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February 12, 2024 **VIA E-MAIL**

Ms. Nancy Marconi
Registrar (registrar@oeb.ca)
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: EB-2023-0195 – Toronto Hydro-Electric System Limited (THESLL or Toronto Hydro)
Custom Rate Application for rates beginning January 1, 2025
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached the interrogatories of VECC in the above-noted proceeding. We have also directed a copy of the same to the Applicant.

Yours truly,

Mark C. Garner

Digitally signed by Mark C. Garner
Date: 2024.02.12 18:50:36 -05'00'

Mark Garner
Consultants for VECC/PIAC

Email copy:
Daliana Coban, Director, Regulatory Applications & Business Support
RegulatoryAffairs@TorontoHydro.com

REQUESTOR NAME	**VECC**
TO:	**Toronto Hydro-Electric System Limited (THESL or Toronto Hydro)**
DATE:	**February 12, 2024**
CASE NO:	**EB-2023-0195**
APPLICATION NAME	**2025 Custom Rate Application**

1.0 ADMINISTRATION (EXHIBIT 1B)

1.0-VECC-1

Reference: Exhibit 1B, Tab 2, Schedule 1, page 13

"*Under a standard IRM scenario, Toronto Hydro's 2025-2029 capital investment plan would be underfunded by approximately 35 percent or $1.5 billion*."

a) Please provide the model, calculations and assumptions which support this statement. Specifically show which capital categories are assumed to be reduced under a lower capital spending plan.

1.0-VECC-2

Reference: Exhibit 1B,Tab 2, Schedule 1, page 13

"*Adoption of a plan constrained by this funding envelope would force the utility into a sustainment plan that would be almost entirely reactive in nature, resulting in roughly an 8 percent deterioration in system reliability by the end of the rate period,*."

a) Please provide the model, calculations and assumptions which derive an 8% system reliability deterioration noted in this reference.

1.0-VECC-3

Reference: Exhibit 1B,Tab 3, Schedule 1, page 2

a) How was the 0.6 ($65 million) value for PIM amount chosen?

1.0-VECC-4

Reference: Exhibit 1B, Tab 2, Schedule 1, page 32

"*Only if the set performance targets are achieved (or forecasted be achieved with a high degree of confidence) by the end of the rate term would the incentive be recovered from customers in the next decade. As such, Toronto Hydro confirms that that there would be no rate recovery associated with the PIM in the 2025-2029 period*."

a) The PIM mechanism may create issues with respect to intergeneration inequities in that the cost (incentive) is recovered in the period after which the efficiencies are achieved. Is this correct? If so how is/could this issue be addressed or mitigated?

1.0-VECC-5

Reference: Exhibit 1B, Tab3, Schedule 1, page 8

"*Toronto Hydro proposes to remove the Scheduled Outages cause code from its 2025-2029 custom SAIDI performance measure for two reasons: (1) major forecasting uncertainty caused by the ongoing implementation of Oracle's Utility Analytics ("OUA"), and (2) the utility expects Scheduled Outages to increase in the 2025-2029 period as the result of a larger work program*."

a) Please confirm (or correct) that the proposal for the PIM measurement includes scheduled outages (as per Table 1 at 1B/T3/S1/pg.7).

b) Given THESL's aggressive capital plan for the rate period could lead to more customer interruptions, what mechanisms are being employed to ensure that customers do not endure more and scheduled outages than during the last rate plan?

c) In its customer engagement did THESL explain that more or longer scheduled outages might occur as a result of implementing the plan? If so, please provide the references which show customers' acceptance of that in order to support the more aggressive capital plan.

1.0-VECC-6

Reference: Exhibit 1B, Tab 3, Schedule 1, pg. 7 Table 1

a) THESL' proposed PIM Scorecard differs from the Board specified Electricity Distributor Scorecard (EDS). Why? Specifically what advantages does THESL see in using its customized scorecard as opposed to adopting the EDS for the PIM?

b) None of the PIM measures provide performance comparability with other electricity distributors in Ontario. For example, with respect to service reliability there are no metrics which would compare THESL performance with, for example adjoining utilities like Alectra, or similar aging utilities like London Hydro or Hydro Ottawa.. Did THESL undertake any studies which compare its performance to other utilities? Specifically, has THESL performed any analysis which compares THESL productivity or service quality performance over the past five years with any other individual or group of Ontario utilities?

1.0-VECC-7

Reference: Exhibit 1B, Tab 3, Schedule 2, pg. 13 /Schedule 3, page 31

"*As the sub-metering market has become more mature in Toronto over the last decade, a greater share of new multi-unit buildings is opting for bulk-metering service connections. The practical effect of operating in this urban environment with a deregulated sub-metering market is a slower rate of formally reported customer growth from 2013 to 2022, which is putting artificial upward pressure on cost performance metrics like Total Cost Per Customer and Total Cost per km of Line*."

a) Does THESL provide sub-metering services in competition with other service providers in Ontario?

b) If yes, are any sub-metering costs included in this application for recovery from ratepayers?

c) It is unclear to us why sub-metering would result in higher costs per customers. For example, presumably THESL avoids the cost of individual metering, meter reading, line connection and other high cost activities associated with individual metered customers. Conversely bulk metered customers are a lower cost to serve. The result would be that while the number of residential units is increasing in the average costs to THESL of serving those customers is also decreasing. In any event, what evidence/studies does THESL have to demonstrate that sub-metering (all other things being equal) results in a higher, rather than lower, or unchanged cost per customer?

d) A similar insinuation of costs per customer is made at Schedule 3 which notes that Toronto Hydro provides an average of 31.8 MWh per customer, more load per customer relative to the peer group of utilities who have a multi-year average of 23.6 MWh. The evidence ascribes this relative difference to the proliferation of high rises. However, it is not clear why this is a relevant consideration if one assumes that there is a lower cost of delivered power for utilities with a greater proportion of bulk metered units. Please provide the studies that THESL relies upon to support its contention that higher density of customers is a more costly delivery model than lower density service.

1.0-VECC-8

Reference:Exhibit 1B, Tab 3,Schedule 2, pg.19 / Decision EB-2023-0143

"*In this regard, the OEB notes that the incremental costs of locates activity anticipated to be triggered by Bill 93 will not be limited to a 12-month period as is typically associated with a Z-factor event and as set out in the OEB's Chapter 3 Filing Guidelines.6 The account will be in place for each utility until their next rebasing application, to be reviewed for disposition as part of that application, unless large balances have accrued that may require disposition in an IRM year.*

a) Does this application incorporate an estimate for the costs of Bill 93 as contemplated by the Board's Decision for utilities in a rebasing application?

1.0-VECC-9

Reference: Exhibit 1B, Tab 3, Schedule 3

a) Does THESL's customer call/contact operations produce a monthly or annual report. If yes, please provide the reports for 2022 and 2023. If not, please explain what reporting is provided to senior and executive management with respect to customer contacts.

b) What proportion (annually) of customer contacts come from sub-metered electricity users. Are these calls generally referred back to the sub-meter entity?

1.0-VECC-10

Reference: Exhibit 1B, Tab 3, Schedule 3, Section 4.7 AFB Benchmarking

a) For each of the AFB benchmarks shown at section 4.7 in tables 10 through 18 please provide a summary table showing the 2018-2022 THEL average and for the same period the associated Ontario distributor average.

1.0-VECC-11

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A Clearspring

"*To make this congested urban variable time variant, Clearspring gathered the number of high-rise skyscrapers at or above 100 metres for each year and for each city served within the U.S. sample and Toronto*."

a) Is the "urban" variable composed entirely of 100 metre (30 story) buildings? If not please provide a description of the other data used as part of the urban variable.

b) Does this variable include data from Canadian cities other than Toronto?

c) What adjustment is made to capture potential differences between high rise buildings which are themselves congested and isolated high rise buildings. That is, how is the difference between isolated building distinguished between multi-complex developments?

d) High rise developments are also often associated with transportation infrastructure improvements, for example in Toronto along the new Eglington LRT. Such developments can allow an opportunity for utilities to replace infrastructure at lower costs due to multi-party sharing of costs.

How is this phenomenon captured in the “urban” variable.

e) The ‘urban” variable captures the correlation as between the change in high-rise buildings and what specific costs?

f) Ontario allows for third party suite metering in high rise developments. Do all or any of the other jurisdictions which are in the data set do the same? Does Clearspring’s model/data capture the relative proportion of suite metered high rises?

2.0 RATE BASE AND CAPITAL (EXHIBIT 2)

2.0-VECC -12

Reference: Exhibit 2B, Section A3.4

a) THESL highlights the potential for incremental costs due to climate change in this section. While the section emphasis negative extreme weather impacts (e.g. severe storms) it does not discuss any offsetting benefits. For example, with milder weather there may be fewer severe snow days or fewer freezing rain days. Such a phenomena might be amplified by Toronto’s proximity to Lake Ontario and the amount by which it has a winter freeze over. Has THESL studied the number of days of severe snowfall (e.g., snow in excess of 5cm in a 24 hour period) or the number of days with severe freezing rain (e.g. accumulating as opposed to non-accumulating freezing rain) or other aspects of weather which affect distribution service?

b) It is unclear to us the relevance Figure 4 – Cumulative rainfall. Why is the annual cumulative rain amount of importance? The descriptive evidence speaks to weather severity (i.e., the amount of rain in a 24 hour period). Please clarify.

c) While climate change has an effect of whether so do other phenomena, for example the El Nino and La Nina Pacific Ocean oscillations. How are these other weather effects taken into account in THELS’ analysis of the data attempting to correlate weather risk to distribution system risk?

d) Please provide the number of outages due to Adverse Weather, Lightning, and Tree Contacts for the period shown in Figure 4 -1998 to 2022.

e) Please provide the number of Major Event Days (MEDs) for the period 1998 to 2022.

2.0-VECC -13

Reference: Exhibit 2B, E5.4

a) Please provide a table showing the number of new meters installed and, separately, the number of meters reverified/resealed for the residential and GS<50 rate classes

b) THESL notes that most smart meters were installed between 2006 and 2008 (E5.4.3.3). What strategy is the Utility employing in order to avoid a repeat of the "bunching up" of expired meters as has occurred due to concentrating meter replacements within a short time frame?

