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September 14, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Evidence Update
OEB File No. EB-2018-0165

Pursuant to Rule 11.03 of the OEB's *Rules of Practice and Procedure*, Toronto Hydro is filing an evidence update. The nature of the updates are summarized in Table 1 below. Toronto Hydro has also submitted the live Excel versions for the relevant appendices and models. Updates to the applicable evidence are marked by /C.

Table 1: List of Updates

	Topic	Update	Reference
1	Updated Table of Contents	Toronto Hydro has updated its Table of Contents as a result of the updates stated herein.	Exhibit 1, Tab 1, Schedule 1
2	Chapter 2 Appendices	Toronto Hydro submits all Chapter 2 Appendices in Excel format (that had not already been filed on August 15, 2018)	N/A
3	Appendix 2-BB	Toronto Hydro submits Appendix 2-BB and an update to the related discussion in Exhibit 4B, Tab 1, Schedule 1.	Exhibit 4B, Tab 1, Schedule 1, Appendix C *[New]*
4	Cost of Power Calculation	Toronto Hydro submits the Cost of Power calculation in Excel format.	Exhibit 2A, Tab 3, Schedule 1, Appendix A
5	Bill Impacts model	Toronto Hydro submits the Bill Impacts model in Excel format (as part of Item #2 above).	Exhibit 8, Tab 6, Schedule 1

6	OEB’s Pole Attachment Workform	Toronto Hydro submits an update confirming that the utility has adopted the OEB’s standard province-wide rate and therefore is not required to file a completed Pole Attachment Workform for a utility-specific rate.	Exhibit 8, Tab 2, Schedule 1
7	Accounting Order from EB-2014-0116	Toronto Hydro submits the Accounting Order from EB-2014-0116.	Exhibit 9, Tab 1, Schedule 1, Appendix B *[New]*
8	Cost Allocation Model	Toronto Hydro has corrected reference errors and resubmits the model in Excel format. Toronto Hydro confirms that the identified errors had no effect on the outputs of the model.	Exhibit 7, Tab 1, Schedule 3
9	2023 Revenue Requirement Workform	Toronto Hydro has corrected a summation error and resubmits the model. Toronto Hydro confirms that there is no effect on bill impacts from the summation error identified above.	Exhibit 6, Tab 1, Schedule 5
10	Group 2 Deferral and Variance accounts	Toronto Hydro has updated its evidence to include a request and rationale to continue certain Group 2 accounts. Toronto Hydro submits that the request and rationale to continue the Capital Related Revenue Requirement, Externally driven Capital and Derecognition variance accounts was already included in the original filing.	Exhibit 9, Tab 1, Schedule 1
11	Anticipated Evidence Updates	Toronto Hydro submits a table summarizing updates to the Application anticipated at this time.	Exhibit 1A, Tab 3, Schedule 1, Appendix B *[New]*
12	Earnings Sharing Mechanism	Toronto Hydro submits an update describing the ESM approach and methodology that the utility proposes to continue in 2020-2024 and was approved by the OEB in EB-2014-0116.	Exhibit 1B, Tab 4, Schedule 1
13	Explanations for Differing Disposition Amounts stated in (i) Summary of Proposed Dispositions; (ii) Continuity Schedule; and (iii) Rate Riders	Toronto Hydro provides an update to the Rate Rider table providing an explanation of the differing amounts presented in other related areas of the Application.	Exhibit 9, Tab 3, Schedule 1, p. 1 [“Rate Riders Table”]

14	CVs and Acknowledgement of Expert's Duty (Form A) for Authors of PSE's Total Cost Benchmarking report	Toronto Hydro has updated its evidence to include the CVs and Form A for Erik Sonju and Steve Fenrick.	Exhibit 1B, Tab 4, Schedule 2, Appendix A *[New]*
15	Power System Engineering Inc.'s Dataset and Models	Toronto Hydro will provide this material in the same manner as was shared with OEB Staff in the utility's last application.	Exhibit 1B, tab 4, Schedule 2

Please do not hesitate to contact me if you have any questions.

Yours truly,

Andrew J Sasso

Andrew J. Sasso
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Toronto Hydro-Electric System Limited
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cc: Amanda Klein, Toronto Hydro
Charles Keizer, Torys LLP
Crawford Smith, Torys LLP

Exhibit List / Table of Contents

PLANNED EVIDENCE UPDATES

Table 1, below, provides information relating to updates Toronto Hydro anticipates at this time. The utility reserves the right to add to this list as new information becomes available.

Table 1: Planned Updates Anticipated as of Sep 14, 2018

	Topic	Reference	Details
1	Rate Framework	Exhibit 1B, Tab 4, Schedule 1	Toronto Hydro proposes to use the OEB's I-factor in its CPCI. As the value for I-factor is updated annually, Toronto Hydro will incorporate the updated value into its CPCI, once released, to appropriately adjust base distribution rates for the following year.
2	Income Tax/PILs Workform	Exhibit 4B, Tab 2 Schedule 2	Toronto Hydro plans to update the PILS workforms once its 2018 tax return is filed in June 2019.
3	Rate Design	Exhibit 8, Tab 1, Schedule 1	Toronto Hydro's proposed Retail Transmission Service Rates in the model reflect the projected 2020 billing units, applied to the current Uniform Transmission Rates ("UTRs"). Toronto Hydro will update the calculated rates prior to the 2020 rate implementation based on OEB approved UTRs at that time.
4	Wireline Pole Attachment Rate	Exhibit 8, Tab 2, Schedule 1	Toronto Hydro plans to update the escalation percentage for the wireline attachment rate once the OEB releases the final inflation factor for 2020.

	Topic	Reference	Details
5	Deferral and Variance Accounts- Retail Settlement Variance Accounts	Exhibit 9, Tab 1, Schedule 1	Toronto Hydro will update the evidence and propose to clear the Retail Settlement Variance Accounts balances for the 2018 period when the 2018 balances are finalized.
6	Deferral and Variance Accounts- Lost Revenue Adjustment Mechanism Variance Account	Exhibit 9, Tab 1, Schedule 1	Toronto Hydro will update the evidence and propose to clear the Lost Revenue Adjustment Mechanism Variance Account amount for the 2018 period when the 2018 Final CDM Annual Report and Persistence Savings Report is available from the IESO.
7	Carrying Charges	Exhibit 9, Tab 1, Schedule 1	Carrying charges have been applied to specific accounts using the OEB's Prescribed Interest Rate. For the periods up to 2018 Q3, the rates are as determined by the OEB. For the periods 2018 Q4 through 2019 Q4, the 2018 Q3 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.
8	Earning Sharing Mechanism ("ESM")- 2018 Calculation	Exhibit 1B, Tab 4, Schedule 1	Toronto Hydro will update its 2018 ESM calculation when 2018 year-end financial results become available. Toronto Hydro will clear any applicable amounts as part of this Application.
9	ESM- 2019 Calculation	Exhibit 1B, Tab 4, Schedule 1	Toronto Hydro will update its 2019 ESM calculation and clear any applicable amounts as part of its 2021 annual rate application.
10	2018 Financial Figures	N/A	Toronto Hydro plans to update 2018 financial figures in April 2019.

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.

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[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:

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

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:

$$\mathbf{PCI = I - X}$$

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.

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[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.

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[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

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[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

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[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:

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[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.

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[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:

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

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

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:
    - $\mathbf{C_n}$, a reflection of Toronto Hydro's capital investment need, and
    - $\mathbf{S_{cap} * I}$, 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.

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[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.

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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

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[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.

STEVEN A. FENRICK, M.S.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling.

