RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-03

References: Report of the Board, Renewed Regulatory Framework for Electricity, p. 11
Report of the Board, Handbook for Utility Rate Applications, p. 26

Preamble**:**

Reference 1 states the following:

"[Performance-based rate-setting] decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviours described by the Board in 2000. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for rate base to be re-calibrated annually."

Reference 2 states the following:

"If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service."

QUESTION (A):

a) Please provide a table showing each element of THESL's revenue requirement resulting from its 2025-2029 investment and spending plans if its rates were established on a cost of service basis, as well as the total for each year.

RESPONSE (A):

Please see Exhibit 6, Tab 1, Schedules 2 – 7 at Tab 9 of the Revenue Requirement Work Form for the full details of the 2025-2029 Revenue Requirement. For ease of reference, a summary table is provided below in Table 1.

Table 1: 2025-2029 Revenue Requirement Related to the Proposed Investment Plan1

	2025	2026	2027	2028	2029
OM&A Expenses (A)	343.0	358.0	370.1	385.5	399.6
Amortization/Depreciation (B)	285.3	299.6	319.9	342.1	354.5
Deemed Interest Expense (C)	143.1	152.4	162.8	174.0	184.5
Return on Equity (D)	220.9	235.3	251.4	268.7	284.8
Payments in Lieu of Taxes (PILs) (E)	27.9	30.5	20.0	56.2	47.7
Service Revenue Requirement [F=SUM(A:E)]	1,020.3	1,075.8	1,124.2	1,226.5	1,271.1
Revenue Offsets (G)	- 47.9	- 48.9	- 49.8	- 50.8	- 51.8
Base Revenue Requirement (H=F-G)	972.4	1,027.0	1,074.4	1,175.7	1,219.2

QUESTION (B):

b) Please provide a table showing each element of THESL's revenue requirement from 2025-2029 as proposed in this application, prior to the application of a Performance Incentive Mechanism (PIM), stretch or productivity factor, as well as the total for each year.

RESPONSE (B):

Toronto Hydro notes that this question seeks the same information requested in question (a) above. As such, Toronto Hydro assumes that the question is asking for the Revenue Requirement <u>after</u> the application of the X-Factor composed of the PIM, the efficiency factor and productivity factor. To that end, Table 2 below show the revenue impact of the Custom Revenue Cap Index (CRCI) when it is applied to the base revenue requirement identified in the table above in part (a).

[1] Based on the pre-filed evidence as of November 17, 2023.

Table 2: 2025-2029 Revenue under the Custom Revenue Cap Index (CRCI)2

	2025	2026	2027	2028	2029	Total
Base Revenue Requirement (A)	**972.4**	**1,027.0**	**1,074.4**	**1,175.7**	**1,219.2**	**5,468.6**
Revenue collected in previous year (B)	n/a	972.4	1,019.6	1,059.1	1,151.0	n/a
X-Factor (PIM): 0.6% (C=B*0.6%)	n/a	- 5.8	- 6.1	- 6.4	- 6.9	n/a
X-Factor (Efficiency): 0.15% (D=B*0.15%)	n/a	- 1.5	- 1.5	- 1.6	- 1.7	n/a
Inflation (E=B*2.0%)	n/a	19.4	20.4	21.2	23.0	n/a
Incremental Revenue via the Revenue Growth Factor (F=B*RGF)	n/a	35.1	26.7	78.7	19.7	n/a
Funded Revenue in current year (G=Sum(B:F))	**972.4**	**1,019.6**	**1,059.1**	**1,151.0**	**1,185.1**	**5,387.1**
Revenue Deficiency (H=A-G)	n/a	7.3	15.3	24.7	34.2	81.5

QUESTION (C):

c) Please explain similarities and differences between the tables in a) and b) and THESL's proposed revenue requirements, by element, while demonstrating how the resulting revenue changes throughout the term accord with the OEB's policy expectations expressed at the references above.

RESPONSE (C):

Table 1 sets out the revenue that Toronto Hydro requires to fund the proposed 2025-2029 Investment Plan based on a cost-of-service review (i.e. the base revenue requirement in row H). This is the starting point for a PBR rate-setting mechanism as outlined on page 11 of the RRF: "*Going into PBR, distribution rates are set based on a cost-of-service review*."

In contrast, Table 2 shows the application of a custom index, which applies a performance and productivity based X-Factor to determine the utility's actual revenue to be collected through rates

[2] Based on the pre-filed evidence as of November 17, 2023.

over the rate term. The difference between the Base Revenue Requirement in Table 1, Row H and the Funded Revenue in Table 2, Row G is the utility's revenue deficiency (column H in Table 2) as a result of the application of the custom index. The total revenue deficiency over the rate period is approximately $81.5 million. This deficiency is further explained in Table 3 below.

Table 3 shows that the $81.5 million revenue deficiency resulting from Toronto Hydro's proposed custom index is made up of two components: (1) efficiency gains that the utility is expected to make consistent with the results of the Total Cost Benchmarking study filed in Exhibit 1B, Tab 3, Schedule 3, Appendix A (row D), and (2) a pro-active performance incentive factor that Toronto Hydro has proposed to balance risk between ratepayers and the utility (row E).

Table 3: 2025-2029 Revenue Deficiency under the Custom Revenue Cap Index (CRCI)

	$ Million	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
A	Revenue Requirement (Investment Plan)	972.4	1,027.0	1,074.4	1,175.7	1,219.2	5,468.6
B	Funded Revenue (CRCI)	972.4	1,019.6	1,059.1	1,151.0	1,185.1	5,387.1
C = B – A or D + E	Revenue Deficiency	n/a	- 7.3	- 15.3	- 24.7	- 34.2	- 81.5
D[3]	**X-Factor** : 0.15% Efficiency Component of Deficiency	n/a	- 1.5	- 3.1	- 5.0	- 6.9	- 16.4
E[1]	**X-Factor**: 0.6% Performance Component of Deficiency	n/a	- 5.8	- 12.2	- 19.7	- 27.3	- 65.1

[3] Note the annual adjustment yielded by the Efficiency and Performance components of the X-Factor shown in Table 2 at rows C and D, is a different figure than the revenue deficiency shown above in Table 3 at rows D and E. This is because Table 3 shows the *cumulative annual impact* of the Efficiency and Performance components of the X-Factor when comparing funded revenue under the custom index (CRCI) against Toronto Hydro's revenue requirement to fund the 2025-2029 Investment Plan proposed in this application.

QUESTION (D) :

d) Please discuss the extent to which Toronto Hydro's custom index is the result of anything other than a forecast of its annual costs supplemented by a PIM, stretch and productivity factor.

RESPONSE (D):

In accordance with the OEB's requirements and expectations set out in the RRF and the Rate Handbook, the custom index proposed by Toronto Hydro is informed by:[4] (1) the distributor's five-year cost and revenue forecasts which are supported by detailed historical and forecast evidence; (2) the OEB's inflation[5] and productivity analyses with proposed customization to reflect business challenges and conditions that the utility faces; and (3) extensive benchmarking evidence to assess the reasonableness of the distributor's forecasts.[6] This approach to developing a custom index has been relied on by the OEB in numerous Custom IR applications.[7]

The analysis above in part (c) demonstrates that the 2025-2029 custom index does not fund the entirety of the revenue requirement (i.e. costs) that the utility forecasts to deliver its 2025-2029 Investment Plan. As noted in response to 1B-Staff-12(a), there is a $469 million difference between Toronto Hydro's 2025-2029 revenue requirement and the revenue that the utility could collect under a standard Price Cap IR rate-setting approach – this is the difference that gives rise to the need for a multi-year custom rate-setting approach. The $81.5 million revenue deficiency imposed by the custom index (as described above) represents approximately 17.4% of this funding difference. In other words, under the custom index proposed by Toronto Hydro 17.4% of the incremental revenue required remains unfunded in rates, and is placed at risk subject to the achievement of efficiency and performance expectations associated with the proposed X-factor.

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[4] Report of the Board, *Renewed Regulatory Framework for Electricity* (October 18, 2012) at page 17; *Handbook for Utility Rate Applications* (October 13, 2016), at page 28.
[5] Please see response to 1B-Staff-93
[6] Exhibit 1B, Tab 3, Schedule 3, at Section 4 (page 27).
[7] E.g. EB-2014-0116, EB-2017-0049, EB-2018-0165, and EB-2019-0261.

The X-Factor thus effectively decouples the price (the distribution rate) that a distributor charges for its services from the utility's actual costs (i.e. the revenue requirement), specifically to incent the behaviours that underpin the RRF: continuous improvement in efficiency and productivity (through the efficiency factor) and performance outcomes (through the incentive factor and PIM). The PIM earn-back proposal provides the utility the opportunity (*not guarantee*) to earn its OEB-approved rate of return on equity in accordance with the quoted statement in the RRF.[8]

Unlike a cost-of-service rate-setting approach where the utility comes in annually or every two years to recalibrate its rate base and establish rates which reflect actual costs, under the proposed custom rate framework Toronto Hydro forecasts its rate base, costs (and revenues) prospectively for five years, and subject to specific adjustments as proposed, the utility must manage within the funding envelope provided even though actual costs may vary from the forecast. Managing actual costs over the five-year period while continuing to achieve performance outcomes and provide high-quality services to customers is another important way in which the proposed rate framework decouples the rates (price) that customers pay over the rate term from costs the utility incurs over the forecast period to serve customers.

[8] Exhibit 1B, Tab 2, Schedule 1 at s. 3.3.1 starting on page 47.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-4

Reference: Exhibit 1B, Tab 1, Schedule 1

Preamble:

Of the four strategic priorities for Toronto Hydro's integrated planning, sustainment and stewardship, modernization, growth and electrification and general plant, Toronto Hydro aligns performance objectives with customer feedback. Such feedback is to "prioritize investments in technology…", and to "invest proactively in system capacity…".

QUESTION (A):

a) Please confirm that this objective applies exclusively to new technology investments that will reduce Toronto Hydro's costs (i.e., revenue requirement), as noted in section 3.1. If not confirmed please explain why not.

RESPONSE (A):

Through Phase 1 of its Customer Engagement study, Toronto Hydro learned that customers support investments in new technologies that would make the system better (even if it could increase customer rates, and even if the benefits are not immediate) as long as the Toronto Hydro is clear about the cost to customers and the potential benefit. Please see Exhibit 1B, Tab 5, Schedule 1, Appendix A – Executive Summary at page 10.

QUESTION (B):

b) Confirm that all new technology investments planned for the test period have been evaluated to reduce Toronto Hydro's costs. If not confirmed, please list all such investments that will not reduce Toronto Hydro's costs in the planning period and explain why they are being proposed.

RESPONSE (B):

Toronto Hydro confirms that new technology investments are aligned with the objective to reduce costs (i.e., cost reductions or avoidance) and/or make the system better with respect to outcomes such as safety, reliability, customer service, security. For more information about how Toronto Hydro intends to leverage new technology to reduce cost and make the system better over time, please refer to (i) the Grid Modernization Strategy at Exhibit 2B, Section D5, (ii) the IT Investment Planning process in Exhibit 2B, Section D8.5, (ii) the Facilitating Innovation evidence in Exhibit 1B, Tab 4, Schedule 1, and the (iii) the Innovation Fund proposal in Exhibit 1B, Tab 4, Schedule 2. For more information on how Toronto Hydro considers value for modernization investments in planning, please refer to the response in interrogatory 2B-Staff-170.

QUESTION (C):

c) Confirm that all proactive system capacity investments have been evaluated using the "least regrets" principle described in section 2.2. d) Please identify Toronto Hydro's marginal system capacity investment, i.e., the project demonstrated to have just made the threshold of an acceptable probability of creating unacceptable regrets by applying Toronto Hydro's "least regrets" investment principle.

RESPONSE (C):

Confirmed as outlined in the evidence in Exhibit 2B, Section D4. One example of a least regrets project that can be found within the plan is the Downsview TS. While it is theoretically possible to defer this expansion investment into the next rate period, this project is being advanced as a least regrets investment because the capacity outlook for this area in the next decade shows an expected increase in peak demand due to the Municipal Energy Plan for Downsview TS along with other drivers of growth. In these circumstances, Toronto Hydro believes that the risk of not having sufficient lead-time to build a new station that is required to connect and serve customers in this area should the pace of growth accelerate over the rate period, is a far more regrettable choice than pulling forward this investment by a few years.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

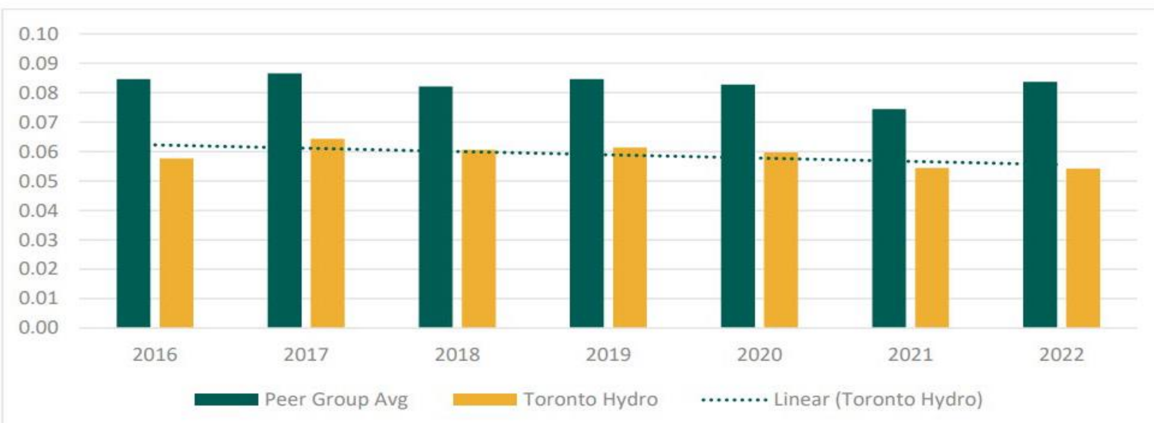
INTERROGATORY 1B-STAFF-5

Reference: Exhibit 1B, Tab 1, Schedule 1

Preamble:

Figure 6 is reproduced below.

Figure 6: FTE per GWh of Load Served



QUESTION (A) - (B):

a) Why was GWh of load chosen as the normalization parameter to compare against other utilities?

b) Why does Toronto Hydro believe GWh of load is a more appropriate parameter to utilize versus one of the following:

   i. Service area

   ii. Customer count

RESPONSE (A) - (B):

Toronto Hydro applied various normalization parameters to compare FTE and OM&A trends to other utilities (i.e. GWh, customer count, circuit-km and net fixed assets). Please refer to the OM&A Overview evidence in Exhibit 4, Tab 1, Schedule 1 at pages 14 to 19 for the full analysis.

Gigawatt-hour ("GWh") per load was chosen to normalize FTEs based on electricity consumption by customers served. As indicated in the text right above the graph, this measure was chosen to show "*the utility's past efforts to increase resource throughput and utilization.*"

QUESTION (C):

c) Provide FTE per each of the following parameters for each year inclusive of 2016-2022 for Toronto Hydro and the peer group:
    i. Service area
    ii. Customer count
    iii. Km of line

RESPONSE (C):

Please see Exhibit 4, Tab 1, Schedule 1 at Figures 7 and 8, pages 17 and 18, respectively for FTE per Circuit-km and FTE per customer count. Please see Figure 1 below for an analysis of FTE per service area. The comparative results observed below are logically consistent with the Ontario Cities Population Density analysis presented in Table 1 of Exhibit 1B, Tab 3, Schedule 3 at page 3, which is reproduced in Figure 2 below in a bar graph format for ease of reference.

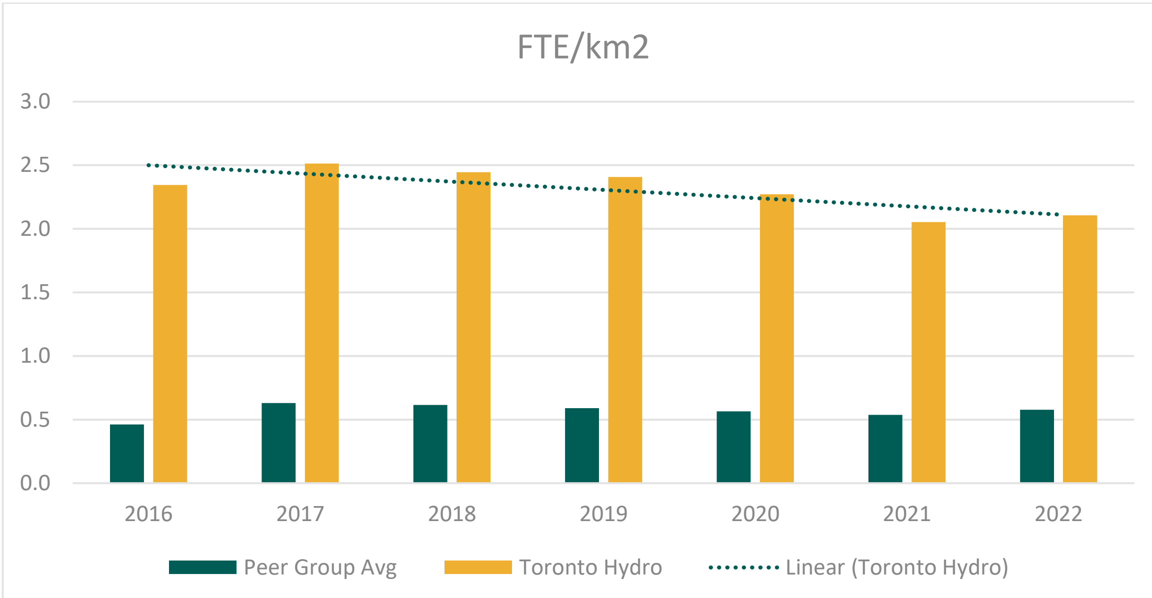


Figure 1 – FTE per Service Area

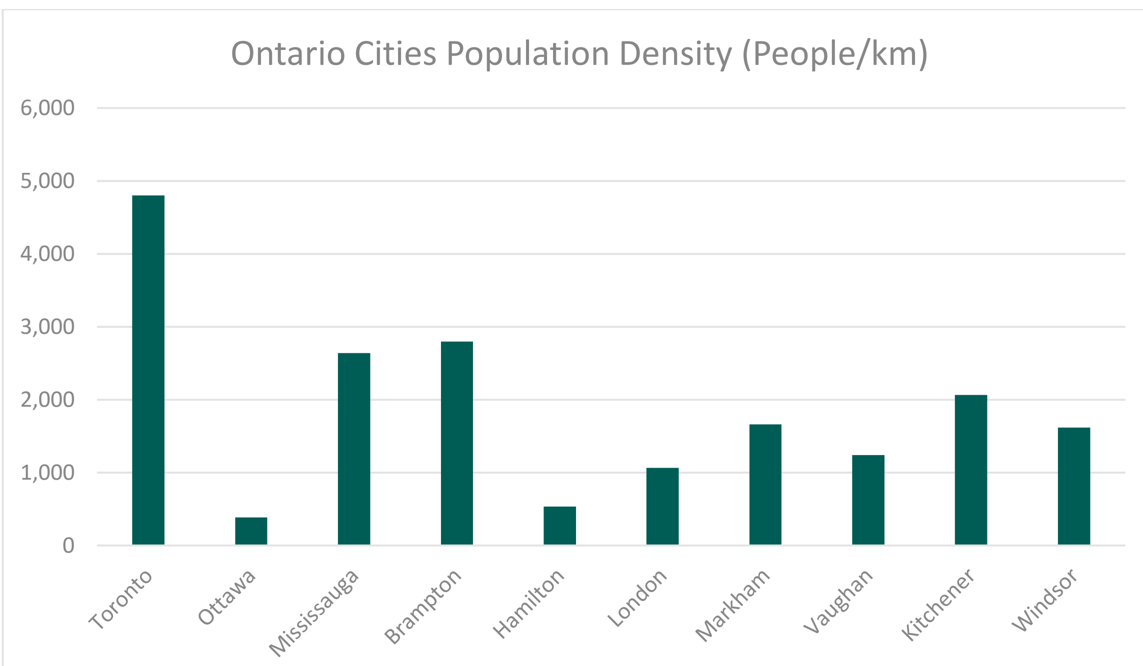


Figure 2 – Ontario Cities Population Density

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-6

Reference: Exhibit 1B, Tab 1, Schedule 1

Preamble:

Toronto Hydro makes multiple references to the "Horseshoe area" within its service area.

QUESTION (A):

a) Of Toronto Hydro's service area, what percentage is made up of the horseshoe?

RESPONSE (A):

Approximately 85 percent of Toronto's service area is made up of the horseshoe region.

QUESTION (B):

b) Of Toronto Hydro's customer count, what percentage are within the horseshoe?

RESPONSE (B):

Please see Toronto Hydro's response to interrogatory 2B-AMPCO-24, part (i).

QUESTION (C):

c) What is Toronto Hydro's calculated building density for:
   i. the service area as a whole,
   ii. within the horseshoe,
   iii. outside the horseshoe?

RESPONSE (C):

Based on the latest City Landbase information acquired from the City of Toronto:

i. The building density for the service area as a whole is approximately 700 per square kilometers.
ii. Within the horseshoe, the calculated building density is 560 per square kilometers.
iii. Within the core, the calculated building density is 1,520 per square kilometer.

Please note that building density does not take into account the large variation of building or customer types within Toronto Hydro's service area. For example, a greater proportion of buildings can be multi-residential high rises and office towers within the downtown core compared to the horseshoe area.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-7

Reference: Exhibit 1B, Tab 1, Schedule 1

Preamble:

The material challenges outlined in section 3, along with customer feedback and the principle of least regrets investments established investment priorities for Toronto Hydro's capital plan. Specifically, Toronto Hydro notes the importance of investments including Distributed Energy Resources to support "Growth & City Electrification".

Question (A):

a) Does Toronto Hydro evaluate proposed DERs to determine if they will increase or decrease system reliability during summer peak demand, winter peak demand, or during peak generation periods of the proposed DER technology?

RESPONSE (A):

Yes. Toronto Hydro performs connection impact assessments (CIA) to assess the impact of connecting DERs on the system and evaluates criteria required to be met to maintain the stability of the grid including during peak demand periods. This assessment takes into consideration the Minimum-Load-to-Generation Ratio, a key determinant of grid stability.

QUESTION (B):

b) How does Toronto Hydro allocate the costs of system investments needed to mitigate any negative reliability impacts that may be associated with implementation of specific DER technologies in specific parts of its system?

RESPONSE (B):

Please see Toronto Hydro's response to 2B-Staff-160 part (c).

QUESTION (C):

c) Please identify the incremental investments in this application that are required to enable Toronto Hydro to integrate new energy storage batteries into its system.

   i. Please explain why such investments would be needed in the planning period.

RESPONSE (C):

Please see 2B-Staff-250 for a response to Toronto Hydro's ESS investments in 2025-2029 and an explanation for why such investments are needed.

QUESTION (D):

Considering that energy storage batteries have been utilized by other utilities as a non-wires alternative technology to help defer or eliminate the need for wires investments, please explain why this would not also apply to Toronto Hydro.

RESPONSE (D):

Please refer to Toronto Hydro's responses to 1B-Staff-88 and 1B-Staff-89 for information about the utility's non-wires strategy, investments and proposed incentives. Toronto Hydro is agnostic to the technology (type of DER) or approach (load curtailment) utilized by aggregators or customers to deliver dispatchable demand response capacity. As such, participants relying on energy storage batteries are welcome to offer capacity into Toronto Hydro's Local Demand Response market, if they are able to provide the required service. Please see the evidence in Exhibit 2B Section E7.2 for more information about the Non-Wires Solutions program.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-8

References: **Exhibit 1B, Tab 1, Schedule 3, Page 5, Table 5**
Exhibit 1B, Tab 1, Schedule 1, Page 2
"Toronto Metropolitan University, Toronto Second Fastest Growing Metropolitan Area, City of Toronto the Fastest Growing Central City, in the United States/Canada in 2022" (May 23, 2023) <https://www.torontomu.ca/centre-urban-research-land-development/blog/blogentry7311/>
Ontario Ministry of Finance "Ontario Population Projections Update, 2022-2046" (July 19, 2023) https://www.ontario.ca/page/ontario-population-projections

<u>Preamble:</u>

In Reference 1, Toronto Hydro shows that Toronto Hydro's customer count has been slowing and is projected to average 0.3% annually in the last three years of the rate period. The same reference shows a downward trend in normalized MVA that is forecast to continue.

In Reference 2, Toronto Hydro states that "Toronto Hydro distributes electricity to Canada's largest - and North America's second fastest growing city."

Reference 4 indicates the City of Toronto's population growth rate will slow.

QUESTION (A):

a) Please explain Toronto Hydro's view of the importance of absolute increase in population as compared to the growth rate of a population in the context of planning a distribution system. Please confirm that in the context of Toronto Hydro's distribution system planning, absolute growth is a more important consideration than the rate of growth. If not, please explain.

RESPONSE (A):

Reference 1 above relates to customer and load growth changes from 2018 to 2029 for the purpose of establishing a customer and load growth forecast to determine revenue to be collected through rates, as fully described in Exhibit 3.

Reference 2 above contextualizes the size and characteristics of Toronto Hydro's system and customer base. Similar information is relied upon in the productivity evidence at Exhibit 1B, Tab 3, Schedule 3 at pages 2 to 4, wherein Toronto Hydro describes its unique characteristics as a dense urban distributor and the resulting operational challenges that it must manage in connecting and serving its customers and carrying out prudent and necessary work to keep the system safe and reliable in accordance with good utility practice.

Neither of the above references relate to growth for the purposes of distribution system planning, which is articulated in full in Exhibit 2B, and summarized in Section A of that Exhibit at page 10: "*The growth is concentrated in certain pockets, namely the downtown core and along the transit corridors, and is oriented vertically with a continuing trend of high-rise developments. This has resulted is a marked need for new housing, transit solutions, and infrastructure, all of which needs to be serviced by Toronto Hydro in the years to come*."

As outlined throughout the evidence in Exhibit 2B, distribution system planning is complex and relies on a long list of varied inputs and planning considerations. There is no single metric of growth relied upon to inform system planning.

QUESTION (B) :

b) Please reconcile the apparent discrepancy between the statement that the City of Toronto's population is growing, in absolute terms, more than other cities with Toronto Hydro's forecasts showing slowing system load growth rates and the Ontario Ministry of Finance's projections that population growth is slowing for the City of Toronto.

RESPONSE (B):

Based on the response in part (a) above, Toronto Hydro submits there is no discrepancy, as absolute growth and growth rates are referenced for different purposes in different contexts.

Both Reference 3 and Reference 4 are based on Statistics Canada data released in January 2023. Reference 3 looks at growth over the preceding 12-month period and concludes that Toronto's population grew by 138,240 people, which is second only to Dallas-Fort Worth-Arlington in the cities compared. Reference 4, on the other hand, is prospective and looks at population projections from 2022-2046. Reference 4 notes that Toronto's population is projected to rise from 3.03 million in 2022 to 4.20 million in 2046, which is the largest population gain among the census divisions, but that the rate growth of 37.7 percent is slightly slower than the provincial rate of growth of 43.6 percent.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-9

Reference: **Exhibit 1B / Tab 1 / Schedule 1 /**
Exhibit 1B / Tab 3 / Schedule 1 / pp. 8-21

Preamble:

Requesting clarification of components of individual PIM measures.

QUESTION (A):

a) Does the Total Recordable Injury Frequency PIM measure include subcontracted field resources or only Toronto Hydro employees?

RESPONSE (A):

Total Recordable Injury Frequency measure does not include subcontracted field resources. Only Toronto Hydro employees are included.

QUESTION (B):

b) Does the Emissions Reduction PIM measure include emission reductions (ex. Fleet reductions or building square footage reductions) resulting from the contracting out of work or business activities?

RESPONSE (B):

Toronto Hydro's Scope 1 emissions do not include emissions by its contractors. Similarly, Toronto Hydro's Net Zero 2040 Strategy,[1] which will contribute to the achievement of the Emissions Reduction PIM, does not include reducing Scope 1 emissions through the contracting out of work or business activities.

[1] Exhibit 2B, Section D7.

QUESTION (C):

c) Regarding Ref 2 please provide the data and calculations used to create Figure 1 and Figure 2. For Figure 1 provide the data by cause code and year including and excluding MEDs. Also include the calculation for the standard deviation.

RESPONSE (C):

Please refer to the Excel spreadsheet entitled "*1B-Staff-9 Appendix A.xlxs*" for tabular data used to prepare Figures 1 and 2, as filed, in addition to a breakdown of Figure 1 by major cause code (excluding MEDs), on a 5-year rolling average basis. The inclusion of MEDs was not considered for the reliability projections. For a detailed explanation of Toronto Hydro's Reliability Projection Methodology, see response to interrogatory 2B-SEC-42.

QUESTION (D):

d) Regarding Ref 2 Provide the detailed calculation for the 5 yr projected values of Figure 1 and Figure 2. Was each individual cause code projected? Please provide the projection per cause code? If a projection was not completed by cause code how were random failures (such as weather) versus non-random failures (such as aging defective equipment) incorporated into a single projection model? Did these projections incorporate the submitted investment plans as per the application?

RESPONSE (D):

See response to 2B-SEC-42 for more information regarding Toronto Hydro's reliability projections.

Refer to part (c) (above) for the projections broken down by Major Cause Code and supporting tabular data for the figures.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-10

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 33

Preamble:

Toronto Hydro has proposed funding for an Innovation Fund to support work that is exploratory and development in nature, where outcome is uncertain, but benefits could be significant.

QUESTION (A):

a) Please list grant funding that Toronto Hydro has applied for from different government agencies over the past 5 years, along with a list of what was granted.
    i. If Toronto Hydro has not applied, please explain why not?

RESPONSE (A):

The table below lists grant funding that Toronto Hydro has applied for from different government agencies over the past 5 years.

Table 1: Grant funding that Toronto Hydro has applied for from government agencies (5-years)

Agency	Grant/Fund	Project Name	Submitted	Granted
NRCan	Electric Vehicle Infrastructure Demonstration	MURB Parking Lot Charging Pilot	October 2019	No
NRCan	Electric Vehicle Infrastructure Demonstration	MS Fleet EV Charge Hub	October 2019	No
NRCan	Electric Vehicle Infrastructure Demonstration	Pantograph Demonstration Project	October 2019	No

Agency	Grant/Fund	Project Name	Submitted	Granted
NRCan	Zero Emission Vehicle Infrastructure Program	MURB/Workplace Chargers	June 2020	Yes $250,000
NRCan	Zero Emission Vehicle Infrastructure Program	Curbside and Fleet EV	June 2021	Yes $350,000
NRCan	Zero Emission Vehicle Infrastructure Program	Toronto Curbside EV Chargers	September 2021	No
NRCan	Zero Emission Vehicle Infrastructure Program	Customer Fleet Charging	September 2021	No
TAF	ZEVIP - SUB	CF-025 – Curbside EV	May 2022	Yes $103,000
IESO & OEB	Grid Innovation Fund & Innovation Sandbox (Joint Call)	Benefit Stacking Transmission & Distribution Non-Wires Alternatives Pilot	November 2021	Yes $2 million
IESO	Grid Innovation Fund	LSE Demonstration	November 2020	No
NRcan	Deep Retrofit Accelerator Initiative	n/a	April 2023	No
NRCan	Smart Grid Demonstration	Hosting Capacity Analysis Standardization	January 2024	In Progress
NRCan	Smart Grid Demonstration	EV Load Management Project	January 2024	In Progress

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-11

Reference: Exhibit 1B / Tab 2 / Schedule 1 / p. 34

Preamble:

Toronto Hydro states that it "decided to allocate 0.3 percent of the proposed revenue requirement to the Innovation Fund, which amounts to approximately $16 million over the 2025-2029 rate period."

QUESTION (A):

a) Please provide examples of the other jurisdictions that have this type of funding, describe their programs and with their rationale for their proposed funding levels.

RESPONSE (A):

Please refer to Toronto Hydro's response to interrogatory 1B-DRC-06 part (d).

QUESTION (B):

b) What was Toronto Hydro's rationale to conclude that 0.3% was appropriate?

RESPONSE (B):

Toronto Hydro's research revealed that utility investments across comparable innovation initiatives and research and development activities range from 0.3 to 1 percent of revenues. Recognizing the novelty of this proposal in the Ontario electricity distribution sector context, Toronto Hydro decided to adopt the low-end of this range.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-12

References: **Exhibit 1B / Tab 2 / Schedule 1, Figure 1**
Exhibit 1B / Tab 2 / Schedule 1
EB-2014-0219: Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 2014

Preamble:

Reference 1 is reproduced below:

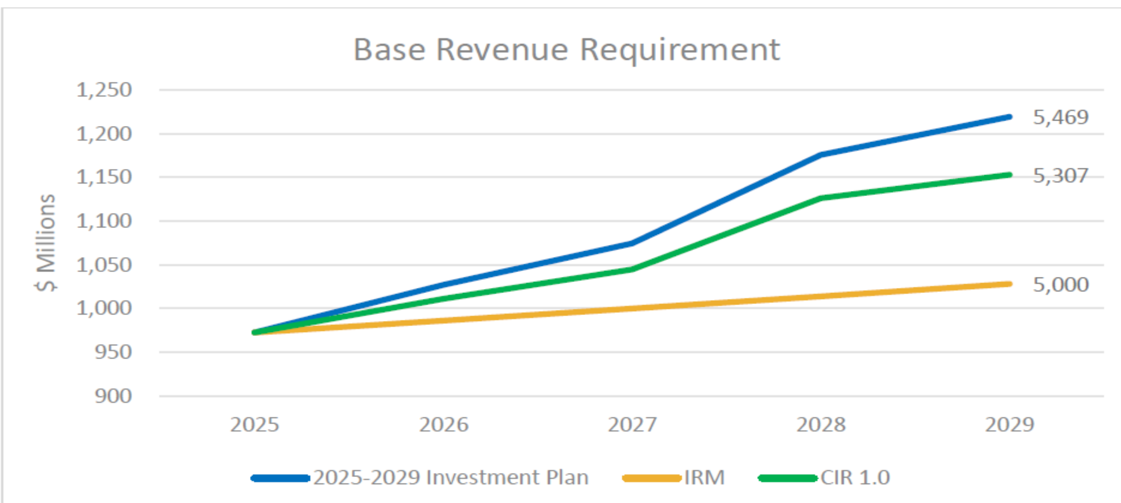


Figure 1: Cumulative 2025-2029 Base Revenue Requirement

QUESTION (A):

Please populate the following table, adding the proposed Custom Revenue Cap Index (CRCI):

Revenue Requirement ($ million, two decimal places)	2025	2026	2027	2028	2029
2025-2029 Investment Plan					
IRM					
Current Custom IR formula (Custom Price Cap Index (CPCI) / CIR 1.0)					
Proposed CRCI					

RESPONSE (A):

Table 1: 2025-2029 Revenue Projection Scenarios ($ Millions)[1]

		2025	2026	2027	2028	2029	Total
A	2025-2029 Investment Plan	972	1,027	1,074	1,176	1,219	**5,469**
B	Revenue under IRM	972	986	1,000	1,014	1,028	**5,000**
C	Revenue under CIR1.0 with Custom Price Cap Index (CPCI)	972	1,011	1,044	1,126	1,153	**5,307**
D	Revenue under proposed Custom Revenue Cap Index (CRCI)	972	1,020	1,059	1,151	1,185	**5,387**
A-B	Revenue Deficiency under IRM	0	41	75	162	191	**469**
A-C	Revenue Deficiency under CIR1.0 with Custom Price Cap Index (CPCI)	0	16	30	50	66	**162**
A-D	Revenue Deficiency under the proposed CRCI	0	7	15	25	34	**81**

QUESTION (B) :

Please populate the following table with the values that correspond with developing Reference 1:

CPCI Components	**2026**	**2027**	**2028**	**2029**
I				
X – productivity				
X – stretch				
Xcap				
Cn				
Scap				
g				
CPCI				

RESPONSE (B):

Table 2: 2025-2029 Custom Price Cap Index (CPCI) Scenario

CIR 1.0	**2026**	**2027**	**2028**	**2029**
I - Inflation	2.00%	2.00%	2.00%	2.00%
X - Productivity	0.00%	0.00%	0.00%	0.00%
X - Stretch	-0.60%	-0.60%	-0.60%	-0.60%

[1] The Revenue Requirement referenced herein will be updated as noted in the response to 1A-Staff-01.

CIR 1.0	2026	2027	2028	2029
Xcap* Scap	-0.21%	-0.21%	-0.21%	-0.21%
Cn - Cn factor	4.17%	3.53%	8.09%	2.59%
I x Scap	-1.40%	-1.40%	-1.43%	-1.43%
G - Growth	-0.20%	-0.20%	-0.20%	-0.20%
Custom Price Cap Index (CPCI)	**3.76%**	**3.12%**	**7.64%**	**2.15%**

CIR 1.0	2026	2027	2028	2029
I - Inflation	2.00%	2.00%	2.00%	2.00%
X - Productivity	0.00%	0.00%	0.00%	0.00%
X – Stretch (Non-CRRR)	-0.18%	-0.18%	-0.17%	-0.17%
Cn - Cn factor (including 0.9% Stretch)	3.54%	2.90%	7.45%	1.95%
I x Scap	-1.40%	-1.40%	-1.43%	-1.43%
G - Growth	-0.20%	-0.20%	-0.20%	-0.20%
Custom Price Cap Index (CPCI)	**3.76%**	**3.12%**	**7.64%**	**2.15%**

QUESTION (C) :

To what extent did Toronto Hydro consider other, non-Custom IR regulatory tools, such as, but not limited to, options discussed in Reference 3, to solve the funding gap identified throughout Reference 2. Please explain why Toronto Hydro rejected these other regulatory options.

RESPONSE (C):

Toronto Hydro considered all the non-custom regulatory mechanisms available under existing OEB policy. Toronto Hydro did not pursue the ICM or ACM options because the OEB policy is clear that: "*projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs*."[2] The OEB Report goes on to say that "*[t] he use of an*

[2] https://www.oeb.ca/sites/default/files/uploads/Board_ACM_ICM_Report_20140918.pdf at pp. 13-14

ACM is most appropriate for a distributor that: [a] does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding; [b] is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects).

The vast majority of Toronto Hydro's capital expenditures as outlined in the Distribution System Plan at Sections E4-E8 consist of annual capital programs, rather than discrete projects. There are only a handful of discrete projects in Toronto Hydro's 2025-2029 Distribution System Plan that are not part of the utility's annual capital plan namely: Enterprise Data Center (Exhibit 2B, Section E8.1) , ADMS (Exhibit 2B, Section E8.4, page 22), AMI2.0 as part Metering (Exhibit 2B, Section E5.4), ERP (Exhibit 2B, Section E8.4, page 21), Stations Expansion (Exhibit 2B, Section E7.4). These projects total approximately $504.0 million out of the total $3,927.8 million capital expenditure plan. Applying for ACM treatment for these projects would not have been sufficient to carry out the necessary and prudent investments outlined in the 2025-2029 Distribution System Plan. In addition, it is key to note that there is no incremental funding available under ICM or ACM options for non-capital related expenditures. Approximately $66M of the revenue deficiency identified above is attributed to non-capital related revenue requirement expenses (i.e. OM&A and Other Revenue) that exceed revenue available to fund operations under a standard Price Cap IR framework.

QUESTION (D):

Please confirm that the IRM scenario in Reference 1 does not include consideration for the capital modules available to utilities on a Price-Cap IRM. Please add an "IRM with Capital Module(s)" scenario to both Figure 1 and the table in part a).

RESPONSE (D):

Confirmed. Please refer to the response in part (f) below.

QUESTION (E):

Based on the Capital Module regulatory mechanism, which projects or initiatives, would qualify? Please explain how they would apply.

RESPONSE (E):

Please refer to the response to part (c) above.

QUESTION (F) :

Please confirm that the revenue requirement projection presented in Reference 1 includes projects that would be subject to variance account treatment in the DRVA of the proposed plan. Please calculate the residual annual revenue requirement that would result if costs of generation protection monitoring and control, externally-initiated plant relocations and expansions, Hydro One contributions, metering, and non-wire alternatives were not funded by the index. Please then adjust this for Toronto Hydro's proposed X factor and place the results as a new row in the table of part a), or a new table, whichever suites Toronto Hydro.

RESPONSE (F):

Confirmed. The requested analysis entails complex modelling of ISAs, Depreciation and PILs. Toronto Hydro does not have sufficient time to complete this analysis within the timelines for responding to IRs, but will undertake to provide this information at the Technical Conference.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-13

References: **Exhibit 1B, Tab 2, Schedule 1, Section 3.2.2**

EB-2014-0219, Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014

Preamble:

Toronto Hydro has proposed an Innovation Fund to address needs that cannot be met by existing funding mechanisms. Toronto Hydro states that the variance account proposal and resultant rate rider will provide transparency to rate payers on their bill.

QUESTION (A):

a) Please summarize Toronto Hydro's evaluation of the Incremental and Advanced Capital Modules and articulate how these mechanisms are unable to fund the work Toronto Hydro proposes for the Innovation Fund.

RESPONSE (A):

Please see the response to interrogatory 1B-Staff-12(c).

QUESTION (B):

b) Please confirm it is Toronto Hydro's proposal, that if this proposal is approved, to identify the "Innovation Fund" as a separate line item on customer bills. Please identify which customer bills are proposed to display this charge. Please explain whether Toronto Hydro will request an exemption from the regulation on invoices for low volume customers to make this charge visible to them.

RESPONSE (B):

Toronto Hydro incorrectly used the term customer bills in the context of this evidence. The utility was referring to the Tariff Sheets for the different customer classes that are included in Exhibit 8. In the context of the Tariff Sheets, the Innovation Fund rate rider is separately identified and named.

QUESTION (C):

c) Please articulate how this proposed rate rider differs from, and is superior, to an Advance Capital Module rider to provide transparency, of any form.

RESPONSE (C):

Compared to an ACM rider, the Innovation Fund rider provides more specificity on the Tariff as to the investment purpose of the amounts being collected through the rate rider.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-14

References: **Exhibit 1B, Tab 2, Schedule 1, Table 1**

Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Base Approach, October 2012

Preamble:

Reference 1 provides a comparison of Toronto Hydro's current Custom Incentive Rate-setting Framework with that which is proposed in this application.

Reference 2 states:

"The Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast."

QUESTION (A):

a) Please explain and quantify which cost and revenue deviations Toronto Hydro is managing within the rates to be over the 2025-2029 rate term, given the proposed revenue growth factor, demand-related variance account, and a revenue cap approach.

RESPONSE (A):

As noted in the response to interrogatory 1B-Staff-3, under the proposed custom rate framework Toronto Hydro forecasts its costs (and revenues) for five years, and the utility has to manage its business within those forecasts even though actual costs may differ from forecasted costs. Over a five-year term, differences between forecasted and actual costs can, and in Toronto Hydro's experience over the last ten-years, do occur due to a multitude of business factors and operating conditions that the utility is responsible for managing. These factors and conditions include, but are not limited to:

i. Utility-specific cost pressures that exceed input price adjustments provided through the standard inflation factor;

ii. New and evolving regulatory and legislative requirements;
iii. Evolving customer expectations and requirements;
iv. Market-based conditions such as supply chain constraints and labour shortages;
v. Geopolitical instability and other impactful events such as the COVID-19 pandemic;
vi. Weather-related risks including the rising risk of adverse weather due to climate change;
vii. Changes in the overall business risk profile due to factors such as asset health, system utilization, cyber security, labour market, technological advancements, etc.; and,
viii. Coordination challenges and complexities associated with doing work in a dense, congested, and growing urban environment.

For the reasons noted in Exhibit 1B, Tab 2, Schedule 1 at pages 35 to 47, Toronto Hydro's 2025-2029 Custom Rate Framework proposes specific adjustment to manage deviations in cost and revenues associated with changes in customer demand. This adjustment is provided by the *Demand Related Variance Account (DRVA)* which seeks to protect ratepayers, the utility and its shareholder, from structural unknowns in forecasted costs and revenues related to demand growth in a time of unprecedented change and transformation in the economy and energy system. The RRF issued in October 2012 could not have contemplated these unprecedented changes. Given the uncertainty that is outlined in the evidence supporting this account, the DRVA is a mechanism that enables the utility to manage within the rates set for the 2025-2029 period without having to compromise customer and/or shareholder financial outcomes that could impede progress towards beneficial electrification and/or destabilize investor confidence in Ontario's regulatory system.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-15

References: Exhibit 1B, Tab 2, Schedule 1
EB-2007-0673: Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

Preamble:

In Reference 1, Toronto Hydro makes the following statements:

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

"The needs of Toronto Hydro's 2025-29 investment plan remain unmet under the current custom framework….[Its] investment plan would be underfunded by approximately $450 million."

"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."

Table 2 of Reference 1, which is titled as "ROE Implications of the Existing Custom Framework" is reproduced below:

	2025	2026	2027	2028	2029
2025-2029 Investment Plan Revenue Requirement (A)	972	1,027	1,074	1,176	1,219
2025-2029 funding under the existing custom framework (B)	972	1,011	1,044	1,126	1,153
Variance (A) – (B)	-	16	30	50	66
ROE Impact (basis points) *	-	59.6	110.8	183.5	245.6

QUESTION (A):

a) Please provide a forecast of financial performance under a standard IRM scenario while maintaining capital expenditures as proposed in this application, detailing net income, depreciation, regulatory return on equity performance, and values which correspond to the 300 basis point dead band which may trigger a review under the OEB's rate-setting policy. Present these figures in a manner that supports comparison to the analysis contained in Table 2 of Reference 1.

RESPONSE (A):

Table 1 below provides a forecast of financial performance (ROE) under a standard IRM scenario while maintaining capital expenditures as proposed in this application.

Table 1: Financial Performance (ROE) under a standard IRM Scenario

	2025	2026	2027	2028	2029
2025-2029 Investment Plan Revenue Requirement (A)	972	1,027	1,074	1,176	1,219
2025-2029 funding under IRM (B)	972	986	1,000	1,014	1,028
Variance (C)=(A)-(B)	**-**	**41**	**75**	**162**	**191**
ROE Impact (basis points)	**-**	**151.8**	**276.2**	**599.6**	**708.4**

*Estimated where $27M per year equals approximately 100 basis points

Variance (C)	**-**	**41**	**75**	**162**	**191**
Tax impact (D) = (C) x 26.5%	-	11	20	43	51
Net Income Impact (C)-(D) (loss)	**-**	**30**	**55**	**119**	**141**

QUESTION (B):

b) Please calculate the expected change in reliability performance in the case where Toronto Hydro continues under its current custom framework, using the same methodology applied to estimate an 8% decline in reliability performance were Toronto Hydro to proceed with "a standard IRM scenario" discussed on page 13 of Reference 1 above.

RESPONSE (B):

Please see the response to 1B-SEC-21.

QUESTION (C):

c) Please discuss the acceptability of Toronto Hydro's financial performance were Toronto Hydro to continue under its current custom framework, with specific reference to the ROE impacts outlined in Table 2 of Reference 1 and the 300-basis point threshold at which a regulatory review may be initiated, in accordance with the policy established under Reference 2.

RESPONSE (C):

The financial performance associated with a continuation of the current rate framework is not acceptable. As noted in the evidence at Exhibit 1B, Tab 2, Schedule 1 at pages 14-15, the only way for Toronto Hydro to close the funding gap posed by a continuation of the current framework is through cost-reduction efforts that will *also* negatively impact customer outcomes and service levels. For this reason, a continuation of the current rate framework would effectively preclude the utility from having a reasonable opportunity (not guarantee) to earn the allowed rate of return. This is not a financially sustainable outcome for the next rate period, nor is it consistent with (i) customer needs and expectations, or (ii) the Fair Return Standard that is the bedrock of the regulatory compact.

As noted above, this is also not in the best interest of customers since the only reasonable option to manage financial performance under this outcome is to reduce prudent and necessary investments in the utility's grid, operations and workforce that will compromise outcomes that customers need and expect. For example, a deferral of work contained within the Grid Modernization Strategy at Exhibit 2B, Section D5 would mean that customers can expect a deterioration in reliability performance over the next rate period (see 1B-SEC-21), higher customer interruption costs and higher costs and system constraints in the next decade as the grid becomes more heavily utilized by customers due to electrification. Similarly, investments to increase grid capacity to connect and enable beneficial electrification, including DER adoption, could be compromised – jeopardizing customer choice and impeding progress towards energy transition goals.

Toronto Hydro does not believe that the 300 basis points off-ramp is the appropriate test to assess whether a new (or existing) rate framework will yield just and reasonable rates and outcomes for customers and the utility when a rate plan is being established. To the best of the utility's knowledge, the 300-basis points test has never been used this way in forward-looking rate application. Rather, this test has been applied to evaluate and manage the financial performance during an incentive-rate period – the most recent example being the application of this 300-basis points threshold to determine whether distributors were eligible for relief during the COVID-19 pandemic. Applying a 300 basis point off-ramp test to determine the utility's revenue adequacy and resulting rates would compromise the financial viability of the electricity sector and weaken market confidence in Ontario's regulatory system.

QUESITON (D):

d) Please describe the actions Toronto Hydro would take if ROE results were to materialize as projected in Table 2.

RESPONSE (D):

If the ROE results in Table 2 were materialize as a result of the OEB approving a rate framework that constrains the utility's revenue through the imposition of a non-empirical stretch-factor and/or the denial of funding for prudent OM&A expenses that cannot be funded under IRM, Toronto Hydro would be faced with a difficult decision to reduce necessary investment in the grid, operations and its workforce. For the reasons noted above and supported by the evidence in Exhibits 1B, 2B and 4, this decision would put customer outcomes (e.g., reliability and customer service) and energy transition objectives at risk.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-16

Reference: Ontario Energy Board, Handbook for Utility Rate Applications

<u>Preamble:</u>

At page 26, Reference 1 states:

"Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application."

QUESTION (A):

a) Please describe Toronto Hydro's proposals for continuous improvement within the rate term, with specific reference to its preference for targets to be established on a five-year basis rather than annually, as noted at page 31 of Reference 2.

RESPONSE (A):

Toronto Hydro's proposals for continuous improvements within the rate term are found both within and beyond the 2025-2029 Custom Scorecard and related targets that underpin the Performance Incentive Mechanism ("PIM").

Within the 2025-2029 Custom Scorecard and related PIM, Toronto Hydro has put forward various new performance measures and objectives that reflect the utility's ongoing commitment to continuous improvement. More specifically:

- reducing the duration of unplanned outages that customers experience;
- enhancing physical and cyber security threat detection and mitigation in accordance with NIST standards;
- advancing grid automation readiness for the horseshoe area of the grid by increasing remote operability of the distribution system and laying the foundation for self-healing;

- holding itself accountable for delivering demonstrative efficiency achievements commensurate with the expectations of the empirical stretch-factor proposed as part of the rate framework;
- tracking and reporting post-transactional customer satisfaction performance with respect to customer inquiries (phone and email), Key Accounts engagements, customer connections, and customer communications re planned outages and construction projects.
- tracking, reporting and resolving customer escalations in a timely manner.
- achieving and maintaining certification with international best practices (ISO) in various key management systems.
- reducing the company's GHG emissions in a paced and prudent manner
- expanding the scope of non-wires solutions by procuring 30MW of flexible capacity to address system capacity constraints.

The proposal for targets to be established on a five-year basis rather than annually reflect the necessary and practical considerations of: (i) operational complexity and uncertainty that the utility must manage in the normal course of business serving the needs of customers in a large, dense, urban environment; (ii) the multi-year nature of the work that utility needs to perform in order to achieve the target objectives reflects an integrated five-year plan (not five one-year plans); and (iii) the need to preserve operational flexibility within this integrated five-year plan to execute work programs effectively.

Outside of the 2025-2029 Custom Scorecard, Toronto Hydro's commitment to continuous improvement is detailed throughout the evidence. Notable examples include:

- Continuous improvement of the Asset management system, including:
    - Continue to improve the maturity of Toronto Hydro's asset risk management framework through the full implementation of the Condition Based Risk Management ("CBRM") methodology and fully embedding the Engineering Asset Investment Planning ("EAIP") solution within asset management processes, including a custom value framework to enable portfolio optimization.

  - Develop Toronto Hydro's Asset Information Strategy to improve the quality of asset data and related data sources to support improved analytics & asset management decisions, as detailed in Exhibit 2B, D1.2.1
  - Collect, store, classify, and integrate critical data to allow improvements in asset decision-making, increased operational forecasting and enable automation of processes
  - Refine the Integrated Planning and Portfolio Reporting and Execution Work Program processes for increased integration with Toronto Hydro's EAIP tool
- Continuous improvement of operational and planning functions through Grid Modernization efforts as described in Exhibit 2B, Section D5.2, including:
  - Increase real-time system awareness efficiently through the use of monitoring technology, leading to enhanced fault location while allowing improved asset management and operational decision-making
  - Consolidate outage management and distribution management systems within an Advanced Distribution Management System ("ADMS") to establish a self-healing grid, optimize the integration and management of DERs, manage two-way flow of electricity, perform advanced outage management, manage DR programs, and enhance advanced analytics effectively
  - Improve monitoring, visibility, and forecasting of DER connections, allowing the utility facilitate DERs connections more efficiently and leverage DER connections to optimize the grid
  - Leverage advancement in advanced analytics, such as Machine Learning and Artificial Intelligence tools, to develop new descriptive, predictive, and prescriptive analytical capabilities to drive process efficiency and improve decision-making
- Continuous improvement with respect to reducing distribution system line losses and increasing system capacity to support electrification through paced investments in 4kv voltage conversions.