2.0-VECC -14

Reference: Exhibit 2C, E5.3

Table 5: Station Buses Planned for Relief within 2025-2029

Station	Bus	Estimated Load to Transfer (MVA)	Area
Basin	*A7-8*	15 – 25	Downtown
Bathurst	*J&Q*	5 – 20	Horseshoe
Bermondsey	*B&Y*	10 - 25	Horseshoe
Bridgman	*A1-2B*	5 -15	Downtown
Copeland	*A1-2CX*	5 – 15	Downtown
Dufferin	*Note 1*	5 – 15	Downtown
Esplanade	*Note 2*	10 - 20	Downtown
Fairbank	*B & Q*	15 – 30	Horseshoe
Finch	*B&Y, J&Q*	25 - 55	Horseshoe
Horner	*B&Y*	25 - 40	Horseshoe
Leslie	*B&Y*	25 – 40	Horseshoe
Manby	*B&Y, Q&Z*	20 - 50	Horseshoe
Rexdale	*B&Y*	5 - 20	Horseshoe
Runnymede	*J&Q*	15 – 30	Horseshoe
Sheppard	*E&Z*	5 – 20	Horseshoe
Terauley	*Note 2*	10 - 20	Downtown
Windsor	*Note 2*	10 - 20	Downtown

Table 5: Station Buses Planned for Relief within 2020-2024 FROM: EB-2018-0165 Section E5.3

Station	Bus	Target Year	Estimated Load to Transfer (MVA)	Planned Transfer Type
Cecil	*A5-6CE*	2020	2.5 - 10	Downtown Intra-station
Wiltshire	*A5-6W*	2020	5 - 20	Downtown Intra-station
Esplanade	*A1-2X*	2023, 2024	5 - 20	Downtown Inter-station
Basin	*A5-6BN*	2022, 2023	10 - 40	Downtown Inter-station
Horner	*B&Y*	2022, 2023	10 - 40	Horseshoe
Strachan	*(Note 1)*	2023,2024	5 - 20	Downtown Inter-station
Manby	*Q&Z, V&F*	2024	10 - 40	Horseshoe
Windsor	*(Note 2)*	2023,2024	5 - 20	Downtown Inter-station

a) Please confirm or correct that the Station Buses for Basin, Esplanade, Horner, Manby and Windsor are the same (or substantively the same) in both tables.

b) Specifically identify what costs related to these station buses are incremental to the work planned in the prior DSP and what amounts in the new DSP are for work that was not completed as previously planned.

2.0-VECC -15

Reference: Exhibit 2, E6 Area Conversions

Table 11: Planned Rear Lot Projects for 2025-2029

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2022)	Number of Outages Greater than 5 Hours (2012-2022)
Thorncrest Phase 12	147	2025	1	0
Markland Woods	285	2025-2026	17	8
Martin Grove Gardens	307	2025-2027	7	2
Willowridge	201	2027-2028	11	3
Mount Olive	61	2027-2028	2	2
Kingsview	156	2028-2029	11	2
Eringate Centennial-West Deane	130	2028-2029	18	2
Richview Park	263	2028-2029	1	0

a) Please provide a table showing for the period 2020 through 2023 the number of non-momentary outages in backlots which excludes MEDs.

b) Please show the same as a) but for the period 2012 through 2019.

c) Please provide the budgeted capital cost for each of the projects listed in Table 11. Please clarify which of these projects entails replacement of rear lot with underground plant.

2.0-VECC -16

Reference: Exhibit 1B, Tab 3, Schedule 1/ Exhibit 2B, Section C Reliability Performance

a) Please provide the annual audit reports completed by or for the ESA under Ontario Regulation 22/04 for each year 2020 through 2023.

2.0-VECC -17

Reference: Exhibit 1B, Tab 3, Schedule 1, pg. 8 /Exhibit 2B, Section C, DSP pgs. 5-6

"*Toronto Hydro proposes to remove the Scheduled Outages cause code from its 2025-2029 custom SAIDI performance measure for two reasons: (1) major forecasting uncertainty caused by the ongoing implementation of Oracle's Utility Analytics ("OUA"*)"

"*Toronto Hydro upgraded its existing Outage Management System with Oracle's Network Management System ("NMS"). This new system provides Toronto Hydro with more robust data and enhanced visibility into near real-time system events. As part of the multi-year NMS upgrade initiative, Toronto Hydro is implementing a new commercial solution, Oracle's Utility Analytics ("OUA"), which will serve as the future successor to IT IS*"

Furthermore, the following changes are expected over the course of the multi-year upgrade, leading to more interruptions being captured in 2023 to 2029

1. Increased number of outages affecting a small number of customers.

2. Improved resolution of outage duration, down to the second.

3. Increased number of scheduled outages reported; and

4. Changes in outage structuring: currently, outages are structured manually, typically broken down by feeder. OUA will streamline this process by automatically generating outage reports based on restoration actions recorded in NMS.

a) Please clarify which aspect of the OUA replacement project interfere with the use of scheduled outage duration or frequency as a metric for the proposed PIM?

b) If the conversion to a new outage management system is ongoing in the 2024 through 2026 period will this interfere with an effective evaluation of those programs later? That is if THESL is unable to appropriately monitor outages until it has fully implemented OUA then why is it not best to defer some capital spending until such time as that system is fully operational?

2.0-VECC -18

Reference: Exhibit 2B, Section C, pgs. 15-

a) Presumably customers are concerned with the duration of outages irrespective of their reason and especially if the outage is a matter within THESL's ability to address. The PIM measure for Outage Duration excludes Scheduled Outages. Why?

b) Are there any other measures used by THESL to gauge the response capability/efficiency of outage recovery?

c) With respect to scheduled outages are planned projects provided guidelines or expectations for maximum outage time? If so, please provide or explain the process that is used to ensure that a given project meets the expected outage time.

2.0-VECC -19

Reference: Exhibit 2B, E7

a) THES is proposing to a significantly more expense system enhancement program that in the past (26.3M vs $151.2M). What metrics, statics or measurable outcomes is the Utility employing to judge the success of this initiative?

b) How would THESL prioritize projects if faced with a 20% reduction in the annual amount expended on this capital program segment.

2.0-VECC -20

Reference: Exhibit 2B, E8

a) We are unable to locate any budget costing for the closure and relocation of EDC1. Please provide the current budget which shows separately, the budgeted cost of land, building, furnishings, incremental IT equipment (as separate from equipment to be moved) and other major project components. Please also clarify the time frame over which the project is expected to be completed (i.e. land acquisition, building, move-occupation).

b) Is there expected to be proceeds from the sale of the current EDC 1 location?

c) Are there any plans to relocate or refurbish EDC 2 during the rate plan period?

3.0 OPERATING REVENUE (EXHIBIT 3) – LOAD AND CUSTOMERS

3.0-VECC -21

Reference: **Exhibit 3, Tab 1, Schedule 1, pages 1-2**

Preamble: The footnotes to Table 1 state:

"*Total Customers are an annual average and exclude street lighting devices and unmetered load connections*."

a) Please confirm that by "annual average" THESL means the average of the 12 monthly values for each year.

b) Please confirm that the annual totals reported in Table 1 include the Street Lighting and USL classes based on the number of customers (not connections) for each of these classes.

3.0-VECC -22

Reference: **Exhibit 3, Tab 1, Schedule 1, page 4**
Exhibit 3, Tab 1, Schedule 1, Appendices H and I

a) Please explain why the regression model used to forecast the Residential customer count was developed using historic data starting in April 2013 and did not use any data for the months prior to that.

b) With respect to the Residential customer count model, please explain the basis for the Seasonality variable and the rationale for its inclusion.

c) With respect to the Residential customer count model, please provide a schedule that compares the actual average annual customer count for each of the years 2013-2022 with the predicted values based on THESL's regression model. (Note: For 2013 please use the actual vs. predicted average monthly values for April through December).

d) What is the source of the historic monthly population data used to develop the Residential and GS<50 customer count models?

3.0-VECC -23

Reference: **Exhibit 3, Tab 1, Schedule 1, page 4**
Exhibit 3, Tab 1, Schedule 1, Appendices A, H and I

a) Please explain why the regression models used to forecast the GS<50 and GS 50-999 customer counts were developed using historic data starting in February 2015 and did not use any data for the months prior to that.

b) With respect to the GS<50 customer count model, please provide a schedule that compares the actual average annual customer count for each of the years 2015-2022 with the predicted values based on THESL' regression model. (Note: For 2015 please use the actual vs. predicted average monthly values for February through December).

c) With respect to the GS 50-999 customer count model, please provide a schedule that compares the actual average annual customer count for each of the years 2015-2022 with the predicted values based on THESL's regression model. (Note: For 2015 please use the actual vs. predicted average monthly values for February through December).

d) What is the source of the historic monthly employment data used to develop the GS 50-999 customer count model?

e) Please provide the Conference Board of Canada (CBoC) document with the forecast monthly employment and population values used by THESL and demonstrate that the historic employment and population data used in the development of the models are consistent with the CBoC's forecasts for these variables.

f) Does the City of Toronto develop/produce population forecasts for use in its planning processes? If yes, please provide the City of Toronto's most recent population forecast and the associated reference document.

g) In Appendix A (Columns S and U), are the GDP and Employment values meant to be those for the City of Toronto?

h) For the GS 50-999 customer count model, were population and GDP also tested as explanatory variables? If yes, why were they rejected? If not, please provide the resulting regression model and statistics where population or GDP are used as an explanatory variable as opposed to employment.

3.0-VECC -24

Reference: Exhibit 3, Tab 1, Schedule 1, page 4
Exhibit 3, Tab 1, Schedule 1, Appendices A, H and I

a) For each of the Residential, GS<50 and GS 50-999 customer classes please provide a schedule (i.e., a working excel file) that sets out the calculation of the 2023 to 2029 monthly (and resulting annual) customer count forecast using the forecast values for each class model's explanatory variables and the coefficients from the regression models in Appendix I.

b) For each of the Residential, GS<50 and GS 50-999 customer classes please provide a schedule that sets out the predicted monthly customer count values for 2023 versus the actual monthly customer counts for all months where actual data is available.

3.0-VECC -25

Reference: **Exhibit 3, Tab 1, Schedule 1, page 4**

Eb-2018-0165, Exhibit 3, Tab 1, Schedule 1, page 16

Preamble: The current Application states:

"*The customer forecast for GS 1000-4999 kW, Large Use, CSMUR, and Street Lighting rate classes are based on market knowledge of construction in Toronto Hydro's service area, as well as an application of expert judgement. Toronto Hydro regularly communicates with developers, municipal representatives and commercial and residential associations to identify new larger connection projects and their expected connection years.*

The EB-2018-0165 Application stated:

"The utility's forecast of new customers is primarily based on extrapolation models for each rate class with the exception of the CSMUR rate class (implemented on June 1, 2013), whose forecast customer additions are based on market knowledge of suite metering and multi-unit dwelling construction in Toronto Hydro's service area, as well as an application of expert judgement."

a) Please provide a schedule that sets out: i) THESL's forecast average customer count for the CSMUR class for each of the years 2018-2022 per EB-2018-0165 and ii) the actual average annual customer count for the CSMUR class for the same years.

b) Please describe the typical planning/construction lead times for customers in each of the GS 1000-4999 kW, Large Use, CSMUR, and Street Lighting rate classes.

c) For each of these customer classes, please comment on whether planning/construction lead times are sufficiently long that THESL can rely on current "market intelligence/knowledge" to predict new customer additions out to 2029 (i.e., how far into the future can current market knowledge be expected to provide a reasonable estimate of future customer additions for each of these classes)? If not, how has THESL addressed this issue in developing the customer count forecasts for these classes?

d) Please explain the reason for the decline in the GS 1,000-4,999 customer count in 2022 (e.g., is it the result of customer reclassification?).

e) Please explain why THESL expects the GS 1,000-4,999 customer count to continue to decline annually in 2023, 2024 and 2025.

f) Please explain the annual change in the Large Use customer count (relative to the preceding year) for each of the years 2023 to 2029 as the values fluctuate up and down during this period.

3.0-VECC -26

Reference: Exhibit 3, Tab 1, Schedule 1, page 9

Preamble: The Application states:

"*All of Toronto Hydro's regression models use monthly kWh per day as the dependent variable and monthly values of independent variables from July 2002 through to the latest actual values (December 2022) to determine the monthly regression coefficients*."

a) Please explain why July 2022 was used as the starting point for the data used to estimate THESL's regression models.