EDUCATION

University of Wisconsin - Madison, WI
Master of Science, Agriculture and Applied Economics

University of Wisconsin - Madison, WI
Bachelor of Science, Economics (Mathematical Emphasis)

Publications & Papers

- “Peak-Time Rebate Programs: A Success Story”, *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- “Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- “Evaluating the Cost of Reliability Improvement Programs”, *The Electricity Journal*, November 2013. (With Lullit Getachew)
- “Expected Useful Life of Energy Efficiency Improvements”, Cooperative Research Network, 2013 (with David Williams).
- “Cost and Reliability Comparisons of Underground and Overhead Power Lines”, *Utilities Policy*, March 2012. (With Lullit Getachew).
- “Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- “Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy”, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- “The Value of Improving Load Factors through Demand-Side Management Programs”, Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).

- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.

Expert Witness Experience

- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Moderator at WPUI conference on cost allocation and innovative rate designs, June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, “An Introduction to Peak Time Rebates”. September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2015.
- EUCI conference chair, 2015. “Evaluating the Performance of Gas and Electric Distribution Utilities.”
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2014.
- Cooperative Exchange Conference, Williamsburg VA. “Smart Thermostat versus AC Direct Load Control Impacts”. August 2014.
- EUCI conference chair in Chicago. “The Economics of Demand Response”. February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2013.
- EUCI conference chair in Chicago. “Evaluating the Performance of Gas and Electric Distribution Utilities.” August 2013.
- Presentation to the Ontario Energy Board, “Research and Recommendations on 4th Generation Incentive Regulation”.
- Presentation to the Canadian Electricity Association’s best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, “Performance Benchmarking for Electric and Gas Distribution Utilities.”
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, “Performance Benchmarking for Electric and Gas Distribution Utilities.”
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, “Reliability Target Setting and Performance Evaluation”.
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, “Making the Business Case for Reliability-Driven Investments”.
- Conference chair for EUCI conference in 2012 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. St. Louis.
- Conference chair for EUCI conference in 2012 titled, “Demand Response: The Economic and Technology Considerations from Pilot to Deployment”. St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, “Maximizing the Value of DSM Deployments”. Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.

- Conference chair for EUCI conference in 2011 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

FORM A

Proceeding: EB-2018-0165

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Steven A. Fenrick (*name*). I live at Verona (*city*), in the Wisconsin (*province/state*) of United States.

2. I have been engaged by or on behalf of Toronto Hydro (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 9-12-18

Signature

ERIK S. SONJU, P.E.

PRESIDENT

SUMMARY OF EXPERIENCE AND EXPERTISE

- Consultant in the electric utility sector helping clients analyze and develop strategic decisions around industry best practices, policies, standards, and contracts.
- Principal engineer for electric power studies and design projects.
- Instructor for professional development courses.
- Expert witness in regulatory hearings and civil trials.
- Licensed Professional Engineer in 20 states.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Madison, WI (2006-present)

President (2018-present)

Active consultant to PSE clients in areas of expertise. Responsible for the day-to-day operations of PSE.

Executive Vice President (2017-2018)

Executive for PSE business operations and active consultant to PSE clients.

Vice President – Power Delivery Planning and Design (2010 - 2017)

Responsible for PSE's efforts in electric transmission and distribution studies and planning, substation design, transmission line design and distribution line design. Other responsibilities include overseeing system protection and coordination studies, system operations and maintenance support, distributed energy resource studies and design, and specialty studies of electric power systems.

Leader of System Planning and Line Design (2008 – 2010)

Senior engineer and leader of system planning and line design. Emphasis included short range and long range system planning studies, distributed generation system impact studies, system protection studies, and expert testimony in regulatory proceedings associated with engineering analysis used for State Commission and FERC filed tariffs. Other responsibilities included distribution and transmission line design.

Leader of System Planning (2006 – 2008)

Senior engineer and leader of distribution system planning projects.

Great Lakes Energy – Boyne City, MI (2001-2006)

System Engineer and Manager of Engineering

Heartland Engineering Services – Rockford, MN (1999-2001)

System Engineer

United Services Group – Elk River, MN (1997-1999)

Planning Engineer

EDUCATION

North Dakota State University, Fargo, ND
Bachelor of Science in Electrical Engineering with Emphasis in Power Systems, 1997

University of Nebraska, Lincoln, NE
NRECA Management Internship Program, 2006

Numerous technical and business continuing education courses focusing on issues and topics within the power industry.

TRAINING SEMINARS AND CONFERENCE PRESENTATIONS

- Instructor for professional development courses in the areas of:
  - Distribution System Planning
  - Distribution System Protection and Sectionalizing
  - Power Quality
  - Electric Power Line Design
  - Post Construction Inspections
- Industry conference presentations on:
  - Distribution Independent System Operators
  - Distributed Energy Resource Interconnection and Integration
  - Aging Electric Utility Infrastructure
  - Economic Conductor Analysis
  - Mechanical Loading of Overhead Electrical Equipment on Wood Poles
  - Application of Series Capacitors on Distribution Systems
  - Application of Shunt Reactors on Distribution Systems
  - Impact of Electric Motors, Drives, and Phase Converters on Distribution Systems
  - Substation Protection Considerations
  - National Electric Safety Code Rules and Requirements Pertaining to Communication Attachments on Power Supply Structures.

STATES LICENSED AS PROFESSIONAL ENGINEER

Arizona
Arkansas
Colorado
Florida
Illinois
Indiana
Iowa
Kansas
Michigan
Minnesota
Montana
Nebraska
New Hampshire
New Mexico
Ohio
South Dakota
Texas
Virginia
Wisconsin
Wyoming

EXPERT WITNESS AND TESTIMONY

Utility / Entity	Jurisdiction Body	Case No.	Description	Year
Chevron Pipe Line Company	United States District Court of Utah, Central Division	2:12-cv-00287	Industry expert on behalf of plaintiff in the matter of electrical damage to an oil pipeline. Included expert report and deposition.	2016-17
Lorain-Medina Rural Electric Cooperative	State of Ohio Median County Common Pleas Court	15CIV0749	Industry expert on behalf of defendant in the matter of the application of an electric rate schedule dispute. Included expert report and deposition.	2014-16
Toronto Hydro-Electric System Limited	Ontario Energy Board	EB-2015-0173	Industry expert on behalf of Toronto Hydro. Developed filed report regarding the variance of forecasted vs. actual expenditures associated with an OEB approved 2012-14 Incremental Capital Module request.	2015-16
Toronto Hydro-Electric System Limited	Ontario Energy Board	EB-2014-0116	Industry expert on behalf of Toronto Hydro. Developed filed report regarding independent review of the cost to serve developed environments including core downtown areas. Followed by oral testimony.	2014-15
Crow Wing Power	State of Minnesota District Court - Cass County	Court File No: 11-CV-12-1670	Testimony on behalf of defendant in the matter of a stray voltage lawsuit. Specific evidence related to conditions of underground distribution cable running adjacent to a dairy farm.	2013-14
MidAmerican Energy Company	State of Iowa District Court - Polk County	Law No. CL 114962	Industry expert on behalf of defendant providing engineering analysis showing the probable cause of failure of a 161kV transmission structure while under construction. Included affidavit of the analysis results and deposition.	2013
Toronto Hydro-Electric System Limited (THESL)	Ontario Energy Board	EB-2012-0064	Written and oral testimony regarding the replacement of aging electric infrastructure in the matter of THESL's application for 2012, 2013, and 2014 IRM Rate Adjustments and ICM Rate Adders	2012

Utility / Entity	Jurisdiction Body	Case No.	Description	Year
Governor Dannel P. Malloy's Two Storm Panel	State of Connecticut	N/A	Expert witness presentation to Governor Malloy's Two Storm Panel regarding distribution system reliability in the aftermath of Tropical Storm Irene and 2011 Halloween nor'easter snow storm.	2011
Mid-Kansas Electric Company	Kansas Corporation Commission	09-MKEE-969-RTS	Written expert rebuttal testimony on certain aspects of transmission and sub-transmission losses applied in proposed open access transmission tariffs and local access charges.	2009

FORM A

Proceeding:.EB-2018-0165..........