- Continuous improvement of operational efficiency, safety, and environmental objectives through the elimination of obsolete assets and system configurations as detailed in various capital programs within Exhibit 2B, Section E6.
- Continuous improvements with respect to process automation and business modernization is supported by IT initiatives that improve operational processes and enable responsiveness towards emerging electrification objectives as described in Exhibit 4, Tab 2, Schedule 17.
- Continuous improvement with respect to operational efficiency as evidenced throughout the programmatic evidence in Exhibit 4.
- Continuous improvement with respect to reducing restricted feeders and short capacity constraints to enable timely and efficient connection of DERs
- Continuous improvement with respect to proactive investments in reducing system capacity constrains to enable timely and efficient customer connections in areas of concentrated load growth.
- Continuous improvement with respect to the pursuit of innovative pilot projects that are aligned with the OEB's objectives as set out in the Framework for Energy Innovation, and the commitment to share learnings derived from these projects with the OEBs Innovation Sandbox as outlined in Exhibit 1B, Tab 4, Schedule 2.
- Continuous improvement with respect to core tools and processes that enable efficient day-to-day operation of the distribution system, as described in Exhibit 4, Tab 2, Schedule 5, p. 17-22 and Exhibit 4, Tab 2, Schedule 7, p. 18-23.
- Continuous improvement of the ways in which customers interact with Toronto Hydro, the information they have available to them, and the ease of interacting with Toronto Hydro, as described in Exhibit 4, Tab 2, Schedule 14, p. 39-41. This section also describes improvement of customer service efficiency and effectiveness of technology solutions, process optimization, and reporting. Examples of these improvements include:
    - Providing customer and staff a view of every interaction a person has had with Toronto Hydro including bills, calls, outages and connections,
    - Enhanced knowledge management systems and quality evaluation tools to train agents faster and service customers more consistently,

- Use of analytics and advanced technologies, such as artificial intelligence to identify potential issues and take steps to avoid the issue before the customer becomes aware,
- Advanced process management and control tools to identify when a customer service is at risk of being late or incomplete, and
- Evolution of new channels such as mobile application, chatbots, and the self service portal to manage customer interactions across each stage of their journey.

- Collections segment continuous improvement includes offering additional payment options for customers, improved outstanding debt management including due date notifications, and reporting, see Exhibit 4, Tab 2, Schedule 14, p. 40.
- Continuous improvement of the Low-Income Energy Assistance Program (“LEAP”) by providing additional assistance and reaching a greater number of customers through higher grant amounts and funding, greater simplicity and assistance to customers during the sign-up process, and improved program awareness, see Exhibit 4, Tab 2, Schedule 19.

QUESTION (B):

b) What commitments, if any, does Toronto Hydro make to customers about improvements in cost and service performance to be achieved within the five-year term?

RESPONSE (B):

Please see the response above for a summary of numerous continuous improvement commitments that are form part of the utility’s 2025-2029 investment plan underpinning this rate application.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-17

References: Exhibit 1B, Tab 2, Schedule 1, Table 5
Exhibit 1B, Tab 2, Schedule 1

Preamble:

Reference 1 is reproduced below:

Table 5: Efficiency Factor (0.15%) Revenue Reduction ($ Millions)

	2025	2026	2027	2028	2029
Revenue Requirement based on the 2025-2029 Investment Plan	972.4	1,027.0	1,074.4	1,175.7	1,219.2
Revenue Collected after 0.15% Efficiency Factor	972.4	1,025.5	1,071.3	1,170.9	1,212.2
Revenue Reduced by 0.15% Efficiency Factor	-	1.5	3.1	5.0	6.9

Note: There could be minor differences due to rounding.

In addition to the proposed 0.15% efficiency factor, Toronto Hydro also proposes a 0.6% performance incentive factor, and revenue growth factor of varying degrees for each of 2026 to 2029.

QUESTION (A):

a) Please confirm Toronto Hydro agrees with the following table produced by staff. If not, please provide Toronto Hydro's table for the revenue reduction in each year due to the proposed 0.6% performance incentive factor. For any changes to the values of the table, please provide all calculations to demonstrate the derivation of the number(s).

	2025	2026	2027	2028	2029
Revenue Requirement based on the 2025-2029 Investment Plan	972.4	1,027.0	1,074.4	1,175.7	1,219.2
Revenue Collected after 0.6% PIM factor	972.4	1,021.2	1,061.8	1,156.0	1,192.2
Revenue Reduction	-	6.2	12.6	19.7	27.0

RESPONSE (A):

Please see response to 1B-Staff-3 c), which demonstrates the revenue reductions resulting from application of the 0.6% incentive component of the X Factor. The response shows minor variances from OEB Staff's prepared table above.

QUESTION (B):

b) Please confirm Toronto Hydro agrees with the following table produced by staff. If not, please provide Toronto Hydro's table for the revenue enlargement in each year due to the proposed revenue growth factor. For any changes to the values of the table, please provide all calculations to demonstrate the derivation of the number(s).

	2025	2026	2027	2028	2029
Revenue Requirement based on the 2025-2029 Investment Plan	972.4	1,027.0	1,074.4	1,175.7	1,219.2
Inflation Adjusted RGF	-	3.61%	2.62%	7.43%	1.71%
Revenue Enlargement	-	35.1	62.0	141.9	162.0

RESPONSE (B):

The table presented above would provide an accurate depiction of revenue enlargement resulting from the RGF in a scenario where the RGF was applied to unreduced revenue requirements year over year. In actual practice, the CRCI's inclusion of a two-component X Factor totaling 0.75% has the effect of reducing the base revenue requirement to which the CRCI is applied. One result of this, are RGF revenue enlargements which are smaller than those shown above. Table 1 below shows RGF revenue enlargements taking this dynamic into account:

1 **Table 1: RGF Revenue Enlargement for 2025-2029 Period**

	2025	2026	2027	2028	2029
Revenue Requirement based on 2025-2029 Investment Plan	972.4	1,027.0	1,074.4	1,175.7	1,219.2
Revenue for previous year post-CRCI (used for application of CRCI in present year)	n/a	972.4	1,019.6	1,059.1	1,151.0
Revenue Growth Factor (RGF)	n/a	3.61%	2.62%	7.43%	1.71%
RGF Revenue Enlargement	n/a	35.1	61.8	140.5	160.2

2

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-18

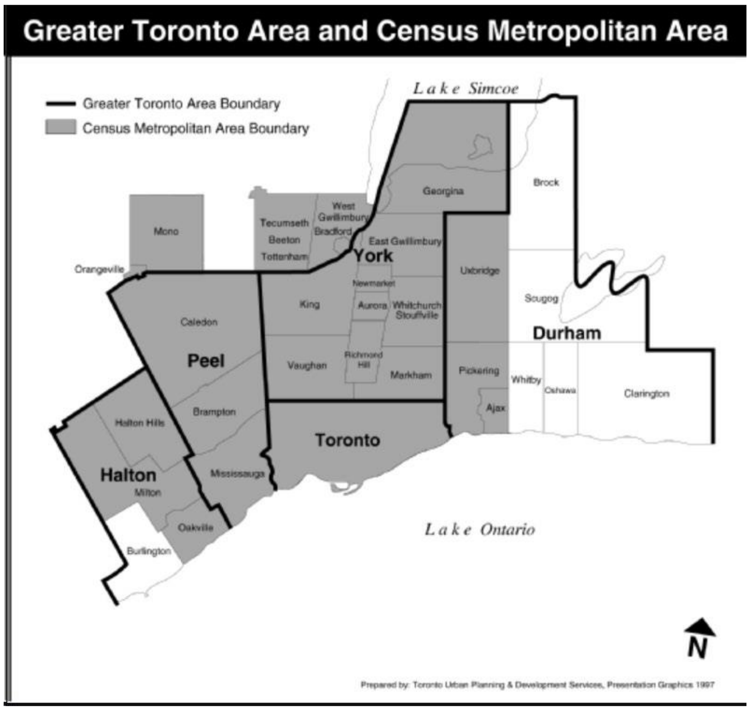
References: **Exhibit 1B, Tab 2, Schedule 1, Page. 7**
Exhibit 1B, Tab 2, Schedule 1, Table 3
Statistics Canada Map of Census Metropolitan Area 535 - Toronto, retrieved from: https://www12.statcan.gc.ca/census-recensement/geo/maps artes/pdf/S0503/2016S0503535.pdf
Simplified Toronto CMA map: https://www.toronto.ca/wp content/uploads/2017/10/90c1-EDC-Map-GTA-CMA.png

Preamble:

Toronto Hydro states that "over the 2025-2029 period, its operations and capital investment needs are growing by approximately 37.5% due to a number of distinct and interrelated drivers." These drivers include:

"Responding to the extraordinary inflationary pressures experienced over the 2020-2024 period, wherein the non-residential Construction Index in the Toronto Census Metropolitan area rose 37.7% from Q1 2020 through Q1 2023."

Reference 3 is reproduced below (Statistics Canada Map of Census Metropolitan Area 535):



QUESTION (A):

a) Please provide details of the calculations that support the claimed need for 37.5% growth in "operations and capital investment needs." In particular, what definition of cost is used? If not the revenue requirement, why use an alternative definition of cost for this commentary?

RESPONSE (A):

Table 1 below provides a summary of Toronto Hydro's growth in capital and operational investments needs comparing actual/forecast expenditures in the current 2020-2024 rate term with the forecasted expenditures in the 2025-2029 rate term. The costs referenced in this table tie back to the expenditures outlined in OEB Appendix 2-AA and 2-AB (Capital) and OEB Appendices 2J (Operational).

Table 1: Comparison of 2025-2029 vs. 2020-2024 Expenditures ($ Millions)

	2020-2024	2025-2029	Variance ($)	Variance (%)
Capital Expenditures	2,787.4	4,001.8	1,214.4	43.6%
OM&A	1,460.7	1,856.3	395.6	27.1%
Total Expenditures	**4,248.1**	**5,858.1**	**1,610.0**	**37.9%**

Expenditures are a key aspect of financial management, and tracking them is essential for budgeting and financial planning. Revenue requirement is a concept in utility regulation and rate-setting processes – it reflects the total amount of money that a utility needs to collect from its customers in order to cover its costs (i.e. OM&A, depreciation, interest expense, return on equity and PILs/taxes).

QUESTION (B) :

b) Please explain Toronto Hydro's view regarding the relationship between the design of attrition relief mechanisms and the growth rate of revenue requirement for the years of the rate term that are affected by these mechanisms. Please confirm Toronto Hydro's proposed growth rate for revenue requirement in these years, i.e., 2026 to 2029.

RESPONSE (B):

An attrition relief mechanism is designed to address the utility's revenue deficiency over the rate term. Pleases see the response to 1B-Staff-12 where Toronto Hydro shows the revenue deficiency under standard Price Cap IRM.

The revenue deficiency is informed by two key considerations: (1) the growth rate of the revenue requirement over the rate period, and (2) the growth rate of the revenues to be collected from customers through existing rates over the rate term considering any expected increases in billing determinants per the utility load forecast.

QUESTION (C) :

c) Please explain how extraordinary inflation in 2020-2024 presages rapid cost growth for the 2026-2029 period.

RESPONSE (C):

The reference upon which this question was based seems to have been misinterpreted to mean that the extraordinary inflation in the current rate term is driving the rate of growth over the next rate term. Rather, as explained above in part (a), the referenced statement denotes the absolute growth in total expenditures comparing the current 2020-2024 rate term with the 2025-2029 rate term. The extraordinary inflation that the utility experienced in the current rate term is in part driving the absolute growth in in total expenditures in the next rate term compared to the current rate term.

QUESTION (D) :

d) Please identify what other indices Toronto Hydro considered for assessing inflation for the unit costs for power distribution system construction in Toronto Hydro's service territory. Please explain how Toronto Hydro determined the non-residential Construction Index in the Toronto Census Metro Area is the most relevant index of inflation in the unit cost of power distribution system construction in its service territory.

RESPONSE (D):

Toronto Hydro believes Reference 2 intends to refer to Exhibit 1B, Tab 3, Schedule 3, Table 3, which corresponds to the data point noted.

The reference is taken from a section of the evidence that provides a retrospective look at the steps taken by Toronto Hydro to complete its work programs and manage its business during a challenging time of 40-year high inflation in Canada, and the Toronto Area. Toronto Hydro was not able to locate any specific indices to assess inflation for the unit costs for power distribution system construction in Toronto Hydro's service territory. In the absence of a more specific index, Toronto Hydro believes that the NRBCI is an instructive index for assessing the retrospective inflationary pressures of undertaking construction work in the Greater Toronto Area (GTA), which includes the City of Toronto.

QUESTION (E) :

e) Provide the filters and settings used on the Statistics Canada website to derive these values in Reference 2. Please detail the type of building and divisions selected. Explain why these filters and settings were selected and how all the categories selected are applicable to Toronto Hydro's inflationary pressures?

RESPONSE (E):

The settings selected on the Statistics Canada website were

a) Type of Building: Non-Residential Buildings
b) Division: Division Composite
c) Reference Period: Q1 2020 to Q2 2023

QUESTION (F) :

f) Please confirm the percentage land area of the Toronto Census Metropolitan Area that is served by Toronto Hydro.

RESPONSE (F):

Toronto Hydro has not completed a km^2 analysis of its service territory relative to the Toronto CMA.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-19

Reference: **Exhibit 1B, Tab 2, Schedule 1, Appendix A**

<u>Preamble:</u>

Page 2 of Reference 1, Toronto Hydro states:

> "the Company's proposed *changes* to the Rate Framework are generally consistent with how other electric *utilities* have responded to developments in the energy industry. [italics added]"

On page 3:

> "Given these developments in the energy industry, many regulatory jurisdictions have implemented changes to ratemaking frameworks and practices. These changes are designed to incorporate expanded objectives and priorities, such as clean energy goals, affordability, reliability, emission reduction, and utility financial integrity."

QUESTION (A):

a) Please confirm the following statements. If Toronto Hydro disagrees with any or all of these statements, please explain why.

   i. Toronto Hydro already operates under an approach to custom incentive rate-setting that it has dubbed CIR 1.0.

      1. This ratemaking system includes a price cap index formula with a C factor that effectively replaces capital revenue growth based primarily on inflation and productivity indexing with capital revenue growth based primarily on a cost forecast.
      2. The inflation measure in this formula includes a relevant input price index: the average weekly earnings on Ontario workers.

3. An asymmetrical Capital-Related Revenue Requirement Variance Account returns any and all capital-related revenue requirement savings to customers.
4. There is also a two-way variance account for miscellaneous externally-driven costs.

ii. Toronto Hydro's new CIR proposal entails the following changes from its old proposal.

1. A revenue growth factor ("RGF") would effectively replace OM&A as well as capital revenue growth based primarily on inflation and productivity indexing with growth that is based primarily on cost forecasts.
2. A revenue cap index would replace the price cap index, and a demand revenue variance account ("DRVA") would effectively establish weather-normalized revenue decoupling.
3. The DRVA would also establish two-way variance account treatment for a wide range of demand-sensitive costs.
4. The Capital-Related Revenue Requirement Variance Account would be discontinued.
5. There would, additionally be an Innovation Fund, a Getting Ontario Connected Act Variance Account, and PIM tied to customer service quality and various policy goals.

RESPONSE (A) - PREPARED BY SCOTTMADDEN:

i. Confirm.

1. Partially confirm. The C factor is subject to inflation and productivity factors.
2. Partially confirmed. The inflation factor includes a labour and non-labour component.
3. Confirm.
4. Confirm.

ii.

1) Partially confirm. The RGF factor is still subject to inflation and productivity factors.

2) Partially confirm. DRVA trues up billing determinants on a weather normalized basis.
3) Confirm.
4) Confirm.
5) Confirm.

QUESTION (B):

b) Does Toronto Hydro mean that each of these changes is individually consistent with industry trends or instead that many of these changes are consistent with industry trends?

RESPONSE (B) - PREPARED BY SCOTT MADDEN:

ScottMadden did not evaluate industry trends. Instead, ScottMadden evaluated Toronto Hydro's proposed custom IR plan for its relative consistency with other electric utility ratemaking frameworks and practices that support a clean energy transition. Please refer to the response to 1B-EP-23, part (a).

QUESTION (C):

c) Is Toronto Hydro stating that ratemaking in North America is moving away from the use of price and productivity indexing to escalate OM&A revenue and towards its escalation based on forecasts? If so, please substantiate.

RESPONSE (C) - PREPARED BY SCOTT MADDEN:

ScottMadden did not evaluate industry trends. Instead, ScottMadden evaluated Toronto Hydro's proposed custom IR plan for its relative consistency with other electric utility ratemaking frameworks and practices that support a clean energy transition. Please refer to the response to 1B-EP-23, part (a).

QUESTION (D):

d) Is Toronto Hydro stating that that ratemaking in North America is moving towards variance account treatment of most costs of demand growth, including the traditional costs of customer connections, billing, and collection? If so, please substantiate.

RESPONSE (D) - PREPARED BY SCOTT MADDEN:

ScottMadden did not evaluate trends in variance account treatment. Please refer to the response to 1B-EP-23, part (a).

QUESTION (E):

e) Please list the approved multi-year rate plans that Toronto Hydro thinks are most similar to Toronto Hydro's proposed CRCI plan and explain the similarities and differences.

RESPONSE (E) - PREPARED BY SCOTT MADDEN:

Please refer to Figure 1 in Exhibit 1B-2-1 Appendix A, (Review of Rate Framework), pp. 5-6.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-20

Reference: Exhibit 1B, Tab 2, Schedule 1, Appendix A, Pages 3-4.

Preamble:

Reference 1 states that:

> "The changing energy industry has prompted various modifications to ratemaking frameworks and practices. These changes are generally designed to provide cost recovery flexibility and stability to help address challenges related to the changing grid needs. Specifically, multi-year rate plans and performance-based regulation ("PBR") frameworks and practices have been modified as follows.
>
> 1. Attrition Relief Mechanisms ("ARMs") modified to reflect the scale and timing of investments.
>   − For example, regulatory jurisdictions, such as the United Kingdom ("UK"), Australia, Philippines, and Malaysia, utilize a "building blocks" approach that reflects forecasted capital investments and operations, maintenance, and administration ("OM&A") expenditures within multi-year ratemaking frameworks. This approach better aligns cost recovery with the scale and timing of capital and OM&A needs."

QUESTION:

a) Please confirm the following statements. If Toronto Hydro disagrees with any statements, please explain why.

   i. Basing ARM escalation on cost forecasts is nothing new. This approach has, for example, been used for many years for OM&A and capital costs in New York and Great Britain and for capital cost in Australia.

   ii. The British energy utility regulator Ofgem has extensive experience with cost forecasting. Insofar as Ofgem's building block approach to ARM design is based on cost forecasts, is it therefore not necessarily based on utility forecasts.

iii. Stairstep rates in New York are usually the outcome of settlements.

iv. Indexing and forecasting are not the only established bases for escalation of capital revenue in ARMs. In particular, capital revenue has been based on a utility's recent average historical plant additions (sometimes adjusted for inflation) in the out years of multi-year rate plans (MRPs) in several jurisdictions that include Alberta, California, and Massachusetts.

v. Indexing is currently used or has recently been used to escalate OM&A revenue in a number of jurisdictions that include Australia, British Columbia, Ontario, Massachusetts, and Québec.

vi. Interest is growing, not diminishing, in indexed ARMs, as evidenced by recent developments in British Columbia, Connecticut, and Indiana ratemaking.

vii. Several MRPs have no explicit provision for OM&A revenue growth other than that which results from billing determinant growth and depreciation of plant value. Examples include the "tracker/rate freeze" ARMs of Cleco Power in Louisiana, Florida Power & Light, and Appalachian Power in West Virginia.

viii. The focus on the modernization of PBR rather than ratemaking generally sidesteps the reality that MRPs are increasingly popular in North America even though these may afford more risk of cost recovery than frequent rate cases. Jurisdictions that have recently adopted MRPs include British Columbia (for BC Hydro), North Carolina and West Virginia.

RESPONSE - PREPARED BY SCOTTMADDEN:

i. Confirm.

ii. Under the RIIO-ED2 price control, Ofgem sets regulated revenues and required outputs for the electricity distribution network operators using information obtained from the companies based on activities they intend to undertake in RIIO-ED2 and their associated costs. Companies provide this information in the form of a Business Plan, and utilize the building blocks method to establish revenues based on forecasted capital and O&M expenditures for each year of the rate period.

iii. ScottMadden's review found New York utilities generally develop Joint Proposals (jointly sponsored by utilities and intervenors) based on capital spending and OM&A expense forecasts filed in their direct case. Joint Proposals are then filed before the New York Public Service Commission and subject to their approval. The Commission may approve, reject, or modify the Joint Proposals, which then forms the basis for setting electric utility rates in New York over the past several years.

iv. Utilization of historical data for capital spending forecasts in MYRP has generally been accompanied by some form of capital spending riders for electric utilities reviewed in the study.

For example, Massachusetts establishes a capital budget based on a historical five-year average of capital additions. However, the capital budget does not include capital spending for projects recovered through separate, non base rate mechanisms, such as solar, meter-related capital, and grid modernization projects.[1]

v. Confirm.

vi. ScottMadden did not evaluate trends in indexed ARMs.

vii. ScottMadden did not review the referenced utilities.

viii. ScottMadden did not review the referenced rate cases. Disagree with premise of the question. PBRs and MYRPs are not mutually exclusive. The building blocks method referenced in the report represents a form of multi-year ratemaking.

[1] Massachusetts D.P.U. 22-22, Final Order, November 30, 2022

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-21

References: Exhibit 1B, Tab 2, Schedule 1, Appendix A, Page 15
Exhibit 1B, Tab 2, Schedule 1, Appendix B

Preamble:

At Reference 1, Toronto Hydro identifies certain advantages of forecasting OM&A as well as capital costs.

Throughout Reference 2, Toronto Hydro cites Ofgem.

QUESTION:

a) Please explain Ofgem's Information Quality Incentive. Please explain the context under which the IQI was developed and implemented by Ofgem, particularly noting the regulatory risks it aims to address.

RESPONSE - PREPARED BY SCOTTMADDEN:

The Information Quality Incentive (IQI) provided an incentive to distribution companies to minimize variances between actual and forecast expenditures. The IQI mechanism was intended to address information asymmetry between Ofgem and electric distribution or network companies.

In RIIO-2, Ofgem replaced the IQI with a Business Plan Incentive (BPI) mechanism. Under BPI mechanism, companies present business plans that identify costs and outputs, such as service quality. The quality of the business plans are subject to rewards or penalties up to +/-2% of the utility revenues.[1]

[1] Jamasb, Tooraj. "Incentive Regulation of Electricity and Gas Networks in the UK: From RIIO-1 to RIIO-2." Economics of Energy & Environmental Policy, vol. 10, no. 2, Sept. 2021

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-22

Reference: Exhibit 1B, Tab 2, Schedule 1, Appendix B, Pages 3-11

Preamble:

At Reference 1, Toronto Hydro states that

"PBR mechanisms have been "modernized" to reflect energy transition.

- Modernized PBR mechanisms address cost recovery uncertainties that facilitate meeting policy objectives and utility financial health… (p. 3)
- Alternative Cost Recovery Mechanisms, such as cost trackers, provide cost recovery related to certain public policy goals (p. 5).

Modernized PBR mechanisms provide utilities with flexibility to address changing grid needs while maintaining safe and reliable service

- Address cost recovery challenges of achieving policy objectives
- Fund traditional and new investments to meet clean energy transition
- There is recognition that policy objectives cannot be achieved without ensuring cost recovery for necessary investments (p. 10)

Jurisdictions have implemented cost trackers for *traditional utility projects* and emerging cost categories (such as clean energy programs) (p. 11) [italics added]"

QUESTION:

a) Please confirm the following statements. If Toronto Hydro disagrees, please explain.

iii. In multiyear rate plans, regulators are increasingly approving cost variance accounts to encourage utility activities that advance public policy goals such as beneficial electrification and accommodation of distributed energy resources on the customer side of the meter. The cost of these activities is hard to predict accurately and utilities in some circumstances have weak incentives to pursue them. However, major expansions of distribution system (e.g. substation) capacity to accommodate the energy transition have rarely been accorded tracker treatment in MRPs to date.

iv. Cost trackers for traditional utility capex in the States (e.g., distribution system improvement charges) have usually been approved not in the context of a multiyear rate plan but instead where the alternative is frequent rate cases. Roughly half of all US jurisdictions do not employ forward test years in rate cases.

RESPONSE - PREPARED BY SCOTTMADDEN:

iii. ScottMadden did not evaluate trends in cost variance accounts. Instead, ScottMadden evaluated Toronto Hydro's proposed custom IR plan for its consistency with other electric utility ratemaking frameworks and practices that support a clean energy transition.

iv. ScottMadden is unable to confirm the first sentence; however, one of the benefits of multiyear rate plans is to avoid frequent rate cases. Specifically, capital spending trackers are designed to achieve multiple benefits, including adequate cost recovery, address uncertainties related to the magnitude and pace of investments, and avoid frequent rate cases. There are several examples of adjustment clauses that recover investments in the distribution system as part of multi-year rate plans, such as in Hawaii and Massachusetts.

- Confirmed that approximately 50.00 percent of U.S. jurisdictions do not employ forward test years in rate cases.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-23

Reference: Exhibit 1B, Tab 2, Schedule 1, Appendix B, Pages 11 and 13

Preamble:

Reference 1 states the following regarding Hawaiian electric utility regulation:

- Hawaii's Exceptional Project Recovery Mechanism (EPRM) provides cost recovery certainty for eligible projects (primarily clean energy-related infrastructure and grid modernization investments) placed in service between rate cases (p. 11)
- The Commission has taken a broad approach to eligible projects, noting that "limiting eligible projects to pre-determined plans made in other dockets may limit the flexibility to address unforeseen events or take advantage of unexpected opportunities (e.g., improvements in technology, changes in consumption behavior, etc.)" (p. 11)
- The Hawaii PUC noted, "The PBR Framework approved in this D&O has been carefully designed to include multiple safeguards and review opportunities to protect the Companies' financial health from extreme hardship" (p. 13)

QUESTION:

a) Please confirm that the Hawaii Public Utilities Commission approved a revenue cap index formula that was much more favorable to consumers than the one that the Hawaiian Electric (HECO) companies requested.

RESPONSE - PREPARED BY SCOTTMADDEN:

Scott Madden did not evaluate whether the approved revenue cap index formula was much more favorable to consumers than the one HECO requested. Scott Madden found the approved revenue cap index formula is a ratemaking framework and practice used by electric utilities to support a clean energy transition.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-24

Reference: Exhibit 1B, Tab 2, Schedule 1, Appendix B, Page 20

<u>Preamble:</u>

Reference 1 provides a table that contains a taxonomy of "ARMs Cost Forecasting Methodologies" and includes the statement that a Forecasted/"Stairstep" methodology is "based on forecasted revenue requirements."

QUESTION (A):

a) For each item in the table, please explain the forecasting methodology employed for each attrition relief mechanism (ARM). For example, please explain how a "Rate Freeze" is a cost forecasting methodology for an attrition relief mechanism. Please do so for each item in the table.

RESPONSE (A) - PREPARED BY SCOTT MADDEN:

Please refer to the table below.

Attrition Relief Mechanism	Forecasting Methodologies
Rate Freeze	Rates are set for MYRP term based on a set revenue level. Revenue growth depends on growth in billing determinants.
Forecasted/ Stairstep	Rate adjustments based primarily on multi-year forecasts
Indexed ("I-X")	Rates or revenue adjusted annually to account for inflation less a productivity factor
Hybrid	Utilize a mix of indexing and other escalation methodologies, such as indexing O&M expenses and forecasting capital costs

QUESTION (B):

b) Please confirm that some approved stairstep and hybrid ARMs have not involved much if any capital cost forecasting. Budgets for most gross plant additions (or capex) have, for example, been set for several years at an average of recent historical capex or at the approved test year value (and these budgets have sometimes been adjusted for inflation). If Toronto Hydro disagrees with any of these statements, please explain why.

RESPONSE (B) - PREPARED BY SCOTTMADDEN:

ScottMadden is unable to confirm the general statement, but denies it with respect to utilities referenced in the report. The utilities referenced in the report generally rely on capital cost forecasting for rates based on the stairstep method.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-25

Reference: Exhibit 1B, Tab 2, Schedule 1, Appendix B, Page 21

Preamble:

Toronto Hydro provides information regarding the first generation of multiyear rate plans in Alberta ("PBR1") but not later generations. In the PBR1 plans, cost trackers provided supplemental capital revenue.

QUESTION:

a) Please confirm the following statement. Insofar as Toronto Hydro disagrees, please explain.

The Alberta Commission has since approved two additional generic MRP design frameworks that it has called "PBR2" and "PBR3". In these frameworks the role of capital cost trackers and cost forecasting was greatly reduced. In each plan, most supplemental capital revenue has been provided by a "K-Bar" mechanism linked to the utility's recent historical capex. OM&A revenue has been escalated chiefly by a price cap index (for power distributors) or a revenue per customer index (for gas distributors).

RESPONSE - PREPARED BY SCOTT MADDEN:

Confirmed that the role of capital cost trackers and cost forecasting to provide supplemental capital revenue was reduced in PBR2 and PBR3 relative to PBR1. However, the role of capital cost trackers in PBR3 has not been greatly reduced as compared to PBR2. On the contrary, Alberta Utilities Commission (AUC) recognized the importance of the capital cost tracker to recover future investments related to the achievement of net-zero objectives. AUC also recognized the uncertainties related to the pace and scale of the investments, stating:

"The Commission agrees that there is the potential for net-zero objectives to drive the need for additional expenditures during the PBR3 term, and that the level of

> uncertainty and risk associated with the need for and timing of net-zero objectives makes capital investments required to respond to any such objectives unsuitable for funding through the Type 2 K-bar mechanism."[1]

The PBR3 framework also includes supplemental capital funding through the K-bar mechanism which is a formulaic approach that provides utilities with additional capital funding calculated based on average recent historical capital additions.

Finally, cost forecasting is utilized to determine the going-in rates for the PBR3 framework. The AUC set the respective 2023 (rebasing year) revenue requirements for Alberta utilities based on approved forecasted costs.[2]

[1] Alberta Utilities Commission, Decision 27388-D01-2023, p. 62
[2] Id., p. 10

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-26

Reference: Exhibit 1B, Tab 2, Schedule 1, page. 5

Preamble:

Toronto Hydro proposes to replace the Custom Price Cap Index in its current plan with a Custom Revenue Cap Index ("CRCI").

QUESTION (A):

a) Why does the CRCI formula not include an escalator for growth in the number of customers that Toronto Hydro serves and/or some other external metric of Toronto Hydro's operating scale?

RESPONSE (A):

The CRCI formula does not include such an escalator because growth is captured inherently through the revenue cap approach, relying on the billing determinants projected for each rate class in the five-year load and customer forecast in Exhibit 3, Tab 1. Please see part b) for more information.

QUESTION (B) :

b) Please confirm that, in the absence of such an escalator, the entire cost of customer growth must instead be addressed by some combination of forecasting and variance accounts.

RESPONSE (B):

In both a price cap and revenue cap, incremental revenues driven by billing determinant growth is based on the load and revenue forecast in Exhibit 3, Tab 1. The difference is with respect to <u>how</u> the forecasted growth is reflected in rates. In a price cap, the growth is captured through a top-line growth factor (i.e. g-factor). As noted in Exhibit 1B, Tab 2, Schedule 1 at page 21: *The g-factor* *translates billing determinant growth across customer count, kWh, and kVa in all rate classes into a simplistic top-line figure that is applied formulaically to base rates.* As noted in Exhibit 1B, Tab 2, Schedule 1 at pages 21, in a revenue cap, [r]*ather than escalate rates themselves each year, and use a simplistic g-factor to account for expected billing determinant growth, Toronto Hydro proposes to escalate revenue requirement each year, and design rates for each revenue requirement on the basis of forecasted customer and load growth over the rate term.*

QUESTION (C) :

c) Please describe Toronto Hydro's view on the advantages and disadvantages of a growth escalator in a revenue cap index. Please discuss any additional considerations, highlighting advantages and disadvantages, in the context of rapid growth in the number of customers in classes that are especially costly to serve.

   i. In the above context, please explain how common is it for Toronto Hydro to serve bulk-metered residential apartment buildings or condominiums or residential apartment buildings with a single or bulk meter?

   ii. What costs does Toronto Hydro incur for the ownership of assets or the provision of services inside these buildings?

RESPONSE (C):

Toronto Hydro is unclear about the definition of a "growth escalator" within the context of the question. To the degree a growth escalator is an adjustment to rates to account for growth in billing determinants over the rate term, there are no advantages to such an inclusion, as the effect would be to inappropriately account for growth in billing determinants twice. Under a Price Cap, *rates* are escalated each year based on an index. Absent an adjustment for growth, (i.e. a g-factor), the result is that the utility will retain all increased revenues resulting from increased billing determinants. In EB-2014-0116 and EB-2018-0165 a g-factor was implemented to remove a forecast of this increased revenue, on the rationale that Toronto Hydro's 5-year forecast costs should include the forecast cost of growth.

Under a Revenue Cap, *revenue requirement* is escalated each year by an index. Subsequently, the escalated revenue for each rate class is divided by the billing determinant forecast for the year to determine the rates. This adjustment reduces the rates by the expected growth in billing determinants for the year in question. The end result is a downward adjustment to rates (assuming billing determinants are forecast to increase year over year), in the same manner a Price Cap g-factor implements a downward adjustment to rates. The core difference is that the g-factor implements the adjustment on a generic, system-wide basis, while the revenue cap approach calculates adjustments on a rate class specific basis, based upon specific forecast billing determinants.

Please see response to interrogatory 2B-ED-25 for information regarding the proportion of multi-residential buildings served by Toronto Hydro which are served via bulk meter. Toronto Hydro does not incur any costs for assets not owned by the utility. For bulk metered buildings (e.g. residential apartment buildings or condominiums), Toronto Hydro owns the main service connection cable from the main distribution system to the electrical demarcation service point with the customer and the bulk meter. Toronto Hydro does not own any assets beyond this electrical demarcation point including any part of the buildings own electrical infrastructure or distribution system (e.g. panelboards, switchboard, secondary wires, and any meter provided by a third party unit sub-metering provider).

QUESTION (D):

Funding for connections to large commercial establishments can be increased using a revenue-weighted index of growth in various customer categories, such as a scale escalator in a revenue cap index formula. Please accordingly divide the number of customers served by Toronto Hydro into residential and other and, if practicable, itemize as well the revenue and customers receive general service 1,000 to 4,999 KW and larger) for the forecast period and back to 2015.

RESPONSE (D):

Tables 1 and 2 provide 2015-2029 customer numbers and distribution revenue by rate class.

Table 1: 2015-2029 Customer Numbers

Year		Residential		Non-Residential						Total
		Residential	CSMUR	GS <50 kW	GS 50-999 kW	GS 1,000-4,999 kW	Large Use	Street Lighting	USL	
2015	Actual	610,971	55,997	70,561	10,427	439	44	1	866	**749,306**
2016	Actual	611,150	65,791	70,534	10,418	438	44	1	866	**759,242**
2017	Actual	611,575	71,071	70,529	10,411	430	44	1	860	**764,921**
2018	Actual	612,262	75,028	71,266	10,470	427	42	1	839	**770,333**
2019	Actual	614,206	79,882	71,515	10,444	455	40	1	827	**777,369**
2020	Actual	614,229	83,686	71,899	10,213	480	44	1	824	**781,374**
2021	Actual	614,181	88,478	72,408	9,846	482	45	1	819	**786,258**
2022	Actual	614,926	92,126	72,614	9,731	461	42	1	799	**790,699**
2023	Bridge	615,795	94,391	72,871	9,672	455	47	1	793	**794,025**
2024	Bridge	616,778	96,411	73,152	9,685	453	46	1	793	**797,318**
2025	Forecast	617,563	98,427	73,396	9,699	451	45	1	793	**800,374**
2026	Forecast	618,292	100,404	73,632	9,712	462	48	1	793	**803,344**
2027	Forecast	618,985	102,150	73,857	9,725	460	47	1	793	**806,017**
2028	Forecast	619,849	103,674	74,165	9,740	463	46	1	793	**808,731**
2029	Forecast	620,742	104,994	74,455	9,754	461	46	1	793	**811,245**
* The Numbers are aligned with Exhibit 3, Tab 1, schedule 1, Table 2										

1 **Table 2: 2015-2029 Distribution Revenue** ($ Million)**

Year		Residential		Non-Residential						Total
		Residential	CSMUR	GS <50 kW	GS 50-999 kW	GS 1,000-4,999 kW	Large Use	Street Lighting	USL	
2015*	Actual	250.7	18.2	89.6	170.6	54.4	27.4	12.3	3.2	**626.4**
2016*	Actual	259.6	21.9	92.2	176.9	56.1	28.8	12.8	3.3	**651.5**
2017	Actual	276.4	25.6	98.8	187.7	59.1	30.8	13.7	3.6	**695.7**
2018	Actual	294.0	28.8	105.3	196.8	62.6	31.0	14.5	3.7	**736.6**
2019	Actual	306.4	32.1	109.8	202.2	64.3	30.7	16.9	3.8	**766.2**
2020*	Actual	290.1	32.3	106.6	189.1	60.1	29.3	17.0	3.3	**727.8**
2021	Actual	299.6	35.4	115.9	196.7	61.8	30.9	18.0	3.5	**761.8**
2022	Actual	304.5	37.4	121.7	205.3	65.1	30.8	18.0	3.6	**786.5**
2023	Actual	324.5	40.8	128.7	214.5	68.4	34.5	19.0	3.8	**834.3**
2024	Bridge	340.0	43.6	136.5	223.8	71.5	35.4	19.6	4.0	**874.3**
2025	**Forecast**	372.1	44.3	155.4	254.1	81.6	38.9	21.7	4.4	**972.4**
2026	**Forecast**	390.2	46.5	163.0	266.5	85.5	40.8	22.7	4.6	**1,019.7**
2027	**Forecast**	405.2	48.3	169.3	276.8	88.8	42.4	23.6	4.8	**1,059.1**
2028	**Forecast**	440.4	52.4	184.0	300.8	96.5	46.0	25.6	5.2	**1,151.0**
2029	**Forecast**	453.4	54.0	189.4	309.7	99.4	47.4	26.4	5.3	**1,185.1**

* Include foregone revenue
** The Distribution Revenue shown in the table is weather-normalized.
*** The Distribution Revenue is aligned with Exhibit 3, Tab 1, Schedule 1, Table 1

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-27

Reference: Exhibit 1B, Tab 2, Schedule 1, Pages 26-27

Preamble:

Toronto Hydro states that

"Toronto Hydro proposes to replace the Ontario Average Weekly Earnings ("ON-AWE") inflation index within the OEB's inflation factor methodology with a custom Toronto Hourly Salary and Wages Index. This index can either be derived by the Conference Board of Canada ("CBC") economic data subscription service or can be reproduced by purchasing relevant tax data from Statistics Canada. For efficiency purposes, Toronto Hydro proposes to rely on the Conference Board of Canada index."

QUESTION (A) – (E):

a) Please provide a live spreadsheet (e.g., with formulas intact) with the calculations for the proposed custom Toronto Hourly Salaries and Wages Index and a detailed description of the methodology underlying these calculations, including but not limited, to the timeseries file IDs for the Conference Board of Canada data used in the calculations and any assumptions underlying the calculations.
b) Please confirm that the salary and wages data provided by the Conference Board of Canada are derived from tax data purchased from Statistics Canada such that whether the data are purchased from the Conference Board of Canada or Statistics Canada, the result will be the same. If not confirmed, please explain why.
c) Are tax data used in the construction of Statistics Canada's indexes for Average Hourly Earnings, Average Weekly Earnings, or fixed weighted index of average hourly earnings?
d) Please provide the live spreadsheet (e.g., with formulas intact) with the calculations for Toronto Hydro's Average Blended Salary Increase (Appendix 2-K) and a detailed description

of the methodology used for these calculations including any underlying assumptions (e.g., number of hours worked).

e) Please confirm that the Alberta Utilities Commission chose the fixed-weighted index of average hourly earnings as the labor price index for its inflation factor formula in PBR3. What is Toronto Hydro's view of this alternative?

RESPONSE (A) – (E):

Please see response to 1B-Staff-93.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-28

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 25

Preamble:

Toronto Hydro states that

"Aside from achieving the objective of providing funding certainty and stability in rates which is necessary to enable effective multi-year planning and operations, the RGF offers the added benefit of simplicity relative to the current C-factor since the entire revenue requirement is being escalated by the same inflation and productivity factors. [italics added]"

QUESTION:

a) Please confirm that firms in unregulated markets have achieved effective multiyear planning and operations without funding certainty and price stability. If not, please explain.

RESPONSE:

Toronto Hydro is unsure how this question applies to a proceeding to set rates for a regulated monopoly, and cannot comment on how unregulated organizations operate in a competitive market. However, it notes that the considerations of certainty and stability in rates are echoed in the Renewed Regulatory Framework objective of setting a more flexible (multi-year) approach to rate-setting that will: "(i) enhance predictability necessary to facilitate planning and decision-making by customers and distributors; (ii) better align rate-setting with distributor planning horizons; (iii) facilitate the cost-effective and efficient implementation of distributor multi-year plans that have been developed to achieve the outcomes for customer service and cost performance; and (iv) help to manage the pace of rate increases for customers."[1] [numbering added for organization]

[1] OEB Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (October 18, 2012) at page 10.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-29

Reference: Exhibit 1B, Tab 2, Schedule 1

<u>Preamble:</u>

Toronto Hydro proposes that future revenue from the PIM-DA rate rider, if achieved, should be exempt from Earnings Sharing Mechanism treatment.

QUESTION (A):

a) Please elaborate Toronto Hydro's proposal that the future PIM-DA riders be exempt from ESM treatment. Please also articulate Toronto Hydro's view of how this potential rider would qualify as "certain adjustments" cited on page 47 of Reference 1. What other Toronto Hydro riders are, or have been, exempt from ESM treatment.

RESPONSE (A):

The PIM is a *mechanism* that proactively reduces the utility's regulated allowed earnings to the benefit of customers. As such, achievement of the PIM and receipt of any resulting incentive amounts would only return Toronto Hydro to a position of earning its OEB-approved ROE. In other words, the PIM does not contribute to earnings in excess of OEB-approved ROE. Given the ESM is explicitly in place to protect against excessive overearnings, it would be inappropriate to subject incentives received under the PIM to ESM treatment. Consequently, any recognition of PIM-related revenue (that would be captured in the PIM-DA) should be adjusted/normalized out of the ESM calculation as an "*out-of-period items and to ensure there is no double counting.*"[1] This is consistent with how the 2012-2014 ICM rate riders (i.e. *out of period items*) were treated/adjusted for the purposes of the ESM calculation in the 2015-2019 custom rate period. If adjustments are not made, and the ESM is triggered, PIM-related earnings captured in the PIM-DA, would be clawed back

[1] EB-2018-0165, Decision and Order (December 19, 2019) at page 193.

through the ESM. This treatment leads to an outcome of penalizing the utility for lost revenues that is entitled to earn-back under the PIM as proposed.

QUESTION (B) AND (C):

b) Referencing only OEB policy and other OEB regulated utilities, please provide all examples known to Toronto Hydro where an incentive measure is exempt from that utility's ESM. Please articulate how Toronto Hydro's proposal is similar to these examples.

c) Referencing only OEB policy and other OEB regulated utilities, please provide all examples known to Toronto Hydro where an incentive measure is not exempt from that utility's ESM. Please articulate how Toronto Hydro's proposal is different from these examples.

RESPONSE (B) AND (C):

Toronto Hydro is not able to comment on the particulars of how other utilities handle their ESMs. The utility notes that ESMs were established by the OEB through adjudication of major rate applications, rather than as a matter of policy. In the 2016 Rate Handbook, the OEB only mentions ESMs under rate-setting considerations for distributors undergoing consolidation, which is not applicable to Toronto Hydro's circumstances. As noted above, Toronto Hydro's proposed ESM and its interaction with the PIM-DA is consistent with the OEB's decision in previous applications, and yields a fair and reasonable outcome where the ESM does not penalize Toronto for allowed earnings which its has proactively given up and proposed to earn-back through the achievement of performance outcomes under the PIM.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-30

Reference: Exhibit 1B, Tab 2, Schedule 1, Pages 3, 30

Preamble:

Toronto Hydro proposes to add a "pro-active 0.6% performance factor" to its revenue cap index formula. Toronto Hydro further states that this factor would provide customers with "a significant upfront rate reduction benefit of approximately $ 65 million over the 2025-2029 rate term." This factor is linked to the proposed custom scorecard.

QUESTION (A):

a) Please address the notion that if Toronto Hydro does not achieve the scorecard targets, the "up front rate reduction" constitutes compensation to customers for Toronto Hydro's poor performance. In this context, please explain Toronto Hydro's view of the nature of the proposed PIM. That is, does Toronto Hydro view the PIM proposal as an asymmetrical penalty-only PIM? Please explain.

RESPONSE (A):

Toronto Hydro does not agree with the characterization posed by this question. Toronto Hydro would make every effort to complete its plan. All the PIM does is shift the risk of completing the Plan away from the ratepayer and onto the utility. Its effect is to provide incremental benefits, and decreased risks to, ratepayers. The PIM was designed to be responsive to the OEB's guidance in the last decision (EB-2018-0165) with respect to *improving the balance of risk between customers and the utility*. For more information about how the PIM achieve this balance please refer to the utility's response to 1B-SEC-13.

QUESTION (B):

b) Please explain, from a ratemaking and design perspective, Toronto Hydro's view as to why is this ratemaking treatment preferable to separate ratemaking treatment of the PIM (e.g., a penalty-only PIM not linked to the X factor or to a $65 million rate discount in the first year of the plan)?

RESPONSE (B):

The proposed PIM is preferable to the two examples posed above for the following reasons:

- Toronto Hydro infers that "penalty-only" PIM, which is not linked to the X-factor, would operate such that in the event Toronto Hydro did not achieve targeted performance, amounts would be recorded in a deferral account for future disposition to ratepayers as a credit. This proposal is inferior to the proposed PIM, as customers would not receive the upfront benefit of lower rates during the next rate term. This approach would also place less risk on the utility and more risk on customers as they would be paying for benefits in rates that may or may not be achieved.
- Regarding the proposal of a "$65 million rate discount in the first year of the plan" Toronto Hydro assumes such an approach would work as a *one-time bill credit* of $65 million in 2025. This approach creates unnecessary rate volatility (i.e. lumpiness) in that it provides a short-term rate-relief in 2025 followed by a jump in rates in 2026 when the credit expires. This approach also places unnecessary pressure on the utility's liquidity (i.e. cash flows) by forcing the utility to increase borrowing in order to pay the one-time credit in 2025.

QUESTION (C):

c) Please describe whether and how Toronto Hydro established that customers accept the PIM cost and design.

RESPONSE (C):

Toronto Hydro's approach to application-specific customer engagement focuses on understanding customers needs and preferences with respect to investment priorities (Phase 1) and preferences with respect to trade-offs between price and other outcomes (Phase 2). The insights that Toronto Hydro gained from customer engagement informed the development, refinement and finalization of the Plan, and the outcomes featured on the 2025-2029 Custom Scorecard, as described in Exhibit 1B, Tab 3, Schedule 1 at page 4. Customers were not directly consulted on the PIM design and cost because (as noted in the evidence and shown in the timeline provided in the response to 2B-SEC-32) the PIM was developed after the Plan was refined and finalized post Phase 2 Customer Engagement.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-31

Reference: Exhibit 1B / Tab 2 / Schedule 1 / pp. 30-31

Preamble:

Toronto Hydro states that

"Toronto Hydro carries the risk of achieving the performance outcomes since, if the targets are not achieved, Toronto Hydro cannot earn its approved return on equity ("ROE"). As such, the PIM is an asymmetrical incentive to the benefit of customers in that it provides Toronto Hydro with the opportunity (not the guarantee) to earn the approved ROE and make a fair return for its shareholder. It is aligned with the RRF, and responsive to the OEB's feedback in Toronto Hydro's 2020-2024 decision encouraging the utility to consider an alternative approach in the future that meets RRF requirements and improves the balance of risk between customers and the utility."

QUESTION (A):

a) Please confirm the following statements, explaining any disinclination to confirm statements.

i. If the proposed PIM were ultimately to result in a net penalty, this would compensate customers for Toronto Hydro's failing to achieve targets.

ii. Customer revenue under the proposed plan would in many cases fund activities, such as vegetation management and replacement of aging assets, that made achievement of the target possible.

iii. The asymmetrical design of the PIM improves the balance of risk between Toronto Hydro and customers in favor of customers.

RESPONSE (A):

i. Toronto Hydro disagrees with the characterization posed by the question. Please see the response to 1B-Staff-30(a).

ii. Yes, revenue collected from customers in exchange for the distribution services provided by Toronto Hydro funds the utility's capital and operations work programs. As stated in Exhibit 1B, Tab 3, Schedule 1, at page 5 the targets are based on Toronto Hydro's plan as-filed in this application.

iii. Yes. Please see the response to 1B-Staff-30(a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-32

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

Preamble:

Toronto Hydro states that

"To implement the PIM, Toronto Hydro proposes a new deferral account - the Performance Incentive Mechanism Deferral Account (PIM-DA) - to record the PIM earnings. This account would be brought forward for review and disposition in the utility's next rebasing application, based on known (or forecasted) performance results for the 2025-2029 rate period. 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. [italics added]"

QUESTION:

On what ground would TH believe the likely outcome of performance on a specific measure ought to be sufficient to dispose of the balance in the account, rather than the actual results, regardless of when they are known?

RESPONSE:

If the likely outcome of achieving a target is *probable* based on the historical results (i.e. 2025-28) and the forecasted results for the bridge year (i.e. 2028-29), Toronto Hydro believes that it would be most efficient to deal with the disposition of the incentives associated with that target in the context of the rebasing application. As noted in the response to 1B-SEC-14, in the event that a target is forecasted to be achieved, but is not in fact achieved at year-end 2029, the utility would withdraw its request to recover the associated balances in the PIM-DA at the Draft Rate Order stage which normally occurs in the first quarter of the new rate period (i.e. Q1/2030).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-33

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 30

Preamble:

Toronto Hydro states that "Toronto Hydro carries the risk of achieving the performance outcomes since, if the targets are not achieved, Toronto Hydro cannot earn its approved return on equity."

QUESTION:

Please confirm that Toronto Hydro will have other means of achieving its target ROE, including accelerated efficiency gains and unexpectedly favorable external business conditions. If Toronto Hydro disagrees, please explain.

RESPONSE:

For clarity, the statement referenced above should have read: "Toronto Hydro carries the risk of achieving the performance outcomes since [*all things being equal*], if the targets are not achieved, Toronto Hydro cannot earn its approved return on equity."

While financial performance (ROE) can be impacted by factors such as changes in external business conditions, Toronto Hydro notes that such factors are both outside the utility's control and symmetrical (i.e. unfavourable conditions are equally as likely favourable ones). Please see the response to 5-Staff-315(a) for a list of the existing and emerging business risks that Toronto Hydro faces and must continue to manage to be successful in delivering its Plan and achieving its ROE.

With respect to the example of accelerated efficiency gains, it is unrealistic to expect that under a rate framework with the highest X-factor in the province as Toronto Hydro proposed in this application, Toronto Hydro would be able to achieve its allowed rate of return through accelerated efficiency gains. The various benchmarking studies and analyses filed in this application show that

Toronto Hydro exceeds the performance of its peers when the relevant operating conditions (e.g. dense urban environment) are taken into consideration, and even without factoring in those conditions is a good cost performer relative to its peers.

The proposed 0.75% X-factor yields a cumulative revenue reduction of approximately $81 million over the rate term, as shown in the response to 1B-Staff-03(b). Given the magnitude of this revenue reduction/deficiency resulting from the X-factor and Toronto Hydro's historical track-record of harvesting efficiency gains, the utility would not be able to achieve the allowed rate of return through accelerated efficiency gains.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-34

References: **Exhibit 1B, Tab 3, Schedule 1, Table 1**
Exhibit 1B / Tab 2 / Schedule 1, Appendix A
Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Base Approach, October 2012

Preamble:

Toronto Hydro proposes linking its custom scorecard to a performance incentive mechanism. At pages 17 and 18 of Reference 2, Toronto Hydro's evidence states that Toronto Hydro's proposed performance incentive mechanisms are consistent with similar mechanisms employed by other electric utilities.

In the questions below, for any utilities that have a combined regulated business type, for example a utility with both electricity distribution and transmission, or electricity and gas distribution, or any other such combination, respond only in the context of their electricity distribution service. Also, for the questions below, only consider what has been approved through a decision and order, or equivalent regulatory action, and thus in place at this moment in time. Please do not include "proposals" or examples in a currently ongoing proceeding where the given utility has not previously had a performance incentive mechanism.

QUESTION (A):

a) Please identify how many utilities were considered as part of the jurisdictional review. How many jurisdictions/regulators/commissions? Please provide a list or table identifying each jurisdiction/regulator/commission and the number of utilities for each.

RESPONSE (A) - PREPARED BY SCOTTMADDEN:

Please refer to the table below.

