014, not actual S_{cap}.

Table 3: Adjustments to distribution revenue [a] ($ Millions):

-	2015	2016	2017
Rate Rider Revenue			
Smart Meter	- 10.9	- 7.9	- 2.4
Smart Grid Funding Adder	-	-	- 0.1
OCCP: Operation Centres Consolidation Program	-	5.2	6.6
Amortization of 1575 (IFRS transition cost) (return)	-	- 0.9	- 1.2
HONI Contribution	- 1.9	-	-
Named Properties	- 5.8	-	-
Out of Period Items			
Incremental Capital Module	-	- 41.2	-
Harmonized Sales Tax	-	1.1	-
Lost Revenue Adjustment Mechanism	- 9.0	- 4.5	- 10.9
Others			
CRRRVA, External Initiated Projects (EIP) and Derecognition	12.6	9.0	20.2
Tax on gain on sale of properties (50/60 Eglinton)	-	-	- 1.2
Monthly billing	-	0.4	1.8
POEB tax	0.9	-	-
Total Adjustments	- 14.1	- 38.8	12.8
A RRR 2.1.7 – Trial balance			

g) There is insufficient information in this question for Toronto Hydro to produce the requested calculation.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC4.3:

Reference(s): 1B-Staff-25(g)

With reference to 1B-Staff-25, part g, Board Staff's request to recalculate the earnings sharing mechanism comparing ROE to actual achieved, THESL to further consider probity and provide a response; if deemed not probative, to advise why not.

RESPONSE:

Please see Table 1 for the calculation of ESM based on Toronto Hydro's understanding of Board Staff's request in 1B-Staff-25 part (g) ("ROE Method"). Consistent with Toronto Hydro's direct method of calculating the ESM results,[1] the following method does not cause the ESM threshold to be exceeded in 2015, 2016, or 2017.

Toronto Hydro notes that the ROE Method is not consistent with the OEB Decision in the last rate application, which required the ESM account to track the variance between the non-capital related revenue requirement embedded in rates and the actual non capital related revenue requirement.[2]

[1] See Toronto Hydro's response 1B-Staff-25 part (a).
[2] EB-2014-0116, Decision and Order (December 29, 2015) at page 49.

Table 1: ESM Calculation per 1B-Staff-25(g) ($ Millions)

		2015	2016	2017
Earnings as per RRR 2.1.5.6	A	137.7	173.0	139.8
Adjustments (see Table 2)	B	- 20.9	- 47.2	- 9.6
Adjusted Earnings	**C=A+B**	116.8	125.8	130.2
Less: Earnings (funded through base rates)[3]	D	- 120.2	- 132.3	- 143.2
Earnings Variance	E=C+D	- 3.5	- 6.5	- 13.0
Actual Deemed Equity as per 2.1.5.6 (box "x1")	F	1,285.2	1,420.1	1,540.4
ESM Variance	G=E/F	0.27%	0.45%	0.84%
Threshold	H	1.00%	1.00%	1.00%
Result	G compared to H	ESM not triggered	ESM not triggered	ESM not triggered

The adjustments for rate riders and out of period are detailed in Table 2 below.

Table 2: Adjustments to Net Income in Table 1 Above ($ Millions)

Description	Category[4,5]	2015	2016	2017
Lost Revenue Adjustment Mechanism	DVA	-9.0	-4.5	-9.6
Monthly Billing	DVA	-	0.4	-
Smart Meter Recognition	DVA & Out of Period	-10.9	-7.9	-
Amortization of return on IFRS transition costs (account 1575)	DVA & Out of Period	-	-0.9	-
Incremental Capital Module (Distribution Revenue, less Depreciation)	DVA & Out of Period	-	-30.3	-
Harmonized Sales Tax	DVA & Out of Period	-	1.1	-
HONI Contribution	DVA & Out of Period	-1.9	-	-
Named Properties	DVA & Out of Period	-5.8	-	-

[3] Determined based on the annual ROE included in Table 2 of the EB-2014-0116 Draft Rate Order Update (February 29, 2016, page 6), less 0.6% stretch factor.
[4] Out of period items represent earnings recognized in 2015-2017 but pre-dating 2015. These are adjusted as they do not form base rates for 2015-2017.
[5] DVA items represent earnings related to deferral and variance accounts which are recognized in 2015-2017. These are adjusted as they do not form base rates for 2015-2017.

Description	Category[4,5]	2015	2016	2017
POEB Tax Savings	Out of Period	0.9	-	-
Rate/ Fiscal year synchronization	Unrelated to Non-Capital Rev. Requirement	22.0	-	-
PILs consequences of foregone revenue	DVA	-16.2	-5.1	-
Total adjustments		**-20.9**	**-47.2**	**-9.6**