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ...Erik S. Sonju..........*(name)*. I live at .Madison..... *(city)*, in the ...Wisconsin... *(province/state)* of ..United States..... .

2. I have been engaged by or on behalf of .Toronto Hydro....... *(name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ...9-12-18.......................

Erik S. Sonju
Signature

2.1 Depreciation Expense Details

Appendix A to this schedule provides the depreciation expense by Uniform System of Accounts for the historical (2015 to 2017), bridge (2018 to 2019) and forecast (2020) years. These amounts are based on MIFRS and include derecognition as described in Exhibit 4B, Tab 1, Schedule 2.

3. DEPRECIATION AND AMORTIZATION

In accordance with the OEB's Accounting Procedures Handbook for Electricity Distributors (the "APH"), Toronto Hydro depreciates and amortizes its assets on a straight-line basis over the estimated useful lives of the assets. Tables 1 and 2 below provide Toronto Hydro's annual depreciation and amortization rates by asset category for 2015 to 2017 (actual), 2018 and 2019 (bridge) and 2020 (forecast). Toronto Hydro does not expect any changes to the annual depreciation rates for 2021 to 2024.

In accordance with the OEB's filing requirements, Toronto Hydro is not required to file Appendix 2-BB as the utility has not made any changes to its depreciation and amortization practices or to estimated asset useful lives since its last rebasing application (EB-2014-0116). Regardless, a completed Appendix 2-BB is enclosed as Appendix C to this schedule. / C

As part of its normal course of business, Toronto Hydro has added new asset classes and made minor presentation changes to the grouping of asset categories related to depreciation. These presentation changes are discussed below.

OEB Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures (Streetlighting Assembly)	40	3%	40	3%	Yes	No
								1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95	1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	30	3%	30	3%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices (Streetlighting Assembly)	40	3%	40	3%	Yes	No
								1835	Overhead Conductors and Devices	50	2%	50	2%	No	No
								1855	Services (Overhead & Underground)	50	2%	50	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	30	3%	30	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	3%	32	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	3%	32	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	3%	32	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	3%	32	3%	No	No
	14	Station Grounding Transformer			30	40	40	1820	Distribution Station Equipment - Normally Primary Below 50 kV	25	4%	25	4%	Yes	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	No	No
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	10%	10	10%	No	No
			Charger		20	20	30	1820	Distribution Station Equipment - Normally Primary Below 50 kV	20	5%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	50	2%	50	2%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	Yes	No
	18	Station Switch			30	50	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	30	3%	30	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	10%	10	10%	No	No
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	3%	35	3%	No	No
	23	Steel Structure			35	50	90	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	3%	35	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	35	3%	35	3%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	1845	Underground Conductors and Devices	60	2%	60	2%	No	No
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	Underground Conductors and Devices	20	5%	20	5%	Yes	No
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	20	5%	20	5%	Yes	No
								1855	Services (Overhead & Underground)	20	5%	20	5%	Yes	No
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
								1855	Services (Overhead & Underground)	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50	1850	Line Transformers	20	5%	20	5%	No	No
			Protector		20	35	40	1850	Line Transformers	20	5%	20	5%	No	No
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	30	3%	30	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	30	3%	30	3%	No	No
	36	UG Foundation			35	55	70	1840	Underground Conduit	50	2%	50	2%	No	No
	37	UG Vaults	Overall		40	60	80	1840	Underground Conduit	40	3%	40	3%	No	No
			Roof		20	30	45	1840	Underground Conduit	20	5%	20	5%	No	No
	38	UG Vault Switches			20	35	50	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	20	5%	20	5%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	30	3%	30	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80	1840	Underground Conduit	50	2%	50	2%	No	No
								1840	Underground Conduit (Cable Chamber Roof)	20	5%	20	5%	Yes	No
S	43	Remote SCADA			15	20	30	1835	Overhead Conductors & Devices	30	3%	30	3%	No	No
								1980	System Supervisory Equipment	15	7%	15	7%	No	No
								1980	System Supervisory Equipment	30	3%	30	3%	No	No

OEB Appendix 2-BB
Service Life Comparison

Table F-2 from Kinetrics Report[1]

	Asset Details		**Useful Life Range**		**USoA Account Number**	**USoA Account Description**	**Current**		**Proposed**		**Outside Range of Min, Max TUL?**	
#	**Category| Component | Type**						**Years**	**Rate**	**Years**	**Rate**	**Below Min Range**	**Above Max Range**
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	8	13%	No	No
		Trailers	5	20	1930	Transportation Equipment	5	20%	5	20%	No	No
		Vans	5	10								
3	Administrative Buildings		50	75	1908	Buildings and Fixtures	20	5%	20	5%	Yes	No
					1908	Buildings and Fixtures	30	3%	30	3%	Yes	No
					1908	Buildings and Fixtures	50	2%	50	2%	No	No
					1908	Buildings and Fixtures	75	1%	75	1%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold Improvements	5	20%	5	20%	Yes	Yes
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	20	5%	20	5%	Yes	No
					1808	Buildings and Fixtures	30	3%	30	3%	Yes	No
					1808	Buildings and Fixtures	36	3%	36	3%	Yes	No
					1808	Buildings and Fixtures	75	1%	75	1%	No	No
		Parking	25	30	1808	Buildings and Fixtures	30	3%	30	3%	No	No
		Fence	25	60	1808	Buildings and Fixtures	30	3%	30	3%	No	No
		Roof	20	30	1808	Buildings and Fixtures	20	5%	20	5%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	4	25%	4	25%	No	No
					1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
					1920	Computer Equipment - Hardware	6	17%	6	17%	No	Yes
		Software	2	5	1611	Computer Software	4	25%	4	25%	No	No
					1611	Computer Software	5	20%	5	20%	No	No
					1611	Computer Software	10	10%	10	10%	No	Yes
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	6	17%	6	17%	No	No
					1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
					1950	Service Equipment	8	13%	8	13%	No	No
					1960	Miscellaneous Equipment	10	10%	10	10%	No	No
					1930	Transportation Equipment	8	13%	8	13%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	10	10%	No	No
					1970	Load Management Controls - Customer Premises	10	10%	10	10%	No	No
					1975	Load Management Controls - Utility Premises	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	5	20%	5	20%	No	No
					1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	40	3%	40	3%	No	No
13	Smart Meters		5	15	1860	Meters (Smart Meters)	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

Additional Notes

The useful life of Toronto Hydro handwells is twenty years. The streetlighting handwells is fourty years

The useful life of the IT related data centre is ten years.

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.