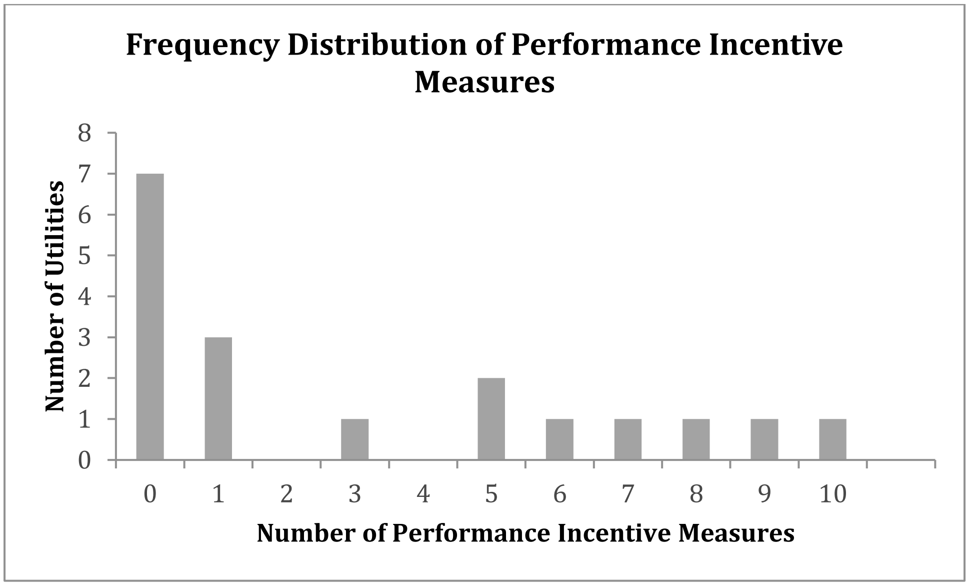
Jurisdiction	Utility
Alberta	ATCO Electric
California	SDG&E
California	PG&E
Hawaii	Hawaiian Electric
Illinois	Ameren
Maine	Central Maine Power
Massachusetts	Eversource
Minnesota	Northern States Power Company
New Jersey	PSE&G
New York	Con Edison
New York	National Grid
North Carolina	Duke Energy
Nova Scotia	Nova Scotia Power
Ohio	AEP
Pennsylvania	PECO
Rhode Island	Rhode Island Energy
UK	General Review
Vermont	Green Mountain Power

QUESTION (B):

b) For all the utilities in the jurisdictional review, provide a distribution of the number of measures in the performance incentive, with a resolution of one for the distribution. For example, how many utilities have only one measure? Two measures? And so on. As a further example, Toronto Hydro has proposed 12 measures. Please include the number of utilities that do not have any such performance incentive and thus the number of measures would be zero.

RESPONSE (B) - PREPARED BY SCOTTMADDEN:

Please refer to the figure below.[1]



QUESTION (C):

c) For all the utilities in the jurisdictional review, provide a count of utilities with: no performance incentive, penalty only performance incentive, reward only performance incentive, and mix of penalty and reward incentives. Please confirm Toronto Hydro's definition of a "penalty only performance incentive" and a "reward only performance incentive."

[1] Alberta Utilities Commission. Decision 27388-D01-2023. 2024-2028 PBR Plan for Alberta Electric and Gas Distribution Utilities. October 4, 2023; Rulemaking 14-10-003, Decision 16-12-036, California Public Utility Commission, December 15, 2016; Docket No. 2018-0088, Decision and Order No. 37507 Instituting a Proceeding to Investigate a Performance-Based Regulation, Hawaii Public Utilities Commission; Illinois Commerce Commission, Docket 22-0487, Order, December 14, 2023; Maine Public Utilities Commission, Docket No. 2022-00152, Order Approving Stipulation, June 6, 2023; Massachusetts D.P.U. 22-22, Exhibit ES-METRICS-Rebuttal-1, June 13, 2022; Minnesota Public Utilities Commission, Docket No. E-002/CI-17-401, Order, September 18, 2019; New Hampshire Public Utilities Commission, Docket No. DE 23-039, Liberty Utilities Direct Testimony, May 5, 2023; Cases 19-E-0065 et al., Consolidated Edison Company of New York, Inc. - Rates, Order Approving Electric and Gas Rate Plans (issued January 16, 2020) (2020 Rate Order); New York Public Service Commission, Niagara Mohawk Rate Case, Order Adopting Terms of Joint Proposal, January 20, 2022; North Carolina, Docket E-2, Sub 1300, Order, August 18, 2023; Nova Scotia Utility and Review Board, Decision, M10431, February 2, 2023; Rhode Island Public Utilities Commission, Docket No. 4770, Order No. 24088, July 27, 2022; Ofgem, RIIO-2 Framework Decision, July 2018; Vermont Public Utilities Commission, Case No. 22-0175-TF, Order, August 31, 2022

RESPONSE (C) - PREPARED BY SCOTTMADDEN:

Please refer to the figure below.

Jurisdiction	Utility	Penalty Only Performance Incentive	Reward Only Performance Incentive	Penalty and Reward Incentives	Total Metrics
Alberta	ATCO Electric	-	-	-	0
California	SDG&E	-	1	-	1
California	PG&E	-	1	-	1
Hawaii	Hawaiian Electric	-	3	2	5
Illinois	Ameren	-	-	1	1
Maine	Central Maine Power	6	-	-	6
Massachusetts	Eversource	7	1	-	8
Minnesota	Northern States Power Co.	-	-	-	0
New Jersey	PSE&G	-	-	-	0
New York	Con Edison	-	7	-	7
New York	National Grid	-	9	-	9
North Carolina	Duke Energy	1	2	-	3
Nova Scotia	Nova Scotia Power	-	-	-	0
Ohio	AEP	-	-	-	0
Pennsylvania	PECO	-	-	-	0
Rhode Island	Rhode Island Energy	4	1	-	5
UK RIIO	General Review	-	-	10	10
Vermont	Green Mountain Power	-	-	-	0

Under ‘penalty only’ incentives, utilities are penalized (such as through a downward adjustment in allowed revenues) if a performance target is not achieved. There is no reward or penalty if a performance target is achieved.
Under ‘reward only’ incentives, utilities are rewarded (such as through an upward adjustment in allowed revenues) if a performance target is achieved. There is no reward or penalty if the performance target is not achieved.

QUESTION (D):

d) Regarding part c), please comment on any general trends in the jurisdictional scan regarding penalty or reward incentive mechanisms. For example, is there a trend or relationship regarding incentive measures that are reliability based and whether they are penalty or reward focused? Similarly, is there a trend or relationship regarding incentive measures related to government or regulatory policy?

RESPONSE (D) - PREPARED BY SCOTTMADDEN:

ScottMadden's review did not evaluate general trends in penalty or reward incentive mechanisms. Please refer to the response to 1B-EP-23, part (a).

The report found PIMs are one of the ratemaking frameworks and practices used by utilities to support a clean energy transition. There are jurisdictions, such as New York, where incentive measures are tied to government policies.

QUESTION (E):

e) For all the utilities in the jurisdictional review, provide a count of the number of utilities that have and a count of the number of utilities that do not have a performance incentive mechanism in place, by the length of the multi-year rate period in their currently effective rate period. For utilities that have more than one type of business, provide information only for its electricity distribution service. For example, for a multi-year rate plan that was set for a period of two years, identify how many such electrical distribution utilities have an incentive, and how many do not, across the jurisdictional review.

RESPONSE (E) - PREPARED BY SCOTTMADDEN:

Please refer to the table below.

MYRP Plan Term	Utilities With Performance Incentives	Utilities Without Performance Incentives
2-Year Plan	1	0
3-Year Plan	4	2
4-Year Plan	3	1
5-Year Plan	3	1

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-35

Reference: Exhibit 1B, Tab 2, Schedule 1, Appendix A

Preamble:

Pages 17 and 18 of Reference 2 state that Toronto Hydro's proposed performance incentive mechanisms are consistent with similar mechanisms employed by other electric utilities.

QUESTIONS:

a) Please explain why the first question of Part D to Reference 1 uses the plural of "performance incentive mechanisms"? Is Toronto Hydro proposing one mechanism with multiple measures, or multiple mechanisms? Please explain.

b) If Toronto Hydro is proposing more than one mechanism, please list and describe each of the mechanisms in the context of part a).

RESPONSE (A) AND (B):

The plurality referenced above is a typographical error. Toronto Hydro proposes one mechanism with multiple measures.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-36

References: **Exhibit 1B, Tab 2, Schedule 1, Section 3.2.3**
Exhibit 9, Tab 1, Schedule 1, Section 9.2

Preamble:

With both references, Toronto Hydro proposes a subaccount to the DRVA to track externally driven capital expenditures. Toronto Hydro states it proposes a symmetrical variance account that protects both ratepayers and the utility from structural unknowns in forecasted costs and revenues. Toronto Hydro states this particular subaccount, is approved, would enable Toronto Hydro to respond to unforeseeable increases in demand-related investment needs without having to defer other priority work and put customer outcomes are risk. Toronto Hydro further states that this subaccount would protect ratepayers by ensuring that they do not pay for demand-driven work that can be deferred and that funds are not repurposed to manage variance in other programs.

QUESTION (A):

a) Please summarize the internal decision-making process that would, in the rate-setting term, evaluate Toronto Hydro's policy environment and decide to reduce capital expenditure as a response to the policy environment. Please provide examples.

RESPONSE (A):

Please refer to the evidence Exhibit 2B, Section D1 for an overview of Toronto Hydro's Asset Management (AM) process through which capital investment decisions are made. On page 18 of this evidence the utility describes how System Growth & Capacity Needs are assessed as part of the AM process. Every year, Toronto Hydro prepares a 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") using a driver based, top-down forecasting methodology. This forecast underpins the stations capacity planning process which enables Toronto Hydro to identify capacity availability and anticipated constraints at substations in relation to future load growth. Please refer to the Capacity Planning evidence in Exhibit 2B, Section D4 for more information.

QUESTION (B):

b) Please explain how Toronto Hydro would manage workforce capacity or other potential constraints, including such considerations as impact on centralized planning and coordination functions, in the face of increases in unforeseen or unforeseeable demand-related investments. Even if additional work were funded, please explain how incremental demand could be satisfied "without having to defer other priority work" while still delivering and completing the planned capital program.

RESPONSE (B):

Toronto Hydro would rely on the talent strategies identified in the Staffing evidence at Exhibit 4, Tab 4, Schedule 3 starting on page 22 to ensure that it has the resourcing capacity necessary to execute its work programs safely and effectively.

QUESTIONS (C) AND (D):

c) Please demonstrate, with examples from this current proceeding and by illustrative scenarios, how Toronto Hydro would determine a change in its stations expansion program or regional planning process was tied to an external factor and would lead to a debit entry in this proposed sub-account.

d) Please demonstrate, with examples from this current proceeding and by illustrative scenarios, how Toronto Hydro would determine a change in its stations expansion program or regional planning process was tied to an external factor and would lead to a credit entry in this proposed sub-account.

RESPONSES (C) AND (D):

The question infers that only certain types of variances would be recorded in the account. However, as all changes in demand are driven by external factors "*the Expenditure Variances subaccount <u>would record [all] symmetrical revenue requirement impacts</u>, including PILs, arising from the variance between 2025-2029 planned and actual expenditures*"[1] in the program.

Toronto Hydro would identify variances in the Stations Expansion program through the Asset Management planning processes noted in the response to part (a). For example, if the outputs of the annual System Peak Demand Forecast described in Exhibit 2B, Section D4 trigger the need for additional investment to address capacity constraints, Toronto Hydro would identify this change as a positive (debit) variance for the purposes of the account. Conversely, if the System Peak Demand forecast shows a reduction in peak demand the utility would reassess the need for certain investments, as was the case with the Scarborough TS expansion which was deferred from the 2025-2029 Investment Plan through the January 29, 2024 evidence update. This would result in a negative (credit) variance for the purposes of the account.

QUESTIONS (E) AND (F):

e) Please provide a list of all externally driven factors that occurred in the current 2020-2024 rate period that have or are anticipated to have a material impact on the need, pacing, or prioritization of Toronto Hydro's demand related expenditure plan.

f) For the items in part e), please identify commensurate measures or responses from the OEB. For any externally driven factors where the OEB provided a regulatory mechanism to respond to, identify any which Toronto Hydro decided to not use or pursue. For any such items, please explain why Toronto Hydro did not utilize the regulatory mechanism provided by the OEB.

[1] Exhibit 1B, Tab 2, Schedule 1 at page 36.

RESPONSES (E) AND (F):

In the current rate period, Toronto Hydro experienced a material increase in demand-related expenditures relative to its forecasted plan, as explained in Exhibit 2B, Section E4 and in the applicable program evidence, namely Customer Connections (Exhibit 2B, Section E5.1) and Load Demand (Exhibit 2B, Section E5.3). The demand-driven pressures in these programs were managed within the approved 2020-2024 capital envelope by reducing prudent and necessary investments in other areas of the plan, namely the underground and overhead renewal programs. For detailed evidence with respect to the uncertainty factors and considerations that may impact demand related investments in the 2025-2029 rate period please refer to the detailed evidence in Exhibit 1B, Tab 2, Schedule 1 at pages 37-46.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-37

Reference: Exhibit 1B, Tab 2, Schedule 1, p. 36

Preamble:

The DRVA would also include a Revenue Variance subaccount that "would record the revenue impacts resulting from weather-normalized variances in billing determinants (i.e. customer count, kWh and kVA)."

QUESTION (A):

a) Please provide more details of how the decoupling mechanism would work. For example, is Toronto Hydro proposing any caps on the amounts of refunds or surcharges to customers? When and how would true ups occur? Please provide numerical examples of how the true up and revenue adjustments would function.

RESPONSE (A):

To determine debits or credits to ratepayers as part of the proposed DRVA - Revenue Sub-Account, the following exercise would be completed:

- For the applicable period, compare (1) weather-normalized actual revenue to (2) forecasted revenue based the approved rates and billing determinants, for each rate class
- Determine the variance values between the actual and forecasted revenue for each rate class as noted above;
- Enter the resulting debit or credit into the Revenue Variances Sub-Account.

Toronto Hydro has not proposed any caps to debits or credits which would be entered into the Revenue Variance Sub-Account. Amounts placed in the DRVA would be brought forward for disposition in the utility's next rebasing application.

QUESTION (B) :

b) Please confirm that, in noting that the DRVA would be weather normalized, Toronto Hydro means that it would shield customers from the risk of high or low loads that result from unusual weather conditions. If not, please explain.

RESPONSE (B):

Not confirmed. The term "weather-normalized variances" refers to variances between weather-normal values. Toronto Hydro's billing determinant forecasts, by virtue of being a forecast, are weather-normalized. To calculate weather-normalized variances, actual billing determinants would be adjusted to reflect billing determinants for the year in question under a weather-normal scenario. As such, ratepayers and the utility would not be "shielded" from weather-driven variances in billing determinants.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-38

Ref 1: Exhibit 1B / Tab 2 / Schedule 1, Table 1

Preamble:

Toronto Hydro has proposed a custom incentive rate-setting framework, as summarized with Reference 1.

QUESTION(A):

a) For all parameters or components in Toronto Hydro's proposed custom framework, please provide a table identifying which of each is set as per established OEB policy and which of each is set as per the proposals set out in this application.

i) For example, Toronto Hydro proposes a 0% productivity factor in accordance with current OEB policy.

ii) For example, Toronto Hydro proposes the labour component of the industry-specific price index to be set as per this application.

RESPONSE (A):

Please see below a reproduction of the table noted in Reference 1 with the requested information.

1 **Table 1 - Comparison of Current and Proposed Custom Rate Frameworks**

	2025-2029 Custom Rate Framework	Basis for the Proposal as Requested by the IR
Year 1	Standard COS rebasing	**Consistent with OEB policy**: the RRF notes that going into PBR, distribution rates are set based on a cost of service review.[1]
Year 2	Custom Revenue Cap Index ("CRCI"): $I_n - X + RGF_n$	**Consistent with OEB policy**: the RRF provides a custom rate-setting method with an index informed by the distributor's five-year forecasts of costs and revenues.[2] **Consistent with OEB convention:** Since the RRF was implemented in October 2012, the OEB has approved 10 Custom IR rate plans, providing multi-year custom rate funding for incremental funding needs.[3] **Per this application:** Request for custom rate-funding for both capital and OM&A investments.
OM&A	Five-year plan funded through the Revenue Growth Factor ("RGF")	
Capital	Five-year plan funded through the Revenue Growth Factor ("RGF")	
Inflation	OEB Inflation Factor	**Consistent with OEB Policy**: Reliance on the OEB's annual inflation factor applicable to electricity distributors. Please see response to 1B-Staff-93.
X-Factor	0% Productivity Factor	**Consistent with OEB policy:** The OEB's annual stretch factor assignment continue to reference and rely on the 0% productivity factor in PEG's November 2013 Report.[4]
	0.75% Incentive comprised of a 0.15% efficiency factor and a 0.6% performance incentive mechanism.	**Consistent with OEB policy**: the Rate Handbook expects implementation of an X-Factor which is higher than the OEB-approved X-Factor for Price Cap IR.[5]

[1] RRF at page 11.
[2] RRF, p.18
[3] Custom IR approvals not including Ontario Power Generation and Hydro One's rejected / truncated EB-2013-0416 application: EB-2012-0459, EB-2014-0002, EB-2014-0101, EB-2014-0116, EB-2015-0004, EB-2015-0083, EB-2017-0049, EB-2018-0165, EB-2019-0261, EB-2021-0110
[4] Pacific Economics Group, Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board, November 2013, p.53
[5] Handbook for Utility Rate Applications, p.26

	2025-2029 Custom Rate Framework	Basis for the Proposal as Requested by the IR
		Per this application: A proactive incremental 0.6% performance incentive factor plus an empirically-derived 0.15% efficiency factor combining to form the proposed 0.75% X-Factor. In addition, Toronto Hydro proposes the opportunity (not the guarantee) to earn-back the revenue reductions resulting from the incremental 0.6% performance incentive factor on the basis of performance against a balanced custom scorecard.[6]
Growth	CRCI sets rates annually based on projected growth in billing determinants in each rate class	**Consistent with OEB convention:** Under standard Price Cap IR, utilities establish test year rates based on their cost of service, and subsequently retain any increased revenue resulting from growth in billing determinants during the IR term. Custom IR applicants forecast their costs and revenues over the full IR term, which historically resulted in a "growth factor" reduction to Toronto Hydro's Custom Price Cap Index. The CRCI accomplishes the same outcome by allocating escalated revenue requirement across forecast billing determinants each year, and reducing the rates by the forecasted billing determinant increases. See 1B-Staff-26(c).
Deferral and Variance Accounts (DVAs)	Demand-Related Variance Account	**Consistent with OEB policy**: Chapter 2 Filing Requirements three-part test for establishing new DVAs. **DRVA – Expenditures Sub-Account is consistent with OEB convention in past Custom IR applications:** Similar symmetrical variance accounts include Toronto Hydro Externally Driven Capital,[7] Hydro Ottawa subset of System Access Capital Additions Revenue Requirement Differential Variance Account,[8] or Hydro One Externally Driven Distribution Projects Variance Account[9]

[6] Exhibit 1B, Tab 3, Schedule 1
[7] EB-2014-0116; EB-2018-0165
[8] EB-2019-0261
[9] EB-2021-0110

	2025-2029 Custom Rate Framework	Basis for the Proposal as Requested by the IR
		Per this application: DRVA—Revenue Sub-Account
	Performance Incentive Mechanism Deferral Account	**Consistent with OEB policy**: Chapter 2 Filing Requirements three-part test for establishing new DVAs; DER Filing Guidelines include a fixed target scorecard option for setting incentives related to use of DERs and non-wires solutions. **Per this application:** use of an existing regulatory mechanism (i.e. a deferral account) to implement an innovative incentive-based rate framework proposal
	Innovation Fund Variance Account	**Consistent with OEB policy**: Chapter 2 Filing Requirements three-part test for establishing new DVAs.
	Getting Ontario Connected Act Variance Account	**Consistent with OEB policy:** Chapter 2 Filing Requirements three-part test for establishing new DVAs; Generic account established by the OEB.[10]
	Earning Sharing Mechanism	**Consistent with OEB convention:** ESMs have been approved in all but one[11] of the Custom IR frameworks referenced above.
	Property Sales	**Consistent with OEB convention:** This account was mandated by the OEB in the 2020-2024 Custom IR decision.[12]

1

[10] EB-2023-0143 – Decision and Order (October 31, 2023), Electricity Distributor Accounting Order (002-2023).
[11] Oshawa PUC EB-2014-0101
[12] EB-2018-0165, Decision and Order (December 19, 2019) at page 2 and at page 188.

QUESTION (B) :

Please explain Toronto Hydro's position regarding the potential for a generic proceeding to issue a decision during the rate term that affects a parameter or component identified in part a) and whether Toronto Hydro would seek to update it in accordance with that policy or maintain it as per this proceeding. Please indicate Toronto Hydro's position in this regard for each item.

iii) For example, if a generic proceeding resulted in a non-zero productivity factor, how would Toronto Hydro respond?

iv) For example, if a generic proceeding resulted in a change to use a different labour inflation index, how would Toronto Hydro respond?

v) For example, if a generic proceeding established a new variance account, how would Toronto Hydro respond?

RESPONSE (B):

With the exception of variance accounts which may be established by the OEB on a generic basis to deal with urgent and/or important policy or business conditions changes that the sector faces (e.g. *Getting Ontario Connected Act Variance Account*), Toronto Hydro would not update the parameter/components noted in the chart above. In order for the rate framework to provide predictability and stability to manage within the rates set, Toronto Hydro and the OEB must be committed to the rate framework approved for the duration of the rate term.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-39

References: **Exhibit 1B / Tab 2 / Schedule 1 / p. 1**
Exhibit 1B / Tab 2 / Schedule 1 / pp. 8-9
Exhibit 8 / Tab 6 / Schedule 1

Preamble:

Toronto Hydro states in Reference 1 that one of the principles that guided development of its 2025-2029 Custom Rate Framework is to "maintain rate stability and funding predictability to enable effective multi-year utility and customer planning and decision making."

In Reference 2, Toronto Hydro states that "the investment priorities and associated outcomes are aligned with customers' needs and preferences, as demonstrated by the results of Toronto Hydro's two-phased customer engagement process.

Reference 3 shows the bill impacts for various Toronto Hydro customer classes.

QUESTION (A):

How are annual residential distribution rate service charge increases averaging 7% during the proposed plan consistent with the principle of rate stability?

RESPONSE (A):

Rate stability refers to the consistency/uniformity and predictability/certainty of rates or prices in a particular market or industry over a certain period. It is a measure of how much rates fluctuate and how well they remain relatively constant/uniform, providing consumers with a sense of predictability for planning and decision-making. Stable utility rates allow households to budget more effectively, as they can anticipate and plan for their ongoing expenses without significant fluctuations (i.e. swings up and down) in their utility bills. The year over year variations in the residential distribution bill-impacts (sub-total A) are relatively uniform. By virtue of this application, the bill impacts also provide the utility and customers predictability for planning and decision-making over the 2025-2029 period.

QUESTION (B) :

Where do Toronto Hydro's customer survey results indicate that 7% annual rate increases are acceptable?

RESPONSE (B):

As noted in Exhibit 1B, Tab 5, Schedule 1, Appendix A at page 244, residential customers participating in Phase 2 customer engagement were presented with a workbook which included both annual and cumulative distribution rate impacts. Customers were not asked specifically to opine on the acceptability of the 7% annual rate increases as the rates presented to customers in the workbook were not yet smoothed.[1] Residential customers opined on the acceptability of the total distribution rate increase associated with Toronto Hydro's 2025-2029 draft plan by the end of the rate period. As noted in Exhibit 1B, Tab 5, Schedule 1, Appendix A at page 17, in total, 32,187 residential respondents completed the Phase 2 survey. Eighty percent of residential customers gave the draft plan social permission indicating either:

1. They think Toronto Hydro should accelerate spending beyond the level in the draft plan to deliver better system outcomes.
2. They support the proposed rate increase that is reflected in the draft plan, or
3. They feel that the proposed rate increase in the draft plan is necessary, even though they don't like the proposed increase.

[1] Rate smoothing occurs in the final stages of the rate-making process shortly before filing the application.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-40

Reference: Exhibit 1B, Tab 2, Schedule 1, Pages 10-11

Preamble:

Toronto Hydro states on page 10 that

"While the pace and nature of electrification required to decarbonize the economy remains unsettled, there is broad societal and public consensus that an energy transition is required to mitigate the existential and economic impacts of climate change."

Toronto Hydro states on p. 11 that

"system peak demand could grow significantly, or more moderately, depending on technology, policy and consumer choices that will be made in the future."

QUESTION (A):

a) Please confirm the following statements. If Toronto Hydro disagrees, please explain.

   i. If beneficial electrification is a public policy priority, matching capacity to demand is one of the biggest cost management challenges facing North American electric utilities.

   ii. With Toronto Hydro expecting brisk demand growth, peak load management will play a key role in cost containment.

   iii. Just as it is prudent to lay the groundwork in the next five years for future capacity expansion, it is prudent to lay the groundwork for more dynamic load management options, including distribution rate design, that reduce the need for such expansions.

   iv. The regulatory cost savings from the new multiyear rate plan will free up Company resources to reconsider rate designs and experiment with changes.

RESPONSE (A):

With respect to i) and ii) Toronto Hydro agrees that matching required system capacity to forecasted demand is a challenge facing the electricity sector, and that part of the response to this sector-wide challenge requires utilities to: (a) modernize the grid to integrate new technology that enhances system observability and controllability (see Exhibit 2B, Section D5); and (b) develop enhanced operational capabilities for load management to optimize system investments and manage costs, which includes the use of non-wires solutions, such as demand-side management programs, to complement traditional capacity planning tools, as well as rate design structure to create demand management incentives and pricing signals for customers.

Toronto Hydro has been a leader in Ontario in developing non-wires solutions capabilities by integrating the use of demand-side management into its planning process, as described in the evidence at Exhibit 2B, Section 7.2, summarized below in part (b), and further explained in the responses to interrogatories 1B-Staff-88 and 1B-Staff-89.

With respect to iii) and iv) Toronto Hydro supports an evolution towards more dynamic load management/rate design and is investing in capabilities (i.e. technology and people) to pursue experimentation in the future. However, the utility notes that distributor tariff sheets and cost allocation policies are regulated by the OEB under various codes and rate filing requirements. Outside of generic revisions to these codes and policies, utilities have an opportunity to propose changes to the rate design structures through rebasing applications, which typically take place every five-years. Thus, any experimentation that the utility may pursue on its own initiative and outside of previous approvals would have to be done under the parameters of the OEB's Innovation Sandbox.

Along with the Innovation Fund proposal outlined in Exhibit 1B, Tab 4, Schedule 2, the regulatory capacity and capabilities proposed in Exhibit 4, Tab 2, Schedule 18 would enable Toronto Hydro to innovate and experiment with new rate design structures for the next rate term.

QUESTION (B):

b) Is Toronto Hydro proposing peak load management initiatives in the next five years that are top quartile by industry standards? If not, why not?

RESPONSE (B):

For Toronto Hydro "peak load management" refers to strategies and measures employed by electric utilities and grid operators to effectively handle and mitigate the challenges associated with high demand periods. Below is a summary of generally accepted best practices and guidelines for peak demand management to ensure the reliability and stability of the electricity grid, and a brief explanation of corresponding proposals and considerations outlined in the application. In many of these areas, Toronto Hydro is taking a leadership position within the Ontario context and following in the footsteps of leaders in the North American and the UK contexts.

- **Demand Response Programs:** Implementing demand response programs allows utilities to manage peak demand by incentivizing consumers to reduce their electricity usage during periods of high demand. As discussed in more detail below, Toronto Hydro is a sector leader in utility-scale demand response in Ontario. Based on its experience, the utility has created a plan to utilize DERs for targeted load-management with quantifiable distribution benefits, and will continue to explore opportunities and develop capabilities to expand the use of non-wires in the 2025-2029 period and beyond. Please see below for more information.
- **Advanced Metering Infrastructure (AMI)**: The deployment of smart meters and advanced metering infrastructure enables more granular and real-time monitoring of electricity consumption. This data can be used to identify patterns, forecast peak demand, and implement targeted strategies for demand management. As one of the first utilities in Ontario to implement smart meters (AMI 1.0), having deployed them between 2006-2008, Toronto Hydro is investing in this technology in the next rate period and plans to replace approximately 680,000 meters with next generation AMI 2.0 meters between 2023-2028. Please see Exhibit 2B, Sections D5.2.2 and D5.3.1 for more information.
- **Energy Storage**: Integration of energy storage systems, such as batteries, can help utilities store excess energy during low-demand periods and release it during peak demand,

improving grid stability. Toronto Hydro is investing in grid-side energy storage systems to enable renewables, and explore other use cases in the process of achieving that objective. Please see Exhibit 2B, Section E7.2 for more information.

- **Pricing Signals**: Encouraging consumers and businesses to shift their electricity usage to off-peak hours can help balance the load on the grid. Toronto Hydro continues to work proactively with the OEB to implement new rate structures such as the Ultra-Low Overnight (ULO) rates and provide customer choice with respect to Time of Use (TOU) versus Tiered pricing.
- **Grid Modernization**: Investing in grid modernization technologies, such as telemetry and advanced control systems, enables utilities to monitor and control the flow of electricity more efficiently, contributing to better demand management. It also supports enhanced forecasting and planning to help utilities anticipate future peak demand scenarios and implement proactive measures to address them. Toronto Hydro's Distribution System Plan outlines a detailed Grid Modernization Strategy in Exhibit 2B, Section D5, and the utility's operations and workforce plan supports this strategy. Please see Exhibit 4, Tab 1, Schedule 1 and detailed in programmatic evidence in Exhibit 4, Tab 2, as well as the staffing evidence in Exhibit 4, Tab 4, Schedule 3.
- **Renewable Energy Integration**: Renewable energy sources, such as solar, can help diversify the sources of electricity generation. Improving the ability to monitor these resources and forecast anticipated generation can help utilities capture the value during system peaks, enhancing planning capabilities. This requires investment in grid modernization technology and capabilities as noted above.
- **Energy Efficiency Programs:** Promoting energy efficiency measures and technologies can reduce overall electricity demand, particularly during peak hours. Toronto Hydro continues to support the IESO's CDM framework, including Local Initiatives programs, and will identify opportunities to benefit-stack where appropriate.

Active Peak Load Management Initiatives at Toronto Hydro

Toronto Hydro's flagship NWS program, Local Demand response ("LDR"), has been running since 2018 and is intended to continue in the 2025-2029 rate period with a target to triple the amount of system capacity (30MW) procured from flexible resources to support six stations across the city.

The focus on the six identified stations (i.e., Finch TS, Manby TS, and Leslie TS, Cecil TS, Strachan TS, and Copeland TS) is due to the high potential for NWSs to defer or avoid capital expenditure in these areas, based on system needs. Cumulatively, these stations will require about 130 MVA of load-transfers in the next rate-period, and if Toronto Hydro is able to successfully procure 30 MW of demand response, this could help avoid about 25% percent of the total load required to be transferred in these areas.

Setting a 30 MW target for demand-side capacity to defer or displace 25% of traditional capacity investments is ambitious given the current DER market capacity and maturity. To the best of Toronto Hydro's knowledge, it is also unprecedented by any other local distribution company in Ontario, given that the OEB only recently published its Framework for Energy Innovation (January 2023), Filing Guidelines for DERs (April 2023) and Benefit Cost Assessment Framework (October 2023).

Sector-Wide Peak Load Management Projects and Thought Leadership

Toronto Hydro has also demonstrated leadership in the area of NWS through its Benefit Stacking Transmission and Distribution Pilot ("Benefit Stacking Pilot"), supported by the IESO's Grid Innovation Fund, and the Ontario Energy Board's (OEB's) Innovation Sandbox. Toronto Hydro identified an opportunity to build on the LDR program planned for Manby TS and Horner TS to examine how Toronto Hydro and other distributors can work with IESO to better coordinate the use NWSs to maximize value and lower resource acquisition costs. Toronto Hydro partnered with Power Advisory LLC and Toronto Metropolitan University's CUE, to create a project that explores how to efficiently procure and deploy DR capacity to address overlapping distribution and transmission system level needs.

Toronto Hydro is an active member of the Transmission-Distribution Coordination Working Group (TDWG), established to support the IESO, LDCs, DER owners, and aggregators to develop operational coordination protocols intended to improve DER integration into local and bulk markets. Toronto Hydro has volunteered to co-lead, in partnership with Alectra, the development of a Functional Assessment work package that identifies the operational functions, capabilities, and tools required for utilities to support such coordination. Details about this work and all the deliverables can be found on the IESO's website (https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Transmission-Distribution-Coordination-Working-Group).

Future DER Usage and Capability Building at Toronto Hydro

As noted here and in the pre-filed evidence, the current scope of Toronto Hydro's NWS program applies to *dispatchable demand response*, and this is because Toronto Hydro has a high-degree of confidence that these resources can be deployed reliably to meet an identified grid need. To be able to leverage other types of DERs*, particularly non-dispatchable resources*, as part of distribution planning and system management, it is essential to first have well-developed tools for grid observability. As demonstrated through the work of the TDWG, distribution utilities in Ontario are in the process of identifying the level of DER visibility required to be able to reliably predict generation patterns and the resulting grid impact.

In addition to the procurement and use of NWSs, as well as thought leadership and collaboration with energy sector stakeholders, Toronto Hydro has also made a significant effort to track, monitor and observe DERs currently connected to its system. Developing this situational awareness will enable utilities to credibly and reliably factor in forecasted DER generation in future capacity planning activities. Toronto Hydro currently requires SCADA telemetry for all DERs greater than 50 kW, and is undertaking several projects, including the AMI 2.0 initiative, which could significantly improve monitoring capabilities for DERs (discussed in detail in Exhibit 2B Section D5.3.1). Please see Exhibit 2B Section D5.2.2.3 for more information.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-41

References: **Exhibit 1B, Tab 2, Schedule 1, Section 3.2.3**
Exhibit 9, Tab 1, Schedule 1, Section 9.2
EB-2010-0060: Review of Distribution Revenue Decoupling Mechanisms, Pacific Economics Group Research, LLC, March 2010

Preamble:

Toronto Hydro proposes a revenue variance subaccount as part of the proposed demand related variance account. Toronto Hydro proposes this subaccount to symmetrically record revenue variances resulting from differences between forecasted and actual billing determinants on a weather normalized basis, doing so by rate class. Toronto Hydro states this account would record the revenue impact due to variances in billing determinants, kVA, kWh, and customer count, as set out in Exhibit 3, Tab 1.

QUESTION (A):

a) Please explain any differences between the proposed normalization process and that used for forecasting customer load for rate setting purposes as part of this application. Please confirm all billing determinants Toronto Hydro proposes to weather-normalize, such as kVA, kWh, customer count, or other variables if applicable and not explicitly mentioned in the evidence. For each, please explain why it is appropriate to do so.

RESPONSE (A):

There are no differences between the proposed normalization process and the process used for forecasting customer load. Toronto Hydro confirms its intention to weather normalize only KWh and kVA and no other variable.

QUESTION (B) :

b) Please confirm whether Toronto Hydro proposes to only track variances on a weather normalized basis, or to also normalize for other identifiable variances in energy usage such as economic and population factors that are also captured in its load forecasting methodology.

RESPONSE (B):

Toronto Hydro proposes to track all variances on a weather normalized basis. Stated differently, no other normalizing calculations outside of weather normalization will be completed for the purpose of making entries to the Revenue Variances Sub-Account.

QUESTION (C):

c) Please identify the data sets that underly the proposed variance account normalization process. Historically, how often has Toronto Hydro reviewed and updated these data sets? Please describe the circumstances under which Toronto Hydro would review and update these data sets in the future.

RESPONSE (C):

Please see weather-related drivers such as CDD, HDD and dew point that underlie the proposed variance account normalization process, as outlined in Exhibit 3, Tab 1, Schedule 1, page 9 and Appendices A-B of Exhibit 3, Tab 1, Schedule 1. Historically, there were no revenues subject to similar symmetrical variance account treatment as the proposed sub-account. The HDD, CDD, and dew point regression coefficients defined in the load forecast of Exhibit 3 in the rate application, once approved will remain for the duration of the rate period.

QUESTION (D)

d) Identify any other data sets or assumptions that Toronto Hydro would utilize in this weather normalization process. Similar to b), when is the last time these data sets were updated. Under what circumstances would Toronto review and update these data sets?

RESPONSE (D):

Please see subpart c) above.

QUESTION (E) :

e) By way of both monthly summary tables and any underlying calculations and modelling, please demonstrate the proposed "weather-normalization process for actual billing determinants" and the resulting account additions for each of:

   i. 2020 actual in comparison the forecast(s) that underly the rates in place that year, i.e., those of EB-2018-0165
   ii. 2023 actual in comparison the forecast(s) that underly the rates in place that year, i.e., those of EB-2018-0165
   iii. 2023 actual in comparison to the 2019 forecast(s) that underly this proceeding

RESPONSE (E):

Please refer to 1B-SEC-16, Table 2. These variances would have formed entries to the DRVA Revenue Variances Sub-Account, if the account were in place at the time.

QUESTION (F):

f) For part e), please explicitly identify inputs and outputs to the process, including any intermediate steps or steps where one model, tool, or methodology interacts with another in the overall process. Please identify which data items are held constant as the reference forecast(s) and which items are inputs based on actual data. For all inputs, identify the source. Please identify any data variables that are calculated, derived, or otherwise require a mathematical operation to perform the process to derive variance account entries. Please explain the basis for those operations. For example, if a piece of recorded data requires conversion or "normalization" identify the operation and the technical basis for the mathematical operation.

RESPONSE (F):

Please see the response to part c) above and 1B-Staff-37 a).

QUESTION (G):

g) Please confirm that, in accordance with footnote 40 in Reference 1 and Reference 3, Toronto Hydro is proposing a variance account that will allow revenues to track costs. Is Toronto Hydro proposing a variance account that allows revenues to fully track costs, or only partially? Please explain.

RESPONSE (G):

Toronto Hydro proposes to book variances in distribution revenue to the DRVA Revenue Variances Sub-Account on a weather normalized basis, that is, on a partially decoupled basis.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-42

Reference: Exhibit 1B, Tab 2, Schedule 1, Pages 36, 41

<u>Preamble:</u>

Toronto Hydro proposes a Demand-Related Variance Account ("DRVA") with two subaccounts (p. 36). An Expenditure Variances subaccount

"would record the symmetrical revenue requirement impacts, including PILs, arising from the variance between 2025-2029 planned and actual expenditures related to the following capital and operations programs: Customer Connections, Customer Operations, Stations Expansion, Load Demand, Non-Wires Solutions, Generation Protection Monitoring and Control and Externally-Initiated Plant Relocations and Expansions (collectively the "Demand-Related Investments")."

Toronto Hydro states on p. 41 that

"In circumstances where demand-related investments are lower than planned, the subaccount would protect ratepayers by ensuring that (i) they do not pay for demand-driven work that can be deferred, and (ii) funds are not repurposed to manage variances in other aspects of the plan that are not driven by demand."

QUESTION (A):

a) Please provide analysis which demonstrates that the use of a variance account best serves customers from a cost perspective, including, but not limited to, the aggressive use of load management and other techniques to efficiently accommodate demand growth and other changes in system use.

RESPONSE (A):

In circumstances where demand-related investments can be adjusted down based on updated forecasting inputs, the subaccount would protect ratepayers by ensuring that (i) they do not pay for demand-driven work that can be deferred, and (ii) funds are not repurposed to offset variances in other aspects of the plan that are not driven by demand. Such circumstances can occur due to a number of factors, including the impact of greater use of load management techniques, material changes in economic conditions that slow down the pace of growth in forecasted demand, or market constraints that alter the adoption of electrified technologies such as EVs. For more information about the use of "use of load management techniques" please see Toronto Hydro's response to interrgoatory 1B-Staff-40.

QUESTION (B):

b) Why is it necessary to track the entirety of these various costs when

ix) a sizable share of these costs will result from normal demand growth;

x) a customer growth escalator can address many/most costs of customer connections and customer operations with minimal regulatory cost or diminution of cost-containment incentives;

xi) variance account treatment is less controversial and likely to be approved for costs of NWAs, beneficial electrification, generation protection monitoring and control, Getting Ontario Connected Act compliance, and externally-initiated plant relocations and expansions.

RESPONSE (B):

Please refer to Exhibit 1B, Tab 2, Schedule 1 at pages 37 to 46 for detailed evidence of the need and justification for the Expenditure Variance Subaccount.

Implicit in this question is an assumption that what was "normal load growth" in the past will continue in the future. It is evident that the future will not be like the past in terms of load and demand. For example, and as noted in the above-referenced evidence at pages 38-39, Toronto Hydro saw a significant increase in the volume and complexity of load connections in the current rate period. From 2020 to 2022, high voltage connections (which often require system expansion work) increased by 27.6 percent, with a substantial increase in larger commercial and multi-use projects requiring greater than 10 MVA of demand load per project, as well data centers with larger loads (e.g., 30-50 MVA) than ever before. These circumstances resulted in gross expenditures in the Customer Connections program that are expected to be approximately 1.75 times greater than the forecast that formed the basis of 2020-2024 rates. As a result, capital in-service additions related to demand-driven investments in System Access were approximately $153 million (32.5 percent) greater than the amounts included in base rates in the current period.

A "*customer growth escalator*" does not address the business concern underlying the proposed DRVA. As noted in the above-referenced evidence at page 35, due to a confluence of external factors (i.e., policy, technology and consumer behaviour changes) Toronto Hydro is entering a period of unprecedented change and transformation, as customers, communities and governments at all levels are actively embarking on an energy transition to mitigate the existential and economic impacts of climate change. Decarbonization is expected to create new roles for electricity, including as an energy source for transportation and building heating systems. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g., the pace and adoption of electrified technologies such as EVs and heat pumps; the role of low-emission gas; and the scale of local vs. bulk electricity supply). A "*customer growth escalator"* would fail to address the noted concerns with respect to uncertainty and variability in demand, and would not provide Toronto Hydro the necessary flexibility to manage demand-driven aspects of its plan in order to protect both rate payers and the utility from structural unknowns in forecasted costs and revenues.

Toronto Hydro believes that many of the same considerations which render the listed programs/priorities more likely to be approved for variance account treatment, apply to the other programs that form part of the DRVA Expenditure Account proposal, as detailed in Exhibit 1B, Tab 2, Schedule 1 at pages 37 to 46:

- **Customer Connections and Customer Operations:** Investments in these programs are driven by the utility's fundamental obligation to serve customers who want to connect to the system. In addition to enabling beneficial electrification, the need for investment is also driven by other important policy considerations, including governments' priorities to accelerate transit and housing development.[1]

- **Stations Expansions and Load Demand:** Investments in these programs are subject to an ongoing regional planning process. Outputs of that process, which may extend beyond the timelines for adjudicating this application, or additional updates to regional plans that may be necessary during the 2025-29 rate term, could modify planned investments under the Stations Expansion and Load Demand programs. For example, Station Expansion projects such as Scarborough TS and Load Demand investments in the Horseshoe area of the grid, which were deferred through the evidence updated filed on January 29, 2024 may have to be pulled forward if needs in these areas of the grid exceed current expectations due to either (or both) *normal demand growth* and *beneficial electrification*.

[1] https://news.ontario.ca/en/backgrounder/1002525/more-homes-built-faster-act-2022

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-43

Reference: Exhibit 1B, Tab 3, Schedule 1, Page 10

<u>Preamble:</u>

Toronto Hydro states: "While the projection suggests that Toronto Hydro's investment plan is sufficient only to maintain Outage Duration as measured by the custom SAIDI metric over the 2025-2029 period, the utility challenged itself to set a modest improvement target, recognizing the importance of outage duration to customers when it comes to reliability performance. To set an achievable improvement target, Toronto Hydro calculated the statistical variability of the historical rolling five-year average (relative to the historical trendline), and on this basis applied two standard deviations to the most recent five-year historical reliability (48.2 min), resulting in an improvement target of 46.2 min."

QUESTION (A):

a) Does Toronto Hydro expect more or fewer scheduled outages for the 2025-2029 period than the previous 5-year period?

RESPONSE (A):

Toronto Hydro expects an increase in the number of scheduled outages during the 2025-2029 rate period compared to the 2020-2024 rate period. This increase is driven by the increase in expenditures within the 2025-2029 Distribution System Plan ('DSP') required deliver on the objectives of the plan.

QUESTION (B):

b) What were Toronto Hydro's projections of SAIDI using the IRM Scenario in the previous application?

RESPONSE (B):

Toronto Hydro did not include a SAIDI projection for an IRM scenario as part of its reliability projections in its previous rate application.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-44

References: **Exhibit 1B, Tab 3, Schedule 1, Pages 3 and 4**
Exhibit 1B, Tab 3, Schedule 1, Table 1
Amended and Restated Shareholder Direction Relating to Toronto Hydro Corporation retrieved from:
https://www.torontohydro.com/documents/20143/411589/Shareholder-Direction THC.pdf/4b8173bf-751e-82df-8593-90c61f33550c?t=1554134778000

Preamble:

Toronto Hydro proposes an incentive mechanism that would allow it to "earn-back" forgone revenue by achieving specific targets. Toronto Hydro proposes targets related to, generally, system reliability, customer service, environmental initiatives, and initiatives related to enhancing the grid for the future. The City of Toronto, as shareholder, has set objectives and principles to guide the Toronto Hydro Corporation, and thus, Toronto Hydro. The objectives and principles include providing a reliable and effective distribution system and operating Toronto Hydro in an environmentally responsible manner consistent with the City of Toronto's energy and climate change policies. The City of Toronto has established numerous energy and climate change policies that Toronto Hydro references throughout this application.

QUESTIONS (A) AND (B):

a) Please explain why Toronto Hydro propose a supplemental incentive mechanism to meet objectives established by its shareholder.
b) Please explain why the objectives and principles set by Toronto Hydro's shareholder are insufficient for Toronto Hydro to meet the reliability, customer service, environmental, and grid enhancement initiatives set out in its 2025-2029 investment plan.

RESPONSES (A) AND (B):

The proposed incentive mechanism applies to distribution-related business activities that are subject to rate regulation by the OEB in accordance with the *Ontario Energy Board Act, 1998*. Toronto Hydro has proposed a plan which meets the needs of its customers and its system within the present-day context of a pending energy transition. This plan is aligned with and responsive to the shareholder's objectives, which is also the municipal authority governing Toronto Hydro's service territory.

Over the upcoming 2025-2029 rate term, the proposed performance incentive mechanism (PIM) reduces the utility's revenue by approximately $65 million, relative to the revenue required to fund capital and operations work programs as part of the 2025-2029 Investment Plan. The PIM puts at risk approximately 14% of the incremental revenue that the utility needs to fund the 2025-2029 Investment Plan, compared to standard Price-Cap IR as shown in the response to 1B-Staff-12.

In the absence of a performance incentive that provides Toronto Hydro the opportunity (not the guarantee) to recover this lost revenue in order to be able to earn its allowed regulated rate of return, the utility would be faced with a difficult decision to reduce prudent and necessary investment in the grid, operations and its workforce putting customer outcomes, grid needs and shareholder objectives at risk.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-45

References: Exhibit 1B, Tab 3, Schedule 1
Exhibit 1B, Tab 3, Schedule 3

Preamble:

On page 42 of Reference 1, Toronto Hydro states that it "expects to achieve efficiencies of approximately $5.6M per year by 2024, consisting of $1.5M of cost reductions and $4.1M in cost avoidances."

On page 16 of Reference 2, Toronto Hydro states that the 2025 rebasing revenue requirement "is approximately $5.7M lower than it otherwise would be if Toronto Hydro had not undertaken" more than 30 initiatives which constitute a collective value of "over $23 million in costs that the utility expects to avoid or reduce by the end of the rate term."

QUESTION (A):

a) Please explain whether the $5.6 million figure of Reference 1, and the $5.7 million figure of Reference 2 denote the same annual savings activities.

RESPONSE (A):

Confirmed. $5.6 million in 2024 annual savings escalated for inflation (2%) results in $5.7 million in 2025 annual savings.

QUESTION (B):

b) Please explain the relationships between the $23 million, $4.1 million, and $1.5 million cited.

RESPONSE (B):

$4.1 million and $1.5 million are annual figures applicable to 2024, whereas $23 million is the cumulative five-year total from 2020-2024.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-46

Reference: **Exhibit 1B / Tab 3 / Schedule 1, Table 1**
Decision and Order, EB-2018-0165, December 19, 2019, Table 4

Preamble:

Toronto Hydro has proposed a 2025-2029 custom scorecard with 12 measures. In its EB-2018-0165 Decision and Order, the OEB set a 2020-2024 custom scorecard with 15 measures.

QUESTIONS (A) – (C):

a) Please confirm, by a list identifying each, which items in the proposed 2025-2029 custom scorecard are exactly the same measure as the 2020-2024 scorecard measure, without considering the target itself.
b) Please list and explain the rationale supporting all measures that have the same or similar name, but Toronto Hydro proposes a different definition of the measure for 2025-2029.
c) For each applicable measure, please explain the rationale supporting the removal of a 2020-2024 scorecard measure from the 2025-2029 scorecard.

RESPONSE (A) – (C):

The 2025-2029 scorecard represents an evolution over the 2020-2024 scorecard. Reliability, customer service, efficiency, safety and environmental outcomes continue to be key areas of performance focus in the 2025-2029 scorecard, but the measures that the utility has proposed to reflect these outcomes have evolved in accordance with the expanded investment objectives, customer needs and priorities, changing business conditions and the rate framework that underpins the plan.

Direct similarities between the two scorecards can be found with respect to reliability (SAIDI & SAIFI) and safety (TRIF) metrics. For 2025-2029 Toronto Hydro proposes to measure SAIDI excluding scheduled outages, Loss of Supply and Major Event Day (rather than on SAIDI Defective Equipment as in the 2020-2024 period) for the following reason, which is articulated in the evidence at Exhibit 1B, Tab 3, Schedule 1 at page 9: *Toronto Hydro intends to improve Outage Duration performance … compared to historical performance. This objective aligns with customer needs and priorities based on the Phase 1 Customer Engagement survey results which revealed that when it comes to reliability performance all customers (except Key Accounts) prioritize reducing the overall length of outages rather than the overall number of outages.*"

As requested, the table below explains the continuity and concordance of the 2020-2024 scorecard metrics in the 2025-2029 scorecard.

2020-24 Custom Measures	Continuity to 2025-29 Custom Scorecard
Customers on eBills	Since 2013, Toronto Hydro converted approximately 381,000 customers, exceeding its target of reaching 347,000 customers on eBills by 2024.[1] Although Toronto Hydro intends to continue to monitor and proactively manage this metric[2], the initial penetration targets have been exceeded, and practices and cultures to drive further eBill adoption are well established. What's more, this metric measures one input that is relevant to the customer experience. Consistent with evolving to focus on measuring outcomes that matter to customers, Toronto Hydro is replacing this metric with two customer satisfaction and experience metrics.
Network Units Modernization	The Network Condition Monitoring and Control program is winding down in 2026. This measure was replaced with a complimentary grid automation readiness metric.
FESI-7 **FESI-6 Large Customers**	Toronto Hydro is supportive of developing more granular reliability metrics. However, recent upgrades to the utility's network management system and analytics had a material impact on the number of very small outages captured by record keeping systems, making it impractical to carry-over these measures without sufficient historical data to re-baseline

[1] Exhibit 1B, Tab 3, Schedule 2 at Section 3.1 (page 22).
[2] Exhibit 4, Tab 2, Schedule 4 at Page 4.

2020-24 Custom Measures	Continuity to 2025-29 Custom Scorecard
	performance that meaningfully reflects customer-specific reliability experience.
MAIFI	As noted in the pre-filed evidence in EB-2018-0165, Toronto Hydro cannot track this metric accurately. As Toronto Hydro modernizes its system, the incremental observability will capture more momentary interruptions making it impractical to carry-over this measure without sufficient historical data to re-baseline performance.
System Capacity	Toronto Hydro did not include this metric because there is greater uncertainty as to the timing and specific location of capacity constraints on the grid. Please see Exhibit 2B, Section D4. The utility is replacing this metric with one that focuses on timely customer connections to the grid.
System Health (Asset Condition) – Wood Poles	Performance is managed as part of the Asset Management System which Toronto Hydro intends to certify under internally recognized standards (ISO55001). The reliability performance impact of these metrics is reflected in the proposed SAIFI (Defective Equipment) and SAIDI measures.
Direct Buried Cable Replacement	
Average Wood Pole Replacement Cost ▪	Replaced with a comprehensive Efficiency Achievements custom measure, which includes a target that is tied to the utility's empirical stretch-factor proposed as part of the custom rate framework.
Vegetation Management Cost per Km	
Oil Spills Containing PCBs	Performance is managed as part of the Environmental Management System which is certified with international standards under ISO14001.
Waste Diversion Rate	

QUESTION (D) :

For each measure and target on the proposed custom scorecard, please identify which initiatives would not be pursued in the absence of a performance incentive related to the initiative. For each such measure, please explain why not.

RESPONSE (D) :

The 2025-2029 Investment Plan, its performance objectives, and the Custom Rate Framework are an integrated proposal to meet the needs of Toronto Hydro's system and customers. The performance incentive mechanism (PIM) is a complimentary part of this proposal to improve the balance of risk between the utility and ratepayers. The PIM itself does not drive or justify the need for specific investments or initiatives within the plan. For more information please see 1B-Staff-52(a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-47

References: **Exhibit 1B, Tab 3, Schedule 1**
Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 2012

Preamble:

With Reference 1, Toronto Hydro describes its overall PIM proposal as an outcomes-based performance framework. Toronto Hydro provides some explanation for the proposed performance measures within this framework.

QUESTION (A):

a) Regarding system security, Toronto Hydro proposes to earn a performance incentive for the completion of a range of cybersecurity projects. Please explain why the completion of planned projects, which represent milestones rather than a measurable outcome, merits an incentive payment within an outcomes-based performance framework.

RESPONSE (A):

Toronto Hydro disagrees with the characterization of cybersecurity improvements as "milestones." Completion of each cybersecurity project *is* an important outcome, as they enhance Toronto Hydro's cybersecurity posture, and reduce exposure to threats. Further, cybersecurity threats are dynamic in nature, and are expected to vary widely in number and variety over time; limiting the degree to which pre-emptive targets for threat defence can be credibly established. Toronto Hydro's targets seek to reward the desired outcome (i.e. robust and resilience cybersecurity) rather than measure against a hypothetical baseline wherein cybersecurity is inadequate.