3.0-VECC -27

Reference: Exhibit 3, Tab 1, Schedule 1, pages 9-10, 17 (Table 4) and Appendix B

Preamble: The Application states:

"*Positive dew point temperature is another type of weather factor included as an explanatory variable for the CSMUR, GS <50 kW, GS 50-999 kW, and GS 1000-4999 kW customer classes." (pg. 9)*

"The forecast for heating and cooling degree-days, and positive dew point temperature inputs is based on a ten-year historical average of HDD, CDD, and positive dew point."

a) Please explain why "positive dew point temperature" was not used as an explanatory variable for the Residential model.

b) At page 9 the Application states that positive dew point temperature was used as an explanatory variable for the GS<50 class. However, positive dew point temperature is not identified as an explanatory variable for the GS<50 class in either Table 4 or Appendix B. Please reconcile.

c) At page 9 the Application does not identify positive dew point temperature as an explanatory variable for the Large Use class. However, positive dew point temperature is identified as an explanatory variable for the Large Use class in either Table 4 or Appendix B. Please reconcile.

d) What 10 year period was used to determine the weather normal values for HDD, CDD, and positive dew point?

3.0-VECC -28

Reference: Exhibit 3, Tab 1, Schedule 1, page 17 (Table 4) / Appendix B

a) Table 4 and Appendix A indicate that the Residential and GS 50-999 class models are the only ones that employ a "blackout binary" variable. Please explain why this variable was not used for the other customer classes.

3.0-VECC -29

Reference: **Exhibit 3, Tab 1, Schedule 1, pages 15, 17 (Table 4) and Appendices A & B**

Preamble: The Application states:

"*Load impacts from the COVID-19 pandemic are captured through a lockdown binary variable. This variable is based on the provincial lockdown periods announced during the pandemic in 2020-2021. Additional load impacts from the pandemic are captured through the economic variables used in the model, such as GDP. The lockdown binary variable was found to be statistically significant in the Residential, GS <50 kW, GS 50-999 kW, and Large Use class models*."

a) Please confirm that, per Appendix A, the lockdown periods used were April & May 2020; January & February 2021 and April & May 2021.

b) Please explain the basis on which these "lockdown" months were identified.

c) At page 15 the Application identifies the Residential class model as using a lockdown binary variable. However, neither Table 4 nor Appendix B do so. Please reconcile.

3.0-VECC -30

Reference: **Exhibit 3, Tab 1, Schedule 1, pages 15-16, 17 (Table 4) and Appendices A & B**

Preamble: The Application states (pages 15-16):

"*The time trend variables used in the model are designed to capture trends which are not otherwise explained by the other driver variables, as well as to improve the overall model fit over the period. The Residential, GS<50 kW, and Large Use classes use a linear spline time trend in the 2012 to 2022 period, the General Service 1,000-4,999 kW class uses a linear spline time trend in the 2018 to 2022 period, and the GS 50-999 kW uses a simple time trend over historical period 2018 to 2022*."

a) To what factors does THESL attribute the statistical significance in the models for the Residential, GS<50 and Large Use classes of a time trend variable that increases monthly over the period 2002 to 2011 but is then constant for the period 2012 – 2022?

b) Why is it reasonable to use constant value for the 2023-2029 monthly value for the time trend variable in the Residential, GS<50 and Large Use class models?

c) To what factors does THESL attribute the statistical significance in the GS 1,000-4,999 class model of a time trend variable that is constant over the period 2002 to 2017 but then increases monthly over the period 2018 – 2022?

d) Why is it reasonable to assume the time trend variable for the GS 1,000-4,999 class will continue to increase over the 2023-2029 period?

e) To what factors does THESL attribute the statistical significance in the GS 50-999 class model of a time trend variable that increases monthly over the period 2002 to 2017 but is then constant for the period 2018 – 2022?

f) Why is it reasonable to use a constant value for the 2023-2029 monthly values for the time trend variable in the GS 50-999 class model?

3.0-VECC -31

Reference: **Exhibit 3, Tab 1, Schedule 1, page 12 and Appendices A & C**
EB-2018-0165, 3-VECC 25 b) & d)

Preamble: The Application states:

"*Toronto Hydro incorporated CDM variables into the multivariate regression: a residential CDM variable for the Residential class, and a business CDM variable for the General Service classes. Both variables are based on the cumulative historical and forecast level of savings from 2006 to 2029, and separated by residential and business program savings for each variable respectively*."

a) Please confirm that, for purposes of the load forecast models, THESL assumed that there was no reduction in the persistence of CDM savings after the first year (i.e. the first years saving continue on in perpetuate). If confirmed, please explain why this is reasonable assumption for DR programs.

b) Please confirm that the savings reported/verified by the IESO are full year savings for each project aggregated to a total and, as such, do not account for the implementation of projects throughout their first year (per VECC 25 d)).

c) Please confirm that, unlike in EB-2018-0165, THESL has not made any adjustments to account for the fact that in the first year the CDM savings realized will be less than the annualized value.

d) If part c) is confirmed, please revise the values for the CDM variables used to reflect this fact, re-estimate the regression models and provide a revised forecast by customer class for 2023-2029.

3.0-VECC -32

Reference: Exhibit 3, Tab 1, Schedule 1, page 12 and Appendix C

a) In Appendix C – Monthly Savings Tab, for 2008 the sum of the Residential monthly values up to December 2008 (Sum of D3 through D80 and F3 though F80) is 249,714.87. However, the cumulative December 2008 value for Residential in Column H is 249,521.8 (Cell H80). Please reconcile.

b) There appear to be similar issues in terms of discrepancies in 2009 and subsequent years through to 2022 for both Residential and Business CDM savings as between the sum of the individual monthly values (columns D and F for Residential and columns E and G for Business) and the reported cumulative values in columns H and I respectively. Please reconcile.

c) Based on the above please revise the CDM inputs to the regression models as necessary, re-estimate the regression models and provide a revised forecast by customer class for 2023-2029.

3.0-VECC -33

Reference: Exhibit 3, Tab 1, Schedule 1, page 13 and Appendices C & D
Preamble: Appendix C reports the following THESL annual savings for 2015-2017:

		Gross Energy Savings - EE		Gross Energy Savings - DR		
Year	Source(s)	Residential	Business	Residential	Business	TOTAL
2015	2015-2017 Final Verified CDM	31,680,379	374,016,196	-	-	405,696,576
2016	Results and Post-CFF Actual	82,342,286	315,948,154	-	-	398,290,440
2017	Savings	149,075,375	300,270,827	-	-	449,346,201

a) Are the results reported in Appendix D meant to reflect the savings described in the third bullet on page 13 as set out below:

> "*for savings to December 31, 2022 that are related to CFF programs, project-level savings for projects that were completed within the 2015-2022 period which a distributor is contractually obligated to finish. For the Retrofit Projects, energy savings and demand reductions are based on the list of projects for which Toronto Hydro paid incentives to customers and which had their status updated to "Project Closed" in CDM-IS system post March 1, 2019. For non-Retrofit CFF Projects, savings are based on the list of projects for which Toronto Hydro has paid incentives and submitted project-level details to the IESO*"?

b) If not, please indicate how the savings reported in Appendix D relate to the various savings sources outlined in the four bullets on page 13.

c) Are the savings reported in Appendix D for the province overall or for THESL? If for the province overall, please provide a schedule that sets out the amounts attributable to THESL and how they were determined for 2015-2017.

d) For each of the years 2015-2017 please provide a schedule that shows the savings reported from each of the sources referenced on pages 12 and 13 such that they total the annual values set out in Appendix C – Annual Savings Tab as provided in the Preamble. If the relevant reference document has already been filed please indicate where in the document the values provided in the requested schedule can be found. If the relevant reference document has not been provided already, please provide and indicate where in the document the values provided in the requested schedule can be found.

3.0-VECC -34

Reference: Exhibit 3, Tab 1, Schedule 1, page 13 and Appendices E & F

Preamble: Appendix F reports the 2019-2020 Interim Framework provincial results. Appendix E extrapolates those results to THESL.

a) Are the 2019-2020 Interim Framework results based entirely on savings achieved by customers of Ontario's electricity distributors or do they also include savings by commercial/industrial customers directly connected to the transmission system?

b) With respect to Appendix E, please provide the source of the 2015-2017 THESL savings and total provincial savings by program area (Cells E3 to H8) used in the 2019-2020 IF Est. Tab.

c) Please provide schedule that sets out THESL's and total provincial Residential sales for each of the years 2015-2018 along with THESL's Residential sales as percent of total provincial Residential sales for each of these years.

d) What would be THESL's share of the 2019-2020 Residential Interim Framework savings if the average percentage per part (c) was used to determine THESL's share?

e) Please provide schedule that sets out THESL' and total provincial Commercial and Industrial sales for each of the years 2015-2018 along with THESL's Commercial and Industrial sales as percent of total provincial Commercial and Industrial sales for each of these years.

f) What would be THESL' share of the 2019-2020 Business (i.e. Commercial and Industrial) Interim Framework savings if the average percentage per part (e) was used to determine THESL's share?

g) With respect to Appendix E, 2019-2020 IF Est. Tab, please provide the source of the Net to Gross Ratio values by program area (Cells G14-H19).

3.0-VECC -35

Reference: **Exhibit 3, Tab 1, Schedule 1, page 13 and Appendices G & F**

Preamble: Appendix G reports the planned 2021-2024 CDM Framework results. Appendix E extrapolates those results to THESL.

a) The 2021-2024 CDM Framework includes savings of 61 GWh in 2022 from Local Initiatives. Did THESL undertake any Local Initiatives in 2022 that would contribute to the 61 GWh result? If yes, what specifically were they and what are the estimated annual savings.

b) The 2021-2024 CDM Framework includes savings of 161 GWh in 2023 from Local Initiatives. Did THESL undertake any Local Initiatives in 2023 that would contribute to the 161 GWh result? If yes, what specifically were they and what are the estimated annual savings.

c) The 2021-2024 CDM Framework includes savings of 181 GWh in 2024 from Local Initiatives. Is THESL currently planning to undertake any Local Initiatives in 2024 that would contribute to the 181 GWh result? If yes, what specifically are they and what are the estimated annual savings.

3.0-VECC -36

Reference: **Exhibit 3, Tab 1, Schedule 1, page 14 and Appendices G & F**
IESO, 2022 Planning Outlook (December 2022)

Preamble: The Application states:

"*Toronto Hydro's annual forecasted savings for 2025 to 2029 were developed based on the assumption that there will be a continuation of CDM program delivery by the IESO. In the absence of a new framework, the projected impact is based on the anticipated "status quo" CDM delivery objectives and expectations assigned for the post-2024 conservation planning period. Toronto Hydro has determined this to be the best estimate at this time given the absence of conservation planning detail for this period.*"

The IESO's 2022 Planning Outlook includes the following cumulative savings from Future Frameworks for 2025 and after (https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook):

Figure 19: Conservation - Future Program Framework Assumption - Annual Energy Demand Savings

Data	Annual Energy Demand Savings (TWh)						
	Year						
	1	2	3	4	5	6	7
	2024	2025	2026	2027	2028	2029	2030
Future Frameworks	-	0.18	0.73	1.53	2.34	3.15	3.97

a) Please confirm that in the Application THESL assumes that the post-2024 Framework will include annual provincial savings of 1,575 GWh, equivalent to the results targeted for 2024. If not confirmed, what annual provincial savings post-2024 does the THESL application assume?

b) What would be the annual savings attributable to THESL for 2025 through 2029 based on the Future Framework savings set out in the IESO's 2022 Planning Outlook? (Note: Please assume split between Residential and Business is the same as that in the 2021-2024 Framework)

c) Please provide a revised Load Forecast for 2025-2029 using the results from part (b) to derive the Residential and Business CDM variables for 2025-2029.