See pages 17-19 of Kinetrics Report

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input (1)

		Initial Application	(2)		(6)	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$7,140,052,883		############		$7,140,052,883	
	Accumulated Depreciation (average)	($2,013,781,505)	(5)	#############		($2,013,781,505)	
	Allowance for Working Capital:						
	Controllable Expenses	$285,057,919		$ 285,057,919		$285,057,919	
	Cost of Power	$3,579,801,165		############		$3,579,801,165	
	Working Capital Rate (%)	6.42%	(9)		(9)		(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$848,702,180					
	Distribution Revenue at Proposed Rates	$885,241,080					
	Other Revenue:						
	Specific Service Charges	$6,760,117					
	Late Payment Charges	$3,853,592					
	Other Distribution Revenue	$38,369,275					
	Other Income and Deductions						
	Total Revenue Offsets	$48,982,985	(7)				
	Operating Expenses:						
	OM+A Expenses	$279,372,150		$ 279,372,150		$279,372,150	
	Depreciation/Amortization	$310,853,964		$ 310,853,964		$310,853,964	
	Property taxes	$5,685,769		$ 5,685,769		$5,685,769	
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($85,418,999)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$26,253,623					
	Income taxes (grossed up)	$35,719,215					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	($2,736,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	3.71%					
	Short-term debt Cost Rate (%)	2.61%					
	Common Equity Cost Rate (%)	8.82%					
	Prefered Shares Cost Rate (%)						

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$885,241,080	($885,241,080)	$ -	$ -	$ -
2	Other Revenue	(1)	$48,982,985	($48,982,985)	$ -	$ -	$ -
3	Total Operating Revenues		$934,224,064	($934,224,064)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$279,372,150	$ -	$279,372,150	$ -	$279,372,150
5	Depreciation/Amortization		$310,853,964	$ -	$310,853,964	$ -	$310,853,964
6	Property taxes		$5,685,769	$ -	$5,685,769	$ -	$5,685,769
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$595,911,884	$ -	$595,911,884	$ -	$595,911,884
10	Deemed Interest Expense		$117,379,488	($117,379,488)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$713,291,371	($117,379,488)	$595,911,884	$ -	$595,911,884
12	**Utility income before income taxes**		$220,932,693	($816,844,577)	($595,911,884)	$ -	($595,911,884)
13	Income taxes (grossed-up)		$35,719,215	$ -	$35,719,215	$ -	$35,719,215
14	**Utility net income**		$185,213,478	($816,844,577)	($631,631,099)	$ -	($631,631,099)

Notes

Other Revenues / Revenue Offsets

(1)

Specific Service Charges	$6,760,117		$ -		$ -
Late Payment Charges	$3,853,592		$ -		$ -
Other Distribution Revenue	$38,369,275		$ -		$ -
Other Income and Deductions	$ -		$ -		$ -
Total Revenue Offsets	$48,982,985	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$279,372,150		$279,372,150		$279,372,150	
2	Amortization/Depreciation	$310,853,964		$310,853,964		$310,853,964	
3	Property Taxes	$5,685,769		$5,685,769		$5,685,769	
5	Income Taxes (Grossed up)	$35,719,215		$35,719,215		$35,719,215	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$117,379,488		$ -		$ -	
	Return on Deemed Equity	$189,613,019		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$938,623,605		$631,631,099		$631,631,099	
9	Revenue Offsets	$48,982,985		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$889,640,620		$631,631,099		$631,631,099	
11	Distribution revenue	$885,241,080		$ -		$ -	
12	Other revenue	$48,982,985		$ -		$ -	
13	**Total revenue**	$934,224,064		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($4,399,540)	(1)	($631,631,099)	(1)	($631,631,099)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$938,623,605	$631,631,099	($0)	$631,631,099	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$39,063,327	($287,310,071)	($8)	$810,764,468	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$889,640,620	$631,631,099	($0)	$631,631,099	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$36,538,900	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	**Costs Allocated from Previous Study** [1]	**%**	**Allocated Class Revenue Requirement** [1] (7A)	**%**
1	Residential	$ 287,079,871	42.26%	$ 360,832,613	38.4%
2	Competitive Sector Multi-Unit Residentia	$ 19,267,312	2.84%	$ 40,334,605	4.3%
3	GS <50	$ 99,019,246	14.58%	$ 146,273,232	15.6%
4	GS - 50 to 999	$ 157,700,127	23.21%	$ 233,587,071	24.9%
5	GS - 1000 to 4999	$ 55,701,964	8.20%	$ 82,524,126	8.8%
6	Large Use >5MW	$ 31,087,389	4.58%	$ 44,939,828	4.8%
7	Street Light	$ 25,331,820	3.73%	$ 25,074,140	2.7%
8	Unmetered Scattered Load	$ 4,173,832	0.61%	$ 5,057,990	0.5%
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 679,361,561	100.00%	**$ 938,623,605**	100.0%
			Service Revenue Requirement (from Sheet 9)	**$ 938,623,605**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	**Load Forecast (LF) X current approved rates** (7B)	**LF X current approved rates X (1+d)** (7C)	**LF X Proposed Rates** (7D)	**Miscellaneous Revenues** (7E)
1	Residential	$ 336,775,618	$ 351,270,826	$ 351,046,981	$ 19,752,861
2	Competitive Sector Multi-Unit Residentia	$ 43,803,895	$ 45,689,265	$ 45,664,205	$ 1,724,893
3	GS <50	$ 113,613,325	$ 118,503,373	$ 118,435,994	$ 8,383,826
4	GS - 50 to 999	$ 225,749,054	$ 235,465,552	$ 235,495,164	$ 7,532,595
5	GS - 1000 to 4999	$ 72,417,879	$ 75,534,827	$ 75,726,989	$ 1,434,357
6	Large Use >5MW	$ 35,504,757	$ 37,032,922	$ 37,139,549	$ 587,261
7	Street Light	$ 16,526,848	$ 17,238,183	$ 17,227,775	$ 9,250,510
8	Unmetered Scattered Load	$ 4,244,397	$ 4,427,080	$ 4,425,373	$ 316,681
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 848,635,773	$ 885,162,029	$ 885,162,029	$ 48,982,986

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	94.3%	102.8%	102.8%	85 - 115
2	Competitive Sector Multi-Unit Residentia	100.0%	117.6%	117.5%	
3	GS <50	91.5%	86.7%	86.7%	80 - 120
4	GS - 50 to 999	119.0%	104.0%	104.0%	80 - 120
5	GS - 1000 to 4999	101.9%	93.3%	93.5%	80 - 120
6	Large Use >5MW	95.3%	83.7%	83.9%	85 - 115
7	Street Light	82.7%	105.6%	105.6%	80 - 120
8	Unmetered Scattered Load	90.5%	93.8%	93.8%	80 - 120
9	Unmetered Scattered Load (Connections)				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2020	Price Cap IR Period 2021	 2022	Policy Range
1	Residential	102.8%			85 - 115
2	Competitive Sector Multi-Unit Residentia	117.5%			
3	GS <50	86.7%			80 - 120
4	GS - 50 to 999	104.0%			80 - 120
5	GS - 1000 to 4999	93.5%			80 - 120
6	Large Use >5MW	83.9%			85 - 115
7	Street Light	105.6%			80 - 120
8	Unmetered Scattered Load	93.8%			80 - 120
9	Unmetered Scattered Load (Connection				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Fixed / Variable Splits [2] Percentage to be entered as a fraction between 0 and 1			Distribution Rates Monthly Service Charge		Volumetric Rate			Revenue Reconciliation 1.013888889		
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	620,899	4,386,740,109	-	$ 351,046,981	$ 351,046,981	$ -	100.00%	0.00%	$ -	$46.47	2	$0.00000	/kWh	5	351,046,981	-	$ 351,046,981.12
2	Competitive Sector Multi-Unit Residential	kWh	101,879	313,817,857	-	$ 45,664,205	$ 45,664,205	$ -	100.00%	0.00%	$ -	$36.84		$0.00000	/kWh	5	45,664,205	-	$ 45,664,205.38
3	GS <50	kWh	71,788	2,187,481,667	-	$ 118,435,994	$ 35,707,207	$ 82,728,786	30.15%	69.85%	$ -	$40.88		$0.03782	/kWh	5	35,705,437	82,730,557	$ 118,435,993.52
4	GS - 50 to 999	kVA	10,341	9,432,138,729	24,813,648	$ 235,495,164	$ 7,121,349	$ 228,373,816	3.02%	96.98%	$ 3,928,646	$56.60		$9.2336	/kVA	4	7,121,157	232,301,517	$ 235,494,028.10
5	GS - 1000 to 4999	kVA	430	4,387,143,302	10,232,645	$ 75,726,989	$ 5,067,463	$ 70,659,526	6.69%	93.31%	$ 5,356,674	$968.61		$7.3270	/kVA	4	5,067,445	76,015,904	$ 75,726,674.92
6	Large Use >5MW	kVA	44	1,962,015,257	4,730,195	$ 37,139,549	$ 2,260,352	$ 34,879,196	6.09%	93.91%	$ 2,906,232	$4,222.33		$7.8787	/kVA	4	2,260,354	37,785,396	$ 37,139,518.74
7	Street Light	kVA	166,107	115,566,836	328,076	$ 17,227,775	$ 3,677,749	$ 13,550,026	21.35%	78.65%	$ -	$1.82		$40.7357	/kVA	4	3,678,166	13,550,022	$ 17,228,188.62
8	Unmetered Scattered Load	kWh	857	41,200,600	-	$ 4,425,373	$ 84,909	$ 4,217,493	1.92%	95.30%	$ -	$8.14		$0.10236	/kWh	5	84,874	4,217,293	$ 4,302,167.87
9	Unmetered Scattered Load (Connections)		12,272	-	-		$ 122,971	$ -	2.78%		$ -	$0.82		$0.00000			122,434	-	$ 122,433.65
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 12,191,552