QUESTION (B):

b) Similarly, regarding grid automation readiness, Toronto Hydro proposes to earn a performance incentive for carrying out projects. Please explain why the completion of planned projects merits an incentive payment.

RESPONSE (B):

Similar to the above, Toronto Hydro submits the achievement of a state of grid modernization readiness is a desired outcome, which unlocks significant value for customers (e.g., improved reliability), while providing a core building block for proliferation of more electrified technologies and the connection of an increasing numbers of DERs onto its system. The use of an incentive mechanism, as is the case with all functioning incentive mechanisms, improves the prospects of Toronto Hydro maintaining the focus and commitment required to realize this important outcome, in a business environment marked by consistent competition for funding and management focus.

QUESTION (C) :

c) Regarding grid automation readiness, please explain the contribution of the 23 projects included in the custom measure, including manual FLISR, to Toronto Hydro's expected reliability performance over the term.

RESPONSE (C):

The 23 projects refer to the technology required to enable manual FLISR at all 20 transformer stations in the Horseshoe area, plus three software enhancements to enable auto FLISR. These projects are not expected to contribute materially to Toronto Hydro's reliability performance in the 2025-2029 period. However, Toronto Hydro does expect them to contribute materially to reliability performance in 2030 and beyond, once auto FLISR is operational.

QUESTION (D) :

d) Please explain any overlap between the PIM measures related to reliability and related to the results associated with grid automation readiness outlined in c)

RESPONSE (D):

The Grid Automation Readiness measure includes the subset of SCADA switch installations from the Contingency Enhancement program (Exhibit 2B, Section E7.1.3.1) that are required to enable automatic FLISR implementation across 90% of the Horseshoe beginning in 2030. These switches will provide some modest reliability benefits during the 2025-2029 period, and are therefore included in the reliability projections that underpin the Outage Duration and Outage Frequency PIM targets.

QUESTION (E) :

e) Toronto Hydro provides a qualitative rationale for the selection of 99% as a target for timely connection of new services, which mentions expected growth in demand, DER connections and expected complexity. Please explain whether there is a quantitative basis for selecting a 99% target for timely connections of new services and provide it as part of this response.

RESPONSE (E):

Yes, the quantitative basis for selecting a 99% target is Toronto Hydro’s 2014-2022 average performance on this metric, which has been 98.36%.

To maintain performance at this level, despite the growth and electrification challenges expected during the 2025-2029 rate period, Toronto Hydro will continue a range of initiatives focused on enhancing timely customer communication, streamlining project planning, optimizing workflows, improving coordination with internal and external stakeholders, and refining asset investment planning.

QUESTION (F) :

f) Please provide annual results for TH’s on-time performance related to new connections since 2014, both in aggregate and for the three connection categories identified.

RESPONSE (F):

Connection Type (weighting)	2014	2015	2016	2017	2018	2019	2020	2021	2022
Low Voltage (70%)	91.49%	96.91%	97.67%	98.32%	99.80%	99.74%	99.73%	99.86%	99.89%
High Voltage (20%)	100.00%	100.00%	100.00%	98.41%	100.00%	99.28%	100.00%	99.26%	99.19%
DER Connections and assessments (10%)	98.56%	100.00%	100.00%	86.75%	100.00%	100.00%	100.00%	96.16%	94.63%
Combined Performance	93.90%	97.83%	98.37%	97.18%	99.86%	99.68%	99.81%	99.37%	99.22%

QUESTION (G) :

g) Please explain the justification for a performance outcome associated with maintaining current customer satisfaction levels in the context of the OEB's statement that "the [Renewed Regulatory Framework] is intended to elevate utility performance by creating incentives for superior performance."

RESPONSE (G):

As noted throughout Toronto Hydro's application, the business environment in which it is operating is marked by both increasing complexity and workload. The result is a heightening of competition for funding and management attention when circumstances materialize in the rate term, necessitating targeted incentives for the most important objectives expected of the utility. As noted in the question, the OEB expects superior performance. An appropriate and targeted incentive will significantly increase the probability Toronto Hydro is able to maintain superior customer satisfaction.

QUESTION (H) :

h) Please provide in table form annual data, from 2014 to 2022, on Toronto Hydro's success in resolving escalated customer inquiries within 10 days.

RESPONSE (H):

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Escalation Resolution Percentage within 10 Days	97.13%	95.63%	97.13%	98.17%	98.53%	98.52%	98.28%	98.71%	99.46%

QUESTION (I) :

i) Please quantify transportation fuel savings over the 2025-2029 period arising from the adoption of electric vehicles in accordance with projections indicated in the table entitled 'GHG Emissions (Scope 1') on page 37 of Reference 1.

RESPONSE (I):

Toronto Hydro estimates the following approximate efficiency savings for the 2025-2029 rate period:

- 110,000 litres in fuel savings;
- $168,000 in fuel expenditure savings; and
- 266 tonne to carbon dioxide equivalent ("tCO2e") greenhouse gas reductions.

QUSTION (J) :

j) Please confirm whether emissions from contracting out of work or business activities, that could reduce fleet size or building square footage, are included. Please explain Toronto Hydro's choice.

RESPONSE (J):

Please refer to Toronto Hydro's response to 1-Staff-9(b).

QUSTION (K) :

k) Please explain whether Toronto Hydro will quantify emissions reductions from the portion of its vehicle fleet that will not be electrified, such as through reduced idling time. If it does not plan to do so, please explain why.

RESPONSE (K):

Yes, Toronto Hydro will continue to monitor and take measures to reduce emissions from the portion of its vehicle fleet that will not be electrified, including through reducing idling time.

QUESTION (L) :

l) Please provide the business case underpinning Toronto Hydro's decision to pursue ISO 550001 certification, including any calculations, estimates or representations of the benefits and costs of doing so.

RESPONSE (L):

Toronto Hydro's decision to pursue ISO 55001 certification is based on the need to continuously improve in asset management, align with internationally recognized best practices and voluntarily be held accountable through independent audits. A formal cost benefit analysis was not undertaken for this initiative; however, Toronto Hydro qualitatively assessed the benefits of pursuing the ISO 55001 Certification prior to undertaking this initiative as the benefits were aligned with Toronto Hydro's goals to continuously improve in asset management. Please refer to Exhibit 2B, Section D1, pages 2 to 3 for Toronto Hydro's commitment to achieving ISO 55001 Certification.

QUESTION (M) :

m) Please provide the business cases underpinning maintenance of ISO 140001 and 450001 certifications, including costs and benefits of doing so or failing to do so.

RESPONSE (M):

The maintenance of the ISO 14001 and 45001 certifications is intended to re-enforce the ongoing framework that enables Toronto Hydro to focus on achieving legal compliance, demonstrating continual improvement, preventing employee injuries, and protecting the environment.
The direct costs associated with completing the audit needed to maintain these ISO certifications averaged $17,025 annually from 2021-2023. These certifications have led to significant benefits including mitigating EHS risks, reduction in injuries and improving environmental performance, all

of which has a positive impact on productivity, costs, and organizational reputation. The ongoing maintenance of the ISO standards following the annual audit increases Toronto Hydro's accountability and ensures that the elements of the ISO standards are maintained, legal compliance is achieved and continual improvement opportunities are pursued.

QUESTION (N) :

n) Does the Total Recordable Injury Frequency PIM metric include subcontracted field resources or only Toronto Hydro employees?

RESPONSE (N):

Please refer to Toronto Hydro's response to 1B-Staff-9(a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-48

Reference: Exhibit 1B, Tab 3, Schedule 1

<u>Preamble:</u>

On pages 2, 7, and 43 of Reference 1, Toronto Hydro has proposed a stretch or efficiency factor of 0.15%, valued at $16.4 million over the term. Achieving the stretch factor is forecast to represent a sustained savings of $6.9M per year by 2029. Toronto Hydro has assigned a performance incentive to the achievement of these forecast efficiency achievements, valued at 15% of the $65M total PIM performance factor.

QUESTION (A):

a) Please confirm the value of the PIM attached to efficiency savings, which appears to be $9.75M (15% of $65M).

RESPONSE (A):

The total proposed incentive is $65 million based on performance against a balanced scorecard. 15% of scorecard achievement is assigned to Efficiency Achievements. 15% of $65 million is $9.75 million.

QUESTIONS (B) AND (C):

b) Please recalculate the value of the stretch factor net of the achievement of the PIMs, or confirm that it is 0.09% ((9.75/16.4)*(0.15)). Please show all calculations.

c) Please explain the rationale for this stretch factor design and net value, including its interaction within the PIMs framework, and with reference to the OEB's standard stretch factor values.

RESPONSE (B) AND (C):

The empirically-derived stretch factor of 0.15% proposed for the 2025 to 2029 rate term is not, and will not be net of any PIM achievement. Customers will directly receive the benefits of reduced rates through the 2025 to 2029 term as a result of the 0.15% stretch factor, which will not be adjusted for any PIM achievement. The purpose of the Efficiency Achievement metric, as articulated on page 42 of Exhibit 1B, Tab 3, Schedule 1, is "*holding the utility accountable for delivering sustained (and quantifiable) efficiency benefits to customers in the next rebasing application*."

The purpose of the Efficiency Achievement metric is to improve the incentive signals which are otherwise naturally embedded in incentive regulation; specifically, near-term cost control. One potential route to financial incentives under standard incentive regulation is the pursuit of short-duration cost cutting, or the deferral of important capital work which will ultimately result in back-logged and increased spending in subsequent years. The Efficiency Achievement metric requires that the utility demonstrate the achievement of sustained savings which would persist into subsequent rate terms. Please see 1B-SEC-20 (f) for more information.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-49

Reference: Exhibit 1B, Tab 3, Schedule 1

Preamble:

Table 18 of Reference 1, which outlines the net present value (NPV) of the benefits of capital deferral and avoidance based on the Local Demand Response (LDR) program proposed for the scored, is reproduced below.

	Deferred Capital	**Avoided Capital**
Parameters	$2.50 million in load transfer capital investment deferred for 5 years at an operational cost of $0.71 million	$7.50 million in load transfer capital investment avoided over the life of the assets (48 years) at an operational cost of $4.99 million
Costs	NPV of the operational costs of the non- wires solution (2025-2029): $0.57 million + NPV of the revenue requirement associated with the load transfer capital investment to be made in 2030: $1.80 million = $2.37 million NPV Costs	NPV of the operational costs of the non- wires solution (2025-2029): $4.00 million
Benefits	NPV of revenue requirement associated with capital investment deferred from 2025-29: $2.42 million *Less (-)* NPV Costs: $2.37 million *Equals (=)* $55.07 thousand NPV Benefits	NPV of revenue requirement associated with capital investment avoided in 2025 over the 48-year EUL: $7.27 million *Less (-)* NPV Costs: $4.00 million *Equals (=)* $3.27 million NPV Benefits
Total NPV Benefits =$3.32 million		

Table 19 of Reference 1 is reproduced below.

	Deferred Capital	Avoided Capital
Approach	Quantify the net present value (NPV) of the foregone ROE associated with the deferred and avoided capital investments.	
Parameters	$2.50 million in load transfer capital investment deferred for 5 years (i.e. from 2025 to 2030)	$7.50 million in load transfer capital investment avoided over the estimated useful life (EUL) of the assets (48 years)
Lost NPV of ROE	NPV of foregone ROE: $0.99 million *Less (-)* NPV of ROE associated with capital investment in 2030: $0.73 million *Equals (=)* $0.26 million NPV of Foregone ROE[29]	NPV of Foregone ROE: $2.97 million
Total NPV of Foregone Revenue: $3.23 Million		

QUESTION:

Please provide detailed calculations that show the derivation of all amounts shown in tables 18 and 19.

RESPONSE:

Please find attached as an appendix to this response a live spreadsheet with the detailed calculations requested. In the process of preparing this interrogatory response Toronto Hydro discovered a minor typographical error in Table 19. The Total NPV of Foregone Revenue is $3.22 million, and not $3.23 million as stated in the written evidence.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-50

Reference: Exhibit 1B, Tab 3, Schedule 1

Preamble:

In Reference 1, Toronto Hydro provides some information regarding local demand response (LDR).

QUESTION:

Please explain the basis for the assumption that "5 years of LDR is sufficient to avoid the capital investment," citing examples or direct experience if available.

RESPONSE:

The assumption of 5 years is based on experience and engineering planner judgement. As noted in Exhibit 2B Section E.7 on pages 10-12, Toronto Hydro has been successful in avoiding incremental load transfers in the Manby TS and Horner TS service areas through the application of targeted demand response. This has allowed Toronto Hydro to reassess the need for these load transfers each year and make the decision to defer them. By the end of the five-year rate-period, the load transfers were no longer necessary. The assumption of five years is subject to change based on the specific area targeted and was selected for the purpose of planning based on the best available assumptions and information at this time.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-51

Reference: Exhibit 1B, Tab 3, Schedule 1

<u>Preamble:</u>

In Reference 1, Toronto Hydro provides some information regarding new High Voltage and Low Voltage connections. Toronto Hydro provides the value of the benefit of the connection on the basis of overall average loads for the given customer groups.

Question (A):

a) For a representative sample of new HV and LV connections, please provide the actual average customer load during the first 21 days following a new HV connection, and 13.5 days following a new LV connection.

RESPONSE (A):

Toronto Hydro is unable to derive a representative sample within the timelines for responding to interrogatories. As explained in more detail in part (b) below, a representative sample would require a relatively large number of data points. Extracting this information entails a labor-intensive manual effort as the data cannot be processed automatically. To be helpful, below Toronto Hydro provides a few examples (categorized by rate class) of customer load during the first days following a new connection.

Table 1: Examples (by rate class) of customer load in the first days following a new connection

HV Connections – Large Users
There have been four customers connected in 2021-2023. 1. A customer was connected in 2022. A new customer owned substation for existing customer was installed and connected. Average load for this customer in the first 21 days was 1.25MW. 2. A customer was connected in 2022. The connection was completed three months prior to the opening to the public. The average load in the first 21 days since the connection was 14kW, with a max demand of 22kW.

HV Connections – GS 1MW-5MW
There have been about 30 customers connected each year in 2021-2023. 1. A condo tower in Etobicoke was connected in the Fall of 2021. At time of connection, the tower was in the final stages of the construction. The average load in the first 21 days since the connection was 52kW, with a max demand of 119KW. 2. A metal fabrication manufacturing site was switched from overhead supply to underground supply and a new pad-mounted transformer was installed in spring 2022. The average load in the first 21 days was 104kW, with a max demand of 471kW. 3. A condo tower was connected in Summer 2022. Construction started about seven years ago and is nearing its completion. The average load in the first 21 days was 21kW, with a max demand of 70kW.
HV Connections – GS 50KW-1000KW
There have been about 90 customers connected each year in 2021-2023. 1. A complex of townhouses was connected in Spring of 2023. The project was in the development for more than 10 years, construction started in 2020, and at the time of the connection, the complex was still under construction. The average load in the first 21 days since the connection was 33kW, with a max demand of 75KW. 2. A two-storey office-industrial building was connected in Fall 2023. The building was in the final stages of its completion. The average load was 20kW, with a max demand of 64kW. 3. A condominium complex was connected in Spring 2023. The condominium is still under construction. The average load in the first 21 days since the connection was 34kW, with a max demand of 84KW.
LV Connections
There have been more than 5,000 LV connections in the recent years. 1. House in Etobicoke, connected in November 2023. The average load in the first 13.5 days was 0.24kW, with a max demand of 1.25kW. 2. House in Old Toronto, connected in August 2023. The average load in the first 13.5 days was 0.11kW, with a max demand of 2.28kW. 3. House in North York, connected in January 2023. The average load in the first 13.5 days was 0.02kW, with a max demand of 0.32kW.

QUESTION (B):

b) For part a), please provide the total number of new HV and LV connections to identify the proportion of the representative samples relative to the total.

RESPONSE (B):

The table below lists the total number of HV and LV connections reported to the OEB through RRR:

Table 2: Number of HV and LV Connections

Year	LV Connections	HV Connections
2019	5826	138
2020	7041	87
2021	4932	135
2022	5260	123

To determine whether a data sample is representative or not, several key pieces of information are needed. These data help ensure that the sample accurately reflects the broader population from which it is drawn, thereby allowing for generalizations to be made with a reasonable degree of confidence. The challenge of achieving representativeness is particularly pronounced in the context of new service connections, where the diversity of customer types necessitates a larger sample size to draw accurate conclusions.

HV connections have diverse customer categories, including Large users (5MW+), GS 1MW-5MW, and GS 50KW-1000KW customers. Each category requires a representative sample to accurately reflect its population. Large User connections are occasional and distinct, making it difficult for a small number of samples from this group to represent the entire category. Similarly, the 1MW-5MW connection category encompasses a wide range of customers, such as industrial sites, hospitals, educational institutions, and residential buildings, each with unique characteristics. The GS 50KW-1000KW category also presents a challenge due to the varied nature of its customers, who differ in physical size, capacity, and energy needs.

The representativeness of data is critical in dynamic areas like energy consumption, where the timing of data collection can significantly influence the accuracy of insights. A representative sample must account for seasonal variations and different days of the week to capture the full spectrum of energy consumption patterns among HV and LV connections.

Furthermore, the greater the variability in characteristics of interest within the population, the larger the sample size required to capture this diversity accurately. In the case of new HV and LV connections, variability can arise from differences in consumption patterns, peak loads, and the effects of industry-specific factors on energy usage.

QUESTION (C):

c) Please recalculate the value of the benefit of connection, using the same customer interruption cost and other inputs, but based on the actual average load in those post-connection periods rather than the overall average loads of these customer groups.

RESPONSE (C):

As noted above, due to time constraints and the manual process required for data extraction, Toronto Hydro is unable to gather hundreds of data samples for HV and LV connections to compile a representative sample. Furthermore, undertaking such an extensive sampling effort is unlikely to yield significant insights.

The load immediately following connection may not accurately represent the customer's operational load. This initial period is often used for business setup or residential preparations rather than full-scale operations or living, leading to a discrepancy between immediate and operational energy usage. Delays in electrical connections can have cascading effects on subsequent phases of the construction and setup process, such as postponing heavy equipment installation, delaying testing and commissioning, and affecting the issuance of occupancy permits. Electrical connections are critical to the timely progression of these stages, highlighting their broader economic significance to customers.

This concept is illustrated by LV connection examples in part b), where the observed electricity consumption significantly increased after the initial low-usage period. For instance, a house in Etobicoke showed an average consumption increase to 1.8kW in the eight days following an initial period of 0.24kW, or seven times higher consumption. Similarly, increases were observed in Old Toronto and North York (respectively, 40 and 15 times higher), demonstrating the potential delay in occupancy and normal electricity usage that could result from postponed connections.

Given these considerations, Toronto Hydro maintains that using an average load for the purpose of benefit calculation remains the most appropriate approach for the purpose of a macro-level benefits analysis. This method acknowledges the variability and uncertainty inherent in the early stages of a new connection and provides a more stable and reliable basis for calculating connection benefits. While the desire for precise data is understandable, it is important to recognize that the benefits derived from new connections are indicative (not exact), and that the purpose of the analysis is to reflect the broader economic and social impacts of Toronto Hydro's services, acknowledging that delays in electrical connections can significantly influence the overall timelines and plans of businesses and residents.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-52

Reference: Exhibit 1B, Tab 3, Schedule 1, Table 1

Preamble:

With Reference 1, Toronto Hydro shows the proposed 2025-2029 custom scorecard with 12 measures and targets.

QUESTION (A):

a) Please reproduce Reference 1 with the following information:
   i. A column which indicates the total revenue requirement during the rate term of all identified key programs associated with the delivery of the result, as detailed throughout Reference 1.
   ii. A column which indicates the dollar value of the PIM at proposed weight and total PIM envelope of $65M as proposed.
   iii. A column which indicates the calculated value of customer benefits realized in the 2025-2029 period (as identified in Table 21, p. 57, or elsewhere if applicable).
   iv. A column which indicates the ratio of iii) to ii) for each proposed PIM

RESPONSE (A):

Please see attached a table which lists each of the 12 scorecard metrics and targets, alongside a column which assign a proportion of the proposed $65 million incentive to each metric, and a column which assigns a proportion of quantifiable benefits realized over 2025 to 2029, as presented in Exhibit 1B, Tab 3, Schedule 1.

Toronto Hydro cannot assign portions of its total revenue requirement to each metric on the custom scorecard as there is not a one to one relationship between expenditures in these programs and achieving specific performance metrics. Multiple programs contribute to multiple performance objectives and it is not possible to attribute specific costs to specific measures and targets. Toronto Hydro also notes that the request appears to infer that the capital and operational programs detailed in this application are proposed on the basis and justification of target achievement and associated economic benefits for customers. This is not the case. The capital and OM&A program budgets proposed stand on their own merits, on the basis of the detailed evidence submitted in Exhibits 2B and 4 describing the processes, needs, inputs, and other factors relied on to conclude that the proposed 2025 to 2029 investment plan is the appropriate plan to meet the needs of Toronto Hydro's system and customers. The performance incentive is a complimentary proposal to improve the balance of risk between the utility and ratepayers in responsiveness to the OEB's feedback in the last rate application.

QUESTION (B):

b) Please Discuss:

   i. The proportion and significance of the PIM and its weighting within the PIM framework, relative to the proportion and significance of identified key programs, as provided in part i) above, in the context of Toronto Hydro's overall spending plan. Please evaluate how well the scope and value of its proposed PIMs correspond with the scope and value of Toronto Hydro's key spending and investment areas within its plan.

   ii. The rationale and basis for the proportions of costs and benefits calculated in iv) above, including variations in the observed ranges.

   iii. For any value where iii) is less than or equal to i), please explain Toronto Hydro's rationale for the particular PIM proposed, including its weight.

RESPONSE (B):

Please see a) above with respect to the comparison of program costs and PIM incentives and benefits. With respect to the PIM incentive relative to quantified benefits, the benefits received by customers outweigh the cost of the PIM incentive in all scenarios, with the lifetime benefits significantly outweighing the size of the PIM. This analysis does not take into account numerous measures and targets (e.g. Customer Satisfaction, Customer Escalations, TRIF, Security Enhancements, Grid Automation Readiness, ISO Certification) which although cannot reliably quantified nonetheless provide long-term value to customers.

Performance	Weight	Measures	Five-Year Target	Incentive	Quantified Benefits (2025-2029)	Quantified Benefits (Lifetime)	Ratio: Incentive vs. 2025-29 Benefits	Ratio: Incentive vs. Lifetime Benefits
System Reliability & Resilience	**15%**	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding Major Event Days (MEDs), Loss of Supply (LoS) and Scheduled Outages	46.2 minutes (five-year average)	$9.8	$32.5	$605.2	3.33	62.02
	10%	**Outage Frequency:** System Average Interruption Frequency Index (SAIFI) - Defective Equipment	0.38 – 0.45 (five-year average)	$6.5	$6.5 - 21.6	$182.5 - 413.4	1.00 - 3.32	28.05 - 63.55
	5%	**System Security Enhancements:** Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework	100% by 2029	$3.3	n/a	n/a	n/a	n/a
Customer Service & Experience	**10%**	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)	99% (five-year average)	$6.5	$31.7 - 142.6	$31.7 - 142.6	4.87 - 21.92	4.87 - 21.92
	5%	**Customer Satisfaction:** Post-transactional customer satisfaction surveys for Customer Inquiries (Phone & Email), Key Accounts Engagements, Customer Connections, and Communications (Outages & Construction Projects)	Maintain historical baselines	$3.3	n/a	n/a	n/a	n/a
	5%	**Customer Escalations Resolution:** Percentage of customer escalations resolved within 10 business days.	98% (five-year average)	$3.3	n/a	n/a	n/a	n/a
Environment, Safety and Governance	**10%**	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.	0.83 (five-year average)	$6.5	n/a	n/a	n/a	n/a

Performance	Weight	Measures	Five-Year Target	Incentive	Quantified Benefits (2025-2029)	Quantified Benefits (Lifetime)	Ratio: Incentive vs. 2025-29 Benefits	Ratio: Incentive vs. Lifetime Benefits
	5%	**Emissions Reductions:** Tonnes of CO2e emissions produced by Toronto Hydro's fleet and facilities.	2.5 kilo tonnes CO2 emissions in 2029	$3.3	$0.2	$1.5	0.06	0.46
	5%	**ISO Compliance and Certification:** Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).	100% by 2029	$3.3	n/a	n/a	n/a	n/a
Efficiency & Financial Performance	15%	**Efficiency Achievements:** Sustained efficiency benefits for customers that will produce a lower revenue requirement in the next rebasing application.	$6.9 million per year by 2029	$9.8	$16.4	$50.7	1.68	5.20
	10%	**Grid Automation Readiness:** Completion of milestones to enable the automation of the overhead system in the horseshoe areas of the grid starting in 2030.	100% by 2029	$6.5	n/a	n/a	n/a	n/a
	5%	**System Capacity (Non-Wires):** Flexible system capacity procured through demand response offerings.	30 MW by 2029	$3.3	$3.1	$21.0	0.95	6.77
			Total	**$65.0**	**$90.4**	**$892.6**	**1.39**	**13.73**
					$216.4	**$1,234.4**	**3.33**	**18.99**

High Range | Low Range

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-53

Reference: Exhibit 1B, Tab 3, Schedule 1

Preamble:

At page 6 of Reference 1, Toronto Hydro states "only if the set performance targets are achieved….by the end of the rate term would the incentive be recovered from customers."

QUESTIONS (A) – (C) :

a) Please explain Toronto Hydro's proposal for recovery of the PIM-DA account balance in the event that not all performance targets are achieved in full. For instance: what amounts, if any, should be paid in the event that only some targets are achieved in full?

b) Does Toronto Hydro propose partial disposition in the event that a particular target is partially achieved?

c) In determining the amount for disposition, does Toronto Hydro propose that outperformance in one area should compensate for underperformance in another?

RESPONSES (A) – (C):

The proposed design of the PIM reflects a series of stacked, binary targets with financial incentives allocated explicitly to each metric. As such, Toronto Hydro does not propose any partial incentive for partial achievement of targets, and performance on one metric will not have any impact (positive or negative) on the performance or financial outcomes of other metrics. Please see response to the response to 1B-Staff-54 for more information, including comments relating to the potential for a reward associated with over-performance.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-54

References: Exhibit 1B, Tab 3, Schedule 1, Pages 12-13

Preamble:

Toronto Hydro details its proposed PIM in Tab 3 Schedule 1. Key attributes include the following.

• The incentive factor term of the revenue cap index formula would include a 0.6% performance factor that has an estimated value to customers of $ 65 million during the five years of the proposed plan.

• The PIM would give Toronto Hydro a means to earn back the $ 65 million depending on its performance as measured using 12 metrics.

• The potential revenue impact of each metric is a share of the $ 65 million.

• Results of the PIM metrics would be detailed on a Custom Scorecard.

• Rewards would be based on performance over the five years of the plan and would be considered in the next rebasing.

QUESTION (A):

a) For each PIM performance category j in year t, suppose that

$\bar{M}_j^{Actual}$ = Toronto Hydro's average value of metric 2025-2029
M_j^{Target} = target value of the metric
α_j = share of the maximum $65 million penalty

i. Does one of the following formulas accurately characterize the proposed net reward from the PIM?

i. $$\textit{Net Penalty} = \max\left[65 - SUM_j \alpha_j \cdot 65 \cdot \left(\frac{\bar{M}_j^{Actual}}{M_j^{Target}}\right), 0\right]$$

ii. $$\textit{Net Penalty} = SUM_j \max\left[\alpha_j \cdot 65 - \alpha_j \cdot 65 \cdot \left(\frac{\bar{M}_j^{Actual}}{M_j^{Target}}\right), 0\right] = SUM_j \max\left[(\alpha_j \cdot 65) \cdot \left(1 - \frac{\bar{M}_j^{Actual}}{M_j^{Target}}\right), 0\right]$$

ii. If not, please provide an alternative formula that does provide an accurate characterization.

RESPONSE (A):

Since it is meant to hold the utility accountable for achieving target performance outcomes, Toronto Hydro's proposal is based on a threshold test, such that if the utility does not achieve the target performance on a particular metric the incentive is not met. This ensures that the utility is not able to earn-back the incentive associated with an individual metric if the performance is below the target.

The following formula can be used to determine the incentive amount for each individual metric. The total entry to the PIM-DA will be the sum of this formula completed for each individual metric.

$$\text{Earnback}_j = \text{IF}(M_j\text{Actual} \geq M_j\text{Target}, \alpha_j * 65, 0)$$

$$\text{PIM-DA Credit} = \text{SUM}(\text{Earnback}_j)$$

QUESTION (B):

b) Please confirm that the design of the PIM would only permit Toronto Hydro to earn back the $65 million value of the proactive 0.6% performance factor. Explain any disinclination to affirm.

RESPONSE (B):

Confirmed.

QUESTION (C):

c) Does this PIM design preclude the use of metrics that should be paired with rewards? Is there merit in permitting rewards in some performance areas?

RESPONSE (C):

The design of the PIM can be altered to include incentives/rewards for superior performance as envisioned by the Renewed Regulatory Framework at page 61. This can be done by enabling the utility to earn incremental incentives (i.e. in excess of $65 million) for achieving higher than target performance on metrics or by setting incremental objectives/goals for the utility to meet in the next rate term, provided that the utility can do so within the overall revenue requirement approved for the purpose of setting rates.

QUESTION (D):

d) Why does demand response receive only a 5% weight in the PIM given the sizable capacity additions that the Company suggests are looming for the energy transition?

RESPONSE (D):

The 5% target for non-wires system capacity is weighed proportionally to the NPV of the efficiency benefits provided by the achievement of the target, as summarized in Table 18 of the referenced evidence.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

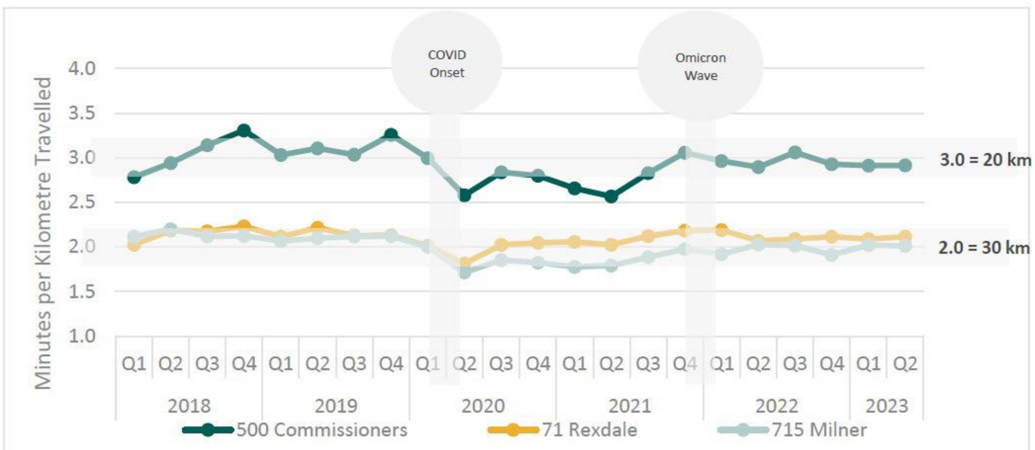
INTERROGATORY 1B-STAFF-55

References: **Exhibit 1B, Tab 3, Schedule 3, Pages 7-8**

THESL_Drive Time Data_20240207

Preamble:

Toronto Hydro provides Figure 1 outlining drive times per kilometer from its 3 work depots; Figure 1 is reproduced below.



QUESTION (A):

a) What drive trips were incorporated into the data for the analysis? Does the data utilize include only the drive time to and from the job site? Does it include any ancillary driving activities?

RESPONSE (A):

The data includes all driving to and from work sites, as well as all ancillary commuting. Omitted from the analysis is any time driven within the designated home zone and any driving/commuting time for vehicles that were taken out of service for five days or more in a given month.

QUESTION (B):

b) What was the calculated average drive time per work activity?

RESPONSE (B):

Drive time includes all driving activity outside of the home zone; Toronto Hydro currently does not possess the capability to distinguish the subset of drive time related to work activity and therefore does not have the data to calculate average drive time per work activity.

QUESTION (C):

c) What was the average drive distance per work activity?

RESPONSE (C):

As noted in the response to subpart (b), Toronto Hydro currently does not possess the capability to distinguish the subset of drive time related to work activity and therefore does not have the data to calculate average drive distance per work activity.

QUESTION (D):

d) What is the percentage of time driving of the overall work activity?

RESPONSE (D):

As noted in the response to subpart (b), Toronto Hydro currently does not possess the capability to distinguish the subset of drive time related to work activity and therefore does not have the data to calculate the percentage of drive time corresponding to work activity.

QUESTION (E):

e) What was the total number of trips used for the calculation of each field depot?

RESPONSE (E):

Drive time includes all driving activity outside of the home zone; the data set in Reference 2 provides a summary of each month for each vehicle by distance and drive time. Toronto Hydro does not have visibility into the total number of trips beyond this data.

QUESTION (F):

f) What is defined as the Home Zone?

RESPONSE (F):

The home zones are defined as Toronto Hydro work centres or stations. Each vehicle is assigned to a work centre or station to track their home zone.

QUESTION (G):

g) Are cars used for typical field work activities or more for supervision and administrative purposes? Why are cars included in the calculations?

RESPONSE (G):

Cars are used for general administrative purposes, supervision, by employees that do not require field work equipment at their job site, such as for media and public relations purposes, or to conduct field work activities where equipment is not required to be transported to the work site or is transported in larger vehicles by other crew members travelling to the same job site. Although cars constitute a small portion of Toronto Hydro's vehicle fleet (2.5% or 9 out of 359 vehicles), the utility includes them in its fleet-related productivity initiatives to monitor and continuously improve efficiency across the board.

QUESTION (H):

h) In Ref 2 why are there multiple entries per vehicle in a given month in the yearly data tabs? What does each row signify?

RESPONSE (H):

Each row signifies monthly usage for each vehicle; multiple entries reflect a change in the vehicles' assigned home zone.

QUESTION (I):

i) Would 5km or less of driving for a vehicle in a given month be representative of typical drive times for field productivity?

RESPONSE (I):

No, Toronto Hydro does not consider 5 kilometres or less to be representative of typical vehicle operations. Distances driven by fleet vehicles is not an indicator of field productivity because field work is achieved when the vehicle is parked at the worksite.

QUESTION (J):

j) Was the drive time per kilometer benchmarked against another city or utility?

RESPONSE (J):

No.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-56

Reference: Exhibit 1B, Tab 3, Schedule 3, Page 12

<u>Preamble</u>**:**

Toronto Hydro provide Table 3 which is reproduced below:

Table 3: Non-Residential Buildings Construction Index for Metropolitan Areas[18]

		Toronto		Canada 11 Census Metropolitan Area Composite	
		Qtr to Qtr	Cumulative	Qtr to Qtr	Cumulative
2020	Q1	0.0%	0.0%	0.0%	0.0%
2020	Q2	0.5%	0.5%	0.1%	0.1%
2020	Q3	0.7%	1.2%	0.5%	0.6%
2020	Q4	0.2%	1.4%	0.1%	0.6%
2021	Q1	1.9%	3.3%	1.4%	2.0%
2021	Q2	5.0%	8.4%	3.9%	6.0%
2021	Q3	4.3%	13.0%	2.9%	9.0%
2021	Q4	3.4%	16.9%	2.9%	12.1%
2022	Q1	3.8%	21.3%	3.0%	15.5%
2022	Q2	5.0%	27.4%	4.0%	20.1%
2022	Q3	2.6%	30.7%	2.1%	22.6%
2022	Q4	2.5%	33.9%	1.6%	24.6%
2023	Q1	1.7%	36.2%	1.7%	26.7%
2023	**Q2**	**1.1%**	**37.7%**	**1.5%**	**28.6%**

QUESTION (A) AND (B):

a) Provide the filters and setting used on the Statistics Canada website to derive these values? Please detail the type of building and divisions selected?

b) Explain why these filters and settings were selected and how all the categories selected are applicable to Toronto Hydro's inflationary pressures?

RESPONSE (A) AND (B):

Please refer to Toronto Hydro's response to interrogatory 1B-Staff-18 part (e).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-57

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Pages 15-16

Preamble:

PEG wishes to better understand the Toronto Hydro cost data used in Clearspring's benchmarking study.

QUESTION (A):

a) Please discuss what labor costs besides salaries and wages might be present in Toronto Hydro's O&M expenses used in the study.

RESPONSE (A):

Besides salaries and wages, labour costs as presented in Toronto Hydro's O&M expenses used in the study include: performance pay, overtime, leaves such as vacation, sick time, and statutory holidays, and other contractual obligations such as stand-by pay, and shift premiums.

QUESTION (B):

b) What types of cost are included in the pension and benefits expenses that Clearspring removed from the Company's O&M expenses?

RESPONSE (B):

Pension and benefit expenses include: Toronto Hydro's portion of OMERS contribution, post-employment benefits, payroll taxes, Canadian Pension Plan ("CPP") and Employment Insurance ("EI") contributions made by Toronto Hydro, and other employee benefits which includes: medical, dental, and group life insurance.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-58

Reference: Exhibit 1B, Tab 3, Schedule 3. Appendix A, Page. 19

Preamble:

The sample period for the power distributor cost research is the twenty-one years from 2000 to 2021. There are data from 78 US distributors in the sample.

Data for 9 of the sampled utilities are excluded from the total cost benchmarking sample only in 2021, the final year of the dataset[1].

QUESTION (A):

a) Please explain why data for 9 utilities were excluded only in 2021.

RESPONSE PROVIDED BY CLEARSPRING (A):

Five of the 2021 observation exclusions are due to implausible substation data. The five are PacifiCorp, Madison Gas & Electric, Kentucky Utilities, Portland General Electric, and Public Service of New Hampshire. Three other utilities were excluded in 2021 due to reported OM&A expenses decreasing by an implausible amount of 90% or more with two of them reporting negative OM&A expenses. These three are Pennsylvania Electric, Southwestern Public Service, and Nevada Power. Duke Energy Ohio was excluded due to reporting zero customers in 2021.

Clearspring conducted a sensitivity analysis regarding the five exclusions in 2021 due to substation data. We used the 2020 value for the number of substations and capacity and included the 2021

[1] Data for 3 additional utilities are excluded from the sample for longer periods. These are California utilities that experienced massive wildfire damage. PEG and Clearspring have discussed and agreed to exclude these data in other proceedings.

observations into the sample to test the impact of excluding the 2021 observations. The impact on Toronto Hydro's benchmark results was essentially zero. The 2025 to 2029 benchmark score decreased to -23.0% from -22.9% indicating the exclusion of the utilities in 2021 does not meaningfully impact the study.

QUESTION (B):

b) Were there additional major omissions with publicly available data which could potentially have been included in the sample, but were excluded altogether? If so, please provide the reasons for the exclusion of each. For example, did Clearspring exclude any subset of utilities because they are small?

RESPONSE PROVIDED BY CLEARSPRING (B):

There are no systematic exclusions to utilities based on size or other common characteristics with plausible data and variable values that were processed and available in the modeling dataset. Given the U.S. investor-owned utility dataset utilized by Clearspring in the study, there are no extremely small utilities in the sample and the econometric model is able to adjust for the modeled service territory conditions of Toronto Hydro.

QUESTION (C):

c) Why did the sample not include 2022 data?

RESPONSE PROVIDED BY CLEARSPRING (C):

The project timeline was not able to accommodate a 2022 data update.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-59

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Pages 20-21 and 38

Preamble:

The model parameters presented in the report result from a sample that excluded Toronto Hydro. While PEG acknowledges that excluding the subject utility is the appropriate way to estimate the model that is actually used for benchmarking Toronto Hydro's cost performance results (and to do the same for each individual company's results), it is common in econometric benchmarking for the model development and presentation to be based on the entire sample.

QUESTION (A):

a) Please provide the econometric model parameter estimates that result when Toronto Hydro is included in the estimation.

RESPONSE (A) – PREPARED BY CLEASPRING:

Please see the table below which provides the reported parameter estimates alongside the requested parameter estimates.

Variable	Reported Parameter Estimates	Requested Parameter Estimates
Constant	12.735	12.766
Customers (N)	0.512	0.530
Peak Demand (D)	0.397	0.388
Area (A)	0.050	0.051
N*N	0.490	0.635
D*D	0.840	0.878
A*A	0.036	0.042
N*D	-1.297	-1.468
N*A	0.096	-0.009
D*A	-0.112	-0.020
% Electric	0.152	0.146
Standard Deviation of Elevation	0.012	0.010
% OH*% Forest	0.052	0.055
% Congested Urban	22.256	12.095
% AMI	0.060	0.047
Dx Work (% Tx Lines Above 50 kV)	0.157	0.147
O&M Scope Variable	0.088	0.081
# of Dx Substations	0.071	0.059
Capacity of Dx Substations	0.011	0.014
Trend	-0.005	-0.005

QUESTION (B):

b) Please comment on whether any changes in the parameter estimates when Toronto Hydro is excluded are of a magnitude which indicates a possible problem with the variable or model specification.

RESPONSE (B) – PREPARED BY CLEASPRING:

The parameter estimate differences do not indicate a possible problem with the variable or model specification. In fact the opposite is true, the differences indicate that the variables and model specification is robust. All the first order parameter estimates continue to be highly statistically significant with minor tweaks in the values due to including Toronto Hydro. The percent congested urban is the possible exception to this, while it remains highly statistically significant the magnitude of the variable value does change noticeably. This is due to the unavoidable fact that Toronto Hydro is an extreme outlier in the challenges it encounters with serving a congested urban core. Only Consolidated Edison of New York City encounters a similar type of condition. It is expected in econometric modeling that either including or excluding an outlier utility would meaningfully impact that variable's parameter estimate. This does not indicate a model specification problem. It does illustrate that, ideally, it would be helpful if it were possible to include more utilities with similar service territory conditions of Consolidated Edison or Toronto Hydro in order to make Toronto Hydro less of an outlier within the dataset and still include the appropriate cost challenge variable, however, that is not a feasible option.

Clearspring also notes that we are in agreement with PEG that the model used for benchmarking should not include the studied utility so that the benchmark is fully external to the cost performance of the studied utility. The reason the percent congested urban variable declines when Toronto Hydro is inserted in the sample is because Toronto Hydro has an extremely large congested urban cost challenge combined with strong cost performance (i.e., actual costs are well below model-expected costs). If Toronto Hydro's cost performance was average, the change in the congested urban variable would be far less pronounced. Toronto Hydro's strong cost performance and outlier status is not a reason to assume the model specification or variable construction is problematic.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-60

References: **Exhibit 1B, Tab 3, Schedule 3, Appendix A, page. 21**
Cunningham, M., Hirschberg, J., and Giovani, A. (Quantonomics) (2023), Memorandum to the Australian Energy Regulator/Australian Competition and Consumer Commission, Subject: Opex Cost Function - Options to Address Performance Issues of Translog Models, October 25.
https://beta.aer.gov.au/system/files/2023-11/Quantonomics%20%E2%80%93%20Memorandum%20%E2%80%93%20Opex%20Cost%20Function%20Development%20%E2%80%93%20October%202023.pdf

Preamble:

Clearspring's power distributor cost model has three scale variables: the number of customers served, a peak load variable, and area. This model also includes second-order (quadratic and translog) terms for these variables. This treatment adds six scale-related variables to the model for a total of nine and results in custom cost elasticities with respect to scale variables for Toronto Hydro.

An ongoing discussion in Ontario Custom IR proceedings is whether a rolling average of past peak demands or a ratcheted peak demand variable are better for a power distributor cost model.

An important result of cost theory is that cost should rise monotonically with output.

QUESTION (A):

a) What are the estimated custom cost elasticities with respect to these three scale variables for Toronto Hydro?

RESPONSE PROVIDED BY CLEARSPRING (A):

We calculated the first derivative with respect to each output to calculate the custom elasticities. The equation for the custom customer elasticity that we calculated is, thus, the first order customer coefficient plus the coefficient on the quadratic customer variable times the natural log of the mean-scaled customer value plus the coefficient on interaction with customers and peak demand multiplied by the natural log of the mean-scaled peak demand variable plus the coefficient on the interaction with the customers and service area variable multiplied by the natural log of the mean-scaled service area variable. For the custom peak demand elasticity and the area elasticity we conducted the same calculation procedure but using the peak demand and area first order, quadratic, and interaction terms.

Since the custom elasticities do not change in any way that would be material to this analysis from year to year for the same utility, the 2021 values for Toronto Hydro are calculated to be 0.235 for customers, 0.895 for peak demand, and -0.062 for service area.

QUESTION (B):

b) Parameter estimates for output variables may be assessed for consistency with the monotonicity condition predicted by cost theory. Reference 2 is an example of such a study in a report to the Australian Energy Regulator. Are Clearspring's scale variable parameter estimates in each year of the sample consistent with the monotonicity conditions predicted by cost theory? Do any other sampled companies have violations?

RESPONSE PROVIDED BY CLEARSPRING (B):

Given the flexibility of the translog cost function it leaves open the possibility of specific output variable elasticities being negative as the model adjusts for economies of scale and interactions with other output variables. In the case of Toronto Hydro it is the service area custom elasticity that is negative. This means that the cost benchmark for Toronto Hydro would decline in the model if Toronto Hydro somehow added service territory area to its service territory variable value. Yet, in the real world, it is difficult to imagine how this would occur and Toronto Hydro at the same time not adding customers and peak demands. The additions of the customers and peak demands would raise Toronto Hydro's benchmark costs likely more than the service area variable would reduce it. There are other instances of custom output elasticities being negative within the sample. The majority of them are regarding the service area variable, similar to Toronto Hydro.

QUESTION (C):

c) The peak load variable that Clearspring uses in its model is a rolling average of past peak load values. Up to ten past values are averaged to the extent that data are available. If the sample period were shortened by ten years, wouldn't this permit ten-year averages for all years? If ratcheted peak demand was then calculated the same way for Toronto Hydro as for the sampled US distributors, why would a moving average peak demand variable be better than a ratcheted peak demand variable?

RESPONSE PROVIDED BY CLEARSPRING (C):

To accommodate all ten years within the ten-year sample average, Toronto Hydro's first year must be 2011 since its first year of peak demand data is 2002. The sample has peak demand data collected from 1994, indicating that 2003 could be the first year where a rolling average variable would have ten years available to calculate it.

Clearspring's sample begins in 2000 which matches the start year that we used in the last distribution total cost benchmarking research for Hydro One in EB-2021-0110. In Clearspring's report in that proceeding we explained the rationale for using an average peak demand variable rather than a ratcheted one. One reason includes Clearspring considering the merits of and then responding to intervenors who in the past questioned how it makes sense that a ratcheted peak demand variable can never decrease even after years of falling peak demands. The total cost research is focused on the long-run total costs of utilities. This is why capital costs are included into the analysis and Clearspring goes back to the 1940's to gather cost data and determine those costs. To say that utilities will never adjust costs downward to declining peak demands is not accurate and so the peak demand variable should be able to decline if that is the reality of the situation. Clearspring agrees there will be a lag and a residual cost impact to prior high peak demand values which is why we used the 10-year rolling average approach. The second rationale for the rolling average peak demand variable versus the ratcheted approach is that a lot of the focus on the benchmarking research results in this context are on the projected years of 2025 to 2029. Those peak demands are weather normalized expectations, or averages, around the probabilities of extreme or mild weather outcomes. Since the peak demand forecasts themselves are essentially averages, using a variable that is itself an average is the more consistent approach in Clearspring's view.

QUESTION (D):

d) Did Clearspring try ratcheted peak demand as an alternative to the rolling average? If so, which had stronger statistical support?

RESPONSE (D) PROVIDED BY CLEARSPRING:

Yes, Clearspring did calculate the variable. The first order ratcheted peak demand variable while still highly statistically significant is less so than the 10-year rolling peak demand used by Clearspring. The t-stat on the ratcheted peak demand is 13.82 versus a t-stat of 22.16 for the rolling average variable. This indicates that it is the rolling average variable that has the stronger t-statistic.

QUESTION (E):

e) Does the company believe that the number of customers it reports on the RRR is significantly affected by high rise housing where the building is only counted as one "customer"? If so, please provide a rough estimate of the number of unmetered residential customers (1 dwelling = 1 customer) that are jointly served from a single meter. Is serving one customer with 100 tenants more costly than serving 100 separately-metered and separately sited households? If so, why?

RESPONSE (E):

As discussed in lines 18-23 on page 11 of Exhibit 4, Tab 1, Schedule 1, Toronto Hydro serves far more electricity users through bulk-metering and competitive sub-metering arrangements than its actual customer count indicates and the utility estimates that it serves at least 340,000 end-consumers behind bulk meters.

Serving 100 separately metered and sited households (e.g. in a multi-unit residential building suite metered by Toronto Hydro), typically drives some additional billing, payment processing and customer contact costs due to the greater number of account holders, compared to a single bulk metered customer with 100 tenants/occupants behind the meter. Other than these costs related to account transactions, there is no material OM&A cost difference between the two types of customers.

QUESTION (F):

f) Did Clearspring consider using other normalization factors other than number of customers due to the stated concern regarding the quantity of high-rise building? What other normalization factors were considered but rejected? If no other normalization factors were considered, why not in consideration of Toronto Hydro concerns regarding using customer count?

RESPONSE (F) PROVIDED BY CLEARSPRING:

We did identify this challenge as a possible candidate for a business condition variable or other possible correction, however, no feasible normalization factors surfaced because of the lack of data visibility into the sampled utilities regarding this condition. Not including a normalization factor that adjusts for this cost challenge likely disadvantages Toronto Hydro in the benchmarking research.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-61

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 34

Preamble:

Clearspring used an employment cost index ("ECI") for the utility industry as the wage rate trend index for US utilities in its sample. The wage rate trend index chosen for Toronto Hydro was Ontario Average Weekly Earnings ("AWE").

The wage rate level chosen for Toronto Hydro was based upon 2011 Census data.

QUESTIONS (A)

a) Why was the Ontario AWE chosen as the wage rate trend index for Toronto Hydro?

RESPONSE (A)– PREPARED BY CLEASPRING:

The Ontario AWE was used to escalate Toronto Hydro's wage rate levels because it is the index used in Clearspring's prior benchmarking research in Ontario and was the index used in the Hydro One Joint Report put forth by Clearspring and Pacific Economics Group (PEG). The index was also deemed appropriate and used in the 4th Generation IR benchmarking and productivity research, and the index is one of two components in the inflation factor. It is Clearspring's understanding that PEG has also used the Ontario AWE to escalate Ontario distributor wage levels in its other Ontario benchmarking research.

QUESTIONS (B)

b) Please confirm that, in its recent "PBR3" decision, the Alberta Utilities Commission decided to replace the Alberta AWE with Statistics Canada's Alberta fixed weighted index ("FWI") of average hourly earnings in its inflation factor formulas for jurisdictional energy distributors.

RESPONSE (B) – PREPARED BY CLEASPRING:

Confirmed.

QUESTIONS (C)

c) Did the AWE or the FWI yield more plausible estimates of wage rate inflation in Ontario and Canada during the recent recession and recovery?

RESPONSE (C)– PREPARED BY CLEASPRING:

The Alberta Utilities Commission (AUC), in the context of that generic proceeding, determined that the FWI was the better index to use within the inflation factor calculation for PBR3.

QUESTIONS (D)

d) Is the methodology for the US Employment Cost Index (ECI) used in Clearspring's study more similar to the Ontario FWI for average hourly earnings or the AWE that Clearspring used?

RESPONSE (D)– PREPARED BY CLEASPRING:

The FWI appears not to be influenced by occupational and hours worked changes. It is Clearspring's understanding this better aligns with how the U.S. ECIs are calculated.

QUESTIONS (E)

e) Did Clearspring use forecasted values of AWE in its benchmarking in some years (other than 2023) where actual values are now available? Is this a problem with other variables in its cost benchmarking study as well? If so, which?

RESPONSE (E)– PREPARED BY CLEASPRING:

Clearspring would not characterize this as a problem. Rather, as time elapses it is possible to update values in the model. As new data becomes available, all of the time variant variables can be updated.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-62

References: **Ref 1: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 30-31**

Ref 2: Exhibit 1B, Tab 2, Schedule 1

<u>Preamble:</u>

Clearspring provides benchmarking values for SAIFI, SAIDI and CAIDI.

QUESTIONS (A)

a. Why is there the expectation that the SAIDI benchmark value increase with time? What is the physical justification for this versus theoretical modelling? Please provide empirical quantitative evidence and not qualitative correlation explanation.

RESPONSE (A) – PREPARED BY CLEASPRING:

This stems primarily from the CAIDI benchmark increasing due to the congested urban variable increasing for Toronto Hydro over time. As congestion increases, the time required to respond increases. The empirical quantitative evidence is the highly statistically significant congested urban variable present in the CAIDI model.

QUESTIONS (B)

b) How does the proposed benchmark and forecasted SAIFI, CAIDI and SAIDI values differ in consideration of Toronto Hydro's proposed IRM as compared to the IRM scenario in Reference 2?