3.0-VECC -37

Reference: Exhibit 3, Tab 1, Schedule 1, pages 7 and 17 (Table 4) and Appendices A & B

a) For each of the six customer classes that uses a regression model to forecast energy usage, please provide a schedule (i.e., a working excel file) that sets out the calculation of the 2023 to 2029 monthly (and resulting annual) energy usage forecast using the forecast values for each class model's explanatory variables and the coefficients from the regression models in Appendix B.

b) For each of these customer classes please provide a schedule that sets out the predicted monthly energy usage for 2023 versus the actual monthly energy usage for all months where actual data is available.

c) For the Street Lighting class, please provide a schedule that set outs: i) the calculation of the average use per device used to forecast energy usage and ii) the calculation of the resulting energy usage forecast for 2023-2029.

d) Please confirm that for the USL class the forecast usage for 2023-2029 was based on actual 2022 usage, adjusted in leap years for the number of days in the year.

3.0-VECC -38

Reference: Exhibit 3,Tab 1,Schedule 1, pgs. 7 & 17 (Table 4) & Appendix B

a) For each of the five customer classes that uses a regression model with CDM/day as an explanatory variable to forecast energy usage, please confirm that the coefficient for this variable ranges from -14 to -41, such that a 1 kWh/day increase in CDM leads a decrease in forecast daily usage that is an order or orders of magnitude larger.

b) If confirmed, please explain why, intuitively, this is a reasonable result.

3.0-VECC -39

Reference: **Exhibit 3, Tab 1, Schedule 1, page 19**

Preamble: The Application states:

"*Toronto Hydro's forecast of monthly peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis (GS 50-999 kW, GS 1000-4999 kW, Large User, and Street Lighting), is established using historical relationships between energy and demand. The utility uses the latest five-year average growth of this relationship for forecasting purposes. The resulting kW demand forecast is explicitly converted based on average power factors to determine the peak kVA demand forecast*."

a) For each of the four customer classes billed on a demand basis, please provide a schedule (working excel file) that sets out: i) the calculation of the energy to demand relationship used to forecast kW demand; ii) the calculation of the forecast 2023-2029 kW demand for each class and iii) the conversion of the forecast kW demand to a peak kVA demand forecast.

3.0-VECC -40

Reference: **Exhibit 3, Tab 1, Schedule 1, page 21**
City of Toronto, Electric Vehicle Strategy, page 13

Preamble: The Application states:

"*Toronto Hydro developed the EV forecast as an input to Clearspring's integration model. The forecast was developed in reference to the three vehicle types: LDEV (battery and plug-in electric), MDEV, and HDEV. The EV forecast was developed to be consistent with the City of Toronto's EV Strategy targets:*
• 2025 – 15% of new vehicle sales and 5% of total light duty vehicles be classified as EVs; and
• 2030 – 40% of new vehicles sales and 20% of total light duty vehicles be classified as EVs, totalling 220,000 LDEVs."

The City of Toronto's Electric Vehicle Strategy states that the interim goals for EV adoption are:

- By 2025, 5% of registered personal vehicles are EVs;
- By 2030, 20% of registered personal vehicles are EVs;
- By 2040, 80% of registered personal vehicles are EVs; and
- By 2050, 100% of registered personal vehicles are EVs.

a) Are Light-Duty (LD) vehicles as referred to in the Application equivalent to the "personal vehicles" referred to the City of Toronto's strategy?

b) The Application indicates that the City of Toronto strategy goal/target is for 220,000 LDEVs by 2030. Please indicate where in the Strategy document the 220,000 goal/target is referenced.

3.0-VECC -41

Reference: **Exhibit 3, Tab 1, Schedule 1, page 22**
City of Toronto, Electric Vehicle Strategy, page 13 (FN #17)

Preamble: The Application states:

"*The LDEV forecast was developed by using historical Light-Duty Vehicles ("LDV") population in Ontario, as well average annual growth rates, for which an extrapolation for Toronto and LDEV forecasts were created. The number of new LDV and LDEV registrations in Ontario were obtained from StatsCan. The reported values were used to estimate the number of new LDVs and LDEVs registered each year in Toronto. It is estimated that approximately 12.7 percent of new vehicles registered in Ontario each year are registered in Toronto*."

a) Please fully explain what data was received from StatsCan and how it was used to estimate the number of new LDVs and LDEVs registered in Toronto each year. Please provide a working excel file setting out the supporting calculations for the forecast LDEVs in Toronto for 2023-2029.

b) It is noted the City of Toronto EV Strategy relied on data obtained from the Ontario Ministry of Transportation regarding registered LDVs and LDEV's in Toronto. Did THESL also use data from the source?

3.0-VECC -42

Reference: **Exhibit 3, Tab 1, Schedule 1, pages 22 – 23**
City of Toronto, Electric Vehicle Strategy

Preamble: The Application states:

"*The MDEV and HDEV forecasts were also developed using the historical vehicle population in Ontario, as well average annual growth rates, for which an extrapolation for Toronto and EV forecasts were created. With the annual growth rate of both vehicle classes, a provincial wide population forecast was derived. Toronto accounts for approximately 20% of the provincial medium and heavy-duty vehicle population. The HDEV forecast also includes vehicle growth from the Toronto Transit Commission ("TTC")."*

"An adoption rate was then developed to establish how rapidly MDEVs and HDEVs would need to be adopted to meet the City's EV Strategy Target. A materialization factor was also added to the MDEV and HDEV forecasts as an adjustment to account for delayed adoption. Internal analysis shows that commercial customers typically have delayed completion dates compared to their original estimated completion dates. Internal 6 analysis was based on energization project materialization between estimated and actual completion dates."

a) Does the City of Toronto's EV Strategy include goals/targets for MDEV and HDEV? If yes, what are they and where are they set out in the Strategy document?
b) With respect to the MDEV and HDEV forecasts, please outline: i) what historical data was employed (including sources) and ii) how it was used (in conjunction with the targets) to develop the forecasts for MDEVs and HDEVs in Toronto. Please provide working excel files setting out the supporting calculations of the forecast MDEVs and HDEVs in Toronto for 2023-2029.

3.0-VECC -43

Reference: **Exhibit 3, Tab 1, Schedule 1, page 22 (Table 6)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 12-13 and 18-19

Preamble: Appendix J states:

"*To integrate the LDEV forecasted energy into the revenue forecast, the incremental load of LDEVs for each rate class from their 2022 adoption levels are added to the revenue forecast*." (page 13)

"*To integrate the MDEV/HDEV forecasted energy into the revenue forecast, the incremental load of MDEV and HDEVs for each rate class from their 2022 adoption levels are added to the revenue forecast*." (page 19)

a) Appendix J provides the number of LDEVs in Toronto dating back to 2019 and the number of MDEVs and HDEVs in Toronto as of 2022. Please provide an estimate as to the number of LDEVs, MDEVs and HDEVs that were registered in Toronto in 2002.
b) Please confirm that: i) the number of registered LDEVs, MDEVs and HDEVs in Toronto have each increased between 2002 and 2022, ii) this increase in registrations will have increased the energy usage in the Residential, CSMUR, GS<50, GS50-999, GS1,000-4,999 and Large Use classes as between 2002 and 2022 and iii) the forecast 2023-2029 energy usage for each of these customer classes will (implicitly) reflect a continuing increase in energy usage by EVs.
c) If part (b) is not confirmed, please explain why.
d) If part (b) is confirmed, will the approach used by Clearspring in Appendix J lead to a double counting of some portion of the incremental load attributable to EVs for these classes? If not, why not?

3.0-VECC -44

Reference: **Exhibit 3, Tab 1, Schedule 1, page 24 (Table 7)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts),

Preamble: Appendix J states:

"*The electric vehicles will mostly be charged at the owner's residence. However, some of the LDEVs will be charged at alternate locations, typically at the place of work. The energy required for home charging will add to residential energy use and the alternate locational charging will add to the general service rate classes. Integration of the LDEVs into the revenue forecast requires an assumption on the rate class split of where charging will occur. The Integration Model assumes 91% of LDEV charging in Toronto will occur at home. The five rate classes based on Toronto Hydro data on the percentage of Level 2 EV chargers in those five rate classes*." (page 11)

"*Toronto Hydro estimated that an average Toronto LDEV driver will average 40.3 km/day. The EV efficiency factor is estimated by Toronto Hydro at .233 kWh/km. Multiplying these two components together produces the estimate of each LDEV requiring 9.4 kWh per day, which appears reasonable to Clearspring based on our experience and other external sources*." (page 12)

"*The forecasts are translated into monthly forecasts using the monthly LDEV counts found in Table 4 and multiplying the average daily kWh charging by the number of days in each month. An additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures. To adjust for this, the Integration Model adds 10 percent to the energy totals in winter months and subtracted 10 percent to the energy totals in summer months*." (page 13)

a) With respect to page 12, what is the basis for THESL's estimates that: i) an average Toronto LDEV driver will average 40.3 km/day and ii) the EV efficiency factor is estimated by Toronto Hydro at .233 kWh/km?

b) With respect to page 11, does the assignment of charging requirements to customer classes take into consideration that some charging of LDEVs registered in Toronto will take place outside THESL's service area (e.g., charging during vacation travel). If not, does THESL have any estimate to how this would impact the forecasts set out in Table 5?

c) With respect to page 13, given there are only 5 summer months (per Footnote #17), does this adjustment increase the total forecasted kWhs attributed to LDEVs?

3.0-VECC -45

Reference: **Exhibit 3, Tab 1, Schedule 1, page 24 (Table 8)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 14-15

Preamble: Appendix J states:

"*A load profile that estimates the hourly charging requirements of an LDEV at the general service customer premise is necessary to forecast the impact of LDEVs on billing demand. Most of this charging will be from commuters who are working at the place of business. The Integration Model uses a load profile that estimates "at work" charging behavior per LDEV from the U.S. Department of Energy (DOE) Alternative Fuels Data Center.*
The DOE profile is scaled to match the LDEV energy charging assumptions that were provided to Clearspring by Toronto Hydro. The model scales the profile to match the energy use estimate of 9.4 kWh and adjusts for summer and winter differences in battery efficiency. The winter and summer LDEV load profiles for "at work" charging used in the analysis are provided in the following table." (page 14)

a) Please explain how the differences in winter vs. summer battery efficiency will impact the kW (as opposed to kWh) requirements for a charging.

b) For each of the customer classes in Table 8, please indicate which of hourly values in Table 7 (Appendix J) were used to determine the billing demand associated with LDEVs and basis on which that hour was chosen.

c) For each of the customer classes in Table 8, please provide a schedule (i.e., working excel file) that sets out how total billing demands associated with LDEVs were determined for the years 2025-2029.