Revenues recovered from rates deviate materially from revenue requirement - check data inputs and calculations

Total Distribution Revenues	$	885,160,191.92
Base Revenue Requirement	$	889,640,619.91
Difference	-$	4,480,427.99
% Difference		-0.504%

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

2. SPECIFIC SERVICE CHARGES – RATE UPDATES

2.1 Specific Charge for Access to Power Poles (Wireline Attachments) ($/Pole/Year)

Toronto Hydro currently charges telecommunication companies for any wireline attachments placed on its poles at a rate of $42[2] per pole per year, a rate that was set specific to Toronto Hydro as part its 2015 CIR application. In its EB-2015-0304 report on Wireline Pole Attachment Charges ("Wireline Report") issued March 22, 2018, the OEB outlined an updated policy for the wireline pole attachment rates to be charged by all Local Distribution Companies ("LDCs") for attachments by telecommunication and cable companies (carriers) to distribution poles, setting a standard province-wide rate of $43.63 per attacher per pole per year for 2019.

In accordance with the Wireline Report, Toronto Hydro proposes to update its wireline pole attachment charge to $44.15 per pole per year effective January 1, 2020. This rate is calculated based on the standard rate of $43.63 for 2019 and the application of 1.2 percent escalation (the OEB's current inflation rate) for 2020. Toronto Hydro proposes that this rate be updated once the final OEB inflation factor for 2020 is determined. In /C
adopting the standard province-wide rate, Toronto Hydro has not filed the OEB's Pole /C
Attachment Workform. /C

3. OTHER RATES AND CHARGES

In accordance with section 2.8.6 of the OEB Filing Requirements (July 12, 2018), Toronto Hydro has identified certain charges that appear in its Conditions of Service but are excluded from the current OEB-approved tariff sheet. These include the following Basic

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[2] Per July 23, 2015 OEB Decision on Toronto Hydro's Settlement Proposal (EB-2014-0116).

Connection Charges for unmetered customers that are not included in distribution rates[3]:

1) Unmetered Connections – Overhead Supply (excludes Street Lighting):
    a) $446 standard allowance plus variable costs - source connection made at the Distributor's supply pole and service mast located on same supply pole; and
    b) $1,011 standard allowance plus variable costs - source connection made at the Distributor's supply pole and service mast is not located on same supply pole.
2) New or Upgraded Street Lighting Services:
    a) $533.36 standard allowance plus variable costs - Municipal Lights attached to Distributor's poles and connected to Distributor's overhead 120/240 V secondary bus;
    b) $573.97 standard allowance plus variable costs - Municipal Lights attached to Distributor's poles in mixed used urban setting and connected to Distributors underground 120/240 V secondary bus; and
    c) $573.97 standard allowance plus variable costs - Municipal Lights attached to Municipality's poles in residential setting and connected to Distributor's underground 120/240 V secondary bus.

These charges were developed to recover the actual cost of labour, materials, equipment and contracts Toronto Hydro incurs to provide the basic connection service for these specific customer groups on an as requested basis.[4] They are comprised of a

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[3] Please refer to Toronto Hydro's Conditions of Service effective January 1, 2018, Tables 2 and 3, pages 101 and 102, respectively for the Basic Connection Charges. These charges are billed directly to the customer.

[4] Basic Connection Charges for unmetered connections are defined in Toronto Hydro's Conditions of Service, Sections 3.8. Cost includes installation and commissioning of single transformer and the associated service drop up to 30 metres in length.

base amount and variable portion (for any costs beyond the base amount), both of which are billed directly. These charges are recovered as capital contributions. Consistent with other similar charges that are recovered through capital contributions, they are not recorded as a Specific Service Charge in Toronto Hydro's OEB-approved tariff sheet. Amounts collected over the 2015-2017 period are shown in the table below. Forecast amounts are not available, as the work is done on a customer request basis.

Table 2: Service Connection Capital Contributions ($)

	2015	2016	2017
Service Connection Contributions	56,880	72,044	35,264

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 life of four years whereas the actual depreciation for meters is based on a useful life of 15 years. The effect was more approved capital-related revenue requirement funding through 2015-2019 rates than Toronto Hydro proposed during that rate-setting process. Toronto Hydro decided that the corresponding amount should not be spent and that the balance with interest should be returned to customers through the clearance of the CRRRVA.

Second, the remaining variance is due to the difference between the forecasted and actual mix of capital programs and the forecasted and actual timing of that capital work going in-service. Toronto Hydro has hundreds of individual capital projects each year, and the selection and timing of those projects varies with dynamic customer and system needs, as well as weather, field conditions, permitting, site access, third party co-ordination, and other factors. A regular part of Toronto Hydro's operation is rebalancing the mix and timing of capital projects to adjust for these factors. Most of this variance was driven by later than forecasted in-service dates for several significant projects.

- The in-service date of the ERP system was delayed from 2016 to an expected completion date of 2018 (Exhibit 2B, Schedule E4).
- The in-service date of Copeland TS – Phase 1 was delayed from 2015-2016 to 2017-2018 (Exhibit 2B, Schedule E7.4).
- The in-service dates associated with capital contributions to Hydro One Networks Incorporated ("Hydro One") were in 2016 instead of 2015 (Exhibit 2B, Schedule E7.4).

The following table summarizes the balances in the account by year.