RESPONSE (B)– PREPARED BY CLEASPRING:

Reference 2: IRM Scenario

Table 1 Year-by-Year Reliability Benchmarks vs. Actual

Year	SAIFI (Actual)	SAIFI (Benchmark)	SAIFI (% Difference)	CAIDI (Actual)	CAIDI (Benchmark)	CAIDI (% Difference)
2005	0.93	0.46	70.2%	76.59	110.00	-36.2%
2006	1.11	0.46	88.1%	64.98	110.73	-53.3%
2007	1.14	0.47	89.7%	69.12	111.59	-47.9%
2008	1.08	0.46	85.0%	67.40	112.68	-51.4%
2009	0.95	0.46	72.8%	84.13	113.75	-30.2%
2010	0.98	0.46	75.5%	77.30	115.32	-40.0%
2011	1.05	0.45	83.9%	80.13	117.26	-38.1%
2012	0.88	0.45	67.4%	68.06	118.66	-55.6%
2013	0.95	0.45	75.8%	70.61	120.35	-53.3%
2014	0.92	0.45	72.6%	63.76	123.09	-65.8%
2015	0.97	0.44	78.4%	64.04	125.48	-67.3%
2016	0.93	0.45	73.3%	59.71	128.08	-76.3%
2017	1.09	0.45	87.4%	53.14	129.25	-88.9%
2018	1.09	0.46	86.8%	53.25	130.44	-89.6%
2019	0.95	0.45	73.9%	50.39	132.46	-96.6%
2020	1.11	0.45	91.2%	50.77	135.21	-98.0%
2021	1.20	0.44	100.3%	48.55	136.49	-103.4%
2022	1.24	0.43	105.0%	45.75	138.95	-111.1%
2020-2022 average	**1.18**	**0.44**	**98.8%**	**48.36**	**136.88**	**-104.1%**
2023	1.28	0.43	108.1%	42.76	141.81	-119.9%
2024	1.20	0.43	101.7%	52.52	144.87	-101.5%
2025	1.19	0.43	100.8%	48.93	148.16	-110.8%
2026	1.20	0.43	101.7%	48.93	151.67	-113.1%
2027	1.20	0.43	101.7%	48.65	155.43	-116.2%
2028	1.21	0.43	102.5%	48.85	159.47	-118.3%
2029	1.22	0.43	103.3%	48.97	163.82	-120.8%
2025-2029 average	**1.20**	**0.43**	**102.0%**	**48.87**	**155.71**	**-115.8%**

Reference 2: IRM Scenario

Table 2 Toronto Hydro's SAIDI Actuals and Benchmarks 2005-2029

Year	SAIDI (Actual)	SAIDI (Benchmark)	SAIDI (% Difference)
2005	71.3	50.7	34.0%
2006	71.9	50.7	34.8%
2007	78.9	51.9	41.8%
2008	72.9	52.1	33.7%
2009	80.2	52.3	42.7%
2010	75.4	52.8	35.5%
2011	84.2	53.2	45.8%
2012	60.2	53.5	11.8%
2013	67.1	53.6	22.4%
2014	58.8	54.9	6.8%
2015	61.9	55.4	11.2%
2016	55.7	57.4	-3.1%
2017	58.1	58.8	-1.1%
2018	57.8	59.7	-3.3%
2019	47.8	60.1	-22.9%
2020	56.3	60.3	-6.9%
2021	58.2	60.1	-3.1%
2022	56.8	60.3	-6.0%
2020-2022 average	**57.1**	**60.2**	**-5.3%**
2023	54.8	61.5	-11.7%
2024	62.9	62.9	0.0%
2025	58.1	64.3	-10.1%
2026	58.5	65.9	-11.9%
2027	58.6	67.5	-14.1%
2028	59.3	69.2	-15.5%
2029	59.8	71.1	-17.3%
2025-2029 average	**58.9**	**67.6**	**-13.8%**

Updated Investment Plan

Table 3 Year-by-Year Reliability Benchmarks vs. Actual

Year	SAIFI (Actual)	SAIFI (Benchmark)	SAIFI (% Difference)	CAIDI (Actual)	CAIDI (Benchmark)	CAIDI (% Difference)
2005	0.93	0.46	70.2%	76.59	110.00	-36.2%
2006	1.11	0.46	88.1%	64.98	110.73	-53.3%
2007	1.14	0.47	89.7%	69.12	111.59	-47.9%
2008	1.08	0.46	85.0%	67.40	112.68	-51.4%
2009	0.95	0.46	72.8%	84.13	113.75	-30.2%
2010	0.98	0.46	75.5%	77.30	115.32	-40.0%
2011	1.05	0.45	83.9%	80.13	117.26	-38.1%
2012	0.88	0.45	67.4%	68.06	118.66	-55.6%
2013	0.95	0.45	75.8%	70.61	120.35	-53.3%
2014	0.92	0.45	72.6%	63.76	123.09	-65.8%
2015	0.97	0.44	78.4%	64.04	125.48	-67.3%
2016	0.93	0.45	73.3%	59.71	128.08	-76.3%
2017	1.09	0.45	87.4%	53.14	129.25	-88.9%
2018	1.09	0.46	86.8%	53.25	130.44	-89.6%
2019	0.95	0.45	73.9%	50.39	132.46	-96.6%
2020	1.11	0.45	91.2%	50.77	135.21	-98.0%
2021	1.20	0.44	100.3%	48.55	136.49	-103.4%
2022	1.24	0.43	105.0%	45.75	138.95	-111.1%
2020-2022 average	**1.18**	**0.44**	**98.8%**	**48.36**	**136.88**	**-104.1%**
2023	1.28	0.43	108.1%	42.76	141.81	-119.9%
2024	1.20	0.43	101.7%	52.52	144.87	-101.5%
2025	1.19	0.43	100.8%	51.86	148.16	-105.0%
2026	1.18	0.43	100.0%	51.68	151.67	-107.7%
2027	1.16	0.43	98.3%	51.52	155.43	-110.4%
2028	1.16	0.43	98.3%	51.82	159.47	-112.4%
2029	1.16	0.43	98.2%	51.81	163.82	-115.1%
2025-2029 average	**1.17**	**0.43**	**99.1%**	**51.74**	**155.71**	**-110.1%**

Updated Investment Plan

Table 4 Toronto Hydro's SAIDI Actuals and Benchmarks 2005-2029

Year	SAIDI (Actual)	SAIDI (Benchmark)	SAIDI (% Difference)
2005	71.3	50.7	34.0%
2006	71.9	50.7	34.8%
2007	78.9	51.9	41.8%
2008	72.9	52.1	33.7%
2009	80.2	52.3	42.7%
2010	75.4	52.8	35.5%
2011	84.2	53.2	45.8%
2012	60.2	53.5	11.8%
2013	67.1	53.6	22.4%
2014	58.8	54.9	6.8%
2015	61.9	55.4	11.2%
2016	55.7	57.4	-3.1%
2017	58.1	58.8	-1.1%
2018	57.8	59.7	-3.3%
2019	47.8	60.1	-22.9%
2020	56.3	60.3	-6.9%
2021	58.2	60.1	-3.1%
2022	56.8	60.3	-6.0%
2020-2022 average	**57.1**	**60.2**	**-5.3%**
2023	54.8	61.5	-11.7%
2024	62.9	62.9	0.0%
2025	61.8	64.3	-3.9%
2026	60.9	65.9	-7.8%
2027	59.9	67.5	-12.0%
2028	60.0	69.2	-14.4%
2029	60.0	71.1	-17.0%
2025-2029 average	**60.5**	**67.6**	**-11.0%**

SUPPLEMENTAL RESPONSE – PREPARED BY TORONTO HYDRO:

Regarding the Updated Investment Plan tables provided above, please see Toronto Hydro's response to 2B-SEC-42, part (c).

Regarding the IRM Scenario tables provided above, Toronto Hydro notes that a substantial deterioration in unplanned outages under the IRM scenario is offset by a material improvement in Scheduled Outages in the projection methodology. This large swing results from the application of Toronto Hydro's limited approach to projecting Scheduled Outages. As discussed in Exhibit 2B, Section E2, pages 16-19, Toronto Hydro's recent and ongoing implementation of more advanced network management and utility analytics capabilities has led to the capture of more detailed and accurate outage information, with the most significant impacts being on the Scheduled Outage cause code. These impacts began in 2022, and for this reason, Toronto Hydro is not able to rely on a multi-year statistical approach to forecast Scheduled Outages. The best-efforts approach that Toronto Hydro applied in order to provide a Scheduled Outages projection for Clearspring's benchmarking study was to take the actual SAIDI and SAIFI impacts from Scheduled Outages in 2022, and relate those impacts to the dollars invested in the subset of programs that overwhelmingly drive Scheduled Outages. The utility then applied this simple ratio to the magnitude of future planned spending. In reality, the utility expects that the ratio of Scheduled Outage impacts to spending will vary materially from year-to-year depending on the mix of project work executed. The application of such a limited and linear approach for Scheduled Outages to an expenditure reduction of the magnitude contemplated in the IRM scenario is of limited value. A reduction in spending of this magnitude would result in a fundamentally different operational reality than the one captured by Toronto Hydro's historical reliability performance.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-63

Reference: Exhibit 1B, Tab 3, Schedule 3, Page 33

Preamble**:**

Toronto Hydro states that increase in costs occurred in 2019 and 2020 due to switching from bi-monthly billing to monthly billing.

QUESTION (A):

Provide detailed explanation of increase in Billing O&M cost from 2018 to 2022 of more than double 2018 customer billing costs.

Explain how productivity and economies of scale was not achieved with the adjustment of billing period?

RESPONSE (A):

The Billing O&M costs provided in Table 10 do not provide a consistent representation of Toronto Hydro's unit cost per customer over the 2018-2022 period. The key contributing factors are: 1) the introduction of monthly billing costs into the calculation; and 2) enhanced mapping precision between the Ontario Energy Board USoA accounts 5315 and 5320 following the utility's conversion from the its legacy accounting system, Ellipse, to its current accounting system, SAP, in 2019.

As shown in Table 1, when USoA accounts 5315 and 5320 are combined from 2018 to 2022, Toronto Hydro's costs are accurately represented, including the impact of monthly billing starting in 2020. Other variances are explained throughout Exhibit 4, Tab 2, Schedule 14.

Table 1: Combined USoA Accounts – 2018 to 2022

Accounts ($ million)	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual
Combined USoA accounts 5315 and 5320	23.3	22.2	26.4	25.1	28.5

As shown above, costs are relatively flat during the period of 2018 to 2022, when normalized for the inclusion of $4.8 million in incremental costs for the conversion from bi-monthly billing to monthly billing in 2020. A detailed discussion of the impact on costs related to the mandatory transition to monthly billing can be found in Toronto Hydro's 2020-2024 CIR rate application.[1]

The vast majority of costs associated with billing customers monthly are not subject to economies of scale benefits. For example, postage, paper and printing, and payment processing costs, which combined make up 64% of the incremental operational costs, are directly related to the number of bills sent.

To minimize the incremental labour costs, Toronto Hydro undertook a number of initiatives, including automation, process improvements, outsourcing and campaigns to drive ebill adoption. An example was the replacement of "gatekeeper systems" which gather and transmit data from meters to Toronto Hydro's billing system, which resulted in more timely and accurate data being gathered automatically and reduced the labour (and associated costs) required to manually collect and estimate hard to read meters. Along with the higher transactional volumes, labour economies of scale were further improved through these initiatives, such that the FTE per 100,000 bills issued reduced from approximately 4.5 FTEs in 2015 to 3.0 FTEs in 2020.

[1] EB-2018-0165, Exhibit 9, Tab 1, Schedule 1, Page 20 to 31

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-64

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 36-37

Preamble:

The service price approach that Clearspring uses to calculate capital costs, prices, and quantities depends on asset price indexes such as Handy Whitman construction cost indexes. It also depends on the assumed rate of decay.

QUESTIONS (A)

a) Please explain the rationale for escalating post-2021 asset prices in Ontario by a 50/50 average of Conference Board projections of growth in the Ontario AWE and the gross domestic product implicit price index ("GDP-IPI"). Why wasn't the Conference Board of Canada's forecast of the Implicit Price Deflator, Business gross fixed capital formation, Non-residential structures for either Ontario or Canada used? Did Clearspring consider incorporating forecasts of Handy Whitman indexes that are available from S&P Global? What other indexes for asset price forecasts were considered if any?

RESPONSE (A)– PREPARED BY CLEASPRING:

In an effort to manage the extent of methodological differences and build upon rather than depart from the foundation laid in the Hydro One Joint Report, Clearspring only considered using the same 50/50 average projections used in the Hydro One distribution total cost benchmarking research by both Clearspring and PEG.

QUESTIONS (B)

b) The assumed 4.59% rate of decay was taken from the TCB benchmarking work in 4th GIR and it applied to all Ontario distributors. Did Clearspring consider other decay rates that might be more appropriate for Toronto Hydro and US distributors? If so, what were they and how did the results differ with an alternative specification?

RESPONSE (B) – PREPARED BY CLEASPRING:

No, Clearspring only considered using the 4.59% rate of decay number. Clearspring and PEG both agreed to and used the 4.59% rate of decay in the 4^{th} GIR research and in all subsequent electric distribution cost benchmarking studies by both consultants within Ontario. Concern regarding the appropriateness of this assumption has not been raised by PEG, or any intervenors, to Clearspring's knowledge in any of the prior CIR applications containing econometric total cost benchmarking research.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-65

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page 34

Preamble:

The price of materials and services is an important cost driver for many utilities in an age when a sizable share of utility OM&A expenses often takes the form of outsourced services. PEG notes the use of a propriety macroeconomic price index such as the GDP-PI as a stand-alone proxy for trends in the prices of materials and services that utilities use.

QUESTION (A):

a) For a selected year in the 2020 to 2022, please provide a break-down of all components of the OM&A expenses, explicitly showing and defining the OM&A expenses of Toronto Hydro exclusive of salary and wage and pension and benefit OM&A that take the form of outsourced services. If not unduly burdensome, please also provide an estimate for additional prior years of the sample period and years in the 2025 to 2029 forecast period.

RESPONSE (A):

Table 1 below shows OM&A costs that take the form of outsourced services for 2020 to 2023 actuals, to 2024 Bridge and 2025 to 2029 forecast period.

Table 1: 2020-2029 Outsourced OM&A Costs ($ Millions)

Actual				Bridge	Forecast				
2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
118.7	134.9	139.2	146.0	151.0	159.2	162.7	164.7	169.5	173.7

QUESTION (B) :

b) What are Toronto Hydro’s four biggest uses of outsourced services?

RESPONSE (B):

Toronto Hydro’s four biggest uses of outsourced services in 2023 were: distribution system maintenance, information technology support, customer care operations, and facilities management.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-66

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 18

Preamble:

Clearspring's distribution cost model also includes a scope of electric services provided variable.

QUESTIONS (A)

a) Did Clearspring consider any alternative specifications for this scope variable? If so, what were the results?

RESPONSE (A)– PREPARED BY CLEASPRING:

In the recent Hydro One Joint Report, PEG suggested and discussed the merits of the OM&A-based scope variable that measures the ratio of distribution to distribution, transmission, and generation activities. We investigated and were persuaded by PEG that the new scope variable is preferable to the plant-based variable we initially used in the Hydro One research. We therefore agreed, in the Joint Report, to use the scope variable put forward by PEG. Given that we had already investigated the merits and agreed that this was the best approach to the variable, we did not consider for inclusion any other scope variable.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-67

Reference: Exhibit 1B , Tab 3, Schedule 3, Appendix A, Page. 18

Preamble:

Mr. Fenrick's new model adds two substation variables that he has not used in prior power distributor cost benchmarking studies he has submitted in OEB proceedings. However, he previously used a substation variable in a transmission cost benchmarking model he prepared for a Hydro One proceeding (EB-2021-0110).

QUESTIONS (A)

a) Please confirm whether the US substation data used in this study reflect the corrections to the double-counting issue PEG identified in Clearspring's transmission substation variable during the Hydro One proceeding (see EB-2021-0110 Exhibit M Appendix B.2)?

RESPONSE (A)– PREPARED BY CLEASPRING:

Yes, that was Clearspring's intention. With the understanding that there are hundreds of thousands of addresses to filter and not all of them are labeled consistently from company to company, year to year, or even within a year. In the case that Clearspring missed some of the distribution substations and double-counted them, this would likely have the impact of disadvantaging Toronto Hydro's benchmark score.

QUESTIONS (B)

b) Please describe how stations were identified in cases in which either no T or D identifier was available or a station was not exclusively designated as distribution.

RESPONSE (B)– PREPARED BY CLEASPRING:

If the station did not have a clear identifier as being either T or D or if it was designated as both or had no designation, we included the station as unknown. We then divided that station as half being T and the other half D.

QUESTIONS (C)

c) Please explain the rationale for the ".5" multipliers in the formulas for "nsub", "mva" and "ntrans". Was this to divide stations designated as T&D?

RESPONSE (C)– PREPARED BY CLEASPRING:

Yes, plus dividing unknown stations between T and D.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-68

References: **Ref 1: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 40**

Ref. 2: ACIL Allen, "Opex Partial Productivity Study 2022" report to Australian Gas Networks (Victoria and Albury), Multinet and Ausnet, June 16, 2022

Preamble:

PEG believes that discussions in ratemaking proceedings of the properties of alternative econometric estimators should be theoretically correct even if the use of a particular imperfect estimator in research is reasonable.

Mr. Fenrick states in Reference 1 that "Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues causes the coefficient values to be biased or less precise."

QUESTIONS (A)

a) Please confirm that, in statistical theory, heteroskedasticity and autocorrelation cause ordinary least squares ("OLS") coefficient estimates to be less precise than the appropriate generalized least squares ("GLS") estimator.

RESPONSE (A)– PREPARED BY CLEASPRING:

Clearspring cannot confirm this. Autocorrelation and heteroskedasticity causes the standard error estimates to be less precise, but not the coefficient estimates themselves. Autocorrelation and heteroskedasticity, along with cross-sectional correlation will distort the standard errors of the parameter estimate, even though the parameter estimate itself remains unbiased and cannot be improved upon. For this reason, Clearspring conducts the Driscoll-Kraay ("DK") method to correct the standard errors due to autocorrelation, heteroskedasticity, and cross-sectional correlation. The DK method does not influence the parameter estimates (which is what is used to calculate the benchmark) and only adjusts the standard errors of the variable. The ordinary least square (OLS) parameter estimates are used in the DK approach, and these parameter estimates are not manipulated based on underlying assumptions like they are when using a GLS estimator. The DK approach is the more modern and transparent approach to dealing with autocorrelation, heteroskedacity, and cross-sectional correlation.

We would further add that these older GLS or Feasible GLS (FGLS) methods that are sometimes employed are inappropriate on an unbalanced or balanced dataset where the time periods (T) are fewer than the cross sections (N), which is the case in this benchmarking dataset. Please see p. 4 of the following journal article: https://journals.sagepub.com/doi/pdf/10.1177/1536867X0700700301 where the author states:

> *In an early attempt to account for heteroskedasticity as well as for temporal and spatial dependence in the residuals of time-series cross-section models, Parks (1967) proposes a feasible generalized least-squares (FGLS)–based algorithm that Kmenta (1986) made popular. Unfortunately, however, the Parks–Kmenta method, which is implemented in Stata's xtgls command with option panels(correlated), is typically inappropriate for use with medium- and large-scale microeconometric panels for at least two reasons. First, this method is infeasible if the panel's time dimension, T, is smaller than its cross-sectional dimension, N, which is almost always the case for microeconometric panels. Second, Beck and Katz (1995) show that the Parks–Kmenta method tends to produce unacceptably small standard error estimates.*

In that same section on p. 5 the author states:

> *Therefore, Driscoll and Kraay's approach eliminates the deficiencies of other large-T–consistent covariance matrix estimators such as the Parks–Kmenta and the PCSE approach, which typically become inappropriate when the cross-sectional dimension N of a microeconometric panel gets large.*

QUESTIONS (B)

b) Please confirm that, in the Reference 2 study by an Australian utility consultant, benchmarking results using a feasible GLS estimator are preferred to results using OLS.

RESPONSE (B)– PREPARED BY CLEASPRING:

Yes, the Australian consultant compared OLS with FGLS, and preferred FGLS although did not mention the newer DK method. The report stated that when hetereoskedacity and autocorrelation are present OLS is inefficient, although it remains unbiased (p. 12). The report continues on page 12 to say that in the context of this type of research the interval estimation and hypothesis testing can no longer be trusted from OLS.

Clearspring fully agrees with these statements, which is why we use the DK method which does not insert potential bias into the coefficient estimates themselves (which enter the calculation of the benchmarks) like FGLS, rather the DK corrects the variance-covariance matrix in calculating improved standard errors (which only are relevant in this context for including or excluding explanatory variables based on statistical confidence testing, that is to say interval and hypothesis testing).

QUESTIONS (C)

c) The ACIL Allen report also favors stochastic frontier benchmarking over econometric benchmarking with OLS. What is Clearspring's view?

RESPONSE (C)– PREPARED BY CLEASPRING:

As stated earlier, the report did not evaluate econometric benchmarking using DK corrected standard errors. The ACIL Allen report seemed to favor stochastic frontier analysis (SFA) and econometric benchmarking with FGLS over OLS but, again, did not evaluate the DK method as Clearspring used in our research. Using and evaluating OLS only seems to indicate to Clearspring that the consultant might not be fully aware of the newer DK method and how it corrects the standard errors and fixes the problems of hypothesis and interval testing that they cite as the shortcoming for the OLS method.

Regarding SFA generally to econometric benchmarking, in our view, SFA still requires sophisticated modeling but then additionally requires a highly questionable exercise in trying to separate out the error term into the components of random noise and inefficiency. Trying to estimate the frontier of the production curve would be fraught with inaccuracy and assumptions that, to Clearspring, would be unhelpful and lead to far more methodological disagreements and misleading conclusions. Better to compare firms, in our view, to the model expectations estimated by a well-specified econometric model which are centered around the mean to compare and contrast utility performance. This makes results less dependent on a fewer number of firms near the frontier because it is established off of the mean of the data rather than the frontier of that data. As even this report states on page 14,

> *"Because of the error term into two separate components, estimation of SFA cost models are more computationally demanding than conventional econometric methods. Moreover, separating random and inefficiency components of the error term requires a large number of data points."*

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-69

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 40

Preamble:

On page 40, Clearspring says "Under the assumptions of the model, this coefficient value (obtained from the OLS estimation procedure that Clearspring uses) is considered an unbiased estimator of the relationship."

The finite sample properties of time series data in OLS require strict exogeneity.[1] This is a strong assumption and if it fails, model parameters estimated with OLS are not unbiased. This strict exogeneity assumption is unlikely to be met in this model due to use of proxy variables, the likely presence of measurement error, and known omitted relevant variables such as system age.

Rather than claiming unbiased parameters, it may be more appropriate to claim consistency of the OLS parameter estimates. This assumption only requires contemporaneous exogeneity[2], which is more plausible for these data and models. PEG believes that the type of retrospective, observational time series data needed for distributor benchmarking will only ever meet claims of consistency, which can be appropriate and sufficient.

To further clarify, PEG is not implying Clearspring's choice of model estimation method is incorrect or inappropriate; rather PEG believes Clearspring's specific claim of unbiased parameters is incorrect. Importantly, as a result of the conclusions above, PEG believes that other estimation

[1] This means that the error term (which by definition must contain all measurement error in the variables, all omitted variables, and any sample bias) is uncorrelated with all explanatory variables in every time period, past and future.
[2] For contemporary exogeneity, the only necessary claim is that the error term is uncorrelated with the variables in the same time period (with no claims about past or future correlation required).

methods such as Feasible Generalized Least Squares may also meet claims for consistency in the estimated model parameters and can be an appropriate choice for distributor benchmarking.

QUESTIONS (A)

a) Please confirm whether Clearspring agrees with this assessment of the requirements of the sample properties for the unbiasedness of OLS parameters, as stated in the Preamble.

RESPONSE (A)– PREPARED BY CLEASPRING:

Clearspring's view is that, as PEG implies, both OLS and FGLS would not meet this definition of strict exogeneity from a technical perspective. However, as the preamble alludes to, this is an extremely technical position that should not impact the choice of estimators or put into question the value of econometric benchmarking. In normal parlance of practioners of applied econonmetrics, it is common to state that OLS is an unbiased estimator. We would point to interrogatory 1B-Staff-68 where the question referenced a report from an Australian consultant. That report also claimed that OLS remained unbiased even in the presence of autocorrelation and heterskedacity.

QUESTIONS (B)

b) Does Clearspring believe its model meets the definition of strict exogeneity?

RESPONSE (B)– PREPARED BY CLEASPRING:

Strictly speaking, no, but this is not be a concern as it is well-established that the estimator is an appropriate and proper method to use. We would suggest that no econometric benchmarking model put forth in any jurisdiction has met this strict definition.

QUESTIONS (C)

c) If yes, please provide Clearspring's theory and data to support this answer.

RESPONSE (C)– PREPARED BY CLEASPRING:

Please see response to part (b).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-70

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 22

Preamble:

Clearspring states that “The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence, except for the distribution substation variable which is significant at an 85% confidence level. In fact, all the other first order explanatory variables are statistically significant at a 99% confidence level. The adjusted R-Squared of the model equals a robust 0.977.”

QUESTIONS (A)

a) Please confirm that the use of panel data is known to result in artificially high R-Squared values.

RESPONSE (A)– PREPARED BY CLEASPRING:

Confirmed, however, the explanatory of the model is quite strong regardless of the exact R-Squared value and the variables themselves display extremely high statistical significance.

QUESTIONS (B)

b) Please confirm that in the portion of the report quoted above, Clearspring meant to say the distribution substation capacity variable is significant at an 85% confidence level.

RESPONSE (B) – PREPARED BY CLEASPRING:

Confirmed.

QUESTIONS (C)

c) Given the lower significance of the substation capacity variable, please explain Clearspring's decision to include it.

RESPONSE (C)– PREPARED BY CLEASPRING:

As we stated in footnote 17 of the Clearspring benchmarking report, the distribution substation capacity fell below our typical 90% confidence level and came in at an 85% level. Since the variable is on the borderline of statistical significance and the theoretical basis for the variable impacting costs is straightforward, we believed it would be helpful to intervenors to see the model with the variable. As stated in the footnote, the results are not significantly impacted by the inclusion of the variable.

QUESTIONS (D)

d) Did Clearspring test any alternative forms of this variable (e.g., MVA per substation)?

RESPONSE (D)– PREPARED BY CLEASPRING:

No.

QUESTIONS (E)

e) Were other variables considered in the modelling that had parameter estimates with significance in the 75% to 90% range but were excluded from the model? If so, what were they?

RESPONSE (E)– PREPARED BY CLEASPRING:

No. Clearspring focused efforts on continuing the model specification that stemmed from the Hydro One Joint Clearspring/PEG Report and exploring if we could add to it by including the substation variables and the time variant urban variable.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-71

References: Ref 1: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 18

Ref 2: EIA 861: https://www.eia.gov/electricity/data/eia861/

<u>Preamble:</u>

Clearspring states that

"The percentage of smart meters variable measures the percentage of customers that have an installed smart meter. Smart meters enable hourly or sub-hourly interval use data to be collected from the meter. While installing more capable meters and the necessary infrastructure is expected to increase distribution costs, these meters enable time-of-use ("TOU") electricity rates that can create efficiencies mainly in the realm of power supply."

QUESTIONS (A)

a) Does Clearspring's definition of smart meters exclude meters that only permit automated meter reading?

RESPONSE (A)– PREPARED BY CLEASPRING: Yes, the smart meter data only includes those meters designated as Advanced Metering Infrastructure (AMI) on the EIA-861 form and does not include those meters designated as Automated Meter Reading (AMR).

QUESTIONS (B)

b) Please confirm that Clearspring relied solely on Form EIA-861 for smart meter data beginning in 2007. If confirmed, please explain why the number of AMI meters for Arizona Public Service in 2007 in the Clearspring working papers is nearly double that reported in the EIA-861 in that year. If not confirmed, please identify your data source.

RESPONSE (B)– PREPARED BY CLEASPRING:

Clearspring did rely solely on the Form EIA-861 for the smart meter data beginning in 2007. Regarding the cited example of Arizona Public Service, we agree that the number in the Clearspring dataset is nearly double (290,769 AMI meters) than what the EIA-861 form reports (154,300 AMI meters). Given that much of this data was processed several years ago, we are unsure regarding why the discrepency is present. In responding to this interrogatory, Clearspring examined the 2007 AMI data. In addition to the APS example, we also noticed that Pacific Gas and Electric (PG&E) was given a zero value in 2007 when the EIA-861 reports 136,469. All other 2007 observations appeared correct. To assure these two data errors did not meaningfully influence the model or results, we modified the AMI data and variable for APS and PG&E. Regarding APS, we also needed to change the 2008 value because due to the 2007 data error we previously extrapolated 2008 data so that AMI meters in 2008 would not decline from the wrong 2007 value. Given the correction, this extapolation is no longer necessary and we removed it. The APS percent AMI value in 2007 shifted from 26.766% to 14.204%, the APS value in 2008 shifted from 29.350% to 17.424%, and the 2007 PG&E value shifted from 0.000% to 2.629%.

After making those three changes, we re-ran the total cost benchmarking model and there were very minimal changes to the parameter estimates and the Toronto Hydro result of -22.9% in the CIR period of 2025 to 2029 was unchanged.

QUESTIONS (C)

c) What data source did Clearspring use to get values for the percentage of smart meters variable for years prior to 2007?

RESPONSE (C)– PREPARED BY CLEASPRING:

Clearspring did not gather AMI data for years prior to 2007 with the exception of PPL. PPL had, by far, the largest AMI deployment in the dataset by 2007. PEG had raised this to our attention in a prior application and we inserted estimates for years prior to 2007 based on PEG's information. Given the lack of AMI deployment from the rest of the dataset, we have not deemed it necessary to gather AMI data prior to 2007 and have assumed values of 0 for those years, except for PPL. To illustrate why gathering the data is unnecessary prior to 2007 note that the modeling dataset has 75 U.S. utilities in 2007. Out of those 75, 66 of the utilities had zero AMI meters in 2007. Seven had deployments of less than 1% of their system (six of those seven with deployments of less than 0.3%). For the remaining two utilities (APS and PPL), the dataset does include estimates for PPL for prior years. APS deployment numbers are still relatively low in 2007 at 14.204% and while it is possible they had some AMI meters deployed prior to 2007, we have already tested the model sensitivity to a change in the APS number and we are confident that the model and the results would not be impacted in a meaningful way.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-72

Refrences : Ref 1: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 17

Ref 2:

https://www.eia.gov/naturalgas/ngqs/#?year1=1997&year2=2022&company=Name

<u>Preamble:</u>

Clearspring states that "The percentage of electric customers measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers."

The query system at Ref 2 shows that Dominion Energy South Carolina had natural gas volumes for residential, commercial, and industrial customers for the 1997-2022 period.

QUESTIONS (A)

a) Please confirm that beginning in 2019, South Carolina Electric & Gas began filing FERC Form 1s as Dominion Energy South Carolina Inc.

RESPONSE (A)– PREPARED BY CLEASPRING:

Confirmed.

QUESTIONS (B)

b) Please explain why Dominion Energy South Carolina (f/k/a South Carolina Electric and Gas) has a percent electric value of 100% in all years.

RESPONSE (B)– PREPARED BY CLEASPRING:

Likely due to the name change, Clearspring did not account for the gas customers in the variable. After making this correction, the model is essentially the same with minor changes and Toronto Hydro's CIR 2025 to 2029 results slightly improve to -23.8%.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-73

References: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Pages 25-29

Exhibit 2B, Section C, Page 4

<u>Preamble:</u>

On page 25 of Ref. 1, Clearspring states

"Several jurisdictions, including Ontario in recent years, exclude extraordinary events from reliability statistics, with the goal of reducing year over year volatility due primarily to extreme weather. If a day is excluded, it is denoted as a major event day ("MED"). The bulk of MEDs stem from major storms. These severe storms vary in number and intensity from year to year."

On p. 4 of Ref. 2, Toronto Hydro presents System Level SAIFI reported in several ways: total SAIFI, SAIFI excluding Loss of Supply ("LOS"), SAIFI Excluding Major Event Days ("MEDs"), SAIFI excluding MEDs and LOS, and SAIFI Excluding MEDs, LOS, and Scheduled Outages.

QUESTION (A):

a) Please confirm that the Toronto Hydro reliability data are for five minute sustained outages, exclude loss of supply outages, and exclude outages for Major Event Days based on the IEEE 2.5 beta methodology. If not confirmed, please explain. Were planned outages also excluded? Are any other characteristics of the outage definition notable?

RESPONSE (A):

Toronto Hydro provided reliability data as requested by Clearspring. This included SAIDI and SAIFI annual reliability data (historical and forecasts), excluding Major Event Days (consistent with IEEE-1366 Standard Beta Method), under a five-minute interruption basis. Loss of Supply and Scheduled Outages interruptions were included.

RESPONSE (A) PROVIDED BY CLEASPRING:

The reliability data are for five minute sustained outages, include loss of supply outages and exclude Major Event Day outages based on the IEEE 2.5 beta methodology.

Planned outages are included in the indexes to align with the U.S. dataset. No other characteristics are notable as we defined the data for Toronto Hydro consistent with the dataset definitions.

QUESTION (B):

b) What versions of SAIFI and CAIDI were used in Clearspring's research for the sampled US utilities (e.g., did the data include or exclude loss of supply or transmission outages, were planned outages included or excluded)?

RESPONSE (B) PROVIDED BY CLEASPRING:

The reliability indexes in the U.S. dataset includes loss of supply and planned outages.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-74

Ref 1: Exhibit 1B / Tab 3 / Schedule 3 / Attachment A/ pp. 25-28

Preamble:

PEG is seeking to better understand the sample and data Clearspring used in its reliability benchmarking models.

QUESTION (A):

a) Please provide the location of the calculations in the working papers that show how Clearspring combined reliability data for US utilities that serve multiple states into a single value for each year. If this information is not included in the working papers, please provide these.

RESPONSE (A) PROVIDED BY CLEASPRING:

Please see the included Excel spreadsheet file named 1B-Staff-74 Excel File, being provided on a confidential basis.

QUESTION (B):

b) Please confirm that the database takes the form of an unbalanced panel. Please provide the rationales for excluding some observations of each utility that contributed data for the model.

RESPONSE (B) PROVIDED BY CLEASPRING:

Confirmed. Observations were excluded in the reliability dataset when they were excluded in the total cost dataset, based on the exclude variable. Additional observations were excluded due to missing or implausible reliability data values.

QUESTION (C):

c) Please explain why the data for some US utilities were excluded from the reliability sample entirely.

RESPONSE (C) PROVIDED BY CLEASPRING:

Observations in the reliability dataset are only excluded due to the total cost exclude variable or due to missing or implausible reliability data observations.

QUESTION (D):

d) What is the source for Toronto Hydro's forecasted SAIDI, SAIFI, and CAIDI? What assumptions underlie these forecasted values?

RESPONSE (D):

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-42 for a description of Toronto Hydro's reliability projection model. The results produced from this model are aligned with IEEE 1366 definitions. To align with US reliability reporting standards, sustained interruptions lasting longer than five minutes in duration were considered for the purpose of the Reliability Benchmarking Study. CAIDI projections were derived from the SAIDI and SAIFI projections (i.e., CAIDI = SAIDI / SAIFI).

For the reliability projections provided to Clearspring, Toronto Hydro included projections of Loss of Supply and Scheduled Outage events. Toronto Hydro's approach for Loss of Supply was to set the projections for SAIDI and SAIFI equal to the most recent five-year average. For Scheduled Outages, the utility calculated the ratio of for each of 2022 actual SAIFI and SAIDI for the Scheduled Outages cause code over the capital spending in 2022 for the programs most responsible for scheduled outages, and applied that ratio to future planned spending. Please refer to 1B-Staff-62, part (b) for additional information on Scheduled Outages.

QUESTION (E):

e) If now available, please provide the 2023 actual SAIDI, SAIFI, and CAIDI values for Toronto Hydro.

RESPONSE (E):

Please see below for Toronto Hydro's 2023 SAIDI, SAIFI, and CAIDI values, based on a 5-minute threshold for sustained outages consistent with the Reliability Benchmarking Study (Exhibit 1B, Tab 3, Schedule 3, Appendix A). For more information, see response to 1B-Staff-73.

Table 1 – Actual SAIDI, SAIFI and CAIDI values for 2023

Metric	2023 Result
SAIDI (A)	51.55 Minutes
SAIFI (B)	1.12
CAIDI (A/B)	45.83 Minutes

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-75

References: **Ref 1: Exhibit 1B, Tab 3, Schedule 3, Attachment A, Page. 25-28**

Ref 2: EB-2019-0261, Exhibit 1, Tab 1, Schedule 12, Attachment A, Page. 28-29

Preamble:

On pages 27-28 Clearspring stated

"Clearspring did not change the variables for either the SAIFI or CAIDI models that were included in the prior Toronto Hydro research, except to take out the percentage AMI variable in the CAIDI model because it was not statistically significant. The procedure for estimating the two reliability models is much the same as the procedure for the cost models, except that different variables are used."

QUESTIONS (A)

a) Please explain why the Clearspring model was not updated when:

i. several years of additional data are available;

ii. Mr. Fenrick subsequently presented different reliability models in a Hydro Ottawa proceeding;

iii. the literature on reliability modelling has grown; and

vi. it is usually possible to improve a model when revisiting the issue with fresh eyes after several years.

RESPONSE (A)– PREPARED BY CLEASPRING:

Research efforts focused on making refinements and incremental improvements to the total cost benchmarking model. Clearspring did not expend time attempting to improve the reliaiblity model. This decision to use resources elsewhere in the research was due to two reasons. First is the limited focus on the reliability results in past proceedings. The reliability benchmark results, to Clearspring's knowledge, have not been mentioned prominently in prior Board decisions and no suggestions on improvement ideas have been made. This point was illustrated during the most recent Hydro One custom IR proceeding where Clearspring did not conduct econometric reliablility benchmarking and this did not seem to be an issue. The second reason is that the findings for SAIFI and CAIDI in relation to Toronto Hydro are both large and have been consistent. SAIFI results have consistently been above benchmarks by large amounts, CAIDI results are the opposite. In Clearspring's view, any improvements or model enhancements are very likely to produce that same conclusion. If, for example, SAIFI is found to be 80% or 120% above benchmarks rather than the 99.4% that we reported, to our thinking this will have no impact on the conclusion that Toronto Hydro's SAIFI metrics are considerably higher than benchmarks. The same is true for CAIDI only with the opposite conclusion that the Company's CAIDI is considerably below benchmarks.

QUESTIONS (B)

b) Did Clearspring not consider the variables (e.g., congested urban in the SAIFI model and rural density, percentage of plant underground, and average wind speeds above 20 MPH in the Hydro Ottawa CAIDI model) included in its SAIFI and CAIDI models from the previous Hydro Ottawa proceeding (EB-2019-0261)? If Clearspring did consider these variables, please provide the results and associated working papers.

RESPONSE (B)– PREPARED BY CLEASPRING:

Please see the response to part (a). We did not consider other variables but updated the data and provided the same models as in the prior Toronto Hydro application.

QUESTIONS (C)

c) Please confirm that the 2025-2029 average value in Table 11 for SAIFI (% difference) should be 94.9% rather than 99.4%.

RESPONSE (C) – PREPARED BY CLEASPRING:

The 99.4% number is the correct one. The % SAIFI Difference column needs to be re-calculated. Below is the table after making that calculation.

Year	SAIFI (Actual)	SAIFI (Benchmark)	SAIFI (% Difference)	CAIDI (Actual)	CAIDI (Benchmark)	CAIDI (% Difference)
2005	0.93	0.46	70.2%	76.59	110.00	-36.2%
2006	1.11	0.46	88.1%	64.98	110.73	-53.3%
2007	1.14	0.47	89.7%	69.12	111.59	-47.9%
2008	1.08	0.46	85.0%	67.40	112.68	-51.4%
2009	0.95	0.46	72.8%	84.13	113.75	-30.2%
2010	0.98	0.46	75.5%	77.30	115.32	-40.0%
2011	1.05	0.45	83.9%	80.13	117.26	-38.1%
2012	0.88	0.45	67.4%	68.06	118.66	-55.6%
2013	0.95	0.45	75.8%	70.61	120.35	-53.3%
2014	0.92	0.45	72.6%	63.76	123.09	-65.8%
2015	0.97	0.44	78.4%	64.04	125.48	-67.3%
2016	0.93	0.45	73.3%	59.71	128.08	-76.3%
2017	1.09	0.45	87.7%	53.14	129.25	-88.9%
2018	1.09	0.46	86.3%	53.25	130.44	-89.6%
2019	0.95	0.45	73.7%	50.39	132.46	-96.6%
2020	1.11	0.45	91.1%	50.77	135.21	-98.0%
2021	1.20	0.44	100.2%	48.55	136.49	-103.4%
2022	1.24	0.43	105.1%	45.75	138.95	-111.1%
2020-2022 average	**1.18**	**0.44**	**98.8%**	**48.36**	**136.88**	**-104.1%**
2023	1.28	0.43	108.2%	42.76	141.81	-119.9%
2024	1.19	0.43	100.8%	51.28	144.87	-103.9%
2025	1.19	0.43	100.7%	51.49	148.16	-105.7%
2026	1.18	0.43	99.9%	51.54	151.67	-107.9%
2027	1.17	0.43	99.3%	51.68	155.43	-110.1%
2028	1.17	0.43	98.8%	51.85	159.47	-112.3%
2029	1.16	0.43	98.2%	51.96	163.82	-114.8%
2025-2029 average	**1.17**	**0.43**	**99.4%**	**51.70**	**155.71**	**-110.2%**

QUESTIONS (D)

d) Clearspring's working papers show that it had the data for SAIFI and SAIDI, but had to calculate CAIDI in its code. Why did Clearspring present an econometric model for CAIDI rather than SAIDI?

RESPONSE (D)– PREPARED BY CLEASPRING:

The relationship between the reliability indexes is that SAIDI equals the product of SAIFI and CAIDI. This is similar to why a load forecaster tends to model customers and model use per customer separately and then multiplies the results together to forecast sales. Separating the models based on the frequency of outages and then duration per outage is the best way to model the impacts of frequency and duration, in Clearspring's view. If SAIDI was modeled alone, which can be done, this would be less than optimal because SAIDI includes both components of frequency and duration in its definition. This is the same approach we used in the last Toronto Hydro application.

QUESTIONS (E)

e) Form EIA-861 has data on whether outages are recorded automatically (e.g., yes/no). Did Clearspring consider using these data in its reliability benchmarking results? If so, please provide these models and associated working papers.

RESPONSE (E)– PREPARED BY CLEASPRING:

No.

QUESTIONS (F)

f) Why don't the SAIFI and CAIDI models include trend variables?

RESPONSE (F)– PREPARED BY CLEASPRING:

Trend variables could be considered in the models, however, trend variables in reliability models can be larger than their total cost counterparts. When projecting out-of-sample benchmarks to

2029 this can make the benchmarks volatile. For this reason, Clearspring is generally reluctant to insert trend variables into reliability models.

QUESTIONS (G)

g) Why isn't the IEEE MED Definition variable in the CAIDI model?

RESPONSE (G)– PREPARED BY CLEASPRING:

Please see response to part (a). The results for Toronto Hydro would improve by less than 2% if the IEEE variable were included in the CAIDI model.

QUESTIONS (H)

h) Why is the number of customers included in the CAIDI model when it has a p-value of 0.341?

RESPONSE (H)– PREPARED BY CLEASPRING:

In prior reliability benchmarking work, we have left the customer variable in regardless of the level of statistical significance. This is analogous to treating it as a second order quadratic or interaction term in the total cost model. The same approach is used for SAIFI. This is because SAIFI and CAIDI are the sum of outages or outage duration divided by either total customers or total outages.

The results for Toronto Hydro would change by less than 0.5% (they would get slightly better relative to the CAIDI benchmark) if the number of customers is excluded in the CAIDI model.

QUESTIONS (I)

i) Please provide the adjusted R-squared values for each model. Are these values robust?

RESPONSE (I)– PREPARED BY CLEASPRING:

The adjusted R-squared is 0.417 for the SAIFI model and 0.205 for the CAIDI model. Yes, they are robust in that the models help to explain the variation of reliability outcomes and are able to adjust for certain challenges and characteristics that impact the reliability metrics.

QUESTIONS (J)

j) Does Clearspring have any insights as to why Toronto Hydro is an extreme outlier in both the SAIFI and CAIDI models? Does this speak to the possibility that the models are missing some relevant variables or have other possible errors?

RESPONSE (J)– PREPARED BY CLEASPRING:

Clearspring cannot speak to the engineering or any other underlying causes for these results. In our view, the models are informative and helpful and we would be surprised if other relevant variables or methodological changes had a large directional impact on the results. While we acknowledge that there may other relevant variables that could be included in the model and those may end up being enhancements, we do not believe that Toronto Hydro being an outlier in the two models is itself evidence of any possible errors.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-76

Reference : Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 10

Preamble:

"Both Clearspring and PEG used the Driscoll-Kraay ("DK") method in the Joint Report and Clearspring continues to use the DK method for this study."

PEG would like to clarify that the estimation method is pooled Ordinary Least Squares ("OLS"), which is followed by Driscoll-Kraay corrections to the standard error estimates. While the dataset consists of panel data, pooled OLS treats each company's data for each variable as though it all occurs in one time period. As a result, each coefficient estimate reflects the variable's average effect on distributor cost over the entire 20-year sample period.

QUESTIONS (A)

a) Please confirm the estimation method and standard error adjustment method Clearspring used in its econometric benchmarking.

RESPONSE (A)– PREPARED BY CLEASPRING:

Confirmed. The Driscoll-Kraay (DK) estimation procedure includes estimating parameter estimates using the pooled OLS procedure and then correcting the standard error estimates for autocorrelation, hetereoskedacity, and spatial correlations.

QUESTIONS (B)

b) Please confirm that, other than the sample-wide yearly cost trend coefficient estimate, the individual coefficients produced by the pooled OLS model reflect a time-indifferent average of the variable's effect.

RESPONSE (B)– PREPARED BY CLEASPRING:

Correct. While many of the variables themselves change over time (i.e., are time variant) the estimate of the impact of the variables is indifferent to the year of that variable value. Clearspring is of the view that using this newer DK method that uses pooled OLS for parameter estimation but produces robust standard error estimates in the presence of a autocorrelation, hetereoskedacity, and spatial correlations is the most straight-forward approach. The alternative of Generalized Least Squares requires the researcher to make assumptions on how to modify the underlying data prior to estimation. There is no need for that step and it introduces the possiblity of a bias and incorrect assumption. Far better, in Clearspring's view, to use the DK method which sidesteps those issues.

QUESTIONS (C)

c) If (b) is confirmed, does Clearspring consider this to be a strength or weakness for its model?

RESPONSE (C)– PREPARED BY CLEASPRING:

A strength. Rather than modifying the underlying data prior to estimation, it is a strength of conducting the DK estimation procedure that pooled OLS can be used which requires no assumptions or modifications to the underlying data but still produces robust standard error estimates.

QUESTIONS (D)

d) If (b) is confirmed, does Clearspring have any concerns about the implications of a two-decade sample period?

RESPONSE (D)– PREPARED BY CLEASPRING:

No. Generally the more data the model has access to the better. There has been no pronounced structural shift in the electric distribution industry during this time period that would cause us to question the 2000 start year. This is the same start year used in the most recent Hydro One distribution benchmarking research conducted by Clearspring.

QUESTIONS (E)

e) Did Clearspring consider or test the model using a shorter sample period? If so, please provide results.

RESPONSE (E)– PREPARED BY CLEASPRING:

No, we did not consider there to be a need to test for different sample periods. We purposed to remain consistent with the Hydro One Joint Report research that Clearspring and PEG put forth. Consistency in the start year from study to study is helpful and starting in 2000 seems an appropriate year to begin the dataset from.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-77

Reference : Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 40

Preamble:

Clearspring says "This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading." Clearspring goes on to claim that the "standard correction procedure" for dealing with serial correlation and heteroskedasticity was to "figure out the nature of each problem" and "strategically [weight] the regression."

QUESTIONS (A)

a) Please confirm that there are numerous standard statistical tests and procedures, available as programmed commands within any modern econometric software program, to identify and rule out the presence of different forms of serial correlation and heteroskedasticity.

RESPONSE (A)– PREPARED BY CLEASPRING:

Confirmed. The older method of FGLS does have programmed commands in standard econometric software programs that allow the researcher to insert their own assumptions on the correlation of the lags. These programmed procedures and inputted assumptions will then modify the underlying data within the statistical program to produce alternative parameter estimates.

QUESTIONS (B)

b) Please confirm that it is proven that researchers can consistently (the same statistical claim which applies to time-series model parameters) estimate the rho-squared - a.k.a. the autocorrelation coefficient - in the model and thus it can be appropriate to use.

RESPONSE (B)– PREPARED BY CLEASPRING:

The autocorrelation coefficient can be estimated after making an assumption that the residuals are only correlated by one lag instead of multiple lags. This assumption then forms the basis to transform the underlying data and, thus, the parameter estimates themselves and the benchmark results. Just because an AR(1) autocorrelation coefficient can be estimated does not mean, however, it is the best estimation method to use. The newer DK method which requires zero assumptions by the researcher and does not impact the underlying data and thus the results, yet still corrects the standard errors (which are the issue in the presence of autocorrelation and hetereoskedacity), should be the preferred approach.

QUESTIONS (C)

c) Please confirm that if specific forms of serial correlation and/or heteroskedasticity are identified, there are programmed systematic procedures which correct for the problem in a clear and reproducible way.

RESPONSE (C)– PREPARED BY CLEASPRING:

Yes, the DK method is the best method for doing that in terms of being both clear and reproducible. It uses pooled OLS which requires no assumptions or modifications of the underlying data and then is able to adjust the standard errors appropriately.

QUESTIONS (D)

d) Please confirm that the systematic procedures for serial correlation and heteroskedasticity do not, in fact, alter the regression estimation procedure, but instead make the appropriate systematic corrections to the data which will then result in different coefficient values.

RESPONSE (D)– PREPARED BY CLEASPRING:

Yes, FGLS is a systematic procedure that does alter the underlying data prior to the estimation procedure after an assumption of how to adjust the data is made by the researcher. It does result in different coefficient values and that is the problem. There is no reason to alter the coefficient values and introduce possible wrong assumptions into the estimation procedure.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-78

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 23

Preamble:

In previous econometric models of total distribution cost presented on behalf of Toronto Hydro (two studies with different samples in 2014, and one study in 2019), Mr. Fenrick has found the Company to be a superior cost performer in early years followed by a markedly large, steady deterioration in cost performance going forward and through the forecast period. These models all predicted Company performance in the forecast period to be generally in the "average" range. The 2014 model with the US-only sample and the 2019 model produced largely similar results. Clearspring's updated model of distribution cost improves Toronto Hydro's entire series of historic and forecasted cost performance by 13-29% across the board compared to the previous models.

QUESTIONS (A)

a) What in Clearspring's view are the main drivers of this wholesale cost performance shift for Toronto Hydro?

RESPONSE (A)– PREPARED BY CLEASPRING:

The refinements and improvements made to the model and methodology are the main driver. This includes the refinement to the percent urban core variable to enable it to be time variant. This refinement increased the explanatory power of the variable and given that Toronto Hydro has a high value for the variable this will have a large impact on its benchmark score. This is especially true for the forecasted periods where Toronto Hydro's cost challenges are increasing relative to the sample because of the fast-growing nature of the city it serves. The new refinement in the variable is now able to capture the increasing cost challenge Toronto Hydro faces and adjust for future years. Other refinements since the last Toronto Hydro proceeding such as adding the substation variables, subtracting out pension and benefits, moving the capital benchmark year back to 1947, not including Ontario distributors to allow better cost and variable definitions, new scope variable, updating data for 2017-2021, and the distribution work variable also impact the scores in either direction but to a lesser extent than the refinement and improvement to the percent congested urban variable.

QUESTIONS (B)

b) Are there any material differences in variables or methods between this work and that done earlier not discussed in the current Clearspring report?

RESPONSE (B)– PREPARED BY CLEASPRING:

No, the material differences are referred to in the Clearspring Report. As indicated in the report, Clearspring replicated the methodology found in the Hydro One Joint Clearspring/PEG Report research after the conferral process with PEG. Other than refining the congested urban variable and adding the two substation variables, the variables and methodology is the same as that in the Joint Report.

QUESTIONS (C)

c) Did any other utilities common to the sample have similar shifts?

RESPONSE (C)– PREPARED BY CLEASPRING:

There were a handful of utilities that had similar sized shifts in both directions.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-79

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Pages 11, 35-36

Preamble**:**

When using a service price approach to the calculation of capital costs, calculation begins in a "benchmark" year in which the capital quantity is the ratio of plant value to an average of asset prices in prior years.

QUESTION (A):

a) The computer code shows that various capital benchmark years were used for US distributors. Please explain why.

RESPONSE (A) PREPARED BY CLEASPRING:

Two capital benchmark years for the U.S. distributors are used: 1947 and 1959. Most of the utilities have a capital benchmark year starting in 1947. Seven utilities had missing capital data from 1947 to 1959, in those cases we used a 1959 capital benchmark year.

QUESTION (B):

b) The OEB's Ontario total cost benchmarking work uses pre-2002 Toronto Hydro data in the capital cost calculations whereas the Clearspring study does not. Please discuss why the exclusion of the pre-2002 data leads to more accurate capital stocks than its inclusion. Does Toronto Hydro have actual values for any plant additions data that were estimated in the Ontario total cost benchmarking work? If so, please provide.

RESPONSE (B) PREPARED BY CLEASPRING:

It is Clearspring's understanding that the pre-2002 data used on the OEB total cost benchmarking work is extrapolated and is essentially an unknown assumption regarding when the plant additions occured and at what level prior to 2002. Clearspring prefers the approach of using the actual data that begins in 2002.

RESPONSE (B) BY TORONTO HYDRO:

Table 1 below presents the gross capital additions for 2000-2001. However, within the amounts presented below, due to the lack of detailed records, Toronto Hydro believes that unregulated gross capital additions and changes in Construction Work in Progress (CWIP) are included, both of which are inconsistent with the cost definitions used by Clearspring in the benchmarking report. Prior to July 1999, the businesses of Toronto Hydro were owned and operated by the Toronto Hydro-Electric Commission, due to which gross capital additions prior to 2000 cannot be provided.