3.0-VECC -46

Reference: **Exhibit 3, Tab 1, Schedule 1, page 24 (Table 7)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 17-19

Preamble: Appendix J states:

"*The MDEVs and HDEVs count forecasts for Toronto Hydro are allocated to the rate classes. The Integration Model uses the Manufacturing and Warehouse kWh usage percentages by rate class provided by Toronto Hydro to allocate the MDEVs by rate class. For the HDEV rate class allocations, the model uses the same Manufacturing and Warehouse kWh usage percentages plus the Toronto Transit Commission ("TTC") garage kWh usage.*

The TTC garage usage, which was provided by Toronto Hydro, and was added to the HDEV allocations because of TTC's Green Bus Program, is forecasted to purchase and add several electric buses to its fleet, which would be classified as HDEVs." (page 17)

"The Integration Model assumes that MDEVs require 103.56 kWh per day and HDEVs require 319.87 kWh of electricity per day. Both of these assumptions were provided from Toronto Hydro." (page 18)

a) Please clarify whether in allocating the MDEVs and HDEVs to rate classes Clearspring uses: i) the total kWh for each rate class as provided by THESL or ii) the HDEV and MDEV charging kWh in Manufacturing and Warehouses as provided by THESL.

b) With respect to page 18, please indicate the basis for: i) the assumed MDEVs requirement of 103.56 kWh per day and ii) the assumed HDEVs requirement of 319.87 kWh of electricity per day.

c) Please explain why the kWh associated with the TTC's Green Bus Program weren't directly estimated and added to the customer class in which TTC load is billed.

d) With respect to page 19, does the assignment of charging requirements to customer classes take into consideration that some charging of MDEVs and HDEVs registered in Toronto will take place outside THESL's service area (e.g., charging during deliveries outside Toronto). If not, does THESL have any estimate to how this would impact the forecasts set out in Tables 13 and 14 (Appendix J)?

3.0-VECC -47

Reference: **Exhibit 3, Tab 1, Schedule 1, page 24 (Table 8)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 14-15

Preamble: Appendix J states:

"*MDEVs and HDEVs will put upward pressure on Toronto Hydro's three rate classes with billing demand, and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. The model accounts for these factors by using hourly load profiles of the MDEV and HDEVs, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated number of MDEV and HDEVs would impact billing demand for each general service customer*." (pages 21-22)

a) For each of the customer classes in Table 20, please indicate which of hourly values in Table 19 (Appendix J) were used to determine the billing demand associated with MDEVs and HDEVs and basis on which that hour was chosen for each class.

b) For each of the customer classes in Table 19, please provide a schedule (i.e., working excel file) that sets out how total billing demands associated with MDEVs and HDEVs were determined for the years 2025-2029.

3.0-VECC -48

Reference: **Exhibit 3, Tab 1, Schedule 1, pages 24-25 (Tables 9 & 10)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 24-27

Preamble: Appendix J states:

"*Toronto Hydro provided the Renewable nameplate capacity forecast, and historical, data to Clearspring. It is Clearspring's understanding that the Renewable forecast is entirely driven by solar. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting solar resources*." (page 24)

"*The Renewable capacity forecasted for Toronto Hydro is allocated to the different rate classes. The Integration Model uses the 2022 participation percentages in Toronto Hydro's net metering program by rate class to estimate the rate class allocations*." (page 24)

"*To integrate the Renewable forecasted energy into the revenue forecast, the incremental production of Renewables for each rate class from their 2022 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2022. The incremental production is used since the base revenue forecast uses a dataset through 2022 and, therefore, already has the 2022 Renewable production embedded into the forecast*."

a) Please provide an estimate at to the renewable (solar) capacity installed in the THESL service area in 2002 and the associated annual energy production.

b) When did THESL' net metering program start? Please provide an estimate of the renewable capacity in place at that time and a breakdown by customer class based on the net metering program's participation.

c) Please confirm that: i) the renewable capacity in Toronto has increased between 2002 and 2022, ii) this increase in capacity will have increased the behind the meter energy production in the Residential, CSMUR, GS<50, GS50-999 and GS1,000-4,999 classes as between 2002 and 2022 and iii) the forecast 2023-2029 energy usage for each of these customer classes will (implicitly) reflect a continuing increase in renewable energy production for these classes.

d) If part (c) is not confirmed, please explain why.

e) If part (c) is confirmed, will the approach used by Clearspring in Appendix J determine the incremental renewable energy production after 2022 result in a double counting of some portion of the incremental energy production attributed to renewable capacity for these classes? If not, why not?

f) For 2022 what was energy delivered to THESL by rate class under the net metering program and what does this represent as a portion of the total renewable energy produced in 2022 (per Table 27) for each customer class?

g) Has the estimation of the load reduction due to renewable capacity in 2022 and also in 2025-2029 been adjusted to account for the fact that not all renewable production leads to a decrease in energy deliveries to THESL' customers (i.e., a portion of the energy is delivered to THESL)? If not, please revise Tables 27 and 28 accordingly.

3.0-VECC -49

Reference: **Exhibit 3, Tab 1, Schedule 1, page 26 (Table 11)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 25 & 27

Preamble: Appendix J states:

"*Renewables will put downward pressure on Toronto Hydro's three rate classes regarding billing demand, and that pressure is a function of the nameplate capacity producing at the premise, the production profiles of those Renewables (provided in the table in the prior subsection), and the base load profile for that customer. The Integration Model accounts for these factors by using the hourly Renewable capacity factors, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated production of the Renewables would impact billing demand for each general service customer*." (page 27)

a) Using the GS 50-999 class, please demonstrate how the impact of renewable on billing demand was determined and provide a working excel file setting out the calculations.

3.0-VECC -50

Reference: **Exhibit 3, Tab 1, Schedule 1, page 25 (Tables 9 &10)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 28-30

Preamble: Appendix J states:

"*Toronto Hydro provided the behind-the-meter Non-Renewable nameplate capacity forecast and historical data to Clearspring. It is Clearspring's understanding that these Non-Renewable DERs will be actively dispatched by the IESO. The forecasts increase substantially until 2024 and then grow by less than two percent thereafter." (page 28)*

"The Non-Renewable capacity forecasted for Toronto Hydro is then allocated to the different rate classes. The Integration Model uses the current nameplate capacity of non-renewable generation by rate class to estimate the rate class allocations." (page 28)

"Unlike Renewables, Non-Renewables can continuously and consistently produce the same amount of electricity in any hour of the day and are not significantly impacted by winter/summer conditions. Toronto Hydro provided the capacity factors by hour for the existing Non-Renewable generation on its system that are dispatched by the IESO. These capacity factors are for an average day and are the same for both winter and summer months." (pages 28-29)

a) Can THESL confirm that all of the current (i.e., as of 2022) non-renewable capacity is dispatched by the IESO? If not confirmed, what percentage of the kW capacity is currently dispatched by the IESO and what is the estimated hourly capacity factor for the non-renewable capacity that is not dispatched?

b) Can THESL confirm that all of the incremental non-renewable capacity to be installed post-2022 will be dispatched by the IESO? If not, for each year 2023-2029 what portion of the incremental non-renewable capacity does THESL expect will be dispatched by the IESO?

c) Does all of the current (i.e. 2022) production by non-renewable capacity go towards reducing customer purchases from electricity or is a portion of it delivered to the THESL system? If a portion was delivered to the THESL system in 2022, what percentage of the total production attributed to each rate class (per Table 35) was delivered to the THESL system?

d) If a portion of non-renewable production is currently (2022) delivered to the THESL system, has the estimation of the load reduction due to non-renewable capacity in 2022 and also in 2025-2029 been adjusted to account for the fact that not all non- renewable production leads to a decrease in energy deliveries to THESL' customers? If not, revise Tables 35 and 36 accordingly.

e) Please provide an estimate as to the non-renewable capacity installed in the THESL service area in 2002 and the associated annual energy production.

f) Please confirm that: i) the non-renewable capacity in Toronto has increased between 2002 and 2022, ii) this increase in capacity will have increased the behind the meter energy production in the GS<50, GS50-999, GS1,000-4,999 and Large Use classes as between 2002 and 2022 and iii) the forecast 2023-2029 energy usage for each of these customer classes will (implicitly) reflect a continuing increase in renewable energy production for these classes.

g) If part (f) is not confirmed, please explain why.

h) If part (f) is confirmed, will the approach used by Clearspring in Appendix J to determine the incremental non-renewable energy production after 2022 result in a double counting of some portion of the incremental energy production attributed to non-renewable capacity for these classes? If not, why not?

3.0-VECC -51

Reference: **Exhibit 3, Tab 1, Schedule 1, page 26 (Table 11)**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 29 & 31

Preamble: Appendix J states:

"*Non-Renewables will put downward pressure on billing demand and is a function of the nameplate capacity producing at the premise, the production profiles of those Non-Renewables (provided in the table in the prior subsection), and the base load profile for every customer. The Integration Model accounts for these factors by using the hourly Non-Renewable capacity factors provided by Toronto Hydro, receiving smart meter interval data for customers from Toronto Hydro, and then analyzing how the estimated production of the Non-Renewables would impact billing demand for each general service customer*.." (page 31)

a) Using the GS 50-999 class, please demonstrate how the impact of non-renewable on billing demand was determined and provide a working excel file setting out the calculations.

3.0-VECC -52

Reference: **Exhibit 3, Tab 1, Schedule 1, pages 25 - 26**
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 29 & 31

Preamble: Appendix J states:

"*Energy storage can be used for multiple purposes. One viable option may be for back-up power when outages are encountered.*

Another possible purpose is to reduce billing peaks or shift energy use from on peak to off-peak. If energy storage is actively used to reduce billing demands, this could have the impact of reducing demands but increasing energy use at the premise through energy losses that result from the inefficiency in the discharge/charging cycle. Under the back-up option, there would be minimal impacts on demand and energy.
It is unclear how energy storage will be used in the future on Toronto Hydro's system. There is no evidence yet that reveals how energy storage may be used on the system and if its presence will result in meaningful energy or billing demand changes. Given this current lack of evidence, it is assumed that energy storage will only be used for back-up power through the forecast period meaning that energy storage is assumed to have zero kWh and zero kW impacts." (page 32)

a) Please provide any insights THESL has as to the use of energy storage by current customers (i.e., is it just used for back-up power in the event of an outage or is also used to reduce billing peaks or shift energy use from onpeak to off-peak)?

3.0-VECC -53

Reference: Exhibit 3, Tab 1, Schedule 1, page 17 and 19
Exhibit 3, Tab 1, Schedule 1, Appendix J (Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts), pages 13, 15, 20, 22, 26, 27, 30, 31 and 34 / Appendix 2-IB

a) For each rate class please provide a schedule that set out for the years 2025-2029 the contribution to the forecast kWh and kVA (where applicable) as set out in Appendix 2-IB from each of the following: i) the results of the energy models, ii) LDEVs, iii) MDEVs, iv) HDEVs, v) renewable resources, and vi) non-renewable resources.

3.0 OPERATING REVENUE (EXHIBIT 3) – OTHER REVENUE

3.0-VECC -54

Reference: Exhibit 3, Tab 2, Schedule 1, pages 1-3
Appendix 2-H

a) With respect to Appendix 2-H and the details regarding Account #4235, please explain: i) the negative microFIT revenues in 2020 and 2021 and ii) why microFIT revenues are lower in the 2024-2029 period than in the previous years.

3.0-VECC -55

Reference: Exhibit 3, Tab 2, Schedule 1, pages 4-5
Appendix 2-H

a) Please provide a detailed breakdown as to the sources of the historic and forecast revenue for Account #4210.