Table 7: Wireless attachment costs and revenues ($ Thousands)

	Actual	Forecast		
	2015- 2017	2018	2019	Total
THESL Wireless Attachment Costs	38	-	-	38
THESL Wireless Attachments Revenues	(450)	(100)	(100)	(650)
THESL Wireless Attachment Costs – carrying charges	2	1	1	4
THESL Wireless Attachments Revenues – carrying charges	(12)	(10)	(12)	(34)
Total	**(422)**	**(109)**	**(111)**	**(642)**

The OEB performed their policy review of pole attachment charges and concluded their findings in EB-2015-0304. The indirect charges for wireless attachments are aligned with those stated in EB-2015-0304. Revenues received by Toronto Hydro for its wireless attachments were in excess to the costs, thus the need to clear the $0.6 million credit in this account. Toronto Hydro requests continuance of this account to capture the /C
ongoing nature of wireless pole attachment costs and revenues. /C

4.8 Account 1508 – Other Regulatory Assets, Subaccount – Monthly Billing

Toronto Hydro's Monthly Billing Deferral Account approved in EB-2014-0116, is intended to record the incremental costs and savings resulting from the mandatory transition to monthly billing for non-seasonal residential and all GS<50 kW customers as of December 31, 2016.[5]

In order to implement the mandatory transition, Toronto Hydro incurred $3.3 million in capital costs, and expects to incur an additional $15.9 million in operational costs from

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[5] EB-2014-0198, Notice of Amendment to a Code, Amendments to the Distribution System Code (April 15, 2015).

2016 through the end of 2019.[6] These ongoing operational costs are offset by $6.0 million in working capital benefits attained over the same period.

The mandatory transition to monthly billing resulted in 3.8 million additional Toronto Hydro bills issued in 2017, representing an almost 70 percent increase (see Figure 3 below). In order to mitigate the cost impact associated with this increase, Toronto Hydro invested in various hardware and software upgrades, promoted electronic billing, and implemented a combination of automation, process improvements, and outsourcing, as detailed in the sections below. Overall, Toronto Hydro has continued to ensure customer satisfaction throughout the transition and has managed to improve its billing accuracy metrics during this period.

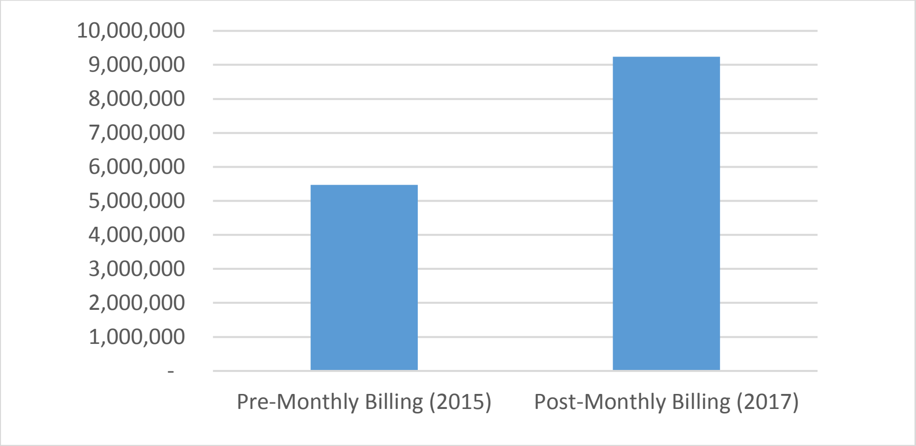

Figure 3: Total Bills Issued in 2015 and 2017

4.8.1 Capital Costs

As shown in Table 8, below, Toronto Hydro incurred $3.3 million in capital costs in order to implement the mandatory transition to monthly billing. This amount is slightly above

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[6] In its 2015-2019 CIR Application, the utility did not include any costs or savings associated with the mandatory transition to monthly billing.

that is funded through Provincial Rate Protection and collected through payments from the IESO and revenue requirement based on actual REI investments, as it occurs over the 2015-2019 CIR period. Toronto Hydro requests continuance of this account for the /C
2020-2024 period. /C

As at the end of 2017, the variance in this account is a $2.4 million credit, as spending on some of the specific projects has been deferred or delayed. Current projections for investment on these approved projects over the 2018-2019 period indicates that the balance of the variance account will be $5.1 million at the end of 2019. Table 16 below provides details.

Table 16: Provincially Funded Renewable Eligible Investment Variance Account ($ Millions)

	2015	2016	2017	2018	2019
Approved Revenue Requirement	0.3	0.9	1.5	2.1	2.6
Actual/Forecast Revenue Requirement	-	-	0.1	0.5	1.6
Variance Account Balance	(0.3)	(0.9)	(1.4)	(1.6)	(1.0)

Toronto Hydro seeks approval to clear this account and return the projected $5.1 million variance to the IESO.

5. TORONTO HYDRO IS NOT SEEKING CLEARANCE IN THIS APPLICATION OF BALANCES IN THE FOLLOWING ACCOUNTS

5.1 All RSVA Accounts

Toronto Hydro will propose to clear the RSVA accounts for 2017 amounting to a $43.9 million credit (refund) to customers as part of Toronto Hydro's 2019 Custom Incentive Rate-setting Update Application. The accounts included are Account 1550 – Low Voltage Variance Account, Account 1580 – Wholesale Market Services, Account 1584 –

APPENDIX E

DECISION AND RATE ORDER

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

EB-2014-0116

MARCH 1, 2016

NEW VARIANCE AND DEFERRAL ACCOUNTS – ACCOUNTING ORDERS

1. VARIANCE ACCOUNT FOR EXTERNALLY DRIVEN CAPITAL – ACCOUNTING ORDER

The OEB approved the revenue requirement associated with $4.0 million of annual in-service amounts for work related to third party initiated relocation and expansion projects (externally driven capital work). Since expenditures under this program can be volatile and difficult to predict, Toronto Hydro will record to this variance account the revenue requirement impact of the amounts for this type of work that vary from the approved amounts. For example, if Toronto Hydro puts in service $10 million of externally driven capital work in 2015, it will record the revenue requirement impact related to the $6 million to the variance account. This symmetrical variance account will record variances above and below $4.0 million and amounts recorded or recordable in this account will not be recorded in the Capital-Related Revenue Requirement Variance Account.

Carrying charges will apply to the opening revenue requirement balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the revenue requirement associated with the balances in these accounts to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement
- Account 1508, Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record the revenue requirement in the Externally Driven Capital Variance Account:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement
   - CR 4080 Distribution Services Revenue

B. To record the carrying charges in subaccount THESL Externally Driven Revenue Requirement:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement Carrying Charges
   - CR 4405 Interest and Dividend Income

2. VARIANCE ACCOUNT FOR DERECOGNITION – ACCOUNTING ORDER

Under Modified IFRS, the gain or loss associated with the derecognition of assets is required to be recorded as a depreciation expense during the period in which the item is derecognized. Due to the dynamic nature of Toronto Hydro's capital program and operating environment, Toronto Hydro is likely to experience a significant degree of ongoing volatility in year over year losses on derecognition over the CIR Period. To manage this volatility, Toronto Hydro will record to a variance account the amounts which vary from the OEB-approved amounts.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in these accounts to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount THESL Derecognition Amounts
- Account 1508, Other Regulatory Assets, Subaccount THESL Derecognition Amounts Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record the amounts that vary from the amounts included in the 2015 Revenue Requirement and the amounts included in the 2016-2019 C-Factor calculations related to the Derecognition amounts:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Derecognition Amounts
   - CR 4080 Distribution Services Revenue

B. To record the carrying charges in subaccount THESL Derecognition Amounts:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Derecognition Amounts Carrying Charges
   - CR 4405 Interest and Dividend Income

3. DEFERRAL ACCOUNT FOR THE MANDATORY TRANSITION TO MONTHLY BILLING – ACCOUNTING ORDER

The OEB requires that all distributors transition customers in the Residential and General Service less than 50 kW (GS < 50kW) rate classes to monthly billing by December 31, 2016. The OEB approved a deferral account in which Toronto Hydro will record the incremental costs and savings that result from this mandatory transition. Since the timing and costs of the transition are yet unknown, no amount related to these incremental costs and savings were included in the Application.[1] Toronto Hydro will also record in a deferral account the revenue requirement associated with the capital cost amounts in the Mandatory Transition to Monthly Billing Deferral Account.