Table 1: 2000-2001 Gross Plant Additions ($M)

	2000	2001
Gross Plant Additions	164.9	131.6

QUESTION (C):

c) Given the general inaccuracy of benchmark year cost calculations and Clearspring's recent benchmark year for Toronto Hydro (2002), should benchmarking results for some of the early years since 2002 be disregarded or downplayed?

RESPONSE (C) PREPARED BY CLEASPRING:

This is a valid point. The earlier year results will contain an unknown influence because of the recent capital benchmark year. This lessens as time increases and actual fixed asset plant additions are added to the capital calculation making it more accurate as more years accumulate from 2002.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-80

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 34

Preamble:

Toronto Hydro states that "To construct the overall OM&A input price we weighted each sub]index using the customized labour and non-labour cost shares calculated from the FERC Form 1 data or based on data provided to us from Toronto Hydro."

QUESTIONS (A)

a) The SST code in the provided working papers has a remark indicating a 70% weight for Toronto Hydro labor in the calculation of the O&M price index whereas the data files and formulas suggest a 40% value was used in the historical period. Please confirm that the 70% labor weight is no longer used in the calculations.

RESPONSE (A)– PREPARED BY CLEASPRING:

The SST code remark is a relic of past projects. Clearspring requested from Toronto Hydro to estimate its OM&A payroll costs as a percentage of OM&A. The Company was able to do this for 2020 to 2029. The 2020 value is 40%, so we used that value for 2020 and prior. The specific year estimates for 2021 to 2029 are used. These can be seen on row 33 in the OM&A Forecast worksheet found in the Excel file titled THESLdata2025 found in the working papers.

QUESTIONS (B)

b) If a 40% share is instead used, what is the basis for this calculation?

RESPONSE (B)– PREPARED BY CLEASPRING:

Please see the response to part (a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-81

References: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page. 22-23, 38

Preamble:

In order to make econometric projections of Toronto Hydro's proposed cost, Clearspring needed to obtain forecasts of labor OM&A, non-labor OM&A, and asset prices.

Clearspring did not provide a detailed description to address these in its report or in the working papers.

QUESTIONS (A)

a) Please provide full descriptions and Timeseries File IDs for each of the input price forecasts that Clearspring used in its research.

RESPONSE (A)– PREPARED BY CLEASPRING:

Clearspring purchased from the Conference Board of Canada the GDP-IPI with the ID of PGDP and the following description : Implicit Price Deflator - GDP at Market Prices (2012=1.0) and the AWE with the ID of RLAWWIO and the following description : Average Weekly Wages & Salaries Per Employee, Ontario ($, Industrial Composite).

QUESTIONS (B)

b) Please explain why forecasts from January 23, 2023, were used when the report was dated October 31, 2023?

RESPONSE (B)– PREPARED BY CLEASPRING:

Clearspring did not purchase forecasts after the January 23, 2023 date. During this time period is when we conducted the majority of our data collection efforts.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-82

Reference: Exhibit 1B, Tab 3, Schedule 3, Page 38

Preamble:

Toronto Hydro states that the ION meter is more expensive than a typical meter and implies small installed quantities of ION meters can have a material effect on Meters CAPEX unit costs.

QUESTION (A):

a) Why is the ION meter being utilized and has a lower cost alternative been investigated and considered?

RESPONSE (A):

As discussed on page 6 of Exhibit 2B, Section 5.4, ION meters provide benefits such as easier data access for customers, enhanced data analytics granularity, and improved power quality data analysis. Through the ION meter, customers have access to enhanced data such as power factor, voltage, power consumption, and waveform analysis. The customer is able to access the meter at any time and export data directly into their energy management systems. In addition, the ION meter provides customers the benefits of power factor correction and the implementation of sag mitigation technology. For example, Toronto Hydro leveraged sag data to help a customer take corrective action on their under voltage protection, prevent multiple outages, and minimize the customer's lost production time.

At the time Toronto Hydro chose to begin installing ION meters in limited circumstances, lower cost alternatives that provided similar benefits and were Measurement Canada certified were not available.

QUESTION (B):

b) What percentage of installed meters in each of 2018 to 2022 were ION meters?

RESPONSE (B):

Please see Table 1.

Table 1 – Percentage of ION Meters Installed Between 2018-2022 Period

Year	Total Installations	ION Meter Installations	Percentage of ION Meter Installations
2018	28,395	31	0.109%
2019	26,182	43	0.164%
2020	24,688	10	0.041%
2021	12,241	2	0.016%
2022	19,603	5	0.026%

QUESTION (C):

c) What is the cost difference between an ION meter and a typical meter?

RESPONSE (C):

The installed cost of an ION meter is approximately $9,300 compared to the installed cost of a typical meter at approximately $1,500.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-83

References: Exhibit 1B, Tab 3, Schedule 3, Appendix C

Preamble:

In its unit cost benchmarking study, UMS Group states that the seven asset categories represent 52% of the planned capital budget and that the five maintenance programs represent approximately 57% of the preventive and predictive maintenance costs.

QUESTION (A):

a) Please show the detailed calculations to derive the above percentages.

RESPONSE (A):

The percentage for the planned capital budget represented by the seven asset categories is based on Toronto Hydro's ISA data for 2020 to 2022. The unit cost methodology outlined as part of the updated approach in interrogatory response 1B-AMPCO-09 is followed to exclude demand driven programs and outliers from the population. The total cost corresponding to the seven asset categories is then divided by the total cost of all assets represented in the ISA data for that year. The average of the three years is taken resulting in a percentage of 48%.

Upon further review, Toronto Hydro identified that the original denominator used in the calculation underrepresented the total cost as it did not consider the exhaustive asset classes in the ISA data. This consequently resulted in the percentage change from 52% to 48%.

Table 1: Calculation of 7 Asset Categories' Percentage of Planned Capital Budget

	2020 – 2022 ($M)
UMS Provided Capital Assets	262.7
Filtered Total Cost View*	551.5
%	48%

**Total costs after unit cost methodology has been applied*

For the five maintenance programs, summation of the actual spend under these five programs was divided by the total spend under the Preventative and Predictive maintenance portfolio for each of the years between 2020 – 2022, and average percentage was obtained resulting in a percentage of 56%. This represents a decrease of approximately 1% from the original calculation following review and update of the total spend under the Preventative and Predictive programs used in the calculation.

Table 2: Calculation of 7 Asset Categories' Percentage of Planned Capital Budget

	2020 – 2022 ($M)
UMS Provided Maintenance Costs	28.6
Total Preventative and Predictive Programs	51.0
%	56%

QUESTION (B):

b) Please show the detailed calculations to derive the respective percentages for the 2025-2029 period.

RESPONSE (B):

Forecasted values are not available for the 2025-2029 period and Toronto Hydro did not forecast the unit costs in the UMS Unit Cost Benchmarking Study. Toronto Hydro forecasts volumes and total costs at a segment/program level using program-specific methodologies and is unable to forecast the 2025-2029 period in a manner that can be relatable to the unit cost as the unit cost methodology utilizes ISA data from completed projects.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-84

Reference: Exhibit 1B, Tab 3, Schedule 3, Section 3.0

<u>Preamble:</u>

In Reference 1, which is titled "2020 to 2024 Productivity Achievements," Toronto Hydro states it has achieved more than $2.2 billion of savings since 1999 through the amalgamation of the six utilities that served the former municipalities that now make-up the City of Toronto.

QUESTION:

Of the cited $2.2 billion in savings generated by the utility since Toronto Hydro was created in 1999, please quantify the new savings that were actually, as opposed to being forecast, realized since 2020.

RESPONSE:

Please see Toronto Hydro's response to 1B-AMPCO-07.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-85

Reference: Exhibit 1B, Tab 3, Schedule 3, section 3.1

Preamble:

Toronto Hydro provides forecast reduced expenditures and forecast avoided operating costs for several corporate projects.

QUESTIONS (A):

a) Please complete the following table to identify the actual realized reduced expenditures in each year:

Project	2020	2021	2022	2023
Enterprise Resource Planning, Enterprise Connect, and People Connect				
e-Tailboard				
Streetlight Management System Project				
Non-conformance Reporting				
Electronic Red Construction Folder				
Accounts Payable Processing Automation				
Storm Prediction Impact Tool				
SAP Business Warehouse Project				

RESPONSE (A):

As requested, the table below lists the cost reduction benefits from 2020-2023 for the noted projects.

Project	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	Total ($000)
Enterprise Resource Planning, Enterprise Connect, and People Connect	$1,150	$1,150	$1,150	$1,532	$4,982
e-Tailboard	N/A	N/A	$6	$6	$12

Project	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	Total ($000)
Streetlight Management System Project	N/A	N/A	N/A	N/A	N/A
Non-conformance Reporting	N/A	N/A	N/A	N/A	N/A
Electronic Red Construction Folder	N/A	$25	$32	$33	$90
Accounts Payable Processing Automation	N/A	$164	$170	$179	$513
Storm Prediction Impact Tool	N/A	$6	$10	$10	$26
SAP Business Warehouse Project	N/A	N/A	N/A	N/A	N/A

Note : The above amounts have been rounded to the nearest thousand.

QUESTIONS (B):

b. Please complete the following table to identify the actual realized cost avoidance in each year:

Project	2020	2021	2022	2023
Enterprise Resource Planning, Enterprise Connect, and People Connect				
e-Tailboard				
Streetlight Management System Project				
Non-conformance Reporting				
Electronic Red Construction Folder				
Accounts Payable Processing Automation				
Storm Prediction Impact Tool				
SAP Business Warehouse Project				

RESPONSE (B):

As requested, the table below lists Cost Avoidance benefits from 2020-2023 for the noted projects.

Project	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	Total ($000)
Enterprise Resource Planning, Enterprise Connect, and People Connect	$305	$612	$990	$716	$2,623

Project	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	Total ($000)
e-Tailboard	N/A	N/A	$725	$309	$1,034
Streetlight Management System Project[1]	N/A	N/A	$628	$659	$1,287
Non-conformance Reporting	N/A	N/A	$400	$420	$820
Electronic Red Construction Folder	N/A	N/A	$245	$257	$502
Accounts Payable Processing Automation	N/A	N/A	N/A	N/A	N/A
Storm Prediction Impact Tool	N/A	N/A	$3	$3	$6
SAP Business Warehouse Project	N/A	$18	$41	N/A	$59

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-86

References: Exhibit 1B, Tab 3, Schedule 1, Section 3.2.2

Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Base Approach, October 2012

Preamble**:**

On page 10 of Reference 1, Toronto Hydro reports that its investment plan is "sufficient only to maintain outage duration as measured by the custom SAIDI metric over the 2025-29 period" (p.10), yet set a target two standard deviations below this level - 2 minutes lower than historical 5 year average of 48.2 minutes.

On page 16 of Reference 1, Toronto Hydro proposes to maintain outage frequency and has established a target range enveloping its most recent five-year historical outage frequency measure of 0.42. Regarding outages, its investment plan is to invest "the minimum level necessary to manage asset condition"; this intent is informed by customers' prioritization of reduced outage duration rather than frequency.

QUESTION (A):

a) Please explain what actions and management decisions Toronto Hydro would need to undertake in order to achieve the 46.2 minute SAIDI target attached to the performance incentive mechanism.

RESPONSE (A):

Toronto Hydro's Asset Management Process (refer to Exhibit 2B, Section D) combined with the necessary funding and resources to execute the work programs outlined in the 2025-2029 investment plan, and the performance incentives proposed in Exhibit 1B, Tab 3, Schedule 1 will enable the utility to attain the proposed System Reliability targets for Outage Duration and Outage Frequency.

QUESTION (B):

b) Please confirm whether the steps in a) are included in Toronto Hydro's investment plan.

RESPONSE (B):

Yes. All of the above are part of the 2025-2029 investment plan and rate application.

QUESTION (C):

c) Please explain under what conditions the steps in a) would be included in Toronto Hydro's plan, and whether any other work would not be carried out if the steps in a) were undertaken.

RESPONSE (C):

Please refer to the response in part a.

QUESTION (D):

d) In the event Toronto Hydro follows its investment plan, which is not sufficient to achieve this target, and it achieves this target nevertheless, to what factors could its success be attributed?

RESPONSE (D):

Toronto Hydro cannot comment on a hypothetical future scenario the parameters of which are unclear and speculative. The utility notes however that in its experience as a performance-drive organization, the achievement of the targets can be attributed to a combination of operational management, innovative approaches, adaptability, collaboration, and risk management. Effective decision-making is at the crux of all these factors. In a balanced incentive regime, where performance targets are set in a challenging but achievable way, the utility is encouraged to optimize decision-making towards achieving performance objectives.

In a regulatory regime that focuses predominately on financial/cost outcomes, decisions are optimized to manage profitability, efficiency and cost containment. Over time and/or under certain circumstances (e.g., the utility faces new requirements or rising cost pressures) this may compromise the utility's ability to achieve target service quality performance objectives.

Toronto Hydro believes that both types of incentives are important to drive effective decision-making and ensure that there is an appropriate balance of risk/reward in the regulatory framework. That is why its proposed X-factor includes both an empirical-based efficiency factor and a performance-focused incentive mechanism. For more information, please refer to the Rate Framework evidence in Exhibit 1B, Tab 2, Schedule 1 at pages 29-33.

QUESTION (E):

e) Please explain why an incentive is warranted in the circumstances referenced above.

RESPONSE (E):

Please see response to (d) above.

QUESTION (F):

f) Regarding outage frequency please explain why an incentive is required or justifiable to prevent deterioration from current service levels and investing "the minimum level necessary."

RESPONSE (F):

Refer to response in part d).

QUESTION (G):

g) Please discuss the proposal to maintain outage frequency in the context of the OEB's statement in Reference 2 that "The [Renewed Regulatory Framework] is intended to elevate utility performance by creating incentives for superior performance."

RESPONSE (G):

In Toronto Hydro's view, the quoted statement must be considered holistically when evaluating the effectiveness of the performance incentive regime. To apply this statement in a wholesale manner to each and every performance objective would run contrary to other important considerations in the RRF: *"The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers.*"

With respect to value for money for customers, the RRF's customer focus outcome encourages distributors to provide services "*in a manner that responds to identified customer preferences*." With this customer focus outcome in mind, the target to maintain (rather than improve) Outage Frequency reflects the key consideration that customers in all classes (except Key Accounts) prioritize outage duration over frequency, and expect the utility to balance reliability performance with price and other key outcomes. Please see Exhibit 1B, Tab 5, Schedule 1 for more information about Toronto Hydro's application-specific customer engagement results that informed development of the 2025-2029 Investment Plan underpinning this application.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-87

References: Exhibit 1B, Tab 3, Schedule 1, Page 48
Exhibit 2B, Section E7.2

<u>Preamble:</u>

Toronto Hydro states the use of Local Demand Response (LDR) to avoid capital spent on load transfers resulting in significant long-term savings for ratepayers.

QUESTION (A):

a) Please provide the benefit-cost analysis, or equivalent document, that supports Toronto Hydro's selection of target stations for demand response and those which have not been proposed, including: Fairbank TS, Finch TS, Bathurst TS, Manby TS, Leslie TS, Cecil TS, Strachan TS, and Copeland TS.

RESPONSE (A):

As noted on pages 8 and 9 of the updated (January 29th, 2024) Exhibit 2B, Section E7.2, the Flexibility Services program will target Finch TS, Manby TS, Cecil TS, Strachan TS, Leslie TS and Copeland TS. The program is not currently focused on Fairbank TS or Bathurst TS, but should the opportunity and need arise to target these stations, Toronto Hydro will investigate the possibility of doing so. A key feature of the Flexibility Services program is that it can easily adapt in terms of scope and location to meet the most pressing system needs. The program target areas will shift based on needs, as has been the case in previous LDR programs.

As noted in Toronto Hydro's response to the OEB's stakeholder consultation on the *Benefit – Cost Analysis Framework for Addressing Electricity System Needs* (EB-2023-0125), submitted on February 1, 2023, Toronto Hydro applies pre-screening criteria when selecting potential applications of NWSs, and selects projects that can be clearly defined and linked to a system need.

These projects are then put through a cost-benefit analysis to ensure the application of NWSs is cost-effective. For more information on the cost-benefit analysis that has been undertaken for the selected stations, please see Interrogatory 1B-Staff-89.

QUESTION (B):

b) Please list any other LDR projects that were considered but rejected for the 2025 to 2029 period.

RESPONSE (B):

As described in Exhibit 2B, Section E7.2, the Flexibility Services program (i.e. LDR) directly supports Load Demand by identifying opportunities to defer or avoid bus-level load transfers when and where it is appropriate. As noted in the evidence, all stations that are targeted for bus-level relief in 2025-2029 were evaluated and considered for the LDR program. Some of these stations are excluded (i.e. Dufferin TS, Terauley TS, Esplanade TS, Horner TS and Windsor TS) as the planned transfers are either carry-over projects that were deferred in 2020-2024, or projects where overloading is not the primary driver. The work planned for these stations is described in Exhibit 2B, Section E5.3. All six of the remaining stations that are expected to require bus-level load transfers in the 2025-2029 period (i.e. Finch TS, Manby TS, Cecil TS, Strachan TS, Leslie TS and Copeland TS) will be targeted for LDR capacity.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-88

References: Exhibit 1B, Tab 3, Schedule 1, Section 2.4.3, Pages 46-56
Exhibit 2B, Section E7.2.1

Preamble:

Toronto Hydro provides details of its proposed system capacity (non-wires) proposals, including the LDR and performance incentive structure. Toronto Hydro proposes a budget of $5.7 million to deploy an expanded version of its LDR initiative to address system capacity constraints and procure 30 MW of flexible system capacity to displace and defer the need for load transfers in the Horseshoe North area over the 2025-2029 term.

QUESTION (A) AND (B):

a) Please discuss what considerations Toronto Hydro undertook about expanding the LDR program greater than 30 MW, including cost, impact on neighboring stations, ability to procure necessary capacity and any subsequent changes to performance incentive structures.
b) Please discuss the rationale for limiting LDR capacity at 30 MW for the 2025 to 2029 period.

RESPONSE (A) AND (B):

Toronto Hydro considered the following key factors in setting the 30 MW target:

Resource Availability: Toronto Hydro's experience shows that procurement of targeted demand response ("DR") for the purpose of capital deferral/avoidance is most successful when targeting areas with a higher penetration of large loads (e.g., 1 MW or more, or large groupings of 100 kW or more customers), as these customer types are more likely to be able to curtail on demand. The utility selects stations with a high penetration of these customer types when possible, and sets achievable targets that reflect the anticipated availability of DR amongst these customers. During the 2020-2024 rate period, Toronto Hydro set a target of 10 MW for a group of two stations (Manby TS and Horner TS), and even this modest target proved to be challenging from a procurement perspective (see below for details). For a group of six stations, Toronto Hydro set an ambitious goal of 30 MW (10 MW per 2 stations), which reflects both the utility's experience and commitment to continuous improvement with respect to non-wires solutions.

Market Dynamics: Local Demand Response ("LDR") is subject to market forces that could impact the outcome of the program. In the current Etobicoke Pilot, the utility intended to procure 10MW but could only secure 4 MW for the first summer (2023). This a reflection of available market capacity, particularly as many resources are already committed to other programs (e.g., IESO's Capacity Auction, the Industrial Conservation Initiative ("ICI"). Aggregators (i.e., participants in LDR) expressed that significant time and effort is required to acquire capacity for new programs, and that the average time required to onboard new capacity for a new program could be anywhere between 6 to 12 months, resulting is some participants choosing to stick with existing market obligations and forego participation in new programs. These are important factors to consider when setting reasonable targets for non-wires solutions ("NWS").

Other Considerations: In setting the 30 MW target, Toronto Hydro also considered the cost recovery impacts of acquiring DR capacity (please see Exhibit 2B Section E7.2 for details) in addition to many other urgent and important operational requirements that the utility must address in the next rate term as summarized in the OM&A Overview evidence at Exhibit 4, Tab 1, Schedule 1, and detailed throughout the programmatic evidence in Exhibit 4, Tab 2. The utility also considered the ongoing regulatory uncertainty with respect to performance incentives and cost recovery for investments that are needed to develop capabilities in this emerging area of focus. Coupled with the operational and market risks identified above, these considerations led Toronto Hydro to set a challenging but achievable target of 30MW.

QUESTION (C):

c) Please discuss what considerations are required if the LDR program was to be leveraged to alleviate long-term capacity needs for the various stations identified.

RESPONSE (C):

For DR to replace a permanent, long-term capacity investment, Toronto Hydro needs confidence that this market-based product can deliver the same safety and reliability requirements as a tried and tested conventional wires solution at a cost-effective price. At this time, adequate volumes of DR resources are not available to meet these requirements. As noted in part (a), it can be difficult to procure even 10 MW of DR. To avoid larger scale, long-term station investments, Toronto Hydro would need to procure upwards of 50 MW in one station area. Furthermore, to rely on DR at this scale, Toronto Hydro would need to pay a high $/MW-day daily capacity payment along with potential energy payments, for each day that the resource is relied upon. As the market matures and more resources become available, Toronto Hydro will evaluate the feasibility and cost-effectiveness of using DR to replace longer-term capacity investments.

QUESTION (D):

d) Please discuss and provide any analysis undertaken to consider similar LDR initiatives in other areas of Toronto Hydro’s system that have identified constraints, including Horseshoe East and West. Please indicate why similar projects have not been proposed for additional areas on the system.

RESPONSE (D):

As described in Exhibit 2B, Section E7.2, the Flexibility Services program (i.e. LDR) directly supports Load Demand by identifying opportunities to defer or avoid bus-level load transfers when and where it is appropriate. As noted in the evidence, Toronto Hydro evaluated all the stations that are targeted for capacity bus-level relief in 2025-2029, including those in Horseshoe East and West, as well as

Downtown.[1] From this evaluation, the utility selected six stations that are expected to require bus-level load transfers in the 2025-2029 period (i.e. Finch TS, Manby TS, Cecil TS, Strachan TS, Leslie TS and Copeland TS) for LDR capacity. The target areas could shift based on system needs, similar to previous LDR programs, because as noted in Exhibit 2B, Section E7.2 on pages 8-9, the ability to easily adapt in terms of scope and location to meet the most pressing system needs is a key feature of the Flexibility Services program.

QUESTION (E):

e) Please discuss what considerations and analysis was conducted by Toronto Hydro related to CDM programs being offered in its service territory, including those in partnership with other entities, including the IESO and the Local Initiatives Program during the 2025-2029 period.

RESPONSE (E):

Toronto Hydro has not proposed its own local programs under the 2021-2024 CDM framework. However, the utility continues to support programs delivered by IESO under the Local Initiatives Program. This includes outreach and marketing support for programs such as Coolsaver, BizEnergySaver, and the upcoming heat pump program. Given the effort and success of centrally delivered CDM, at this time, Toronto Hydro is focused on building on and supporting the IESO's efforts rather than duplicating programs. Toronto Hydro remains open to collaborating on future CDM programs with the IESO, and exploring opportunities for benefit-stacking where possible.

Toronto Hydro's own efforts in the realm of demand-side management, focus on targeted and credible opportunities where capital deferral or avoidance through non-wires solutions can be identified and measured. This is based on a ground up analysis of system needs, and the targeted deployment of demand-side management program called Local Demand Response ("LDR"), as outlined in detail in the evidence at Exhibit 2B, Section E7.2.

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[1] This did not include certain stations (i.e. Dufferin TS, Terauley TS, Esplanade TS, Horner TS and Windsor TS) for which projects carried over from 2020-2024. The work planned for these stations is described in Exhibit 2B, Section E5.3.

QUESTION (F):

f) Please discuss the Benefit Stacking Pilot that is supported by the IESO Grid Innovation Fund and OEB's Innovation Sandbox, including project timelines and how Toronto Hydro expects to apply findings from the pilot project.

RESPONSE (F):

Toronto Hydro has partnered with Power Advisory LLC and Toronto Metropolitan University's Centre for Urban Energy (CUE) to create a project that explores how to effectively and efficiently procure and deploy DR capacity to address overlapping distribution and transmission system level needs. This project is called the Benefit Stacking Transmission and Distribution Pilot ("Benefit Stacking Pilot") and is supported by the IESO's Grid Innovation Fund, and the Ontario Energy Board's (OEB's) Innovation Sandbox. The project began in June 2022 and will be completed by March 2025. An overview of the Benefit Stacking Pilot was provided on pages 12 and 13 of Exhibit 2B Section E7.2.

In its first year (2022), the pilot was focused on designing the program, developing rules, contracts, measurement and verification, and the settlement processes. During this period, Toronto Hydro also ran a procurement for DR capacity to be deployed in Summer 2023.

Last year (2023) was focused on testing the program by deploying DR capacity in the summer, resulting in four dispatch events, with each event yielding close to 5 MW of DR capacity. Throughout the year, the utility's partner Toronto Metropolitan University (TMU) created several tools and platforms to enable auction-based procurement, dispatch coordination, and automated measurement, verification and settlement. Additionally, 6 MW of DR was procured for future deployment.

In summer 2024, Toronto Hydro intends to dispatch this capacity utilizing the TMU tools and upon completion of these events, the utility and its partners will analyze the results.

The utility will apply the learnings from this pilot to inform future LDR programs in its service territory and provide insights to the electricity sector on transmission-distribution coordination.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-89

References: **Exhibit 1B, Tab 3, Schedule 1, Section 2.4.3, Pages 49-55**
OEB Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, March 28, 2023
OEB Draft Benefit-Cost Analysis Framework for Addressing Electricity System Needs, December 2023

<u>Preamble:</u>

Toronto Hydro has proposed a performance incentive related to the LDR program as well as has conducted a Benefit Cost Analysis on the proposal. As part of this analysis, Toronto Hydro outlines the NPV of the benefits of capital deferral and avoided based on the LDR program based on a set of assumptions informed by prior experience with load transfer projects.

QUESTION (A):

a) Please provide any data from Toronto Hydro's existing LDR program that supports the assumption of 75% of load transfer projects in scope can be avoided entirely, while 25% deferred for at least 5 years.

RESPONSE (A):

The LDR program that is currently underway is targeting two stations, Manby TS and Horner TS. As described on page 11 in Exhibit 2B Section E7.2, the consideration of LDR as an NWS has enabled planners to avoid all incremental load transfers that would otherwise have been carried out in order to manage Manby TS between 2022 and 2024.

This experience has confirmed that adding the consideration of NWSs to the load demand project selection and scoping process introduces the opportunity to re-prioritize capital work. As a result, in cases where the LDR can successfully be procured, load transfers that are intended to manage capacity constraints during an interim period (prior to executing a permanent wires solution) can be avoided.

Looking ahead at 2025-2029, as described in on pages 8 and 9 in Exhibit 2B Section E7.2, Toronto Hydro is targeting 30 MW at a group of six stations. Each of these stations currently has an estimated volume of load transfers that could materialize. The high range is 175 MVA and the low range is 100 MVA. Based on the diversity of needs at these stations, it is not prudent to assume that 100% of the load transfers targeted by the procurement of 30 MW of DR can be entirely avoided. Engineering judgement was utilized to estimate that 75% could be avoided, while 25% could be deferred. Note that this estimate, and the resulting BCA, provides a conceptual understanding of the difference in value and benefit that arises in cases where capital is entirely avoided versus capital being deferred. The figures could change based on the actual load demand projects targeted, as well as the ability to procure DR capacity. This is to be expected when considering the use of third-party owned, market-based solutions to address dynamic demand-related system needs.

QUESTION (B):

b) Please discuss the impacts to the analysis, including operational cost figures, summarized in Table 18 using different assumptions, including 50% of load transfer projects in scope are avoided entirely while 50% are deferred for at least 5-years; and, if 100% of projects are avoided entirely.

RESPONSE (B):

Table 1 below restates the analysis applying an assumption that 50% of load transfer projects in scope are avoided entirely while 50% are deferred for at least 5-years.

Table 1

	Deferred Capital	Avoided Capital
Parameters	$5.00 million in load transfer capital investment deferred for 5 years at an operational cost of **$1.43 million**	$5.00 million in load transfer capital investment avoided over the life of the assets (48 years) at an operational cost of **$4.28 million**
Costs	NPV of the operational costs of the non-wires solution (2025-2029): **$1.14 million** + NPV of the revenue requirement associated with the load transfer capital investment to be made in 2030: **$3.59 million** = **$4.74 million** NPV Costs	NPV of the operational costs of the non-wires solution (2025-2029): **$3.43 million**
Benefits	NPV of revenue requirement associated with capital investment deferred from 2025-29: **$4.85 million** *Less (-)* NPV Costs: **$4.74 million** *Equals (=)* $110.14 thousand NPV Benefits	NPV of revenue requirement associated with capital investment avoided in 2025 over the 48-year EUL: **$4.85 million** *Less (-)* NPV Costs: **$3.43 million** *Equals (=)* **$1.42 million** NPV Benefits
	Total NPV Benefits = $1.53 million	

Table 2 below restates the analysis applying an assumption that 100% of load transfer projects in scope are avoided entirely.

Table 2

	Deferred Capital	**Avoided Capital**
Parameters	**n/a**	**$10.00 million in load transfer capital investment avoided over the life of the assets (48 years) at an operational cost of $5.70 million**
Costs	**n/a**	**NPV of the operational costs of the non-wires solution (2025-2029): $4.57 million**
Benefits	**n/a**	**NPV of revenue requirement associated with capital investment avoided in 2025** **over the 48-year EUL: $9.69 million** ***Less (-)*** **NPV Costs: $4.57 million** ***Equals (=)*** **$5.12 million NPV Benefits**
	Total NPV Benefits = $5.12 million	

The analysis presented in the tables above aligns with Toronto Hydro’s understanding that capital avoidance of load transfers constitutes the primary source of economic benefits for the LDR program. At the same time, while deferral of load transfers may ultimately provide small (but positive) economic benefits, this approach can provide operational flexibility to areas of grid that face demand volatility or uncertainty. In these more dynamic circumstances that the utility could be faced with in the next rate period as customers adopt new technologies, deferring load transfers through LDR can be a prudent strategy even if the economic benefits are relatively small. Postponement or deferral of load transfers “buys time” to let the uncertainty and volatility settle before making the decision to undertake a load transfer investment that will add cost to the rate base for many years. Postponement can also result in the decision to avoid the related capital expenditures should it become apparent that such work is no longer needed.

QUESTION (C):

c) Please discuss any consideration or analysis Toronto Hydro has conducted on its BCA analysis following the OEB's release of the draft BCA Framework. If Toronto Hydro has conducted any analysis using the OEB's BCA Framework examples, please provide.

RESPONSE (C):

Overall, the BCA methodology that Toronto Hydro applied is aligned with the draft BCA framework released by the OEB. The largest source of difference is the 'Pre-Assessment' Criteria, which Toronto Hydro addressed in its February 1, 2024 comments to the OEB in EB-2023-0125.[1] Toronto Hydro intends to continue to evolve its BCA methodology to maintain alignment with the OEB framework as it evolves and takes shape.

QUESTION (D):

d) Please clarify if the WACC was used as the sole discount rates as part of the BCA analysis to calculate net present values, or if additional discount rates (e.g., social discount rate, inflation rate) were used.

RESPONSE (D):

WACC used for the BCA analysis is a nominal weighted average cost of capital, that includes inflation. Assuming that inflation will be around 2% post 2025, the real WACC used for the BCA is 4.17%.

QUESTION (E):

e) Please discuss the analysis and consideration Toronto Hydro conducted related to possible bulk system benefits related to the proposed LDR program.

[1] https://www.rds.oeb.ca/CMWebDrawer/Record/835141/File/document

RESPONSE (E):

Toronto Hydro's assessment of NWS benefits applies to distribution systems needs and value. Bulk value assessments have not been included as part of Toronto Hydro's DSP at this time, as there is no established framework for capturing this value.

QUESTION (F):

f) Please confirm that if successful, the LDR program will not require Toronto Hydro to raise the capital required for the traditional wires solution, either in whole or in part, depending on the level of transfer projects entirely avoided or deferred.

RESPONSE (F):

Confirmed for the proposed 2025-2029 program.

QUESTION (G):

g) Please provide the factors and considerations that led Toronto Hydro to the conclusion that the Shared Savings Mechanisms incentive options were not sufficient to level the playing field between the LDR program and load transfers.

RESPONSE (G):

Please see the evidence in Exhibit 1B, Tab 3, Schedule 1 at pages 53-54. To arrive at this conclusion, Toronto Hydro assessed the foregone opportunity to earn a regulated rate of return ("ROE") on the capital investments avoided and deferred, using an NPV approach. The resulting analysis presented in Table 18 of the evidence shows that the LDR target to procure 30MW results in foregone utility ROE of approximately $3.2 million due to the deferral and avoidance of load transfer capital expenditures. By comparison a 50:50 shared saving mechanism based on the calculated NPV of benefits associated with the proposed target ($3.3 million) yields an incentive of approximately $1.7 million. Compared to the foregone revenue of $3.2 million, and the operational and market risk and complexity associated with a successful delivery of the LDR proposal, Toronto Hydro did not find the shared savings outcome acceptable.

QUESTION (H):

h) Please discuss how the LDR program will be evaluated to verify its performance and calculate total costs and benefits, after the fact, and determine final net benefits.

RESPONSE (H):

The LDR program's success will be evaluated on the basis of capacity procured, cost of DR ($/MW-day), capacity deployed, and avoided or deferred load transfers in each station area targeted by the program. The methodology utilized in the BCA provided will be recalculated annually to evaluate cumulative program success throughout the rate-period.

QUESTION (I):

i) Please discuss the proposed method for determining final incentive value for the LDR program if it will be based on final actual or forecast values.

RESPONSE (I):

Consistent with the fixed incentive option outlined at page 8 of the OEB's *Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives*, Toronto Hydro's proposal is that the final incentive value will be based on actual versus forecast "*amount [MW] of system capacity provided by third-party owned DER solutions that would otherwise have to be provided by a wires solution.*"

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-90

References: **Exhibit 1B, Tab 3, Schedule 1, Page 10**
Exhibit 2B, Section A, Page 2
Exhibit 2B, Section E2, Page 23
Exhibit 2B, Section D3, Page 40
Exhibit 2B, Section D3, Page 53

Preamble:

In determining its SAIDI target excluding LoS, MEDs and Scheduled Outages, Toronto Hydro appears to be conflating the stated customer desires of maintaining overall system reliability with the stated customer desires of addressing long outage durations which are primarily caused by MEDs.

QUESTION (A):

a) Please provide a list of projects that contribute to achieving the SAIDI target of 46.2 shown in Figure 1 in Reference 1, and the contribution of each project to achieving that target.

RESPONSE (A):

Please refer to Table 3 (Exhibit 1B, Tab 3, Schedule 1, pages. 12 to 15) for a breakdown of key investments contributing to the achievement of the Outage Duration performance target. Toronto Hydro is unable to provide a specific list of projects that will contribute to successfully achieving the target by the end of 2029, as those projects have yet to be planned, designed, and issued for execution. Toronto Hydro typically issues detailed scopes of work for capital projects 12-18 months ahead of construction.

QUESTION (B):

b) Please reconcile the stated customer preference of reducing the impact of MEDs against Toronto Hydro's stated target of improving SAIDI excluding LoS, MEDs and scheduled outages. Why should the target for SAIDI excluding LoS, MEDs and scheduled outages not be maintained at 48.2 minutes as per stated customer preference?

RESPONSE (B):

Major Event Days ('MEDs') and outages caused by extreme weather are not one and the same. The investments that Toronto Hydro plans to make to improve SAIDI will have benefits for outage duration during adverse and extreme weather events, whether those events meet the statistical classification threshold for MEDs or not.

As stated in the OEB's RRR,[1] "such [Major] events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system." The IEEE 1366 standard[2] clarifies the intended purpose of Major Event Day classification is "to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events". In essence, MEDs are a way of classifying statistical outlier events that would otherwise obscure and distort average performance statistics. MEDs are inherently difficult to predict, highly variable in their circumstances and outcomes, and not suited to reliability performance target setting.

As stated in the evidence (Exhibit 1B, Tab 3, Schedule 1, page 9), for the 2025-2029 period, Toronto Hydro intends to improve Outage Duration performance as measured by the custom SAIDI metric compared to historical performance. This objective aligns with customer needs and priorities identified through Phase 1 of Toronto Hydro's Customer Engagement which highlighted that when it comes to reliability performance, all customers (except Key Accounts) prioritize reducing the overall length of outages rather than the number of outages. For more information on the outputs

[1] Ontario Energy Board: Electricity Reporting and Record Keeping Requirements ('RRR')
[2] IEEE Std 1366-2022: IEEE Guide for Electric Power Distribution Reliability Indices

of the customer engagement process, in particular reliability priorities, please refer to Exhibit 1B, Tab 5, Schedule 1, Appendix A at page 8).

QUESTION (C):

c) Please provide a capital and O&M budget that would achieve a target SAIDI of 48.2 minutes.
   i. Please provide the list of capital projects that are not required or are reduced as part of maintaining a 48.2 minute SAIDI target.

RESPONSE (C):

As illustrated by the IRM scenario in Exhibit 1B, Tab 3, Schedule 1, at page 10, Toronto Hydro would be unable to maintain historical performance of 48.2 (2018-2022 average) without incremental investment. The reliability projection for Toronto Hydro's proposed capital expenditure plan suggests that the utility's investment plan is only sufficient to maintain Outage Duration as measured by the custom SAIDI metric over the 2025-2029 period. However, the utility challenged itself to set a modest improvement target, recognizing the importance of outage duration to customers when it comes to reliability performance as noted in part (a). As such, the entirety of the 2025-2029 Investment Plan (approximately $4.0 billion in capital and supporting OM&A expenditures) is required to support expanding, modernizing and sustaining the foundations of the grid and essential to managing Outage Duration performance in the next rate period.

QUESTION (D):

d) Please provide an updated Figure 1 (with supporting tabular data) that separates SAIDI (excluding LoS, MEDs, and scheduled outages) between the Horseshoe and Downtown areas.

RESPONSE (D):

Please note, Toronto Hydro forecasted SAIDI system-wide for the purpose of the Performance Incentive Mechanism and cannot break the forecast into Horseshoe and Downtown. In lieu of that, the figure below shows historical contribution of each region (Horseshoe and Downtown Core) to SAIDI (Excluding Loss of Supply, Major Events, and Scheduled Outages). See table below for the tabular data.

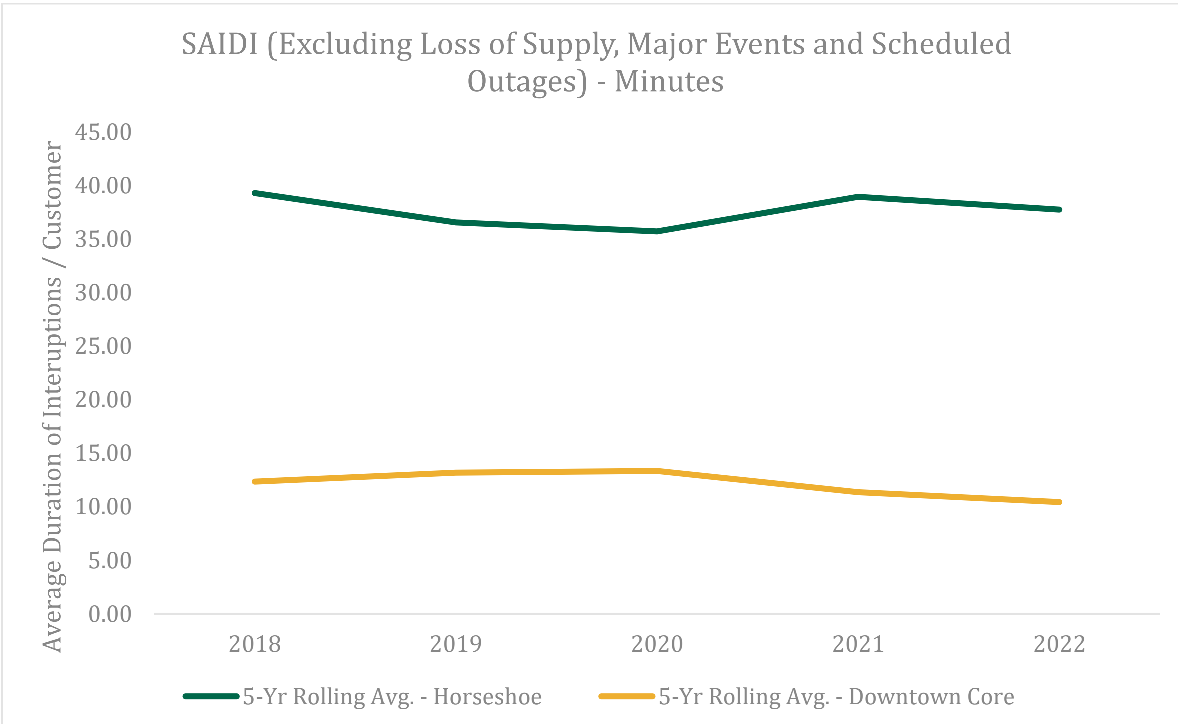

Figure 1: Historical SAIDI Contribution by Region (excluding LoS, MEDs and scheduled outages)

Breakdown of SAIDI Contribution	2018	2019	2020	2021	2022
5-Yr Rolling Avg. – Downtown Core	12.33	13.19	13.33	11.35	10.43
5-Yr Rolling Avg. – Horseshoe Region	39.28	36.54	35.70	38.93	37.73

QUESTION (E) AND (F):

e) Please provide a capital, O&M budget, and resultant SAIDI & SAIFI that would result from a target increase in rates that is the same as the rate increases of the past 5 years.

f) Please provide a capital, O&M budget, and resultant SAIDI & SAIFI that would result from a target increase in rates that is the same as the forecast rate of inflation for the next 5 years.

RESPONSE (E) AND (F):

To determine these values, the utility would need to undertake a bottom-up planning exercise to assess and evaluate the implications of the proposed reductions on its business plan. It is not possible to complete such an exercise within the context of IRs. Please see response to 1B-SEC-21.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-91

References: Exhibit 1B, Tab 3, Schedule 1, Pages. 16-18
Exhibit 2B, Section A, Page. 2

Preamble:

Please refer to Figure 2 from Reference 1 and the associated commentary, and that Toronto Hydro notes in Reference 2 that its key objectives and outcomes for the execution of this plan included "Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition".

QUESTION (A):

a) Please update Figure 2 from Reference 1 and provide the supporting tabular data and the associated calculation of target SAIFI (Defective Equipment) starting in 2013 and ending in the year 2029.

i. If a revised target SAIFI (Defective Equipment) based on the 10-year average is higher than the 5 year average in the original Figure 2, please provide updated capital (and O&M if applicable) budgets that would achieve this revised SAIFI (Defective Equipment) target.

ii. Please provide the list of capital projects (and their capital costs) that are not required or are reduced as part of meeting the revised SAIFI (Defective Equipment) target.

RESPONSE (A):

Please see below for Figure 2, updated in a manner which reflects a target setting approach conducted on a 10-year rolling average basis instead of the filed 5-year rolling average basis (as stated in the evidence under Reference 1). Refer to Appendix A for the supporting tabular data. Under a 10-year rolling average approach, the theoretical target range would be between 0.44 and 0.49 for SAIFI (Defective Equipment).

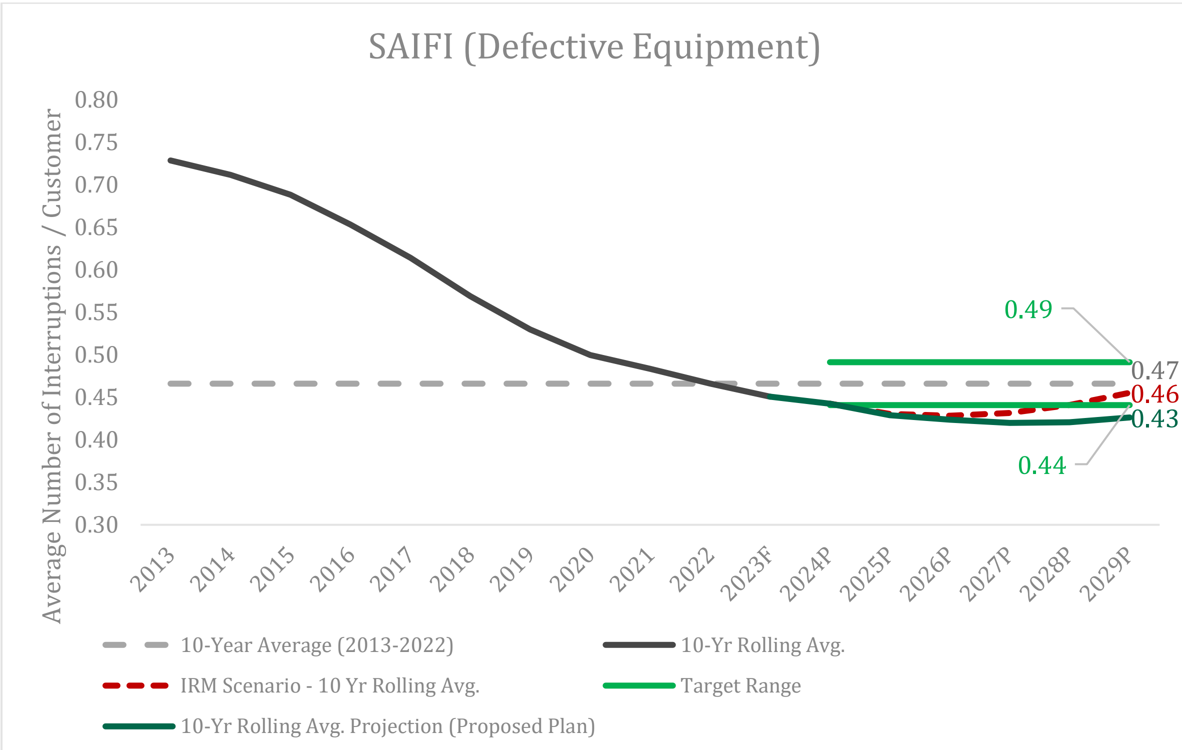

Figure 2: Historical and Projected SAIFI (Defective Equipment) – 10-year Rolling Basis

Toronto Hydro notes that setting reliability targets on a five-year average basis is aligned with the OEB's Electricity Distributor Scorecard approach. Settling reliability targets on a five-year rolling average basis is a common practice in the sector because it allows utilities to track performance over a relatively short time frame while still smoothing out short-term fluctuations and providing a reasonable basis for planning. Expanding the rolling average to 10-years presents several challenges that makes it less valid:

- **Relevance of data:** A 10-year rolling average includes data that is less relevant to current conditions and technology standards.
- **Risk of masking recent trends and investment impacts:** A 10-year rolling average smooths out recent performance fluctuations to the extent that it can mask important trends or issues that need immediate attention within the context of five-year investment planning. It also increases the historical inertia in the measure from year-to-year, making it less

meaningful as performance incentive that can be influenced through actions taken in the next five years.

- **Changing customer expectations:** Customer expectations for reliability change over time due to many factors. A 10-year rolling average may not capture these changing expectations as effectively as a shorter time frame. Applying a 10-year rolling average approach to Toronto Hydro's data would result in a target that would represent significant deterioration in reliability performance compared to the recent five-year average. This outcome would not be aligned with the result of Toronto Hydro's Customer Engagement.

i. Toronto Hydro is unable provide a business plan corresponding to the theoretical 10-year average target. Please see response to 1B-SEC-21.

ii. Please see response to part (a), part (i). A target set on the basis of a 10-year rolling average represents a significant deterioration in reliability. The target would in fact be worse than the reliability performance projected under a high-level IRM scenario measured on the same 10-year average basis. As discussed in Exhibit 1B, Tab 3, Schedule 1, an IRM funding level would translate to a capital plan that would be almost entirely reactive in nature. This level of investment would erase much of the improvement achieved in the last 10-years and set Toronto Hydro on a long-term path of higher costs and worse reliability.

QUESTION (B):

b) Please provide an updated Figure 2 starting in 2013 (with supporting tabular data) that separates SAIFI (Defective Equipment) between the Horseshoe and Downtown areas.

RESPONSE (B):

Please note, Toronto Hydro forecasted SAIFI (Defective Equipment) system-wide for the purpose of the Performance Incentive Mechanism and cannot break the forecast into Horseshoe and

Downtown. In lieu of that, the figure below shows historical contribution of each region (Horseshoe and Downtown Core) to SAIFI (Defective Equipment). See the table below for tabular data.

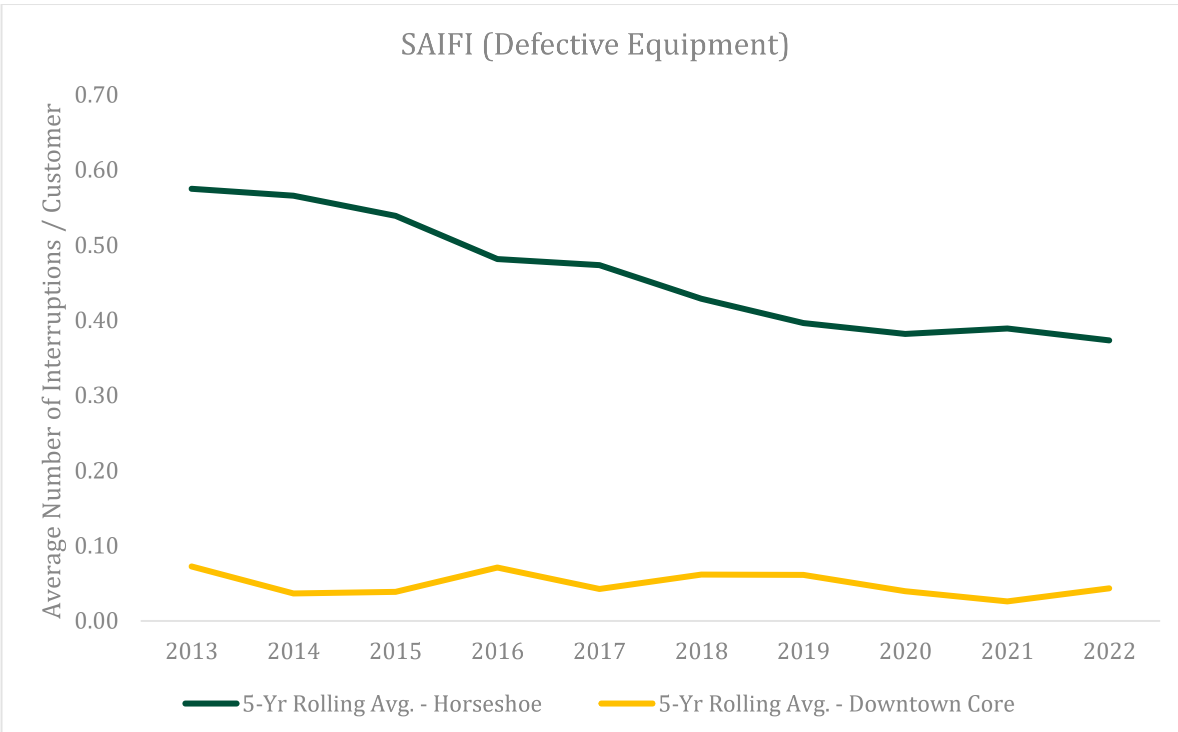

Figure 2: SAIFI (Defective Equipment) – Horseshoe and Downtown areas

Table 1: SAIFI (Defective Equipment) – Horseshoe and Downtown areas

SAIFI (Defective Equipment) Contribution	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
5-Yr Rolling Avg. - Downtown Core	0.07	0.04	0.04	0.07	0.04	0.06	0.06	0.04	0.03	0.04
5-Yr Rolling Avg. - Horseshoe	0.58	0.57	0.54	0.48	0.47	0.43	0.40	0.38	0.39	0.37

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-92

Reference: Exhibit 1B, Tab 2, Schedule 1, Pages 25, 26

Preamble:

Toronto Hydro stated that to allow for updates of the annual inflation factor in rates without double-counting the impact of inflation, Toronto Hydro adjusted the Revenue Growth Factor (RGF) by removing a 2% forecasted annual inflation factor for the 2026 to 2029 period. Toronto Hydro stated that it is presenting the RGF as an increase in revenue requirement, on an inflation-adjusted basis for rate-setting purposes.

Toronto Hydro also noted that there is "current volatility in national and global inflation, which may or may not subside over the 2025 to 2029 rate period."

OEB staff notes that the Canadian consumer price index rose 3.4% in December from a year ago, following a 3.1% increase a month earlier, as reported by Statistics Canada in January 2024.

QUESTION (A):

a) Please explain the basis for the 2% forecasted annual inflation that will adjust the RGF.

RESPONSE (A):

The 2% inflation that was applied to adjust the RGF/CRCI was based on the Bank of Canada's projection for inflation as presented in the quarterly monetary policy reports, which consistently indicated throughout 2023 that inflation will reach the 2% target by the end of 2024 or middle of 2025.[1] The actual inflation factor that Toronto Hydro proposes to apply in the CRCI during the annual

[1] https://www.bankofcanada.ca/publications/mpr/

rate update applications (i.e. 2021-2024) is the OEB's annually published Inflation Factor, made up of 70% GDP-IPI-FDD and 30% Ontario Average Weekly Earnings.[2]

QUESTION (B):

b) Please explain how the 2% forecasted annual inflation relates to capital expenditures, gross plant additions, and OM&A expenses.

RESPONSE (B):

The 2% inflation factor referenced above is a rate-making mechanism for the purposes of establishing an index (i.e., the CRCI) that can be applied to set rates mechanistically during the outer years of the rate period (i.e., 2026 to 2029). This approach is consistent with standard incentive regulation before the OEB which relies on broad indices (rather than bottom-up cost forecasts) to capture variances in costs driven by business market conditions.