3.0-VECC -56

Reference: Exhibit 3, Tab 2, Schedule 1, page 1
Appendix 2-H

a) Please provide a schedule setting out the actual 2023 Other Revenues at the same level of detail as provided in Appendix 2-H. (Note: If actuals are not available for all of 2023, please provide year-to-date numbers and the year-to-date numbers for the equivalent period in 2022).

4.0 EXHIBIT 4 OM&A

4.0-VECC-57

Reference: Exhibit 4, Tab 1, Schedule 1, pg. 10

"Neither cutting compensation costs nor cutting headcount are viable strategies to manage these key objectives within a standard IRM funding framework. Managing workforce-related costs downwards to live within a standard IRM funding paradigm would entail a reduction to Toronto Hydro's overall staffing complement of up to 200 resources by the end of the rate period, putting total FTEs below 2015 levels…..

a) Please show the calculations which supports this statement. Please provide and describe all assumptions

4.0-VECC-58

Reference: Exhibit 4, Tab 1, Schedule 1, pgs. 15-17

"Toronto Hydro spends considerably less OM&A relative to capital in comparison to the peer group, in many years showing an OM&A-to-CAPEX ratio of less than half that of the peer group."

a) Why is the proportion of OM&A to capital spending a relevant comparison statistic? Specifically, what is THESL attempting to demonstrate with this statistic vis-à-vis its performance compared to other distributors in Ontario?

b) A similar comparison is made with respect to FTEs against capital expenditures. However, different utilities may employ different labour strategies (i.e. internal and contracted labour) which impact the FTEs reported to the OEB. What evidence/studies has THESL completed to understand the relevance or comparability of an FTE against capital expenditure statistic?

4.0-VECC-59

Reference: Exhibit 4, Tab 1, Schedule 1

a) With respect to OM&A per MWh of Load what proportion of THESL's load is bulk metered in comparison with the average (or median) bulk metered load of other Ontario electricity distributors?

b) What proportion of THESL's MWh load is provided to customers of GS>50 or higher customer class? How does this compare with the median or average of other Ontario distributors (for the purpose of this response please do not include Hydro One).

4.0-VECC-60

Reference: Exhibit 4, Tab 1, Schedule 1

a) Please provide a table for the years 2020 through 2029 (forecast) which shows the various components of sub/suite metered customers costs to THESL.

b) Please identify in Appendix 2-JC the categories from which the costs shown in response to question (a) are drawn.

c) Please explain and delineate the OM&A cost differences between servicing a bulk metered residential building and an equivalent load large load class customer.

d) What rate class does a typical high-rise (or in Clearspring terminology "skyscraper") suite metered residential building reside?

4.0-VECC-61

Reference: Exhibit 4, Tab 1, Schedule 1 /Tab 4, Schedule 4

a) Please provide the most current actual FTEs as per Appendix 2-K format (with students removed).

b) For the years 2020 and 2024 please provide a table which shows:

   i. all THESL's job positions/classifications;

   ii. annotation for each position/classification to show whether the position is new or eliminated since 2020;

   iii. the number of persons employed in that position/classification;

   iv. the number of current vacancies in that position/classification; and,

   v. the salary range for that position/classification (if confidentiality is a concern - show salary range for only those positions with 5 or more employees or if the salary band is otherwise generally made available – for example in job postings).

4.0-VECC -62

Reference: Exhibit 4, Tab 2, Schedule 1, pg. 34

"*Given the nature of the workload completed by the External Work Execution segment, Toronto Hydro must increase the number of contract managers and project management staff to ensure the utility is able to effectively manage external contractors as the capital program grows. From the end of 2022 to 2029, Toronto Hydro intends to increase resourcing in this area by 74 percent from 69 to 120 staff. In Toronto Hydro's experience, an appropriate resource level has each manager, with a supporting analyst, executing approximately $11 to 13 million in capital projects annually*."

a) Please explain how the correlation between dollars of capital and internal management staff is derived and relevant. For example, it is not clear why a single project with high cost materials would need as much or more internal management resource than a greater number of smaller projects but with lower cost materials.

b) In 2022 the total capital expenditure is reported as 713.7 ('000) or $10.3M per staff of 69. The largest amount of spending in the rate plan occurs in 2028 at 970.9 ('000) which would equate to $8.1M implying a smaller dollar project value for THESL staff to manage than was the case in 2022. Please clarify how there is an equivalence as between 2022 capital spending with 69 staff and the average capital spending for the rate period and the 120 proposed staff need to manage external contractors in the future.

4.0-VECC -63

Reference: Exhibit 4, Tab 2, Schedule 4, pgs. 2-

"*Furthermore, the increase in corrective work requests is due to enhanced inspection forms and introducing new inspection work, such as cable diagnostic testing, which identifies additional deficiencies that may need to be addressed. This results in approximately $20 million worth of backlog for the lower priority ("P3", requiring resolution within 180 days) work requests, which will need to be addressed before the issues worsen and cause a system fault which may lead to a power outage, or other safety incidents*"

a) Please confirm (or correct) that the implication of the above reference is that the cable diagnostic program has added an incremental $4M per year to the Corrective Maintenance budget.

b) THESL is proposing a 35% increase in System Renewal capital spending (2B/E1). This implies significant incremental replacement of aged assets with new ones. Since new assets require less maintenance than old, what was the reduction in annual corrective maintenance spending made due to the planned increase in capital asset replacements during the rate plan period?

4.0-VECC -64

Reference: Exhibit 4, Tab 2, Schedule 5, pgs. 17-

Table 4: Emergency Response Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Emergency Response	22.1	23.0	22.0	20.4	23.1	25.9	26.4	27.2	27.9	28.6
Total	**22.1**	**23.0**	**22.0**	**20.4**	**23.1**	**25.9**	**26.4**	**27.2**	**27.9**	**28.6**

"*Between 2025 and 2029 costs in this segment are expected to increase by $2.7 million, or an average of $0.7 million per year, to maintain the resourcing capacity and capabilities required to support the volume and complexity of work discussed above*"

a) The Emergency Response spending was on average $21.9 million between 2020 and 2023. It is unclear how the $4 million increase for 2025 was derived. Please clarify.

4.0-VECC-65

Reference: Exhibit 4, Tab 2, Schedule 8, pgs. 5-

Table 3: Customer Operations Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Connections	3.7	1.6	1.6	3.2	3.6	3.2	3.3	3.5	3.6	3.8
Key Accounts	-	0.5	0.8	0.9	1.2	1.5	1.5	1.7	1.8	1.9
Public Safety & Damage Prevention	4.7	4.4	5.4	7.3	6.8	6.7	6.9	7.0	7.2	7.3
Customer-Owned Equipment Services	0.9	1.0	1.2	1.2	1.2	1.3	1.4	1.5	1.5	1.6
Total	**9.3**	**7.5**	**9.0**	**12.6**	**12.8**	**12.7**	**13.1**	**13.7**	**14.1**	**14.6**

a) Please confirm (or correct) that the Public Safety line includes spending for locates, but no costs forecast for the implications of Bill 93.

b) What were the actual costs for Public Safety category (or the category which includes locates) in 2023?

4.0-VECC-66

Reference: Exhibit 4, Appendix 2-K Feb 8/24 update

a) Please modify the most recent Appendix 2-K to include for each year the total labour amount capitalized and expensed or confirm that the amounts are the same as those shown in Appendix 2-D under the line "Labour Capitalization" (also updated Feb 8/24).

4.0-VECC -67

Reference: Exhibit 4, Tab 2, Schedule 9, Asset and Program Management

a) Please show the number of FTEs employed in this program in each year 2020 through 2029.

b) Are the number of FTE's employed in this program in any way correlated with the level of capital expenditures. If yes, please explain how.

4.0-VECC -68

Reference: Exhibit 4, Tab 2, Schedule 10, Work Program Execution

"*Work Program Execution (the "Program") is responsible for oversight, administrative training, and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs, which are not eligible for capitalization in accordance with the utility's capitalization policy*."

"*Over the 2025-2029 rate period, the utility expects the cost of this Program to increase by an annual growth rate of 5 percent*."

a) Please show the number of FTEs employed in this program/segment in each year 2020 through 2029.

b) Which programs as delineated in Appendix 2-JC is spending in this program correlated (for example is it only related to spending in the Preventative and Predictive programs or other programs as well)?

c) How was the 5% figure derived?

4.0-VECC -69

Reference: Exhibit 4, Tab 2, Schedule 10, Work Program Execution

Table 1: Supply Chain Services Program Summary

Supply Chain Program Summary									
Outcomes: Operational Effectiveness - Reliability, Environmental, Financial Performance									
Segments: • Supply Chain Services									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
15.8	12.9	13.8	16.7	18.8	21.5	23.5	24.9	25.5	27.1

Table 3: On-cost rates for 2023-2029

Year	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On-Cost Rate	12.0 %	10.5 %	10.0 %	13.1 %	13.3 %	13.2 %	13.6 %	13.8 %	14.5 %	14.9 %

a) Please show the number of FTEs employed in this program/segment in each year 2020 through 2029.

b) Are the "on-cost" rates the same as the labour capitalization rate for this program area?

4.0-VECC -70

Reference: Exhibit 4, Tab 2, Schedule 14, Billing, Remittance

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Billing, Remittance and Meter Data Management	19.4	18.9	19.4	20.9	23.1	23.7	25.0	25.4	26.2	27.0

a) What is the reason(s) for the 10% increase as between 2023 and 2024 in this segment?

4.0-VECC -71

Reference: Exhibit 4, Tab 2, Schedule 14, Customer Relationship

Table 6: Customer Relationship Management Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Relationship Management	11.4	11.4	12.1	14.4	15.1	14.7	15.7	16.1	16.9	17.5

a) For each year 2020 to 2025 (forecast) please provide a table showing the number of FTEs in this segment, the total compensation and, separately, the number of residential, GS<50, GS>50 customers in each year (year average).

b) What is the assumed customer growth (residential + GS<>50) for the years 2026 through 2029.

4.0-VECC -72

Reference: Exhibit 4, Tab 2, Schedule 15, Human Resource

Table 3: Human Resource and Safety Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Environment, Health & Safety	2.4	2.3	2.4	3.0	3.1	3.3	3.4	3.6	3.8	3.9
Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations	5.9	6.3	5.9	8.0	9.4	10.0	10.4	10.8	11.3	11.8
Talent Management, Change Leadership & Sustainability	7.2	9.0	8.4	7.9	8.8	9.3	9.4	9.8	10.2	10.6
Total	**15.5**	**17.6**	**16.7**	**18.9**	**21.3**	**22.6**	**23.2**	**24.2**	**25.3**	**26.3**

a) For each year 2020 to 2029 what are the forecast FTEs employed in this segment?

b) What are the number of new hires in each year (actual and forecast)?

c) What is THESL's annual churn (vacancy) rate?

4.0-VECC-73

Reference: Exhibit 4, Tab 5, Schedule 1

Table 2: Summary of the Costs of Shared Services Provided by and Received by Toronto Hydro to/from THC ($ Millions)

Segment	Approved	Actual			Bridge		Forecast				
	2020	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Services Provided by Toronto Hydro	3.9	2.7	2.6	3.0	3.1	2.9	3.2	3.4	3.4	3.6	3.9
Services Recovered by Toronto Hydro	4.6	4.0	3.8	4.6	3.6	4.1	4.2	4.4	4.4	4.6	4.9

a) It is unclear to us what this table is attempting to demonstrate. Please confirm (or correct) that the first row shows total payment amounts remitted by THC <u>to</u> THESL for services provided (i.e., a credit) and the second row shows the total payments remitted <u>by</u> THESL for services provided by THC (i.e., a debit).