Carrying charges will apply to the opening revenue requirement balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will record as a debit to the deferral account the incremental costs of the mandatory transition to monthly billing.

Toronto Hydro will calculate and record as a credit to the deferral account the incremental savings (if any) arising from benefits realised in the course of the mandatory transition to monthly billing.

Toronto Hydro will establish the following deferral accounts to record the amounts described above:

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[1] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at pp. 51-52.

- Account 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings
- Account 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement
- Account 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement Carrying Charges

The sample accounting entries for the deferral accounts are provided below.

A. To record on a monthly basis the incremental costs of the mandatory transition to monthly billing:
   - DR 1508 Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings
   - CR XXXX Operating, Maintenance and Administration Expenses / Property Plant and Equipment / Depreciation Expense / Construction Work-in-Progress (various accounts - dependent on the type of costs)

B. To record on a monthly basis the incremental savings of the mandatory transition to monthly billing:
   - DR XXXX Operating, Maintenance and Administration Expenses / Property Plant and Equipment / Depreciation Expense / Construction Work-in-Progress (various accounts – dependent on the type of costs)
   - CR 1508, Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings

C. To record the revenue requirement on the capital costs in the Mandatory Transition to Monthly Billing Deferral Account:
   - DR 1508 Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement
   - CR 4080 Distribution Services Revenue

D. To record the carrying charges in subaccount Mandatory Transition to Monthly Billing Revenue Requirement:

  - DR 1508 Other Regulatory Assets, Subaccount Mandatory Transition to Monthly Billing Costs and Savings Revenue Requirement Carrying Charges
  - CR 4405 Interest and Dividend Income

4. VARIANCE ACCOUNT FOR GAINS ON SALE OF PROPERTIES RELATED TO THE COMPANY'S OPERATING CENTERS CONSOLIDATION PROGRAM (OCCP) – ACCOUNTING ORDER

Toronto Hydro will be clearing to ratepayers, through an OEB-approved rate rider, the forecasted net gains on the sale of the 5800 Yonge and 28 Underwriters properties, grossed up for the PILs tax savings. However, since the timing of the sale of both properties and the final amount of the net gain from the sale of both properties are not known at the time of rate finalization, the OEB approved a variance account in which Toronto Hydro will track the difference between the total forecasted gains net of tax with the forecasted gross up for the PILs tax savings and the actual gains net of tax with the actual gross up for the PILs tax savings.

Carrying charges will apply to the opening balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount OCCP Gains Variance Account
- Account 1508, Other Regulatory Assets, Subaccount OCCP Gains Variance Account Carrying Charges

Toronto Hydro will use the following account to record the OEB-approved rate rider associated with the forecasted gains being cleared to ratepayers:

- Account 1508 Other Regulatory Assets, Subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account)

The sample accounting entries for the variance accounts are provided below.

December 31, 2015 entries

A. Record the OEB-approved net forecasted gains to be cleared to customers through a rate rider:
    - DR 4080 Distribution Services Revenue
    - CR 1508 Other Regulatory Assets, Subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account)
B. Record the variance between the approved net forecasted gains and the actual net gains as at the end of 2015:
    - DR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account
    - CR 4080 Distribution Services Revenue

2016 and future years' entries

C. Record the refunding of the rate rider to customers. The offsetting credit will be to Account 1100 Customer Accounts Receivable since the ratepayers' bills should be reduced by the rate rider refund:
    - DR 4080 Distribution Services Revenue
    - CR 1100 Customer Accounts Receivable
    - DR 1508 Other Regulatory Assets, Subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account)
    - CR 4080 Distribution Services Revenue
D. Record the actual PILs tax savings materialized, which is being given back to ratepayers. The PILs tax savings is the result of the rate rider cash refund to customers:

- DR 2294 Accrual for Taxes, “Payments in Lieu of Taxes”, Etc.
- CR 6110 Income Taxes
- DR 4080 Distribution Services Revenue
- CR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account

E. Record the actual sale of the property, net of taxes (assuming a net gain).

- DR 1005 Cash
- DR XXXX Accumulated Depreciation of PP&E (various accounts – depends on type of asset)
- CR XXXX Property, plant and equipment (various accounts – depends on type of asset)
- CR 2294 Accrual for Taxes, “Payments in Lieu of Taxes”, Etc.
- CR 4355 Gain on Disposition of Utility and Other Property

F. Record the reclassification of the actual net after-tax gain to Account 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account

- DR 4355 Gain on Disposition of Utility and Other Property
- CR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account

G. Record the carrying charges based on the net of the balances in Account 1508 subaccount OCCP Gains Variance Account and Account 1508 subaccount Regulatory Deferred Gain on Disposal (Rate Rider Account). The carrying charges are determined using simple interest applied on the monthly net opening balances:

- DR 6035 Other Interest Expense / CR 4405 Interest and Dividend Income
- CR/DR 1508 Other Regulatory Assets, Subaccount OCCP Gains Variance Account Carrying Charges

5. VARIANCE ACCOUNT FOR 2015 OPENING RATE BASE TO CAPTURE PRUDENCE-BASED ICM DISALLOWANCES – ACCOUNTING ORDER

At this time, the ICM True-up process has not been completed. As such, differences in the amount of ICM-eligible work that should be included in the 2015 opening rate base could occur as a result of the OEB’s findings during that process. This variance account will capture any differences between amounts included in 2015 rate base and any revenue requirements associated with disallowances based on prudence that may result from the ICM True-Up. Specifically, this variance account will track the revenue requirement impact of any capital in-service additions and the related depreciation expense included in the 2015 revenue requirement through the CIR Decision that are found to be imprudent in the ICM True-Up.

Carrying charges will apply to the opening revenue requirement balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508 Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account
- Account 1508, Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record the revenue requirement associated with disallowed rate base:
   - DR 4080 Distribution Services Revenue
   - CR 1508 Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account

B. To record the carrying charges in subaccount THESL ICM True-Up Revenue Requirement Variance Account:
   - DR 6035 Other Interest Expense

- CR 1508 Other Regulatory Assets, Subaccount THESL ICM True-Up Revenue Requirement Variance Account Carrying Charges

6. VARIANCE ACCOUNT FOR CAPITAL-RELATED REVENUE REQUIREMENT (CRRRVA) – ACCOUNTING ORDER

In order to address the possibility that Toronto Hydro may not bring its entire capital program in-service during the CIR Period, Toronto Hydro will record in a variance account the variance between the cumulative 2015 to 2019 capital related revenue requirement included in rates and the actual capital in-service additions related revenue requirement over the period. Toronto Hydro will record the variance on a cumulative basis to ensure that Toronto Hydro has the flexibility to optimize the implementation of its capital investment strategy, which may involve shifting the timing of project spending within the CIR Period.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following Variance Accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record the difference between the cumulative 2015 to 2019 capital related revenue requirement included in rates and the actual capital in-service additions related revenue requirement over the period (see note 1 below):
    - o DR 4080 Distribution Services Revenue

- CR 1508 Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account

B. To record the carrying charges in subaccount Capital Related Revenue Requirement Variance Account:
  - DR 6035 Other Interest Expense
  - CR 1508 Other Regulatory Assets, Subaccount Capital Related Revenue Requirement Variance Account Carrying Charges

Note:

1. Capital Related Revenue Requirement Variance Account calculation: Record the net of:
   i. The approved revenue requirement associated with the cumulative 2015 to 2019 capital related revenue requirement;
   AND
   ii. The actual capital in-service additions related revenue requirement over the period.

This account will be asymmetrical in nature.