For planning purposes (i.e. to forecast the capital expenditures and OM&A expenses outlined in Exhibits 2B and 4 that form the revenue requirement presented in Exhibit 6), Toronto Hydro relied on different assumptions for the different components of the plan:

- Internal labour costs: Forecasting for these costs was based on existing negotiated labour agreements. In cases where there are no existing agreements for certain groups of employees, Toronto Hydro relied on historical rolling forecast to estimate future labour-related costs.
- Non-Labour Related Costs: These costs were estimated assuming an annual 2% inflationary increase over the 2026-2029 period.

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[2] In 1B-Staff-93, Toronto Hydro withdrew its request for a custom labour component for the inflation factor.

QUESTION (C):

c) Please explain why a higher amount than 2% to adjust the RGF may be more appropriate, given that inflation remains trending in Canada at a rate greater than 3% and Toronto Hydro also noted that inflation may not subside over its rate term.

RESPONSE (C):

Toronto Hydro does not believe that a higher amount would be more appropriate because the Bank of Canada's latest monetary policy report, issued in January 2024, continues to note that *"[t]he Bank projects that inflation will stay around 3% through the first half of 2024, returning to [the 2%] target in 2025."* In any event, applying a higher amount to adjust the RGF at this stage of the rate-setting process leads to the same outcome on a forecast basis since the proposed RGF has been inflation adjusted so that the actual inflation factor prevailing at the time of the annual rate update can be added back in to set rates for the upcoming year. Table 3 of the Rate Framework evidence at Exhibit 1B, Tab 2, Schedule 1 at page 25 (reproduced below for ease of reference) sets this out:

Table 3: 2026-2029 Revenue Growth Factor ($ Millions)

	2025	2026	2027	2028	2029
Base Revenue Requirement (BRR)	972	1,027	1,074	1,176	1,219
Difference	-	55	47	101	44
RGF before Inflation Adjustment	-	**5.61%**	**4.62%**	**9.43%**	**3.71%**
Forecast Inflation Factor (%)	-	(2.00%)	(2.00%)	(2.00%)	(2.00%)
RGF after Inflation Adjustment	-	**3.61%**	**2.62%**	**7.43%**	**1.71%**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-93

References : Exhibit 1B, Tab 2, Schedule 1, Page. 3, 23, 26, 27, Table 4
THESL_4_T04_S02 - OEB Appendix 2-K_20240208

<u>Preamble:</u>

Toronto Hydro explained that the CRCI includes an inflation factor component. Toronto Hydro stated that the inflation factor (I) is aligned with the OEB's methodology. However, Toronto Hydro noted that it includes an alternative Toronto-based salary and wages index to establish the labour component of the inflation factor to better reflect the real cost drivers of attracting and retaining talent in the Toronto labour market.

Toronto Hydro noted that the inflation factor will be updated annually as per the OEB's standard methodology, with an alternate labour index for Toronto salary and wages.

Toronto Hydro proposes to replace the Ontario Average Weekly Earnings (AWE) inflation index within the OEB's inflation factor methodology with a custom Toronto Hourly Salary and Wages Index. This index can either be derived by the Conference Board of Canada (CBC) economic data subscription service, or can be reproduced by purchasing relevant tax data from Statistics Canada.

Toronto Hydro stated that for efficiency purposes, it proposes to rely on the CBC index. In its evidence, Toronto Hydro has provided "Table 4: 2016-2022 Labour Inflation" which is reproduced below.

Toronto Hydro Table 4: 2016-2022 Labour Inflation

	Statistics Canada Average Weekly Earnings (AWE) Ontario	Toronto Hydro Average Blended Salary Increase (Appendix 2-K)	Conference Board of Canada Toronto Hourly Salary & Wages
2016	2%	1.2%	4.9%
2017	2.6%	2.5%	3.3%
2018	1.1%	3.2%	0.2%
2019	1.9%	3.7%	3.4%
2020	2.9%	3.9%	5.4%
2021	2.8%	3.8%	1.5%
2022	7%	4.6%	4.3%
2016-2022 Average	**2.9%**	**3.3%**	**3.3%**

Question(s):

a) Please provide and summarize Toronto Hydro's analysis of the pros and cons of a custom Toronto Hourly Salary and Wages Index using the CBC economic data as compared to "relevant tax data" from Statistics Canada. Please identify what is meant by relevant tax data and provide an explanation as to the rationale supporting its relevance.

b) Please provide the webpage links to the specific CBC economic data subscription service and the relevant tax data from Statistics Canada that Toronto Hydro references in its application. Please explain step-by-step the process Toronto Hydro used to derive the amounts shown in the column "Conference Board of Canada Toronto Hourly Salary & Wages."

c) As Toronto Hydro is proposing to rely on the CBC index, please confirm that the relevant output from CBC index is identical to the "relevant tax data from Statistics Canada". If this is not the case, please explain, including the impacts on the numbers shown in the above Table 4.

d) Please provide the source data and all calculations that support the data in Toronto Hydro's Table 4.

e) Please confirm that the amounts shown in Toronto Hydro's Table 4 relating to "Toronto Hydro Average Blended Salary Increase (Appendix 2-K)" relate to salary and wage increases only and exclude benefits. If this is not the case, please explain.

f) Please show how the amounts shown in Toronto Hydro's Table 4 "Toronto Hydro Average Blended Salary Increase (Appendix 2-K)" are derived based on Toronto Hydro's Appendix 2-K.

g) Please demonstrate, by way of calculations using one example, the flow through impacts of Toronto Hydro's proposal in each year of the term for each of the three labour inflation parameters considered in Toronto Hydro's "Table 4: 2016-2022 Labour Inflation".

RESPONSE :

In the course of validating the table above, Toronto Hydro discovered an error with respect to the data that formed the basis of the referenced table. Part of this data came from Appendix 2-K (i.e. 2016 and 2017) and other historical assumptions (i.e. 2018-2022) that were not derived from Appendix 2-K. When the full dataset (i.e. 2016-2022) is normalized per Appendix 2-K, the year-over-year increases per FTE is lower than the historical assumptions included in the original table (please see the Table below). This is because the cost per employee in Appendix 2-K is impacted by other variables such as overtime and volume of retirements that Toronto Hydro experienced historically as it replenished its aging workforce (i.e. when higher direct compensation cost of employees are replaced by lower direct compensation cost employees this yield a lower average cost per employee). As such, Toronto Hydro has decided to withdraw the custom labour inflation proposal. The evidence will be updated to reflect this change.

	Statistics Canada Average Weekly Earnings (AWE) Ontario	Toronto Hydro Average Blended Salary Increase (Appendix 2-K)	Conference Board of Canada Toronto Hourly Salary & Wages
2016 Actual	2%	1.2%	4.9%
2017 Actual	2.6%	2.5%	3.3%
2018 Actual	1.1%	5.7%	0.2%
2019 Actual	1.9%	0.8%	3.4%
2020 Actual	2.9%	1.9%	5.4%

	Statistics Canada Average Weekly Earnings (AWE) Ontario	Toronto Hydro Average Blended Salary Increase (Appendix 2-K)	Conference Board of Canada Toronto Hourly Salary & Wages
2021 Actual	2.8%	4.0%	1.5%
2022 Actual	7%	2.6%	4.3%
2016 - 2022 Average	**2.9%**	**2.7%**	**3.3%**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-94

References: **Exhibit 1B, Tab 2, Schedule 1, Table 4**

OEB Letter, 2024 Inflation Parameters, June 29, 2023

Preamble:

In its evidence, Toronto Hydro has provided "Table 4: 2016-2022 Labour Inflation" which is reproduced below.

Toronto Hydro Table 4: 2016-2022 Labour Inflation

	Statistics Canada Average Weekly Earnings (AWE) Ontario	Toronto Hydro Average Blended Salary Increase (Appendix 2-K)	Conference Board of Canada Toronto Hourly Salary & Wages
2016	2%	1.2%	4.9%
2017	2.6%	2.5%	3.3%
2018	1.1%	3.2%	0.2%
2019	1.9%	3.7%	3.4%
2020	2.9%	3.9%	5.4%
2021	2.8%	3.8%	1.5%
2022	7%	4.6%	4.3%
2016-2022 Average	**2.9%**	**3.3%**	**3.3%**

As noted in the OEB Letter, 2024 Inflation Parameters, the OEB's methodology uses a labour component "Average Weekly Earnings (AWE) - All Employees - Ontario."

OEB staff has calculated the Statistics Canada AWE Ontario using the OEB's methodology in the table below.

Table 1B-1: Statistics Canada AWE Ontario using the OEB's Methodology

Table 1B-1: Statistics Canada AWE Ontario using the OEB's Methodology

	Statistics Canada AWE - downloaded January 7, 2024	Average % Annual Change - arithmetic growth rate	Average % Annual Change - logarithmic growth rate
2015	$ 963.37		
2016	$ 974.41	1.1%	1.1%
2017	$ 993.23	1.9%	1.9%
2018	$ 1,022.00	2.9%	2.9%
2019	$ 1,049.72	2.7%	2.7%
2020	$ 1,126.30	7.3%	7.0%
2021	$ 1,166.72	3.6%	3.5%
2022	$ 1,194.21	2.4%	2.3%
Average		3.1%	3.1%

OEB staff observes that the OEB typically uses the logarithmic growth rate in its calculations, as noted in the OEB Letter, 2024 Inflation Parameters, June 29, 2023, Appendix.

As set out in the EB-2021-0212, OEB 2022 IPI Generic Proceeding, Procedural Order No. 1, Fact Sheet, August 27, 2021, the calculations of the "Annual % Change" ….are based on the logarithmic growth rate, as opposed to the arithmetic growth rate.

QUESTIONS (A) – (C):

a) Please explain whether the years noted in Toronto Hydro's Table 4 represent rate years rather than calendar years. If yes, please restate Toronto Hydro's Table 4 with data relating to calendar years, as opposed to rate years. If no, please explain what is being shown.

b) Please reconcile the numbers shown in "Table 1B-1: Statistics Canada AWE Ontario using the OEB's Methodology" to the "Statistics Canada Average Weekly Earnings (AWE) Ontario" values shown in Toronto Hydro's Table 4.

c) Please confirm that Toronto Hydro agrees with the values and calculations shown in "Table 1B-1: Statistics Canada AWE Ontario using the OEB's Methodology". If this is not the case, please update this table.

RESPONSES (A) – (C):

Please see Toronto Hydro's response to 1B-Staff-93.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-95

References: **Exhibit 1B, Tab 2, Schedule 1, Table 4**
OEB Letter, 2024 Inflation Parameters, June 29, 2023, Appendix
Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service. December 15, 2022, Page 6

Preamble**:**

OEB staff notes that the impact of Toronto Hydro's proposal to replace the Ontario AWE inflation index with a custom Toronto Hourly Salary and Wages Index has an immaterial impact on Toronto Hydro's revenue requirement.

OEB staff's calculations demonstrating the immaterial impact are shown below. OEB staff has incorporated the values shown in the above "Table 1B-1: Statistics Canada AWE Ontario using the OEB's Methodology" derived by OEB staff,

Table 1B-2: OEB Staff's Calculations of Immaterial Impact of Toronto Hydro's Proposal

Toronto Hydro's Table 4 – Conference Board of Canada Toronto Hourly Salary & Wages 2016-2022 Average	3.3%
Less: OEB staff's Table 1B-1: Statistics Canada AWE Ontario using the OEB's Methodology 2016-2022 Average	3.1%
Difference	0.2%
Multiplied by the OEB's standard weighting of the inflation factor labour component of 30% for electricity distributors	30%
Equals an approximate net impact of 0.06% on Toronto Hydro's revenue requirement	0.06%
Toronto Hydro's 2025 Base Revenue Requirement as per RRWF	$972,362,213
Approximate net impact of 0.06% on Toronto Hydro's revenue requirement	$583,417
Toronto Hydro's materiality threshold	$1,000,000

As noted in the OEB Letter, 2024 Inflation Parameters, the labour component weighting used in the OEB's calculations of inflation parameters is 30% for electricity distributors.

As per the filing requirements, Toronto Hydro's materiality threshold is $1 million.

QUESTION (A) AND (B):

a) Please confirm that Toronto Hydro agrees with the values and calculations shown in "Table 1B-2: OEB Staff's Calculations of Immaterial Impact of Toronto Hydro's Proposal". If this is not the case, please update this table, showing all associated calculations.

b) Please elaborate whether Toronto Hydro agrees or disagrees with OEB staff's demonstration that the impact of Toronto Hydro's proposal to replace the Ontario AWE inflation index with a custom Toronto Hourly Salary and Wages Index has an immaterial impact on Toronto Hydro's revenue requirement.

RESPONSE TO (A) AND (B):

Please see response to 1B-Staff-93.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-96

References: Exhibit 1B, Tab 2, Schedule 1, Page. 26

<u>Preamble:</u>

Toronto Hydro stated that substituting the labour component of the inflation factor with a Toronto-specific index is responsive to the consideration that labour is a key cost driver within the utility's plan.

Toronto Hydro noted that a Toronto-specific labour index could be more suitable to account for the localized inflationary cost pressures that the utility faces in the 2025-2029 rate period.

Toronto Hydro observed that while it is not possible to predict what these pressures would be, or how they would differ regionally, the historical trend over the last six years (i.e. 2016 to 2022) suggests that regional differences may be a factor.

QUESTIONS (A) AND (B):

a) Please explain why Toronto Hydro should be treated differently than other Ontario electricity distributors in respect of the labour component of Toronto Hydro's proposed inflation factor.
b) Please provide an OEB precedent (including EB#) where the OEB approved a region-specific labour component of the inflation factor.

RESPONSES (A) AND (B):

Please see response to 1B-Staff-93.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-97

References: **Exhibit 1B, Tab 3, Schedule 1, Pages. 37-38 and Table 13 (Summary)**
Exhibit 2B, Section E8.2, Pages. 18-20 (Facilities Reductions)
Exhibit 2B, Section E8.3 (Fleet)
Exhibit 4, Tab 2, Section 11 (Fleet)
Exhibit 4, Tab 2, Section 12 (Facilities reductions)

Preamble:

Toronto Hydro indicates that to further reduce its fleet and facilities emissions to 2.5 kt of (Scope 1) CO_2e by 2029, it plans to: 1) electrify 50% of its fleet by the end of the rate term, and 2) reduce GHG emissions produced at its work centers by 3% annually through fuel switching, conservation and energy efficiency measures.

QUESTION (A):

a) Please confirm that Toronto Hydro's scorecard measure titled "Emissions Reductions" which it has proposed a 5% overall weight, includes the proposed activities to electrify 50% of its fleet and reduce GHG emissions at its work centers by 3% each year.

RESPONSE (A):

Confirmed.

QUESTION (B):

b) Please discuss and define how Toronto Hydro will consider its fleet to be electrified.

RESPONSE (B):

Toronto Hydro considers vehicles in its fleet to be electrified if they are an electric vehicle (“EV”), plug-in hybrid electric vehicle (“PHEV”), or hybrid vehicle. Hybrid vehicles include heavy duty vehicles equipped with an electric power take off.

QUESTION (C):

c) Please confirm that the 3% annual GHG reductions from Toronto Hydro work centers is an incremental annual target and that by 2029, a minimum GHG emissions reduction of 15% will have been achieved.

RESPONSE (C):

Confirmed.

QUESTION (D):

d) Please discuss what baseline Toronto Hydro proposes to establish in order to calculate annual GHG emissions reductions. For example, does Toronto Hydro proposes that annually, 3% net incremental GHG emissions reductions will take place relative to 1990 (consistent with the City of Toronto’s TransformTO Net Zero Strategy)?

RESPONSE (D):

Toronto Hydro will use its 2019 emissions as the baseline.

QUESTION (E):

e) Please discuss and provide the criteria Toronto Hydro proposes to use to determine and verify that it has achieved 3% GHG emissions reductions from improvements at its work centers during the 2025 to 2029 term.

RESPONSE (E):

Please refer to Toronto Hydro's methodology for calculating scope 1 emissions outlined in the response to 1B-SEC-20, subpart (e). The utility will annually determine its emissions levels using this methodology and hold its Facilities Management programs accountable for achieving the 3% GHG emissions reductions.

QUESTION (F):

f) Please discuss how site closures will be included in the calculation of GHG emissions reductions as part of this scorecard item.

RESPONSE (F):

Toronto Hydro does not anticipate a site closure to affect Scope 1 emissions in the 2025-2029 rate period, as the utility's facilities-related emissions are only attributable to its work centres, which will remain in operation for the duration of the rate period. All stations facilities are already 100% reliant upon electrical appliances and amenities.

QUESTION (G):

g) Please provide the detailed plan and decision-making process that Toronto Hydro will use to identify, analyze and prioritize the capital improvements targeted at reducing GHG emissions at its work centers, including fuel switching and improving building efficiency.

RESPONSE (G):

Please refer to the detailed evidence laid out in the following documents:

- Exhibit 2B, Section E8.2, subsection E8.2.3.3 "Work Centres" at pages 18-20;
- Exhibit 4, Tab 2, Schedule 12, subsections 5 "Facilities Maintenance Services Segment" and 7 "Utilities & Communications Segment" at pages 8-12 and 17-18, respectively;
- Exhibit 2B, Section D6 "Facilities Asset Management Strategy"; and
- Exhibit 2B, Section D7, subsection "Toronto Hydro's Facilities Emissions" at pages 4-6.

QUESTION (H):

h) Please discuss if all GHG emissions related capital improvements are proposed to be funded through rates or if any portion will be funded by the shareholder.

RESPONSE (H):

Toronto Hydro proposes to fund all capital improvements listed in the references to be funded through rates, net of capital contributions or revenue offsets from all available government and other rebates the utility is able to obtain. For an overview of funding that Toronto Hydro leveraged in the 2020-2024 rate period, please see the response to 3-DRC-14(c).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-98

References: **Exhibit 1B, Tab 3, Schedule 2, Table 1, Page. 1**
Exhibit 2B, Section D5, Pages 4, 14-17

<u>Preamble:</u>

Regarding stated investments to improve SAIDI and SAIFI in the above referenced sections.

QUESTION (A):

a) Are Toronto Hydro's historical investments in grid sensor, remote-operable switches, smart meters and SCADA controlled switches (advancing "self-healing" grid operations) the primary drivers for the improvements achieved in SAIDI and SAIFI since 2013?
    i. If not, what are the primary drivers of the improvements?
    ii. If yes, please discuss the impact that continued investment in these activities at the same pace will have on improvements in SAIDI and SAIFI results.

RESPONSE (A):

Out of the technologies listed in the question, only remote-operable switches (which are the same as SCADA controlled switches) have had a material impact on reliability since 2013. Specifically, these switches have had a positive impact on SAIDI. Remote operable switches require operator intervention, meaning that they do not typically result in reductions in the frequency of sustained interruptions, and therefore do not have a material impact on SAIFI. As noted in Exhibit 2B, Section E7.1.3.1, page 7, analysis of 2018-2022 reliability data shows that the average duration for outages on feeders with less than three SCADA tie-points was approximately 707 minutes per year per feeder, whereas the average duration of those feeders with three or more SCADA tie-points was approximately 496 minutes. As part of Toronto Hydro's reliability projections for 2025-2029, the utility quantified estimated improvements from SCADA switch installations (see response to interrogatory 2B-SEC-42 for more details).

Regarding the other technologies referenced in the question, Toronto Hydro has not broadly deployed grid sensors, except within its network system (see Exhibit 2B, Section E7.3 for details and benefits), and its existing, first-generation smart meters do not possess "last gasp" technology, meaning that they do not have the capabilities to assist with outage restoration efforts.

(i) Regarding the primary drivers of reliability improvement in the historical period, in addition to the relevant modernization investments discussed above, Toronto Hydro's System Renewal and System O&M investments have been foundational to mitigating asset risk, eliminating obsolete assets and system configurations, and ultimately improving both SAIDI and SAIFI performance since 2013. For additional details on Toronto Hydro's historical performance from 2018 to 2023, please see Exhibit 2B, Section C.

QUESTION (B):

b) Please compare the historic and forecast substantial reliability improvements in SAIDI and SAIFI achieved by Toronto Hydro with the improvements reported by the US Department of Energy for utilities that implemented FLISR.

RESPONSE (B):

To clarify, Toronto Hydro has not yet implemented automated FLISR, nor is Toronto Hydro anticipating benefits from automated FLISR during the 2025-2029 period. For longer-term reliability improvements pertaining to automated FLISR, please refer to the response to 2B-Staff-162.

QUESTION (C):

c) Are the forecast substantial incremental reliability improvements "three to seven percent for SAIFI and four to seven percent for SAIDI on the overhead system"?
    i. If not, what are the forecast substantial incremental reliability improvements for SAIDI and SAIFI?

RESPONSE (C):

The percentages referenced are associated with the forecasted improvements at the end of the 2025-2029 period upon the completion of additional SCADA switches and new mid-line recloser installations, as described in the System Enhancements program (Exhibit 2B, Section E7.1).

For longer-term reliability improvements pertaining to Fault Location Isolation and Service Restoration ("FLISR"), also referred to as Distribution Automation ("DA"), please refer to Toronto Hydro's response to interrogatory 2B-Staff-162.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-99

References: **Exhibit 1B, Tab 4, Schedule 1, Pages 1-20**
Exhibit 1B, Tab 4, Schedule 2
Exhibit 2B, Section D5

Preamble:

In its description of innovation over the 2020 to 2024 rate period, Toronto Hydro describes its approach to building innovative strategies across numerous dimensions of its business including the creation of an Innovation Sandbox.

QUESTION (A):

a) Please explain how Toronto Hydro funded its Innovation Sandbox, how it measured success of the initiatives and provide additional details on which initiatives have been scaled into normal operations.

RESPONSE (A):

The Innovation Sandbox was self-funded by Toronto Hydro over the 2020-2024 rate period. Success of pilot projects developed through Toronto Hydro's Innovation Sandbox is assessed against a set of criteria that is determined as a part of project approval prior to launch. If deemed successful upon completion of proof-of-concept, the project is recommended for full-scale adoption.

Descriptions of projects that have been tested through the Innovation Sandbox and scaled into normal operations can be found at Exhibit 1B, Tab 4, Schedule 1 at pages 2-3.

QUESTION (B):

b) Outside of its sandbox, please explain how Toronto Hydro determines what innovative pilots it will fund and how it assesses when an initiative is ready for scale?

RESPONSE (B):

Outside of the Sandbox, Toronto Hydro has proposed an Innovation Fund, along with an associated Governance Framework, which is described in Exhibit 1B, Tab 4, Schedule 2.

QUESTION (C) :

c) Please explain how Toronto Hydro determines which initiatives fall under the heading of innovation and why this isn't considered a part of normal utility management. For example, under System Observability: Network Condition, Monitoring and Control (1.2 of above noted scheduled), Toronto Hydro references how it continues to advance its Network Condition Monitoring and Control to increase situational awareness the low voltage distribution network.

RESPONSE (C):

As outlined in Exhibit 1B, Tab 4, Schedule 1 and Schedule 2 at page 4, initiatives under the heading of innovation are designed to test new technologies, advanced capabilities, and alternative strategies that are more early stage, exploratory and developmental in nature. These explorations can lead to innovation that is then scaled up into normal utility operations. The Network Condition Monitoring and Control (NCMC) initiative exemplifies this approach. Initially conceived as an innovation project, NCMC has proven successful and has since been integrated into Toronto Hydro's standard utility operations. Furthermore the insights gained, skills honed, and benefits realized through the NCMC program have led to the continued implementation of system observability technologies, as outlined in the Grid Modernization Strategy detailed in Exhibit 2B, Section D5, and summarized in Exhibit 1B, Tab 4, Schedule 1 at section 2.1.

QUESTION (D):

d) Please explain how the areas in which Toronto Hydro plans to test specific new distribution capabilities in the upcoming rate period differ from the areas explored and funded previously by Toronto Hydro in the current rate period (during which it did not have an Innovation Fund).

RESPONSE (D):

The internal sandbox was launched to engage and encourage employees to bring forward ideas for proof-of-concept projects that are novel and provide value to customers across all areas of the company's business and processes. This initiative empowers employees to embrace change and fosters a culture of innovation, meaning a solution-oriented mindset that obstacles can be overcome through creative problem-solving. Please refer to Exhibit 1B, Tab 4, Schedule 01, Section 1.1 for more details on about the internal Sandbox.

The proposed Innovation Fund represents a more targeted approach to the innovation that is required to address the fundamental changes in the energy landscape and manage the uncertainty driven by the imperatives of decarbonizing key sectors of the economy through electrification. Particularly in response to expectations set by the Ontario Energy Board (OEB) regarding Distributed Energy Resource (DER) integration, as outlined in the Framework for Energy Innovation (FEI) report. The Innovation Fund addresses needs that are not adequately met by existing funding mechanisms. In this way, the Innovation Fund would be complementary to existing funding mechanisms insofar as they relate to innovation.

Key differentiators for the Innovation Fund supported projects include an emphasis on adapting operational practices to manage DERs effectively, modifying planning processes to incorporate non-utility-owned DER solutions, and prioritizing the development of skills and knowledge within the organization.

Additionally, the projects under the Innovation Fund are expected to deploy inventive solutions aligned with the OEB's definition of innovation, focusing on leveraging new technologies, innovative business practices, and enhancing distribution services for the benefit of customers. This strategic alignment ensures that Toronto Hydro remains at the forefront of industry advancements and delivers value to stakeholders. Please refer to Exhibit 1B, Tab 4, Schedule 02, Section 3 for more details on Areas of Innovation.

QUESTION (E):

e) Please explain why Toronto Hydro requires both the support of the Future Energy Scenarios tool as well as the Innovation Fund to stress test grid modernization investments in the 2025-2029 rate period.

RESPONSE (E):

The Future Energy Scenarios is a model that was created to help Toronto Hydro understand possible changes to future peak demand under different scenarios, and was used to stress-test whether the utility's capacity plan can accommodate energy transition needs (e.g. building heating electrification) in the early part of the next decade, if required.

The Future Energy Scenarios inform possible grid modernization investments as they relate to the various scenarios. For more information, please refer to Exhibit 2B Section D4.

The proposed Innovation Fund is funding mechanism for exploring innovative capabilities that can help Toronto Hydro better adapt to fundamental changes taking place in the energy system as a result of the transition, by leveraging technology to achieve expanded benefits for customers. It is an important part of Toronto Hydro's approach to innovation because it addresses needs that are not adequately met by existing funding mechanisms. For more information, please refer to Exhibit 1B Tab 4 Schedule 2.

In summary, the Future Energy Scenarios is a tool for planning and conceptualizing innovative approaches relating to peak demand management, while the Innovation Fund provides the necessary funding to scope, design and execute innovative pilot projects.

QUESTION (F):

f) The four pilot areas tagged for the Innovation Fund were identified as part of the Grid Modernization Strategy in reference 3. What focus areas of the strategy do they fall under and can Toronto Hydro please explain why they can't be incorporated into the initiatives already planned?

RESPONSE (F):

The four pilot projects (as described in Exhibit 2B Section D5 Appendix I) would fall under the *Grid Readiness* focus area of the Grid Modernization Strategy. However, these projects are distinct from other initiatives which are proposed in the Grid Readiness focus area, which Toronto Hydro proposes would be funded through normal mechanisms as they may be deployed as standard distribution system solutions or IT projects. Whereas existing mechanisms tend to support spending where the beneficial outcomes are more proven or certain, the proposed Innovation Fund would be able to support work that is more early stage, exploratory and developmental in nature. The four pilot project concepts fall into this earlier stage and exploratory category and were considered to be too nascent to deploy as standard distribution system solutions. They were also identified as posing a funding risk because more developmental work is needed to test the technologies and prove related beneficial outcomes for Toronto Hydro's system.

It is important to note that funding these pilot project ideas through the Innovation Fund would allow Toronto Hydro to determine the funding implications in real time based on the facts of each project or initiative. Thereby, Toronto Hydro would be able to design and implement pilot projects and other exploratory initiatives more effectively.

QUESTION (G):

g) Please provide any additional analysis of comparable jurisdictions innovation funding amounts, other than those included in the application (i.e., Ofgem, New York, Enbridge Gas).

RESPONSE (G):

Please refer to Toronto Hydro's response to interrogatory 1B-DRC-06 part (d).

QUESTION (H):

h) Please provide more details regarding the proposed governance framework, including titles and responsibilities of the steering committee members, anticipated timelines for review of each project, how innovation projects will be staffed (e.g., will existing staff people be leveraged, will new FTEs be dedicated to pilot project owner roles, etc.), and if Toronto Hydro proposes to keep the OEB and industry updated on its progress so opportunities and lessons learned can be considered.

RESPONSE (H):

Please see Toronto Hydro's response to interrogatory 1B-DRC-06 part (i).

QUESTION (I):

i) Please discuss the likelihood of the innovation fund exceeding the requested $16M. If so, what mechanisms does Toronto Hydro propose be put in place to ensure that any additional funding is appropriate and will provide benefits to ratepayers.

RESPONSE (I):

Toronto Hydro cannot speculate on the likelihood of actual expenditures exceeding the requested funding amount since it has not commenced the pilot selection and design phases of the Governance Framework, which is where the projects will be scoped, and workplan and budgets created. For further discussion, please refer to Toronto Hydro's response to interrogatory 1B-CCC-46 part (h).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-100

References: **Exhibit 1B, Tab 5, Schedule 1, Pages 8-10**
Exhibit 2B, Section E2, Page 5

Preamble: In Reference 1 Toronto Hydro states Phase 2 of the customer engagement "solicited detailed customer feedback on the $5.9 billion draft plan… In direct response to customer feedback, Toronto Hydro challenged itself to reprioritize certain investment, and reduce the overall capital plan by approximately $70 million, as further described in Exhibit 2B, Section E2."

In reference 2 Toronto Hydro states it "set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period".

QUESTION (A):

a) OEB staff are unclear where in Exhibit 2B, Section E2 the $70M reduction to the $5.9 billion draft plan is described. Please reference the section of the application that outlines the $70 million reduction Toronto Hydro made in response to the Phase 2 customer engagement or provide the description.

RESPONSE (A):

Please refer to Exhibit 2B, Section E2.1.3 at pages 10-11. Please see response to 2B-SEC-54 for additional details.

QUESTION (B):

b) Please confirm that the $70M reduction is reflected in the capital and OM&A budgets presented in Exhibit 2, Exhibit 4 and the Exhibit 2 excel models.

RESPONSE (B):

Toronto Hydro confirms that the $70 million reduction is reflected in the capital budget presented in Exhibit 2B and OEB Appendices 2-AA and 2-AB.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-101

References: **Exhibit 1B, Tab 5, Schedule 1, Appendix A**
A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 2012

Preamble:

With Reference 1, Toronto Hydro provides the summary of its customer engagement. On page 1 of this report, Innovative Research Group, Inc. provides context regarding the importance of meaningful customer engagement, citing OEB policy documents. The statement is made that the OEB's "consumer-centric" approach to rate applications requires electricity distributors to demonstrate that their services are provided in a manner that responds to identified customer needs and preferences.

Footnote 1 is duplicated below: OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

QUESTION (A):

a) Please confirm that, in footnote 1, Innovative Research Group, Inc, intended to reference the OEB's October 2012 report A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach. If not, please identify which report is referenced.

RESPONSE (A) – PREPARED BY INNOVATIVE:

On review, we confirm that this particular footnote contains an incorrect reference and should instead refer to the 2016 Handbook for Utility Rate Applications.

QUESTION (B):

b) Please provide, as attachments to this interrogatory response, section 2.4.2, section 5.0, and section 5.0.4 of the "OEB Renewed Regulatory Framework for Electricity."

RESPONSE (B) – PREPARED BY INNOVATIVE:

As noted above, the references in the footnote are in error. Given that, we have not provided sections as attached but rather cite below some of the important references in the Handbook, including:

- **Reference to customer focus as one of four categories of outcomes under the RRFE**.
  "Customer Focus: Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences (p2)."
- **Reference to the role of customer preferences in the Business Plan**.
  "The OEB expects the business plan to be informed by the utility's engagement with customers (p6)."
- **Role of customer expectations in the OEB review**.
  "A utility's proposals are expected to demonstrate the alignment of the utility's strategic objectives with its current and future customers' expectations for reliable and reasonably priced service (P9)."
  "The business plan should demonstrate that the utility's goals are appropriately aligned with the needs and preferences of its customers (p10)."
- **Expectation of customer engagement**.
  "Customer engagement is foundational to the RRF. Enhanced engagement between utilities and their customers provides better alignment between utility plans and customers' needs and expectations. Today's customers are more informed and more active participants in their energy services. They should have a say in shaping utility plans,

particularly given the customer's role in conservation efforts and the customer focused nature of future technological innovation. Customers should also help determine the pace of utility investment (p11).

… Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate those interests and preferences into their plans. (p11)

Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs. (p11)

The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities. (p12)"

QUESTION (C):

c) Please identify where, in Toronto Hydro's view, Reference 2 identifies a "consumer-centric" approach to rate applications. Please articulate Toronto Hydro's view as to the relative weight and priority of customer "needs and preferences" in relation to each of prices, adequacy, reliability, and quality of electricity service.

RESPONSE (C) – PREPARED BY INNOVATIVE:

The above response (b) addresses the "customer-centric" aspect of the OEB direction.

The primary role of identifying customer needs and preferences is to help Toronto Hydro set priorities among investments after meeting this primary consideration. While the 2016 Handbook for Utility Rate Applications already requires applications provide "A focus on cost effective delivery of outcomes that matter to customers", the engagement helps Toronto Hydro to understand the range of investments customers would like Toronto Hydro to address and the pace at which Toronto Hydro should implement those investments.

RESPONSE (C) – PREPARED BY TORONTO HYDRO

For Toronto Hydro's position on the balance between price and progress towards other outcomes that customers expect, please refer to the response to Interrogatory 1B-CCC-48(a).

QUESTION (D):

d) Please explain Toronto Hydro's definition of "customer needs and preferences." How does Toronto Hydro distinguish between needs and preferences? How would Toronto Hydro prioritize these compared to economic efficiency and cost effectiveness?

RESPOND (D) – PREPARED BY INNOVATIVE:

On page 4 of the Customer Engagement Executive Summary, customer needs are defined as "understanding the gap between the services and experience customers want and the services and experience customers are receiving". Within the customer engagement, needs are identified in the Phase 1 survey by asking "Is there anything in particular you would like Toronto Hydro to do to improve its services to you?". Needs are also identified on an ongoing basis across the entire customer service team.

Preferences in this engagement include three broad categories:

- What outcomes matters to customers and how important is each outcome (this is the means by THESL can ensure its goals are aligned with customer preferences per multiple references on pages 10 and 11 of the OEB Handbook).
- Trade-offs between competing outcomes (see the reference to trade-offs on p11 of the OEB Handbook).
- Pacing of specific initiatives (see the reference to pacing on p11 of the Handbook).

Cost effectiveness and efficiency are not in conflict with customer needs and preferences. In fact, they are important customer considerations. Customers generally raise cost effectiveness and efficiency in the context of delivering reasonable distribution rates and comments to this effect can be seen in the various comment box summaries in the report. Customers expect Toronto Hydro to find efficiency whenever possible and want to see customer benefits associated with new investments.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-102

References: Exhibit 1B, Tab 6, Schedule 3, Appendix A, Pages 11-13, 17

Preamble:

Several of Clearspring's recent models have contained an urban congestion variable of general form AreaCongested Urban / AreaTotal. In this study, Clearspring has created time-variant values for this variable using data on the number of tall buildings ("skyscrapers") in various urban areas. Skyscrapers are defined as buildings with a height of at least 100 meters.

Adding the high-rise building data to the congested urban variable appears to boost the elasticity estimate for this variable. This matters to Toronto Hydro's score because it has an unusually high value for the variable.

QUESTION (A):

a) Please confirm that the sensitivity of the parameter estimates for the congested urban variable to the inclusion in the sample of one company (Consolidated Edison of New York) that has an extremely high value is disadvantageous.

RESPONSE PROVIDED BY CLEARSPRING (A):

Consolidated Edision is a strong peer to Toronto Hydro and important to include in a benchmark study of Toronto Hydro. It is true that it would be helpful, if it were possible, to add more utilities similar to Consolidated Edison and Toronto Hydro to the sample, however, that is not currently feasible. Both Clearspring and PEG have agreed on the need to and importance of including the percent congested urban variable for the most recent benchmarking applications. In fact, both consultants have used the same percent congested urban variable in their models for the last three applications (Toronto Hydro's last one, Hydro Ottawa, and Hydro One). During the experts' Hydro

One joint conferral process, the inclusion of the percent congested urban variable was not controversial or a concern raised by PEG.

QUESTION (B):

b) Please provide Toronto Hydro's cost performance scores and rankings with and without the congested urban variable in the model.

RESPONSE PROVIDED BY CLEARSPRING (B):

Clearspring is of the view that the score and ranking without the congested urban variable is not a valid or appropriate comparison because it leaves out a known, highly statistically significant, and impactful cost challenge from the analysis. Both Clearspring and Board Staff's benchmarking expert, PEG, have included the congested urban variable in its total cost benchmark models in the last three Custom IR applications involving econometric benchmarking. This was the last Toronto Hydro application (EB-2018-0165), Hydro Ottawa's CIR application (EB-2019-0261), and Hydro One's CIR application (EB-2021-0110). Clearspring recognizes that the variable is quite impactful on the benchmark score of Toronto Hydro and without the variable the score increases. This makes sense, as serving a highly urbanized service area is going to increase costs substantially. A benchmarking analysis without a proper percent congested urban adjustment is not valid in evaluating performance and is not Clearspring's model, nor has it been PEG's model in recent applications.

QUESTION (C):

c) Why were Atlantic City Electric (serving Atlantic City, NJ), Puget Sound Energy (serving Bellevue, WA), Consumers Energy (serving Grand Rapids, MI), and Connecticut Light and Power (serving Hartford, CT) assigned zero values for this variable? All of these cities had skyscrapers higher than 100 meters.

RESPONSE PROVIDED BY CLEARSPRING (C):

Constructing the congested urban variable involved a large effort which required meticulous mapping of city blocks and streets. For this reason, only cities with populations above 200,000 were examined. The cities cited above did not pass that threshold.

QUESTION (D):

d) Please confirm that some utilities serving cities with congested urban areas (e.g., El Paso, TX) do not have skyscrapers that are at least 100 meters tall. Does that suggest that the 100-meter basis for the skyscraper definition is optimal?

RESPONSE PROVIDED BY CLEARSPRING (D):

The first sentence of the question is confirmed. The congested urban variable was constructed based on examining areas of cities that had building clusters of 7 stories or higher. The optimal basis for the skyscraper definition would, therefore, be 7 stories. However, the Council on Tall Buildings and Urban Habitat (CTBUH) does not provide complete building data under 100m, and indicates that building data under 150m may be incomplete in its dataset. Based on this, balanced with the desire to include the shorter skyscrapers because of the 7 story criterion used in the construction of the variable, we used the cut-off at 100m as being a reasonable approach.

QUESTION (E):

e) Did Clearspring produce results using alternative minimum heights for skyscrapers? If so, please provide these results.

RESPONSE PROVIDED BY CLEARSPRING (E):

No. We only gathered and collected the 100m and above dataset and use that as the basis for variable escalation.

QUESTION (F):

f) Please provide the full skyscraper database (e.g., including skyscrapers less than 100 meters in height) so PEG can undertake its own sensitivity analyses.

RESPONSE PROVIDED BY CLEARSPRING (F):

Clearspring does not have an expanded database other than the one provided in the working papers, as we only gathered the 100m and above dataset for the large cities that were served by our sampled utilities and that was provided in the working papers.

QUESTION (G):

g) Please confirm that Clearspring only included data for at most congested urban areas in a single city of a utility's service territory. If a utility served multiple metropolitan areas with one or more congested urban zones (e.g., Pacific Gas & Electric serves the cities of San Francisco and San Jose, two of the twenty largest cities in the United States), was only the metro area with the largest congested urban zones counted?

RESPONSE PROVIDED BY CLEARSPRING (G):

This is not confirmed. We included data for multiple cities in the case where a utility served multiple large cities with skyscrapers above 100m. In the case of PG&E this included both San Francisco and Oakland. San Jose does not have any buildings above 100m according to the CTBUH.

QUESTION (H):

h) For metropolitan areas with sizable suburban business districts (e.g., St. Louis, MO), did Clearspring include the suburban business districts in its calculations?

RESPONSE PROVIDED BY CLEARSPRING (H):

We only used the major city data. If there are buildings above 100m but outside of the city of St. Louis then they were not counted.

QUESTION (I):

i) Did Clearspring confirm that all of the qualifying skyscrapers are served by the utility and located in the congested urban area?

RESPONSE PROVIDED BY CLEARSPRING (I):

We used the full building count for the city and did not locate every single skyscraper and assure it was within the service area of each utility. Given that this data is only used to escalate the urban variable this level of analysis was not required, in Clearspring's opinion.

QUESTION (J):

j) Did Clearspring change the estimated size of the congested urban data for any utilities since the last Toronto Hydro Custom IR proceeding? If so, please provide the new maps.

RESPONSE PROVIDED BY CLEARSPRING (J):

The congested urban variable is the same as used by Clearspring and PEG in the most recent Hydro Ottawa and Hydro One applications. There were a handful of very small refinements made in the Hydro Ottawa application which was the next iteration of Ontario Clearspring benchmarking research right after the prior Toronto Hydro proceeding. No new maps were produced since the changes were so minor. The changes made in the Hydro Ottawa proceeding from the Toronto Hydro proceeding in the percent congested urban were all less than 0.1% changes in the variable value. For example, Toronto Hydro's value was refined and increased by 0.001%.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-103

References: Exhibit 1B, Tab 7, Schedule 3, Appendix A, Pages 22-24

Preamble:

While Clearspring did not present a table of the rankings of each utility in the sample, cost performance data are automatically produced as part of obtaining the values for Toronto Hydro's performance evaluation and forecasting.

QUESTION (A):

a) In the econometric model for total distribution cost, where does Toronto Hydro rank among the sampled utilities?

RESPONSE PROVIDED BY CLEARSPRING (A):

Ranking Toronto Hydro's last three historical years to all of the sample's last three historical years results in a ranking of 6th out of the 79 utilities in the sample (when including Toronto Hydro).

QUESTION (B):

b) How does this compare to their rankings in previous power distribution total cost econometric models and studies authored by Mr. Fenrick?

RESPONSE PROVIDED BY CLEARSPRING (B):

In the last Toronto Hydro CIR application, Toronto Hydro's last three historical years ranked 15th out of the 90 utilities in the sample.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-1

Reference: Exhibit 1B, Tab 1, Schedule 1, Figure 1

Figure 1 provides a percentage breakout of SAIDI (Excluding Loss of Supply & Major Events) by outage cause for 2018-2022.

Please provide the data for each of the years 2018-2023.

RESPONSE:

Please see Table 1 below for the percentage breakdown of SAIDI (Excluding Loss of Supply and Major Events) by major cause code from 2018 to 2023.

Table 1: SAIDI (Excluding Loss of Supply & Major Events) Breakdown by Outage Cause 2018-2023

Major Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	0%	0%	0%	0%	1%	0%
Adverse Weather	21%	10%	4%	10%	7%	11%
Defective Equipment	43%	41%	40%	37%	41%	32%
Foreign Interference	10%	10%	22%	21%	14%	17%
Human Element	1%	6%	3%	4%	2%	2%
Lightning	0%	0%	0%	2%	0%	0%
Scheduled Outage	4%	6%	1%	2%	14%	18%
Tree Contacts	16%	21%	18%	19%	12%	13%
Unknown	4%	6%	11%	5%	7%	7%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-2

Reference: Exhibit 1B, Tab 1, Schedule 1

Please add a column to Tables 5-8 to show 2020-2024 actual spending.

RESPONSE:

See below tables for 2020-2024 actual/forecast spending added to tables 5-8. Please note that tables 5-8 have been updated to the latest forecasts submitted on January 29, 2024[1].

Table 5: Sustainment Capital Programs

Capital Program/Segment	2020-2024 Investment ($M)	2025-2029 Investment ($M)
Area Conversions	209	237
Underground Renewal - Horseshoe	363	476
Underground Renewal - Downtown	81	165
Network System Renewal	116	123
Overhead Renewal	224	273
Stations Renewal	125	218
Reactive and Corrective Capital	307	328
Sustainment Capital	**1,425**	**1,820**

Table 6: City Growth and Electrification Capital Programs

Capital Program/Segment	2020-2024 Investment ($M)	2025-2029 Investment ($M)
Customer Connections	369	476
Externally Initiated Plant Relocations & Expansions	60	76

[1] OEB File No. EB-2023-0195, Toronto Hydro-Electric System Limited ("Toronto Hydro") 2025-2029 Custom Rate Application for Electricity Distribution Rates and Charges – Evidence Update

Capital Program/Segment	**2020-2024 Investment ($M)**	**2025-2029 Investment ($M)**
Load Demand	135	217
Generation Protection, Monitoring, and Control	10	35
Non-Wires Solutions	2	23
Stations Expansion	142	122
Growth Capital	**718**	**949**

Table 7: Modernization Capital Programs

Capital Program/Segment	**2020-2024 Investment ($M)**	**2025-2029 Investment ($M)**
System Enhancement	26	151
Network Condition Monitoring and Control	54	6
Metering	80	248
Overhead Resiliency	-	86
Stations Control and Monitoring	28	65
IT Cyber Security & Software Enhancements	88	95
Legacy Network Equipment Renewal	4	-
Modernization Capital	**280**	**651**

Table 8: General Plant Capital Programs

Capital Program/Segment	**2020-2024 Investment ($M)**	**2025-2029 Investment ($M)**
Control Operations Reinforcement Program	40	-
Enterprise Data Centre	-	72
Facilities Management and Security	85	145
Fleet and Equipment Services	37	44
Information and Operational Technology	169	206
General Plant Capital	**331**	**467**

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-3

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

% Contribution to 4 Strategic Priorities	EB-2023-0195	EB-2018-0165
Growth	25%	
Sustainment	46%	
Modernization	17%	
General Plant	12%	

RESPONSE:

Please see Table 1 below for 2020-2024 actual capital expenditure contributions to each of the four strategic priorities by percentage. Toronto Hydro notes that the percentages presented in EB-2023-0195 reflect the update filed on January 29, 2024[1].

Table 1: Percent Contribution to Four Strategic Priorities

% Contributions to Strategic Priorities	EB-2023-0195	EB-2018-0165
Growth	24%	26%
Sustainment	47%	52%
Modernization	17%	10%
General Plant	12%	12%

[1] EB-2023-0195, Evidence Update (January 29, 2024)

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-4

Reference: Exhibit 1B, Tab 1-3, page.4

Please complete the following Table:

Rate Period	2015-2019	2020-2024	2025-2029
EB#	EB-2014-0116	EB-2018-0165	
Requested Base Revenue Requirement			
OEB-Approved Base Revenue Requirement			

RESPONSE:

Please see the table below for the requested information:

Table 1 Base Revenue Requirement ($ Millions)

Rate Period	EB-2014-0116	EB-2018-0165		EB-2023-0195
	2015-2019	2020-2023	2020-2024	2025-2029
Requested Base Revenue Requirement	3,799	3,351	4,255	5,387
OEB-Approved Base Revenue Requirement[1]	3,533	3,188	4,081	N/A
Actual Revenue[2]	3,455	3,095	N/A	N/A

[1] Based on the OEB-approved inflation

[2] Based on the OEB-approved inflation

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-5

Reference: Exhibit 1B, Tab 1, Schedule 3 page.7

Please provide the footnote to Depreciation in Table 7 and Table 8.

RESPONSE:

The requested footnote has been added under Tables 1 and Table 2 below. Both tables were also updated to reflect the updated Exhibit 2A, Tab 1, Schedule 1 (filed January 29, 2024) at page 2.

Table 1: 2020-2024 Rate Base Summary ($ Millions)

	OEB Approved	Actuals			Bridge	
	2020	**2020**	**2021**	**2022**	**2023**	**2024**
Opening PP&E NBV	4,229.4	4,233.2	4,419.2	4,628.1	4,893.9	5,244.3
In-Service Additions	527.4	447.9	485.2	554.4	607.9	606.3
Depreciation[1]	(265.4)	(262.0)	(276.2)	(288.7)	(257.4)	(271.8)
Closing PP&E NBV	4,491.3	4,419.2	4,628.1	4,893.9	5,244.3	5,578.8
Monthly Avg PP&E NBV	**4,298.6**	**4,284.3**	**4,457.7**	**4,686.3**	**4,954.3**	**5,348.5**
Working Capital Allowance	216.2	249.8	217.2	220.7	221.1	230.3
Rate Base	**4,514.8**	**4,534.1**	**4,674.9**	**4,907.0**	**5,175.3**	**5,578.8**

[1] Excludes allocated transportation depreciation

1 **Table 2: 2025-2029 Rate Base Summary ($ Millions)**

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening PP&E NBV	5,578.8	5,934.5	6,325.6	6,794.1	7,219.0
In-Service Additions	642.1	691.7	789.8	769.2	859.5
Depreciation[2]	(286.3)	(300.6)	(321.4)	(344.3)	(356.5)
Closing PP&E NBV	5,934.5	6,325.6	6,794.1	7,219.0	7,722.0
Monthly Avg PP&E NBV	**5,668.6**	**6,041.6**	**6,460.1**	**6,911.7**	**7,335.2**
Working Capital Allowance	231.5	237.1	242.5	250.8	255.6
Rate Base	**5,900.0**	**6,278.7**	**6,702.6**	**7,162.5**	**7,590.8**

[2] Excludes allocated transportation depreciation

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-6

Reference: Exhibit 1B, Tab 2, Schedule 1, Page. 34

QUESTION:

Toronto Hydro indicates it carefully considered the amount of funding requested for this proposal and based on research, the utility decided to allocate 0.3 percent of the proposed revenue requirement to the Innovation Fund, which amounts to approximately $16 million over the 2025-2029 rate period. This is the low end of a range found in research of comparable ratepayer-funded initiatives aimed at facilitating innovation by utilities and regulatory bodies in other jurisdictions, as well as general data on utility spending for research and development activities.

Please provide a description and details of comparable ratepayer-funded initiatives in other jurisdictions and the corresponding funding amounts.

RESPONSE:

Please see Toronto Hydro’s response to interrogatory 1B-DRC-06 part (d).

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-07

Reference: Exhibit 1B, Tab 3, Schedule 1, Page 42

With respect to Figure 9: 2020 - 2024 Efficiency Achievements (Actual and Forecast), please provide the data and underlying calculations and assumptions used.

RESPONSE:

Table 1 below provides the data behind Figure 9: 2020 – 2024 Efficiency Achievements (Actual and Forecast). Table 2 below provided a breakdown of each initiative along with an explanation of how the benefits were calculated for each particular initiative.

Table 1: 2020-2024 Efficiency Achievements Summary ($ Millions)

Year	2020	2021	2022	2023*	2024*	Total
Cost Reduction	1.16	1.83	1.74	1.45	1.52	**7.70**
Cost Avoidance	1.49	1.58	3.72	3.90	4.10	**14.79**
Total	**2.65**	**3.41**	**5.46**	**5.35**	**5.62**	**22.49**

Table 2: 2020-2024 Efficiency Achievements Breakdown by Initiative ($ Millions)

Productivity Initiative	Cost Reduction or Avoidance Calculation	Total Benefit ($ Millions)
Enterprise Resource Planning, Enterprise Connect, and People Connect	Amount saved through the avoidance of maintenance costs connected to the legacy systems and the hours saved through the automated functionalities multiplied by the standard labour rate.	10.57
e-Tailboard	Amount saved through the avoidance of costs associated with the legacy process (tangible, paper-copy tailboards) and the number of hours saved	2.28

Productivity Initiative	Cost Reduction or Avoidance Calculation	Total Benefit ($ Millions)
	through the use of electronic tailboard creation and use multiplied by the standard labour rate.	
Streetlighting Management System Project[1]	Amount saved through the avoidance of streetlight work management costs following the existing, legacy system reaching end of life.	1.98
Non-conformance Reporting	Number of hours saved through the automated and streamlined process associated with progressing beyond the legacy system multiplied by the standard labour rate.	1.26
Electronic Red Construction Folder	Amount saved through the digitization of the existing red construction folder process and the number of hours saved through the use thereof multiplied by the standard labour rate.	0.89
Accounts Payable Processing Automation	Number of hours saved through the introduction of an automated solution for the invoicing process multiplied by the standard labour rate.	0.70
Storm Prediction Impact Tool	Number of hours saved by utilizing the procured IBM weather dashboard to support disaster response decision making multiplied by the standard labour rate.	0.06
SAP Business Warehouse Project	Amount saved through the implementation of the SAP tool to the business warehousing process.	0.15
Find It Fix It Program	Amount saved for key underground and overhead maintenance programs based on the number of find-it fix-it items completed	2.95

[1] This benefit is associated with Toronto Hydro Energy Services Incorporated (THESI)

Productivity Initiative	Cost Reduction or Avoidance Calculation	Total Benefit ($ Millions)
Regulatory Intelligence Subscription Service	Annual payrolls costs (0.5 FTE) avoided by having access to this subscription service, plus avoided costs related to outsourcing regulatory intelligence research and analysis to higher cost external service providers.	0.40
Porcelain Insulator Replacement Initiative	Year-over-year decrease in cost for insulator washing program.	0.20
Equipment Failure Analysis Dashboard	Year-over-year decrease in time for equipment failure analysis multiplied by the standard labour rate.	0.04
Standardized Outage Tracking Process	Amount of overtime expenses avoided due to the standardized nature of outage tracking which avoided overtime hours of contractor work, including the removal of major rescheduling triggers.	0.06
Online Training	Number of hours saved by delivering a course virtually multiplied by the standard labour rate.	0.59
RISE 360	Number of courses developed using RISE 360 multiplied by $7,500 per course.	0.09
Classroom Maximization	Number of training hours in both the PLT lab and at Parkdale multiplied by $55/hr and $110/hr, respectively.	0.07
CenarioVR	Number of scenarios developed using CenarioVR multiplied by 6000/course plus the number of attendees multiplied by 2.5 and then multiplied by the standard labour rate.	0.04
Change Order Billing Process	The time difference between monthly billing reviews and the review of change orders during closeout review multiplied by the standard labour rate.	0.03
Total efficiency benefits yielded by the above initiatives.		**22.5**

1

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-8

Reference: Exhibit 1B, Tab 3, Schedule 2, p.26

With respect to Figure 4, please provide the MAIFI values for each of the years 2018-2023.