4.0-VECC-74

Reference: Exhibit 4, Tab 2, Schedule 18

Table 3: Legal Services and Regulatory Affairs Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legal Services	6.1	5.7	5.8	7.9	9.2	9.8	10.3	10.7	11.2	11.6
Regulatory Affairs	3.8	4.4	4.1	5.6	6.4	7.0	7.1	7.5	7.9	8.1
OEB Fees	3.4	3.2	3.6	4.0	4.4	4.5	4.6	4.6	4.7	4.8
Regulatory Applications (Custom IR)	1.6	1.6	1.6	1.6	1.6	2.0	2.0	2.0	2.0	2.0
Communications & Public Affairs	3.6	4.1	4.1	5.5	6.4	6.6	6.9	7.1	7.3	7.6
Total	**18.5**	**19.0**	**19.2**	**24.7**	**28.0**	**29.9**	**30.9**	**32.0**	**33.2**	**34.2**

a) Please provide the number of FTEs (year average) for this segment for each year 2020-2029 (forecast).

b) Please provide the actual OEB annual cost assessment for 2023.

4.0-VECC-75

Reference: Exhibit 4, Tab 2, Schedule 18

a)

	Regulatory Costs (One-Time Application)	2025 Test Year Budget	Incurred to date
1	Expert Witness costs		
2	Legal costs		
3	Consultants' costs		
4	Incremental operating expenses associated with staff resources allocated to this application.		
5	Incremental operating expenses associated with other resources allocated to this application.		
6	Intervenor costs		
	TOTAL		

a) Please complete the above table for the one-time application costs that are to be amortized over the rate plan period.

b) Are the amortized costs of this application included in the presentation tables on OM&A (e.g. Appendix 2-JC etc.)?

5.0 EXHIBIT 5 COST OF CAPITAL

5.0-VECC-76

Reference: Exhibit 5, Tab 1, Schedule, 1 page 7

a) Please clarify whether it is THESL's intention to apply the Board's deemed short-term debt rate (as updated in 204) or apply an updated forecast based on the methodology described at the above reference, for the short term debt component of the cost of capital.

b) If the latter please explain the reasons it is reasonable for ratepayers to pay an additional 5 basis point administration fee for access to short-term debt.

5.0-VECC-77

Reference: Exhibit 5, Tab 1, Schedule, 1 pg. 5-7

a) Please provide an update as to the actual rate to be applied for the $200m note to be issued October 15, 2023.

b) Please explain why it is appropriate to include a basis point administration fee on this debt.

c) Does the rate for all of the other notes shown in Table 4 all include a similar 5 basis point administration fee?

d) Please explain what costs administration fees recoup as distinct from the various Finance Costs paid by ratepayers in OM&A and as shown in Appendix 2-JC.

7.0 COST ALLOCATION (EXHIBIT 7)

7.0-VECC-78

Reference: **Exhibit 7, page 1 / Exhibit 8, page 9**
Exhibit 6, Tab 1, Schedule 3 (2026 RRWF)

Preamble: The Application states:

"*Consistent with the methodology relied upon in EB-2014-0116 and EB-2018-0165, Toronto Hydro completed a cost allocation study for the 2025 test year, and extended the results to allocate the 2026 to 2029 revenue requirement to rate classes." (Exhibit 7, page 1)*

"In each annual application, Toronto Hydro will propose new distribution rates based on the escalated base revenue requirement resulting from application of the CRCI, in accordance with the OEB's decision in this proceeding. Toronto Hydro proposes that for the years 2026 to 2029, the final approved base revenue requirements be allocated to each rate class based on the same allocations to rate classes established in this proceeding for 2025." (Exhibit 8, pdf page 9)

a) Based on the forecast 2026 base revenue requirement (per the 2026 RRWF) please demonstrate how the revenue requirement would be allocated to rate classes for that year and the rates for each class subsequently derived.

b) Will the approach proposed by THESL result in each rate class experiencing a different overall increase in distribution rates, where classes experiencing higher annual increases in their billing determinant would see a lower average rate increase (for base distribution rates)?

7.0-VECC-79

Reference: **Exhibit 7, Tab 1, Schedule 1, page 2**
Cost Allocation Model, Tabs I4 & I5.2
Exhibit 8, Tab 2, Schedule 1, page 3
THESL' Conditions of Service, pages 92 and 97
Exhibit 2B, Section E5.1, page 20

Preamble: With respect to the Services weighting factor, the Application states:

"*All rate classes, with the exception of the Competitive Sector Multi-Unit Residential ("CSMUR"), Unmetered Scattered Load ("USL") and Street Lighting classes, received a weighting factor of one, reflecting the reality that service costs greater than a basic allowance are recovered through a direct contribution from the customers. The weighting factor for the CSMUR rate class is derived by dividing the number of units by the number of* *buildings housing these units, as originally directed by the OEB in EB-2010-0142. For the USL and Street Lighting classes, the cost of services is directly collected from those customers, requiring that they receive a weighting factor of zero*." (Exhibit 7)

With respect to the basic connection fee allowance, the Application states:

"*For the next rate period, Toronto Hydro proposes to increase its Basic Connection Fee allowance for Rate Class 1 to 5 from $1396 to $3059. The Basic Connection Fee has not been updated since 2009. The updated Basic Connection Fee reflects the cost of the current connection standards and includes upgraded transformation from 100kVA, to 167KVA*." (Exhibit 2B)

a) Please confirm that the current basic connection fee allowance is the same for all customer classes (excluding USL and Street Lighting)? If not, please provide the basic allowance for each class.

b) Please confirm that: i) the full costs of Services assets for all customer classes are recorded in Account 1855, ii) the offsetting direct contributions from customers recorded as contributed capital in Account 1995 and iii) these capital contributions are associated with Account 1855 in Tab I4. If not confirmed, please explain how the cost and contributed capital are treated in the Cost Allocation Model.

c) Are the actual total costs (including direct contributions) for Services the same for all customer classes on a per connection basis? If not, what are the relative differences?

d) Is THESL responsible for the maintenance, repair and replacement of the Services assets provided for all customer classes? If not, how do the responsibilities differ across customer classes?

e) Please provide the calculations supporting the proposed Services weighting factor for the CSMUR class.

f) With respect to the USL class, Exhibit 7 states: "the cost of services is directly collected from those customers, requiring that they receive a weighting factor of zero". However, THESL' Conditions of Service (page 92) indicates that for Overhead supply the basic charge ($446 or $1,011 depending on the connection arrangements) is funded through rates. Please reconcile and explain whether it is appropriate for the USL class to have a zero weighting for Services.

g) With respect to Street Lighting, Exhibit 7 states: "the cost of services is directly collected from those customers, requiring that they receive a weighting factor of zero". However, THESL' Conditions of Service (page 97) indicates that the basic charge ($553.36 or $573.97 depending on the connection arrangements) is funded through rates. Please reconcile and explain whether it is appropriate for the Street Lighting class to have a zero weighting for Services.

7.0-VECC-80

Reference: **Exhibit 7, page 2**
Cost Allocation Model (CAM), Tab I5.2

Preamble: With respect to the Billing and Collecting weighting factors the Application states:

"*The class-specific weighting factors reflect estimates of billing effort and costs related to each class based on the experience and expertise of Toronto Hydro's billing specialists*".

a) Please provide any analysis undertaken to support/determine the proposed weighting factors for Billing and Collecting.

7.0-VECC-81

Reference: **Exhibit 7, page 2 and Footnote #5**
Cost Allocation Model (CAM), Tab E1

Preamble: With respect to the Density Factor, the Application states:
"*In accordance with past OEB decisions, Toronto Hydro proposes to maintain the use of the modified density factor at 23 percent. This reflects a considerably higher customer density per kilometer in Toronto compared to the OEB's default value."*

"Toronto Hydro's density of 133 customers per kilometers of line, as determined by the model, is well above the OEB's default of 60 customers per kilometers of line."

a) What was the actual customer density for THESL in: i) EB-2014-0116 and ii) EB-2018-0165 as determined by the CAM model for each Application?

7.0-VECC-82

Reference: **Cost Allocation Model (CAM), Tabs I7.1 and I7.2**

a) Do any of THESL's customers have more than one THESL-owned meter (e.g., customers with embedded generation)? If yes, please indicate which customer classes are involved and how many additional meters are associated with each.

b) Do any of THESL's customers have more than one meter that THESL is responsible for reading on a regular basis? If yes, please indicate which customer classes are involved and how additional meters (over and above one per customer) THESL is required to read for each customer class.

7.0-VECC-83

Reference: **Cost Allocation Model (CAM), Tabs I3 and I9**

a) Tab I3 identifies a number of accounts where some (or all) of the costs are directly allocated to one or more customer classes. Please provide a schedule that sets out for each such account: i) the nature of the assets being directly allocated and ii) why direct allocation is appropriate to the classes identified in Tab I9.

7.0-VECC-84

Reference: **Exhibit 7, Tab 1, Schedule 1, pages 2-3 & Tab 1, Schedule 2 Cost Allocation Model (CAM), Tabs I8**

Preamble: The Application states:

"*For the Residential, CSMUR and General Service rate classes Toronto Hydro used sample metering data sets, while entire rate class data sets were used for Unmetered Scatter Load Class ("USL") and Street Lighting rate classes*."

a) Please explain why sample metering data sets were used for the Residential, CSMUR and General Service rate classes.

b) Please explain how the sample set for each rate class was determined and how THESL ensured the sample set was representative of the overall class.

7.0-VECC-85

Reference: **Exhibit 7, Tab 1, Schedule 1, pages 2-3 & Tab 1, Schedule 2 Cost Allocation Model (CAM), Tabs I8**

Preamble: The Application states:

"*The hourly load profiles were reconciled to the 2019 purchased energy and wholesale market participant data and weather normalized to 2025 heating and cooling degree days. The weather normalization methodology is based on a ratio between the 2019 weather normalized and 2019 non-weather normalized loads from the revenue load forecast. Weather normalization in the revenue load forecast is calculated by making adjustments to the monthly energy purchases either in excess or below what would be purchased under average weather conditions. Average weather conditions are based on a ten-year historical average of heating and cooling degree-days, and dew-point temperature*."

And

"*The load profiles were scaled to the 2025 baseline load forecast based on the ratio of 2025 kWh to 2019 kWh by class*."

a) With respect to the first reference, was the ratio used to do the adjustment (per Exhibit 7, Tab 1, Schedule 2, Column (h)) based on the annual weather normal HDD and CDD values relative to the actual annual HDD and CDD values or was a different ratio calculated for each month?

b) With respect to the second reference, was the scaling factor (per Exhibit 7, Tab 1, Schedule 2, Column (i)) used based on the ratio of the annual 2025 forecast kWh versus the annual weather normalized 2019 kWh or was a different scaling factor calculated for each month?