7. OTHER POST-EMPLOYMENT BENEFITS (OPEBS) CASH VERSUS ACCRUAL VARIANCE ACCOUNT – ACCOUNTING ORDER

The OEB has initiated an industry-wide policy consultation on rate-regulated utility OPEBs. Pending a final conclusion on the treatment of OPEBs, for ratemaking purposes, the OEB requires Toronto Hydro to calculate recovery for OPEBs using cash payments instead of the accounting cost calculated under the accrual method. As such, Toronto Hydro will record in a variance account the difference between (i) the forecasted OPEBs costs related to Toronto Hydro's OM&A programs using the accounting accrual method and (ii) the OPEBs cash payments made to the plan.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Other Post-Employment Benefits Cash vs Accrual Variance Account

The sample accounting entry for the variance accounts are provided below.

A. To record the difference between the forecasted OPEBs costs and the OPEBs plan payments made:
    - DR 1508 Other Regulatory Assets, Subaccount Other Post-Employment Benefits Cash vs Accrual Variance Account
    - CR 5646 Employee Pensions and OPEB

8. EARNINGS SHARING MECHANISM (ESM) VARIANCE ACCOUNT

Toronto Hydro shall establish an account to record amounts related to any earnings outside of Toronto Hydro's approved annual return on equity (ROE) exceeding a +/- 100 basis-point dead band, to be shared on an equal basis between Toronto Hydro and its ratepayers. The earnings variance will only arise from differences between the non-capital related revenue requirement embedded in rates and the actual non-capital related revenue requirement. The ratepayer share of the earnings shall be grossed up for any tax impacts and credited to this account.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record half (50%) of the amounts related to any earnings outside of Toronto Hydro’s approved ROE +/- 100 basis points:
    - DR 4080 Distribution Services Revenue
    - CR 1508 Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account

B. To record the carrying charges in subaccount Earnings Sharing Mechanism Variance Account:
    - DR 6035 Other Interest Expense
    - CR 1508 Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account Carrying Charges

Rate Riders Development

	% to split by Class	**Total**	**Residential**	**CS Muti-Units Residential**	**GS < 50 kW**	**GS - 50 to 999 kW**	**GS > 1,000 to 4,999 kW**	**Large User =>5,000 kW**	**Street Lighting**	**USL (Connections)**	**USL (Customer)**
	Allocators										
	2016 kWh	100.0%	20.0%	0.9%	9.6%	40.6%	19.4%	8.8%	0.5%	0.2%	0.0%
	2017 Distribution Revenue	100.0%	39.7%	3.7%	14.2%	27.0%	8.5%	4.4%	2.0%	0.5%	0.0%
	2020 Revenue Offsets	100.0%	49.2%	4.0%	20.4%	18.3%	3.5%	1.5%	2.3%	0.8%	0.0%
	2009/10 Reg Assets Allocation	100.0%	18.2%	0.7%	8.2%	42.4%	19.6%	10.2%	0.5%	0.2%	0.0%
	2013 Non-RPP kWh	100.0%	2.1%	0.0%	2.4%	48.3%	31.0%	15.4%	0.8%	0.0%	0.0%
	LRAMVA	100.0%	7.2%	0.3%	29.8%	48.2%	7.3%	7.3%	0.0%	0.0%	0.0%
	2013 SM Entity Rider Recovery	100.0%	85.2%	5.2%	9.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Stranded Meters	100.0%	51.4%	0.0%	31.8%	16.8%	0.0%	0.0%	0.0%	0.0%	0.0%
	2020 kWh forecast	100.0%	19.3%	1.2%	9.7%	41.0%	19.5%	8.6%	0.5%	0.2%	0.0%
	Monthly Billing Conversion	100.0%	89.6%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distribution Revenue GS>50 kW	100.0%	0.0%	0.0%	0.0%	63.6%	20.0%	10.5%	4.7%	1.2%	0.0%
	AR Credits	100.0%	83.5%	0.0%	15.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Other Allocators 9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

	RA Balance by Class	**Allocators (Drop Down)**	**Total**	**Residential**	**CS Muti-Units Residential**	**GS < 50 kW**	**GS - 50 to 999 kW**	**GS > 1,000 to 4,999 kW**	**Large User =>5,000 kW**	**Street Lighting**	**USL (Connections)**	**USL (Customer)**
1	Stranded Meters	Stranded Meters	- 1,387,244	- 713,195	-	- 441,086	- 232,962	-	-	-	-	-
2	Wireless pole attachments Rev	2020 Revenue Offsets	- 642,230	- 316,243	- 25,559	- 131,157	- 117,558	- 22,533	- 9,534	- 14,644	- 5,003	-
3	Impact for USGAAP (Actuarial loss on OPEB)	2017 Distribution Revenue	85,260,576	33,832,134	3,161,726	12,064,619	23,036,048	7,256,312	3,784,727	1,690,071	434,940	-
4	IFRS-CGAAP PP&E	2017 Distribution Revenue	- 1,558,360	- 618,371	- 57,789	- 220,512	- 421,044	- 132,628	- 69,176	- 30,890	- 7,950	-
5	CRRRVA	2017 Distribution Revenue	- 59,426,130	- 23,580,802	- 2,203,705	- 8,408,970	- 16,055,993	- 5,057,608	- 2,637,933	- 1,177,969	- 303,151	-
6	Monthly Billing (OpEx)	Monthly Billing Conversion	15,845,692	14,205,293	-	1,640,399	-	-	-	-	-	-
7	Monthly Billing	Monthly Billing Conversion	- 4,041,544	- 3,623,150	-	- 418,394	-	-	-	-	-	-
8	External Driven Capital	2017 Distribution Revenue	- 2,331,134	- 925,014	- 86,446	- 329,862	- 629,835	- 198,397	- 103,479	- 46,209	- 11,892	-
9	OPEB cash vs accrual	2017 Distribution Revenue	8,945,000	3,549,453	331,708	1,265,743	2,416,796	761,286	397,070	177,312	45,631	-
10	Derecognition	2017 Distribution Revenue	- 42,070,982	- 16,694,129	- 1,560,122	- 5,953,166	- 11,366,908	- 3,580,555	- 1,867,536	- 833,949	- 214,617	-
11	Deferred Gain on disposals	2017 Distribution Revenue	- 11,749,417	- 4,662,270	- 435,705	- 1,662,577	- 3,174,505	- 999,963	- 521,558	- 232,902	- 59,937	-
12	Operations Consolidation Plan Sharing Variance	2017 Distribution Revenue	- 71,134,277	- 28,226,696	- 2,637,879	- 10,065,706	- 19,219,347	- 6,054,058	- 3,157,659	- 1,410,053	- 362,878	-
13	Excess Expansion Deposits	Distribution Revenue GS>50 kW	- 5,473,272	-	-	-	- 3,482,742	- 1,097,057	- 572,200	- 255,516	- 65,757	-
14	AR Credits	AR Credits	- 3,407,868	- 2,844,480	-	- 510,430	- 52,044	- 415	-	-	- 499	-
	Total		- 93,171,192	- 30,617,471	- 3,513,770	- 13,171,100	- 29,300,095	- 9,125,615	- 4,757,278	- 2,134,750	- 551,113	

Note: The rate riders table (Exhibit 9, Tab 3, Schedule 1) lists all forecasted regulatory account balances proposed for clearance by THESL over the 2020-2024 period ($93.2M). The other two schedules are subsets of this list. The summary of amounts proposed for disposition of $78.0 million (Exhibit 9, Tab 1, Schedule 1) excludes accounts for which balances are not expected to recur. The continuity schedule total of $69.6 million (Exhibit 9, Tab 2, Schedule 1) lists only the regulatory accounts previously approved by the OEB for tracking.

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