7.0-VECC-86

Reference: **Exhibit 7, Tab 1, Schedule 1, pages 2-3 & Tab 1, Schedule 2**
Exhibit 3, Appendix J, page 37
Cost Allocation Model (CAM), Tabs I8
EB-2022-0016 (Bluewater Power), Exhibit 7, pages 5-11
EB-2022-0044 (Kingston Hydro), Exhibit 7, Tab 4, Schedule 1, Attachment 1

Preamble: The Application states:

"*Resulting load profiles were modified to include electric vehicles ("EVs") and distributed energy resources ("DERs") forecasted load impacts*." (page 3)

And

"*One load profile needed to be added to the analysis: a residential LDEV load profile. For the Integration Model, it was not necessary to include a residential LDEV load profile because billing demand is not a component of residential rates. However, how LDEV's may impact the cost allocations between the residential and other classes in the CAM is pertinent*." (Appendix J, page 37)

a) With respect to the second reference, wouldn't it also have been necessary to develop (solely for cost allocation purposes) load profiles for: i) CSMUR LDEV energy usage and ii) GS<50 LDEV, MDEV and HDEV energy usage? If not, why not?

b) If yes, please explain how these profiles were determined and provide the profiles used?

c) With respect to Tab 1, Schedule 2, please explain why the total hourly demand for the customer class (Column (c)) was based on the average use per sample customer for the hour times the number of customers in the class.

d) What implicit assumptions does this approach (per part (c)) assume regarding the nature of the sample used and how did THESL ensure these assumptions were met?

e) With respect to the calculation described in part (c), why wouldn't it be more appropriate to determine the hourly profile for the class by multiplying the hourly profile for the sample by the ratio of class's total energy to the energy use accounted for by the sample?

f) With respect to Tab 1, Schedule 2, is the difference between the hourly values in Column (d) and Column (f) due solely to losses?

g) If the response to part (f) is no, what other factors account for the difference?

h) If the response to part (e) is yes, why does the percentage difference between the two columns vary so widely over the hours?

i) With respect to Tab 1, Schedule 2, why is it more appropriate to use the maximum value in Column (c) as the NCP value as opposed to the maximum value in Column (h)?

j) With respect to Tab 1, Schedule 2, why is it more appropriate to use the maximum value in Column (f) to determine the hour on which to base the CP for the month as opposed to the maximum value in Column (d)?

k) With respect to Tab 1, Schedule 2, please confirm that the weather correction factor used in Column (h) uses the same ratio to adjust each hour's actual use to "weather normal" use and, in doing so, assumes that for each hour in January 2019 the actual HDD value differs from what would be weather normal for that hour in January by the same percent?

l) If part (k) is not confirmed what relationship does the approach used by THESL assumes exists between the actual HDD value for each hour in January and the weather normal for that hour in January?

m) Did THESL consider the use of a methodology such as that employed by Bluewater and Kingston in their 2022 COS Applications which accounts for the fact that the difference between actual and weather-normal HDD and CDD values can vary by day? If yes, why was such an approach rejected?

7.0-VECC-87

Reference: Cost Allocation Model (CAM), Tab I6.1
EB-2023-0054, OEB Decision re: THESL's 2024 Rates

a) In the 2024 Tariff Sheet it is not clear if the Service Charge for USL is billed on a per customer or a per connection basis. Please clarify.

b) Please explain how the 2024 rates used in Tab I6.1 account for both the Service Charge and the Connection Charge applicable to USL customers.

7.0-VECC-88

Reference: **Exhibit 7, Tab 1, Schedule 1, page 5 (Table 1)**
Cost Allocation Model (CAM), Tab O1

c) With respect to the proposed Revenue to Cost ratios for GS<50, GS 50-999, GS 1000-4999 and Large Use, are the differences in the proposed ratios simply due to rounding or did the approach used by THESL to determine each class's ratio lead to distinctly different results for each class?

d) If the approach used by THESL led to distinctly different results for each class please explain the approach used and provide (in a working excel model) the supporting calculations.

7.0-VECC-89

Reference: **Exhibit 7, Tab 1, Schedule 1, page 5 (Table 1)**
Cost Allocation Model (CAM), Tab O1
EB-2018-0165, OEB Decision, pages 156-157

Preamble: The EB-2018-0165 Decision states:

"*However, the OEB is concerned by the large shift for the residential class from well below 100% to above 100% (94.3% to 103.2%) at the same time that residential rates are transitioning to a fully fixed rate design. This shift of 8.9 percentage points has a direct impact on the distribution rates for the residential class, and, when combined with the transition to fixed rates, can have a compounding impact on the bills for low volume consumers. The OEB concludes that this impact should be mitigated. Therefore, the OEB is setting the revenue-to-cost ratio for the residential class at 100% for the Custom IR term. In the next rebasing application, the OEB will assess whether the standard policy range will again be applied, rather than continuing to fix the ratio at 100%*."

And

"*The OEB notes that the revenue-to-cost ratio for the CSMUR class was set at 100% by the OEB when the class was first established for 2012 rates (and as implemented in 2013). There are now several years of actual data for this new class that can be assessed. The OEB concludes that it is appropriate to review in Toronto Hydro's next rebasing application the characteristics of this class, and whether a range should be adopted for the revenue-to-cost ratios going forward*."

The Application states:

"*In accordance with past OEB decisions, rates in the Residential and CSMUR class are set such that the revenue to cost ratios* *are equal at unity (i.e. 1.0 or 100 percent*).”

a) Please explain why THESL considers setting the Residential ratio at 100% to be in accordance with the OEB’s EB-2018-0165 Decision (i.e., why the Residential ratio should continue to be fixed at 100% as opposed to applying the standard policy range).

b) Please provide THESL’s views as to whether, for the CSMUR class, a range should be adopted for the class’s revenue to cost ratio.

7.0-VECC-90

Reference: Exhibit 7, Tab 1, Schedule 1, page 13

a) Please provide the Cost Allocation Models used to produce the results set out in columns B, C and D of Table 4.

8.0 RATE DESIGN (EXHIBIT 8)

8.0-VECC-91

Reference: Exhibit 8, Tab 1, Schedule 1, page 4 (pdf)
Exhibit 8, Tab 1, Schedule 2

Preamble: The Application states:

“*To determine Toronto Hydro’s current fixed/variable split, consistent with previous applications, the utility applied 2025 forecast customer connection counts to anticipated 2024 rates to determine 2025 fixed revenue at 2024 rates. The utility subsequently applied 2025 forecast kWh and kVA billing determinants to anticipated 2024 rates, including variable distribution charges and adjustments for the transformer allowance, to determine the percentage of fixed and variable revenue relative to total revenue, by rate class.*” (emphasis added)

a) If required, please revise Exhibit 8, Tab 1, Schedule 2 to reflect THESL’s approved 2024 rates.

b) Exhibit 8, Tab 1, Schedule 2 does not appear to include adjustments to the variable revenues for the GS 50-999, GS 1,000-4,999 and Large Use classes to account for the transformer allowance. Please explain if/how the transformer allowance has been incorporated

8.0-VECC-92

Reference: **Exhibit 8,Tab 1, Schedule 1, page 6 (pdf)**

a) Please provide a revised version of Table 2 where the proposed rates for 2025 are not adjusted for the 30-day basis and are presented on a basis equivalent to the other values in the Table.

8.0-VECC-93

Reference: **Exhibit 8, Tab 1, Schedule 1, pages 9-10 (pdf)**
RTSR Model, Tabs 3, 4 and 5

a) Please confirm that both the RRR data in Tab 3 and the billing units in Tab 5 are based on data for the same year. If not confirmed, please indicate the basis for the data used in each Tab and update the RTSR Model as required.

b) Are the 2024 UTRs used in Tab 4 the same as those approved by the Board in EB-2023-0222. If not, please update the RTSR Model as required.

8.0-VECC-94

Reference: **Exhibit 8, Tab 1, Schedule 1, pages 10-11 (pdf)**

Preamble: The Application states:

"*Furthermore, since the OEB updates RSCs annually, Toronto Hydro will flow through updated charges as part of the annual rates update process under the CRCI framework throughout the 2026-2029 rate period*."

And

"*Furthermore, since the OEB updates this charge (pole attachment) annually, Toronto Hydro will flow through updated charge as part of the annual rates update process under the CRCI framework throughout the 2026-2029 rate period*."

a) Will THESL also update the Other Revenues for the 2025-2029 period and the resulting base distribution revenue requirement to reflect the impact of any updates to the RSCs or the Pole Attachment charges?

8.0-VECC-95

Reference: **Exhibit 8, Tab 1, Schedule 1, pages 11-12 (pdf)**
Appendix 2-R

Preamble: The Application states:

"*Toronto Hydro is not proposing any changes to the current OEB-approved loss adjustment factors shown in Table 4*."

a) Based on the results set out in Appendix 2-R, please explain why THESL considers it appropriate not to update its loss adjustment factors.

8.0-VECC-96

Reference: **Exhibit 8, Tab 1, Schedule 1, page 13 (pdf)**

Preamble: The Application states:

"*As discussed in detail elsewhere in this application (e.g. Exhibit 1B, Tab 2, Schedule 1; Exhibit 2B; and Exhibit 4, Tab 1, Schedule 1), Toronto Hydro has incorporated consideration of rate impacts as part of its proposed capital and OM&A funding requests*."

And

"*Consistent with EB-2018-0165, Toronto Hydro proposes implementation of a rate smoothing methodology, aimed at assisting customers in managing bill impacts. Toronto Hydro's proposed rate smoothing plan offers several benefits: (i) it avoids a one-time step-change increase for most customers in the rebasing year (2025), while (ii) maintaining relatively consistent year-over-year annual increases for all customer classes*."

a) Does the rate smoothing methodology/plan proposed by THESL involve more than its incorporation of rated impacts as part of its proposed capital and OM&A funding requests? If yes, please explain what the methodology is and the impact it will have on smoothing year over year annual rate increases.

DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -97

Reference: Exhibit 9, Tab 1, Schedule 1, Table 1

a) Please update Table 1 to show the DVA balances as of December 31, 2023. In the updated table please also include the account number for each Group 1 and 2 account.

9.0 –VECC -98

Reference: Exhibit 1B, Tab 1, Schedule 3, page 13

"The total net DVA balances proposed for clearance are $163.7 million (credit/refund) to customers beginning January 1, 2025."

a) We are unable to reconcile this statement with the evidence at Exhibit 9. Please clarify.

9.0 –VECC -99

Reference: Exhibit 9, Tab 1, Schedule 1, page 15

a) We are unable to locate the calculation showing the derivation of Account 1592 – CCA Changes. Please provide a reference for this calculation. If the detailed calculation has not been provided please prove tables showing the AIIP additions, the CCA with and without acceleration and the other annual calculations that support the proposed disposition balance.

9.0 –VECC -100

Reference: Exhibit 9, Tab 1, Schedule 1, Tables 19&20, pgs. 36-

"*As this decision* (EB-2023-0143*) was released just weeks before Toronto Hydro submitted its application to the OEB, the utility intends to file supplemental evidence to forecast the balances that it expects in this account over the current rate period*.

a) We are unable to locate the referenced supplemental evidence. Please clarify whether this evidence has been filed.

b) The Board approved account is to " *track the incremental costs of locates in 2023 and future years arising from the implementation of Bill 93.*" (page 2). This requires that THESL have an amount from which Bill 93 related locate costs are incremental from. What is "normal" annual locate costs from which Bill 93 incremental costs are to vary from.

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