RESPONSE:

Please see Table 1 below for MAIFI results from 2018 to 2023 (excluding major events).

Table 1: MAIFI (excluding Major Events) 2018-2023

Year	MAIFI
2018	2.78
2019	2.85
2020	3.18
2021	3.39
2022	3.36
2023	3.34

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-9

Reference: Exhibit 1B, Tab 3, Schedule 2, Page. 35

In 2021, Toronto Hydro refined its unit cost methodology with respect to wood poles and applied the new methodology retrospectively to ensure year-over-year comparability in the results.

QUESTION (A):

a) Please provide the two methodologies and discuss the differences.

RESPONSE (A):

The two methodologies used by Toronto Hydro for unit costs can be summarized as the following:

Table 1: Summary of Refined Unit Cost Methodology

Previous Approach (pre-2021)	Updated Approach
ISA Data for the respective year is formatted and cleansed to exclude demand driven programs and to group costs and quantities by project and asset type	Unchanged
Unit cost calculated by taking the total cost of the project divided by quantity of the project for that particular asset type	Unchanged
Exclude outliers (top and bottom 10th percentiles)	Unchanged
Aggregate the unit costs and divide by the number of projects	Aggregate the total costs and total quantities from all projects corresponding to that asset type
Sum of all unit costs across projects divided by the number of projects	Compute the average unit cost by dividing total costs by total quantities

Toronto Hydro observed higher volatility in the unit costs when using the former method, particularly in the case when projects had low quantities.

QUESTION (B):

b) Please provide the wood pole unit cost for the years 2018 to 2023 based on the original methodology.

RESPONSE (B):

Please see the table below for the 3-year weighted average wood pole unit costs aligned with the original methodology.

Table 2: Wood Pole Unit Costs 2018 to 2023 – Original Methodology

2018	2019	2020	2021	2022	2023
$7,332.6	$7,639.4	$7,778.7	$7,846.6	$7,973.5	$8,178.6

QUESTION (C):

c) Please explain the difference between the average wood pole replacement cost for the years 2020-2022 in Table 3 at 1B-3-2 page 22 and the wood pole preplacement data in Figure 14 at 1B-3-2 page 35.

RESPONSE (C):

Table 3 in Exhibit 1B, Tab 3, Schedule 2 provides the 2020-2024 Custom Measure results for 2020-2022 which are reported annually as part of Toronto Hydro's MD&A. The 2021-2022 unit costs are derived on the basis of the previous methodology to ensure consistency with 2020 unit cost results (these align with the unit costs in part (b)). On the other hand, Figure 14 utilizes the updated methodology, deriving the three-year weighted average from 2020 to 2022.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-010
Reference: Exhibit 1B, Tab 3, Schedule 3 p.13

Toronto Hydro slowed down the pace of work in the Underground Downtown, Underground Horseshoe, and Overheard Renewal programs by approximately 22 percent leading to a $189 million reduction compared to forecasted budgets for these programs in the 2020-2024 rate application.

QUESTION (A):

a) Please discuss the process Toronto Hydro undertook to reprioritize the capital work and investment levels and conclude where to slow the pace of work.

RESPONSE (A):

Toronto Hydro's Asset Management Process is described in detail in Exhibit 2B, Section D1. This is the overarching process that the utility leverages to implement, track and adjust its capital expenditure plan. More specifically, the utility makes adjustments to short- and long-term plans at appropriate frequencies through the complimentary Program Management & Execution and Investment Planning & Portfolio Reporting ("IPPR") processes (as depicted in Section D1.2). The annual IPPR process produces final recommendations for updated programmatic investment levels. Management arrives at these recommendations by making trade-offs, ultimately working to balance various risks and outcomes in alignment with corporate objectives, including funding constraints.

QUESTION (B):

b) Please provide the impact of the change on the forecast outcomes of each program.

RESPONSE (B):

Toronto Hydro's 2025-2029 investment plan for the referenced programs accounts for the current state of the distribution system. As a result of deferrals within the referenced programs, the current state of the system is worse than it would have been had all work been completed in accordance with the 2020-2024 plan. This contributes to greater investment needs in 2025-2029 to maintain asset condition demographics and reliability performance, and address various asset risks (e.g., safety). (Toronto Hydro refers to this as the "snowplow" effect, where delayed investment within a rate period results in a greater increase in investment needs in the next period.) For a detailed discussion of the relevant program-specific investment needs and variances within the 2020-2024 period, please refer to Exhibit 2B, Sections E6.2, E6.3, and E6.5.

QUESTION (C):

c) Please discuss if incentive payments are impacted by the change.

RESPONSE:

As noted in response to part (b), deferrals within the referenced programs have led to the current state of the system being worse than it would have been had all work been completed in accordance with the plan. This has had an inherent effect on the reliability forecasts that Toronto Hydro used to inform the reliability targets which underpin the Performance Incentive Mechanism. For a detailed discussion of how asset condition demographics and reliability performance trends have influenced Toronto Hydro's 2025-2029 Capital Expenditure Plan (and associated expectations regarding reliability performance in the next rate period), please see Exhibit 2B, Section E2.2.1.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-11

Reference: Exhibit 1B, Tab 3, Schedule 3, Appendix A, Page 14

QUESTION:

With respect to the data in Table 2, Clearspring forecasts that Toronto Hydro's average SAIFI over 2025-2029 (1.17) is stable compared to the 2020-2022 average (1.18). However, Clearspring's average projections for CAIDI show a slight decline in 2025-2029 (51.70) compared to the 2020-2022 (48.36). In Table 3, Clearspring forecasts a slight decline in SAIDI.

Please discuss the drivers for the forecast decline in SAIDI/CAIDI.

RESPONSE:

Toronto Hydro provided Clearspring with projected SAIFI and SAIDI performance for the 2025-2029 period (refer to 1B-Staff-73 for more details). Projected CAIDI performance was derived by dividing SAIDI by SAIFI. Scheduled Outages were the most significant driver that contributed to the slight decline in SAIDI performance (2025-2029 Average vs. 2020-2024 Average). Scheduled Outages are projected to increase due to a larger capital work program. For more information, please refer to 1B-Staff-74, part (d), and 1B-Staff-62, part (b).

All other cause codes are projected using the historical five-year average with the exception of Defective Equipment, which did not contribute to the decline in SAIDI. Defective Equipment was modeled by projected failures and interruption impacts at an asset class level based on asset demographics and the expected benefits of the reliability-related Grid Modernization investments, as detailed in Toronto Hydro's response to interrogatory 2B-SEC-42.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 1B-AMPCO-12

References: **EB-2018-0165, Exhibit 1B, Tab 2, Schedule 1, Appendix B**
Exhibit 1B, Tab 3, Schedule 3, Appendix C

<u>Preamble:</u>

At Reference #1, Toronto Hydro filed a UMS Unit Costs Benchmarking Study. At Reference #2, Toronto Hydro filed an updated UMS Unit Costs Benchmarking Study dated October 2023.

QUESTION (A):

a) Please explain why unit costs for OH Switch Replacement and Switchgear Replacement were included in the EB-2018-0165 study but not included in the October 2023 UMS Study.

RESPONSE PROVIDED BY UMS GROUP (A):

We used the list of asset classes from the previous application (EB-2018-0165) as a starting point for discussion and applying our industry experience, we reviewed the viability of gaining consistency across utilities for each Asset Class and Maintenance Program. Citing significant variability in the selection, installation, and accounting for overhead switches, we opted to remove that category from the study. With respect to Switchgear Replacement, though initially targeted for inclusion in the previous application (EB-2018-0165 1B-2-1 Appendix B), it was ultimately removed from consideration as the number of these replacements within each utility were too few and sporadic to enable viable comparisons.

RESPONSE PROVIDED BY TORONTO HYDRO (A):

In identifying asset types to include for benchmarking, Toronto Hydro sought to ensure major asset classes that accounted for considerable expenditures in the 2020-2022 period were included. Although switches are critical components within the overhead distribution system, they do not pose the same level of asset deterioration pressures to the overhead system as Wood Poles at the current time as discussed in Exhibit 2B, Exhibit 6.5.3.1. In addition, the focus of the Overhead System Renewal program remains on eliminating PCB at-risk transformers through spot replacement approaches while managing reliability concerns through rebuilds. In selecting the asset classes to benchmark, Toronto Hydro also attempted to align to the Activity Based Performance Benchmarking ("APB") asset classes where appropriate, which was another driver for not including OH Switch Replacement within the benchmarking study.

QUESTION (B):

b) Please provide the unit costs for OH Switch Replacement and Switchgear Replacement if calculated as part of UMS' work for the October 2023 study but not included in the report.

RESPONSE PROVIDED BY UMS GROUP (B):

The OH Switch Replacement and Switchgear Replacement was excluded from the October 2023 study, and thus there was no calculation for unit cost.

QUESTION (C):

c) Please provide the drivers for the increase in unit costs in the October 2023 UMS study compared to the EB-2018-0165 UMS Study for the following asset categories: UG Cable, Pole Top Transformers, Padmount/UG Transformer, Network Transformer Replacement and Breaker.

RESPONSE PROVIDED BY UMS GROUP (C):

We have noted a general increase in costs across the industry over the past three years, driven largely by inflation (including its effect on commodity prices), supply chain challenges (limited manufacturing capability and excessive lead times, causing demand to exceed supply resulting in increased prices), and COVID related policies, most notably the requirement that individuals be in separate vehicles thus increasing crew size and fleet / heavy equipment costs. We understand that the industry is only recently beginning to relax COVID-related restrictions, but inflation and supply chain issues have remained an issue.

RESPONSE PROVIDED BY TORONTO HYDRO (C):

For Toronto Hydro, the increases can be attributed to various factors, including but not limited to inflation and supply chain impacts discussed in Exhibit 1B, Tab 3, Schedule 3, and asset-specific variability such as seen with stations assets discussed in Exhibit 2B, Exhibit 2B, Section E6.6.4.1.

QUESTION (D):

d) Please explain the basis for adding Cable Chambers to the asset category in the October 2023 UMS Study.

RESPONSE PROVIDED BY UMS GROUP (D):

Cable Chambers were added with the intention of providing a more diverse and representative sample set of THESL's work, particularly given the amount of civil work being performed. Of the asset classes to be considered, cable chambers represented one that would be most conducive to conducting industry comparisons.

RESPONSE PROVIDED BY TORONTO HYDRO (D):

Toronto Hydro found it prudent to add Cable Chambers to the asset categories within the latest UMS Unit Costs Benchmarking Study due to the continued and increasing investments required for managing this asset class over the long term. Toronto Hydro is proposing to invest 162 percent more in this asset class in 2025-2029 in comparison to the 2020-2024. The asset classes' health demographics also indicate that sustained investments will be required over the long term. Cable Chambers also represent a key investment in civil assets within Toronto Hydro's Underground Renewal – Downtown program and the overall System Renewal category. As such, including Cable Chambers in the study increases the proportion of total investment that is covered by the UMS Unit Costs Benchmarking Study.

QUESTION (E):

e) There were 17 electric utilities in the Peer Group Panel in the EB-2018-0165 study and only 12 electric utilities in the October 2023 UMS study. Please explain and discuss any impact on the results.

RESPONSE PROVIDED BY UMS GROUP (E):

The difference in number of participants for this study as compared to that conducted for the EB-2018-0165 application is reflective of utilities' willingness / capacity to dedicate resources to this effort. As always, we casted a wide net across the North American utilities and experienced the normal churn of some accepting but having to back out as the required completion date neared, and others declining at the initial offering, citing either overriding priorities or general policies not to participate in such endeavors. When we embark on these types of efforts, we prefer a peer group as large as possible, one that has at least 10 to 12 participants to achieve the level of directional accuracy that is called for in focused studies of this type.

QUESTION (F):

f) On page 8 of the UMS report in EB-2018-0165, UMS provides Table II-1 that shows the Fully Normalized Benchmark Comparisons. Please provide the same table using the data in the October 2023 UMS Study.

RESPONSE PROVIDED BY UMS GROUP (F):

Regarding our study in the EB-2018-0165 filing the Board provided THESL and UMS Group constructive feedback that questioned various aspects of the 2018 normalization formula. To be responsive to the Board's questions and feedback, we simplified our normalization efforts to focus on those criteria accepted by the Board in 2018 (i.e., metric and USD to CAD conversions and differences in accounting practices). However, as requested by this question: if we were to have applied the normalization adjusters for other factors as was done in the previous study (modified somewhat to reflect improvements in benchmarking practices), the following comparisons, generally favoring THESL (as THESL's higher congestion undoubtedly has a negative effect on productivity), would have resulted:

Table II – 1: Fully Normalized Benchmark Comparisons (October 2023 UMS Study)

			Median	**Percent from Median**
Asset Categories				
Wood Pole	Each	$8,317	8,317	0.0%
UG Cable (XLPE)	Per Meter	$131	131	0.0%
Pole Top Transformer	Each	$18,691	18,687	0.0%
Pad mount / UG Transformer	Each	$37.373	37,129	0.7%
Network Transformer / Protector	Each	$127,649	130,085	-1.9%
Breaker	Each	$37,983	41,040	-7.4%
Cable Chambers / Manholes	Each	$136,409	139,607	-2.3%
Maintenance Programs				
Vegetation Management	Per Line KM	$2,175	2,140	1.6%
Pole Test and Treat	Each	$17	19	-8.1%
Overhead Line Patrol	Per Line KM	$23	26	-9.9%
Substation Maintenance	MVA	$1,712	1,712	0.0%
Building Vault Inspection	Each	$258	271	-5.0%

QUESTION (G):

g) On page 29 of the UMS report in EB-2018-0165, UMS provides Table C-2 which shows the % of Labour and Non-Labour costs. Please provide the same table using the data in the October 2023 UMS Study.

RESPONSE (G) PROVIDED BY UMS GROUP:

Per your request, the following table is provided:

Table C-2: Labour and Non-Labour Cost Split (October 2023 UMS Study)

Asset Category / Capital	A	B	C	D	E	F	G	H	I	J	K	L	THESL
Wood Poles Installed / Replaced	75%	80%	75%	75%	75%	66%	66%	75%	70%	55%	64%	64%	76%
UG Cable Installed / Replaced	75%	70%	70%	70%	70%	37%	69%	72%	75%	55%	82%	51%	70%
Pole Top Transformers Installed / Replaced	70%	70%	70%	70%	70%	54%	42%	65%	70%	55%		34%	68%
Padmount Transformers Installed / Replaced	60%	55%	55%	60%	60%	45%	37%	62%	60%	55%		25%	56%
Network Transformers / Protectors Installed / Replaced	50%	55%	50%	50%	50%	19%		45%	55%		46%	51%	49%
Breakers Installed / Replaced	70%	70%	70%	65%	65%	35%	85%	70%	75%	70%			64%
Cable Chambers / Manholes Installed / Replaced	95%	95%	95%	95%	90%	60%	57%	80%	90%		76%		94%
Maintenance Programs / OM&A	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**THESL**
Vegetation Management (Inspected / Trimmed)	99%	95%	95%	95%	95%	99%	100%	95%	99%	95%	100%	78%	99%
Pole Test and Treat	99%	95%	95%	95%	95%	99%	93%	95%	99%	95%		76%	99%
Overhead Line Patrol	99%	95%	95%	95%	95%	99%	50%	95%	99%	95%	100%	66%	99%
Substation Maintenance (Inspection, Test)	70%	60%	60%	40%	50%	60%	80%	65%	60%	95%	80%	77%	60%
Building Vault Inspections	99%	95%	95%	95%	95%	99%		92%	99%	100%	80%		99%

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-8

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

The evidence states that the Investment Plan makes the minimum investments necessary (the "least regrets" investments) to maintain key outcomes in the near term while also making paced and deliberate progress in readying the grid and utility operations for the future irrespective of the path the energy transition takes. How does Toronto Hydro demonstrate to the OEB that it is making the minimum investments necessary? What are "least regrets" investments?

RESPONSE:

Please refer to Exhibit 2B, Section D4 starting on page 9 for an explanation of the least regrets planning approach and how it translates into balanced investments as part of the 2025-2029 Distribution System Plan. Please also see Toronto Hydro's responses to interrogatories 1B-DRC-03 and 1B-Staff-4(d).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-9

Reference : Exhibit 1B, Tab 1, Schedule 1, Page 1

QUESTIONS (A) – (G):

Toronto Hydro has referred to a number of City of Toronto initiatives. Please provide a brief summary of each of these initiatives. Please indicate, specifically, how each of these initiatives has impacted Toronto Hydro's revenue and cost forecasts for the rate plan term:

a) Transform TO
b) Net Zero Existing Building Strategy
c) Electric Vehicle Strategy
d) Toronto Green Standard
e) Home Energy Loan Program
f) Energy Retrofit Loans
g) City of Toronto Green Will Initiative

RESPONSE (A) – (G):

Initiative	Summary Description
Transform TO	The TransformTO Net Zero Strategy responds to the climate emergency by focusing on a new target of net zero GHG emissions community-wide by 2040. The strategy outlines the rationale behind the net zero pathway and opportunities needed to successfully reach the net zero target. The Strategy presents a set of 2030 interim targets for community-wide emissions and City corporate targets.
Net Zero Existing Building Strategy	Building on the TransformTO strategy, the Net Zero Existing Building Strategy presents the background information and set recommended building-scale actions and the city-wide policies necessary for the City of Toronto to transform its existing building sector.
Electric Vehicle Strategy	As one of the key goals identified in Transform TO, the Electric Vehicle strategy identifies a range of actions to help the City achieve its 2050 goal of having all transportation powered by zero carbon energy sources. This strategy is one of

Initiative	Summary Description
	many initiatives informing Toronto's approach to sustainable transportation and focuses on activities for passenger light duty vehicle electrification.
Toronto Green Standard	The Toronto Green Standard is Toronto's sustainable design and performance requirements for new and city-owned developments. The Standard performs an important role as a market transformation tool to progressively push development beyond the minimum standards of the Ontario Building Code towards Toronto's zero-emission targets set in TransformTO.
Home Energy Loan Program	To help make it easy and affordable for homeowners to pay for home improvements, Toronto homeowners can borrow up to $125,000 to cover the cost of a variety of applicable home energy improvements.
City of Toronto Green Will Initiative	Connect building portfolio owners with the City of Toronto and other buildings owners to share experiences and best practices to reduce greenhouse gas emissions.

Critical climate change mitigation and adaptation efforts demand a bigger, more efficient and more resilient system that will serve customers for generations to come. In combination with many other business and customers inputs which are detailed throughout the evidence in Exhibits 1B, 2B and 4, the above-noted climate change mitigation initiatives informed Toronto Hydro's strategic direction and investment priorities for the 2025-2029 planning period – to get the grid and its operations ready and able to support long-term societal decarbonization imperatives. For more information about how Toronto Hydro's application enables energy transition via electrification please refer to Toronto Hydro's response to 1B-PP-08.

The Electric Vehicle Strategy specifically impacted Toronto Hydro's cost and revenue forecasts. To align with the goals of TranformTO to have 100% of light duty vehicles to be zero emission by 2050, the City of Toronto Electric Vehicle Strategy outlines interim goals by passenger vehicles. From these goals, the Strategy converted targets to EV sales goals. Toronto Hydro incorporated the City EV Strategy sales targets in the System Peak Demand Forecast found in Exhibit 2B, Section D4 and revenue forecast in Exhibit 3. Please refer to Exhibit 3, Tab 1, Schedule 1, Section 10 and Appendix J for more details on the integration of EV forecasts into Toronto Hydro's revenue load forecast.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-10

Reference: Exhibit 1B, Tab 1, Schedule 1, Page 7

QUESTION:

Toronto Hydro's evidence is that approximately one quarter of the utility's grid equipment continues to operate past useful life. An additional 11% is expected to reach that point by 2030 unless the utility invests in upkeeping system infrastructure in the 2025-2029 period. How does Toronto Hydro calculate the level of the utility's grid equipment operating past its useful life.

Please indicate the level of grid equipment operating past its useful life in 2018. What level of capital spending was proposed at that time to deal with assets operating beyond their useful life. How does that compare to the level being proposed during the rate plan period?

RESPONSE:

Toronto Hydro considers an asset to be operating past useful life if the asset remains in service at an age that is greater than its useful life. To calculate the percentage of Assets Past Useful Life ("APUL"), Toronto Hydro compares the age demographics of its asset population to the useful life of each asset type.

By 2018, approximately 24 percent of the asset population was operating past its useful life with an additional 9 percent by the end of the forecast period (2025). The level of capital spending proposed as part of the 2020-2024 Rate Application was approximately $2.8 billion.[1] Out of which, approximately $1.8 billion was proposed for System Renewal and Metering related investments that would have had the largest impact on addressing assets operating past their useful lives with some contribution from System Access and System Service investments as well.

[1] EB-2018-0165, U-VECC-71

By 2023, approximately 25 percent of the asset population was operating past its useful life with an additional 11 percent by the end of the forecast period (2030). As part of the 2025-2029 CIR Rate Application, Toronto Hydro is proposing approximately $2.2 billion in System Renewal and Metering related investments which is a 27 percent increase compared to the last rate application.

Details on the increased investment can be found in Exhibit 2B, Section E2.2 (page 15) and Section E4.2 (pages 16 and 18).

Please note that Toronto Hydro utilizes the APUL metric as a simple, high-level indicator meant to represent the age demographics of all assets. However, APUL is not intended to furnish detailed insights into the age distribution and condition of assets within a specific class. Such granular details are crucial for assessing the extent of System Renewal investment necessary on a programmatic level. For comprehensive information on this, please refer to the System Renewal programs detailed in Section E6 of the Distribution System Plan (Exhibit 2B). Please also refer to interrogatory response 2B-SEC-44 for a comprehensive discussion regarding expected asset demographic changes over the 2025-2029 period with investment.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-11

Reference : Exhibit 1B, Tab 1, Schedule 1, p. 9

QUESTION:

Toronto Hydro's population is expected to grow by approximately 23.8 % between 2021 and 2031, a marked increase from the 6.8% growth over the prior decade. Please specify how that increased growth has impacted Toronto Hydro's cost and revenue projections for the rate plan.

RESPONSE:

Please see the Customer Connections capital program in Exhibit 2B, Section E5.1 at pages 4 to 6 for an explanation of how population growth impacted the capital expenditure plan. Addressing the pressures of population growth within the City of Toronto requires a concerted effort between the government, the private sector (e.g. developers) and Toronto Hydro. As the need for accommodation (and supportive services such as transit, hospitals, office, etc.) increases, new building connections and service upgrades increase. This yields a greater demand for access to Toronto Hydro's distribution system (e.g. more condominiums, large multi-use developments) which is reflected in the increase of customer connection capital expenditures since 2020 above previous forecasts. The growth of these developments is projected to continue through the 2025-2029 period and is reflected in Toronto Hydro's customer connections forecast.

Increases in capital expenditures associated with Customer Connections also drive costs in the Customer Operations program at Exhibit 4, Tab 2, Schedule 8.

Please see the load and customer forecast in Exhibit 3, Tab 1, Schedule 1 at page 4 for an explanation of how population growth impacted the revenue forecast.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-12

Reference: Exhibit 1B, Tab 1, Schedule 1, Page 10 - 11

Toronto Hydro's evidence refers to extreme weather events and states, "As evidenced by recent events (outlined in Table 3 below), extreme weather has become a regular operating condition that the utility must consider and manage in its day-to-day operations and long-term planning activities. With the frequency and intensity of adverse weather increasing due to climate change, Toronto Hydro's grid and operations must become more resilient to this challenge." Please explain how the frequency and intensity of adverse weather increasing has impacted Toronto Hydro's operating and capital costs for the years 2025-2029.

RESPONSE:

Please refer to the following evidence for a general summary of how the frequency and intensity of adverse weather increasing impacts the distribution system:

- Exhibit 2B, Section D2, Subsection D2.1.2, "Climate and Weather"

Specific program level impacts are discussed in the following evidence:

- Exhibit 2B, Section E6.7 – Reactive and Corrective Capital Program
- Exhibit 4, Tab 2, Schedule 4 – Corrective Maintenance Program
- Exhibit 4, Tab 2, Schedule 5 – Emergency Response Program
- Exhibit 4, Tab 2, Schedule 6 – Disaster Preparedness Management Program.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-13

Reference : Exhibit 1B, Tab1, Schedule 1, pp.11-12

QUESTION :

Toronto Hydro expects to have over 4,400 DER connections by the end of the decade which represents a 67% increase compared to 2022. Please explain, specifically, how the forecast of DERs was derived. How does this impact capital and operating costs for the years 2025-2029? Please provide a full list of DER connection projects for the years 2020-2029. Please include all assumptions.

RESPONSE:

Please see Exhibit 2B, Section E5.1 at page 13 for an explanation of how the forecast was derived and a summary of the projects by year and by capacity.

Capital investments to support DER enablement are detailed under the Generation Protection, Monitoring and Control (Exhibit 2B, Section E5.5), the Non-Wires Solutions (Section E7.2) and Stations Expansion – Sheppard TS (Section E7.4) programs.

Operational investments to support DER maintenance and corrective costs are detailed in the Customer Location Maintenance segment of the Preventative and Predictive Station Maintenance Program at Exhibit 4, Tab 2, Schedule 3 starting on page 8. Operational investments to support system planning related to DER connections are detailed in the System Planning segment of the Asset and Program Management program at Exhibit 4, Tab 2, Schedule 9 starting on page 15.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-14

Reference: Exhibit 1B, Tab 1, Schedule 1, Page 12

Since 2015 Toronto Hydro has served the needs of a growing city, evolving customer and policy demands, and an aging system while addressing intensifying challenges identified above with a staffing complement that is essentially flat from 2015-2024. Over this period Toronto Hydro's replenished a large wave of retirements. It has also "rightsized" its workforce through continuous improvements in productivity, including harmonizing key jobs to create a more agile compliment of staff and automating manual processes to increase employee output levels.

QUESTION (A):

a) Please explain, in detail, how Toronto Hydro determined that a 25% increase was appropriate.

RESPONSE (A):

Please refer to the evidence at Exhibit 4, Tab 1, Schedule 1 at pages 25-50 for a detailed overview of the planning considerations, needs and drivers of the operations and workforce plan. Please refer to the Staffing evidence Exhibit 4, Tab 4, Schedule 3 for more information about the workforce plan.

Toronto Hydro considered the following quantitative and qualitative factors in determining the reasonableness of the 25% workforce increase proposed in this application:

1. FTE-normalized benchmarking analysis presented in the OM&A Overview evidence at Exhibit 4, Tab 1, Schedule 1, which shows that Toronto Hydro has a comparatively lean staffing contingent compared to its Ontario peers using publicly available OEB yearbook data

2. FTE trending which shows that forecasted FTE trends (e.g. FTE/CAPEX and FTE/customer as shown below in Figure 1 and 2, respectively) are keeping in line with (or better than) historical ratios.
3. Increasing volumes and complexity of work requirements across programs/portfolios as presented in the programmatic evidence and summarized in the OM&A Overview evidence.
4. The ability to train and safely absorb new staff (i.e., apprentices) into the utility's operations.
5. Professional judgement of senior utility leaders who have extensive experience managing operational requirements in the areas of construction, engineering, grid operations, customer operations, IT, finance, human resources and public, legal and regulatory affairs.

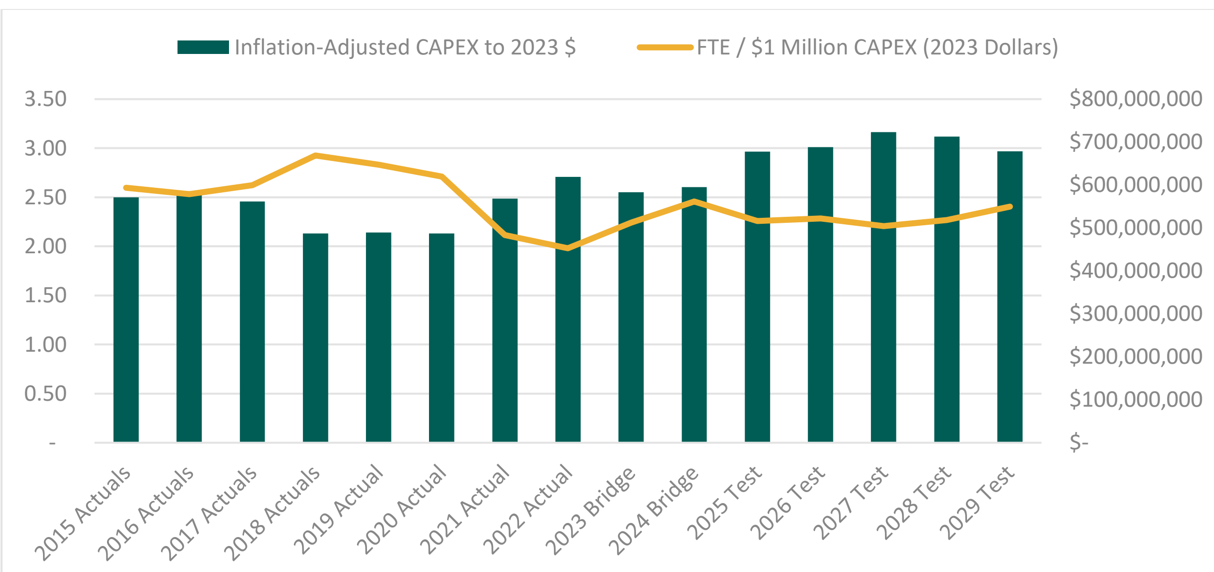


Figure 1: FTE per $1 million CAPEX 2015 – 2029

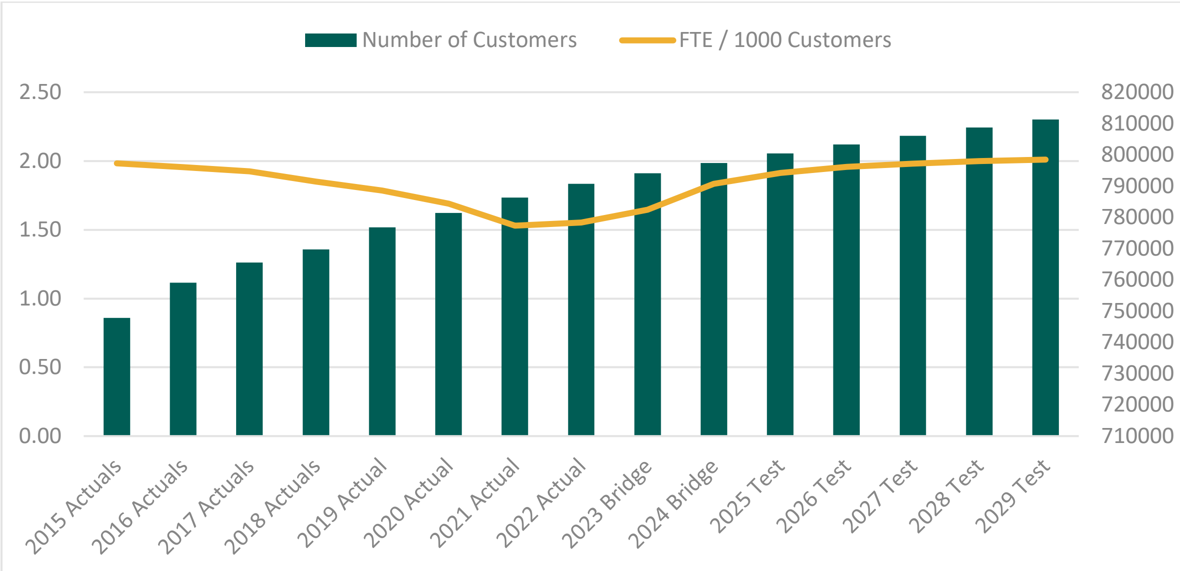


Figure 2: FTE per Customer 2015 – 2029

QUESTION (B):

b) If the staff compliment was the "right size" in 2024, how can that staffing level now be deemed inadequate?

RESPONSE (B):

The reference above notes Toronto Hydro's staffing complement is essentially flat from 2015 to 2024, and that this was made possible through productivity improvements (e.g., process automation, job harmonization, outsourcing) which enabled the utility to right-size (i.e. constrain) staffing levels over this period of time. The reference does not mean to suggest or imply that the staffing complement was right-sized in the year 2024 specifically, but rather, that it was right-sized over this period of time. However, it is no longer possible to operate with the historical staffing levels as business conditions are changing and the utility needs more resources to deliver its work programs, comply with legal and regulatory requirements and meet customer needs safely, reliably and efficiently.

QUESTION (C):

c) When did Toronto Hydro determine it was no longer possible to meet its obligations without additional staffing resources?

RESPONSE (C):

Workforce requirements were assessed through the utility's integrated business planning process which is described in the evidence at Exhibit 4, Tab 1, Schedule 1 starting at page 25. Please refer to interrogatory: (i) 2B-SEC-32 for a chronology of the business planning process and (ii) 4-CCC-58(d) for more information about the workforce planning part of the process.

QUESTION (D) :

d) What is the overall impact on the 2025 revenue requirement of increasing its workforce relative to 2024?

RESPONSE (D):

The 2025 revenue requirement impact of increasing workforce by 68 FTE relative to 2024 levels is approximately $6.5M.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-15

Reference: Exhibit 1B, Tab 1, Schedule 1, Page 26, Table 9

QUESTION:

Table 9 sets out Toronto Hydro's OM&A programs for the period 2025-2029. The CCC is interested in comparing this to the prior period. For each of those programs please provide the forecast and actual spending levels for the period 2020-2024. Please provide the year-by-year numbers as well as the total.

RESPONSE:

Please see Toronto Hydro's response to interrogatory 4-SEC-89 subpart (c).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-16

Reference: Exhibit 1B, Tab 1, Schedule 1, Page. 33

QUESTION (A):

a) Toronto Hydro points to "notable" improvements in cost-efficiency achieved over the last decade.
Please explain how the $200 million which will be returned to customers by the end of the decade was calculated. Please explain how the $132 per customer amount was calculated.

RESPONSE (A):

Table 1: Calculation of $200 Million Returned to Customers

CIR Period	Account	DVA Balance ($ Millions)	Monthly Rate Rider ($)	Clearance Period	Amount paid per customer ($)
2015-2019[1]	Operating Centres Consolidation Program ("OCCP")	72.5	- 1.48	34 months	- 50.32
2020-2024[2]	OCCP	73.7	- 2.13	22 months	- 46.86
2020-2024	50/60 Eglinton	11.8	- 0.34	22 months	- 7.48
Sub-total		**158.0**	**n/a**		**- 104.66**
2025-2029[3]	OCCP	33.4	- 1.73	12 months	- 20.76
2025-2029	50/60 Eglinton	10.7	- 0.14	48 months	- 6.72
Total		**202.0**	**n/a**		**- 132.14**

[1] EB-2014-0116 – Decision and Rate Order (March 1, 2016)
[2] EB-2018-0165, DRO Reply Submission and Draft Rate Order Update at Page 13 of 32.
[3] Exhibit 9, Tab 3, Schedule 1 – Rate Rider Table

QUESTION (B):

b) Please explain how the $26 million reduction related to fleet was calculated. Is this an annual amount?

RESPONSE (B):

The $26 million reduction related to fleet is an aggregate figure for the 2017-2023 period and is not an annual amount. Toronto Hydro calculated it as follows (dollar figures rounded to the nearest thousand or million):

Table 2: Calculation of $26 million Fleet Reduction[4]

	(a)	(b)	(c)	(d)	
Vehicle Type	**Average Capital Replacement Cost by Vehicle Class ($)**	**Number of Units**	**Total Cost Avoidance by Class ($ millions) (a x b)**	**Average OPEX Cost per Year by Vehicle Class ($)**	**Replacement Cost Savings 2017-2023 ($ millions) (c + d) X (7 years) X (# of vehicles per class)**
Light Duty	51,000	62	3.2	4,000	1.7
Heavy Duty	296,000	49	14.5	13,000	4.4
Equipment	113,000	21	2.4	2,000	0.3
Total			**20**		**6.4**

In responding to this interrogatory, Toronto Hydro discovered an error in the original evidence referenced. The $26 million figure calculated above relates to an earlier, outdated fleet vehicle reduction count of 132 vehicles. The correct number of vehicles that Toronto Hydro replaced during the 2017-2023 period is 163 vehicles which, using the above methodology, corresponds to a total OPEX cost savings of $9.2 million and capital cost avoidance of $30.5 million, for a total of $39.7 million.

[4] Variances due to rounding may exist

QUESTION (C):

c) What is the total number of Toronto Hydro customers and the number of those customers on e-billing. How many customers are expected to convert to e-billing during the rate plan term by year. What are the expected annual savings from further conversion to e-billing? Have these savings been incorporated into the forecasts? If not, why not?

RESPONSE(C):

As of 2022, Toronto Hydro had a total of 790,699 customers[5] out of which 381,490 were on ebills. By 2029, Toronto Hydro expects to have 487,917 customers on ebills, with the annual forecast as follows:

Table 3: Number of Customers and Incremental new customers on ebills

	2022	2023	2024	2025	2026	2027	2028	2029
Number of customers on ebills at year end	381,490	404,854	427,275	442,135	455,413	466,433	478,664	487,917
Incremental number of new customers on ebills	30,497	23,364	22,421	14,860	13,278	11,020	12,231	9,254

Based on the above forecast of incremental eBill conversion, Toronto Hydro expects annual savings to increase between $0.1 million and $0.2 million each year over the 2025-2029 period, with cumulative savings adding up to approximately $2 million. Savings resulting from transitioning customers to ebills are primarily seen in forecast paper, printing, and postage costs, offset by the cost of producing an ebill. The 2025-2029 OM&A cost forecast for the Customer Care program in Exhibit 4, Tab 2, Schedule 14 is net of these savings.

[5] Exhibit 1, Tab 1, Schedule 3, Table 5.

QUESTION (D):

d) Please provide an explanation as to how the $23 million in expected cost reductions by the end of 2024.

RESPONSE (D):

For details on the $23 million in expected reduced or avoided costs by the end of 2024, please see Exhibit 1B, Tab 3, Schedule 3, at Section 3, pages 15-27.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-18

Reference: Exhibit 1B, Tab 1, Schedule 1, Page 34

Please provide a complete list of all jurisdictions that Toronto Hydro drew on when developing its Custom Scorecard Measures. Please provide materials setting out the mechanisms and frameworks being used in those jurisdictions.

RESPONSE:

In developing its Custom Scorecard measures, Toronto Hydro drew upon Hawaii, Washington, Massachusetts, New York and the UK. The resulting scan grouped Key Performance Indicators (KPIs) identified in these jurisdictions into 62 categories, which Toronto Hydro organized into the four categories outlined in the OEB's Renewed Regulatory Framework (RRF) of Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. This analysis was relied upon as a starting point for Toronto Hydro to assess common metrics which were applicable to Toronto Hydro's circumstances and investment plan, as well as metrics which Toronto Hydro had confidence in its ability to measure consistently and accurately.

The scan of KPIs described above was not relied upon in establishing Toronto Hydro's mechanisms and/or rate framework. Exhibit 1B, Tab 2, Schedule 1, Appendix B provides a jurisdictional scan completed by ScottMadden Management Consultants which is specific to Modernized Performance-Based Regulation; describing associated mechanisms and frameworks across various jurisdictions. Please also see response to 1B-SEC-19 (a), which lists jurisdictions examined by ScottMadden, and outlines core aspects of their respective frameworks.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-19

References: **Exhibit 1B, Tab 1, Schedule 3, Page. 3**

Preamble:

Please provide the proposed Distribution Bill Impacts on one schedule with and without the impacts of any rate riders.

RESPONSE:

The below table includes the proposed distribution bill impacts with and without the impacts of any rate riders.

		Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed
Residential	Base Distribution (Excluding Rate Riders)	$/30 days	$4.22	$2.35	$1.94	$4.43	$1.80
		%	9.3%	4.7%	3.7%	8.2%	3.1%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$3.24	$3.40	$3.72	$3.97	$2.86
		%	7.6%	7.4%	7.5%	7.5%	5.0%
Competitive Sector Multi-Unit Residential	Base Distribution (Excluding Rate Riders)	$/30 days	-$0.16	$1.03	$0.80	$2.63	$0.81
		%	-0.4%	2.8%	2.1%	6.8%	2.0%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	-$1.27	$1.84	$2.18	$2.27	$1.64
		%	-3.6%	5.4%	6.0%	5.9%	4.0%
General Service <50 kW	Base Distribution (Excluding Rate Riders)	$/30 days	$17.31	$6.62	$5.27	$11.71	$4.63
		%	13.9%	4.7%	3.5%	7.6%	2.8%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$14.18	$9.24	$9.61	$10.67	$7.29
		%	12.0%	7.0%	6.8%	7.0%	4.5%
General Service 50-999 kW	Base Distribution (Excluding Rate Riders)	$/30 days	$278.46	$120.50	$103.45	$207.35	$105.57
		%	14.5%	5.5%	4.5%	8.5%	4.0%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$235.35	$166.42	$175.01	$192.67	$150.45
		%	13.0%	8.1%	7.9%	8.1%	5.8%
General Service 1,000-4,999 kW	Base Distribution (Excluding Rate Riders)	$/30 days	$2,437.49	$1,100.29	$955.20	$1,709.85	$1,027.33
		%	15.5%	6.1%	5.0%	8.5%	4.7%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$1,993.46	$1,466.61	$1,516.65	$1,599.65	$1,381.30
		%	13.4%	8.7%	8.3%	8.0%	6.4%
Large Use	Base Distribution (Excluding Rate Riders)	$/30 days	$10,742.68	$4,022.74	$5,778.50	$10,048.74	$5,794.31
		%	13.2%	4.4%	6.0%	9.8%	5.2%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$10,124.44	$5,874.70	$8,564.26	$9,530.78	$7,560.71
		%	13.1%	6.7%	9.2%	9.4%	6.8%
Street Lighting	Base Distribution (Excluding Rate Riders)	$/30 days	$18,225.20	$10,838.30	$9,668.80	$19,016.70	$10,055.20
		%	11.8%	6.3%	5.3%	9.8%	4.7%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$15,917.30	$12,277.10	$20,691.10	$12,135.60	$15,226.00
		%	11.0%	7.6%	11.9%	6.3%	7.4%
Unmetered Scattered Load	Base Distribution (Excluding Rate Riders)	$/30 days	$3.34	$1.78	$1.49	$3.32	$1.39
		%	10.1%	4.9%	3.9%	8.4%	3.2%
	Distribution Subtotal A (Including Rate Riders)	$/30 days	$2.96	$2.41	$2.49	$3.11	$2.01
		%	9.5%	7.1%	6.8%	8.0%	4.8%

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-20

Reference: **Exhibit 1B, Tab 1, Schedule 3, Page. 6, Table 6: Capital Investment expenditures by Categories**

QUESTION:

Please provide the actual Capital Investment Expenditures by Categories for the period 2020-2024.

RESPONSE:

Please refer to Appendix B to Toronto Hydro's response to interrogatory 2A-Staff-104.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-21

Reference: Exhibit 1B, Tab 1, Schedule 3, Page 7-8

QUESTION :

Please confirm that Toronto Hydro's rate increased from $4,514.8 million in 2020 to $5,596.5 in 2024. Please confirm that with the January 29, 2024 update Toronto Hydro's rate base is going from $5,900 million in 2025 to $7,590.8 in 2029. Please explain how Toronto Hydro has the capacity to increase its rate base so significantly in the forecast period relative to the prior period.

RESPONSE:

Toronto Hydro notes that the appropriate reference for 2020 rate base is the actual amount of $4,534.1 million as presented in the same table referenced in the question. The remaining references to rate base made in the question are accurate.

Please see the Staffing Evidence in Exhibit 4, Tab 4, Schedule 3 at for detailed information about Toronto Hydro's 2025-2029 workforce plan and resourcing strategy.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-22

Reference: Exhibit 1B, Tab 1, Schedule 3, Page 10

Please provide Toronto Hydro's approved and actual debt rates and costs and return on equity for the years 2020-2023.

RESPONSE:

Please find the table below:

Table1: 2020-2023 Approved and Actual Debt Rates and Costs and Return on Equity

	2020	2021	2022	2023
Approved Debt Rate	3.64%	3.64%	3.64%	3.64%
Actual Debt Rate	3.52%	3.36%	3.36%	3.63%
Deemed ROE	8.52%	8.52%	8.52%	8.52%
Achieved ROE	5.90%	7.08%	7.44%	6.80%[1]

[1] This figure is estimated. Please see the response to 9-Staff-344(c).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-23

Reference: Exhibit 1B, Tab 2, Schedule 1

In the EB-208-0165 Decision and Order the OEB encouraged Toronto Hydro to consider an alternative rate-setting approach in the future to better balance the risk between the customers and the utility. Please provide a complete list of the Custom Rate Frameworks that Toronto considered in addition to the one proposed. Please address why these frameworks were not adopted by Toronto Hydro. Please explain how this plan would differ from a five-year cost of service approach.

RESPONSE:

The Custom Rate Framework reflects the output of a multi-year business and regulatory strategy process that evolved over a period of time in conjunction with the development of the 2025-2029 Investment Plan. This process was guided by three key considerations:

(1) The minimum funding requirements to address the asset and operational investment needs articulated in the evidence at Exhibit 2B and 4, which are reflected in the cost forecasts that underpin this application;
(2) The regulatory principles articulated in the Rate Framework evidence, which were informed by the OEB expectations and requirements as set out in the RRF and Rate Handbook; and
(3) Consideration of existing rate-setting approaches and mechanisms and how they may be deployed, innovated or evolved to achieve better alignment with the identified principles.

The result of this process was the proposed Custom Rate Framework which consists of multiple elements as outlined in the evidence at Exhibit 1B, Tab 2, Schedule 1. Other elements, mechanics and approaches that utility explored during this process were ultimately not relied upon, and are thus not relevant to the determination of the issues in this proceeding.

Please see response to 1B-Staff-3 which explains the difference between the proposed rate framework and a five-year cost of service. Please see the response to 1B-SEC-13 which shows how the incentives of the Custom Rate Framework balance risk between the utility and ratepayers.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-24

Reference: Exhibit 1B, Tab 2, Schedule 1 p. 2

Toronto Hydro has been operating using a Custom IR Framework for the past 10 years - 2015-2019 and 2020-2024. The RRFE/Rate Handbook states that Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. It also states that Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs. The Handbook also states that Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. (Handbook to Utility Rate Applications, dated October 13, 2016). Toronto Hydro is rebasing and rates are increase by approximately 7.5% per year for residential consumers. Please explain how Custom IR has benefited Toronto Hydro's customers.

RESPONSE:

For clarity, Toronto Hydro's residential distribution bill impacts are increasing by an average of 7.0% over the 2025 to 2029 rate term, with total bill increases averaging 2.0%.

Since 2015, Custom IR has enabled Toronto Hydro to make the investments necessary to provide safe and reliable service to its customers, during a time of multi-year investment needs that exceed what can be funded through base rates – the precise business condition for which Custom IR was intended.[1] Over this period of time, the utility has made demonstrable gains in productivity and efficiency and continuous improvement in service quality performance outcomes for its customers.

[1] OEB Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (October 18, 2012) at page 19.

These achievements and benefits are detailed in the Historical Performance and Productivity evidence filed at Exhibit 1B, Tab 3, Schedules 2 and 3, respectively and include but are not limited to:

- 19% improvement in customer first contact resolution since 2013;
- 60% decrease in Total Recordable Injury Frequency Rate (TRIF);
- Adding over 381,000 customer on e-bills since 2013 yielding cumulative savings of $4.4 million from avoided paper, printing, and postage costs;
- A 45% decrease in the number of feeders serving large customers that are experiencing a high number of interruptions per year;
- Reduced the average duration of power outages due to defective equipment by 26 percent over the 2013-2022 period;
- Improved billing accuracy from 96.6% in 2013 to 99.1% in 2022, exceeding the OEB's minimum requirement of 98%;
- Improved service levels with respect to customer connections timelines (i.e. New Residential/Small Business Services Connected on Time) from 95% in 2013 to 99% in 2022, exceeding the OEB minimum requirement of 90%;
- Direct customer benefits (i.e. givebacks) exceeding $200 million made possible by a multi-pronged facilities consolidation strategy that reduced the square footage per employee by approximately 40 percent;
- Productivity initiatives totaling $23 million in costs that the utility expects to avoid or reduce by the end of the current rate term, in addition to delivering extensive qualitative benefits that are described in detail in the evidence;
- Effective cost performance as evidenced by total cost custom benchmarking, unit cost benchmarking, IT cost benchmarking and compensation cost benchmarking;
- Stabilizing the rapid deterioration of system health metrics that the utility faced when it embarked on its multi-year ICM before the first Custom IR; and
- Keeping up with the growth and densification of Canada's largest and one of North America fastest growing cities, and enabling the development of transit, housing and major infrastructure projects across the city.

Toronto Hydro intends to sustain the productivity, performance achievements, and improvements made over the last two Custom IR period, and drive continuous improvement with respect to new/expanded performance objectives. To that end, and in direct response to the OEB's decision in EB-2018-0165, Toronto Hydro has brought forward an innovative performance incentive mechanism (PIM) proposal to improve the balance of risk between ratepayers and the utility in this application. The PIM includes explicit financial incentives for:[2]

a) **Continuous improvement** (e.g. reduce the duration of outages, enhance system security, make progress towards grid automation in the horseshoe, track and measure new elements of post-transactional customer satisfaction, achieve and maintain certification with continually improving international standards for key management systems),

b) **Maintaining service quality performance in accordance with customer preferences** (e.g. invest no more than is necessary to maintain the frequency of outages caused by defective equipment and maintain customer service performance)

c) **Public policy responsiveness** (e.g. connect DERs in an timely manner, expand the use of non-wires alternatives for system capacity, reduce gHg emissions); and

d) **Cost control targets** (e.g. achieve quantified efficiency benefits that will provide demonstrable value to customers in the next rate period).

[2] Exhibit 1B, Tab 3, Schedule 1

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-25

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 5

Please provide examples of rate frameworks that are similar to the one being proposed by Toronto Hydro.

RESPONSE:

As noted in the evidence, Toronto Hydro's Custom Rate Framework is an evolution of the Custom IR rate frameworks approved by the OEB in other recent applications.[1] The evidence filed by Scott Madden in Exhibit 1B, Tab 2, Schedule 1, Appendix B reviews a series of jurisdictions which have implemented framework components similar to those proposed by Toronto Hydro, such as recognition of expanded utility objectives, performance incentives, modified attrition relief mechanisms (such as I-X), alternative cost recovery mechanisms for large or volatile investments, and funding for demonstration projects.

[1] Toronto Hydro (EB-2014-0116 and EB-2018-0165), Hydro One (EB-2017-0049 and EB-2021-0110), Hydro Ottawa (EB-2019-0261 and EB-2015-0004), Enbridge Gas (EB-2012-0459), Kingston Hydro (EB-2015-0083), Horizon (EB-2014-002), Oshawa PUC (EB-2013-0101)

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-26

References: Exhibit 1B, Tab 2, Schedule 1, Page 5

QUESTION:

The evidence states that the proposed X-factor is higher than the OEB-approved X-factor under standard price Cap Incentive Regulation. How will customers benefit from the X-factor if Toronto Hydro earns back the .6% through the Performance Incentive measure?

RESPONSE:

The proactive component of the X factor is a voluntary contribution by Toronto Hydro reflecting an amount that it ordinarily would be able to recover in rates as a fair return, but which Toronto Hydro has put at risk with the opportunity to earn it back upon the achievement of certain results under the Plan. As shown in Exhibit 1B, Tab 3, Schedule 1 at page 58, achievement of the targets included in the proposed scorecard will result in minimum nominal benefits over the 2025 to 2029 term of between $90.3 million and $216.3 million, with lifetime nominal benefits of $892.5 million to $1.2 billion. The proposed PIM incentive which would be awarded as a result of target achievement is $65 million on a nominal basis. Benefits for customers will exceed costs in the event Toronto Hydro achieves targets and is awarded the full PIM incentive. For a further explanation and illustration of how the PIM balances utility risk/reward and customer costs/benefits, please see the response to 1B-SEC-13.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-27

References: Exhibit 1B, Tab 2, Schedule 1, Page. 7

QUESTION:

Over the 2025-2029 rate period Toronto Hydro's operations and capital investment needs are growing by approximately 37.5% due to a number of distinct and interrelated drivers. Please attribute a percentage to each of those drivers set out in the evidence. For example, how much of the increases are related to inflationary pressures? How much s related to the aging and deterioration of Toronto Hydro's asset base?

RESPONSE:

As noted, the drivers identified on page 7 of Exhibit 1B, Tab 2, Schedule 1 are "interrelated", and thus cannot be broken down as requested. At the reference noted, each driver is accompanied by a footnote directing the reader to the evidence where detailed information, including cost breakdowns as appropriate, about each driver can be found.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-28

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 9

QUESTION:

Toronto Hydro concludes from its Customer Engagement process that 84% of the customers surveyed supported the rate increase associated with the draft plan or one that does even more to advance outcomes. In any of its customer engagement has Toronto told its customers that included in rates is a return on equity that is currently more than 9%. If not, why is this not relevant?

RESPONSE:

The materials provided to customers during customer engagement were focused on customer outcomes, customer priorities, and bill impacts, in a manner that allowed for customers to meaningfully express their priorities and speak to their willingness to pay for such priorities. Given space limitations, it did not make sense to raise topics outside the scope of Toronto Hydro's planning process

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-29

Reference: Exhibit 1B, T2, S1, p. 9

QUESTION:

The evidence states that, "an energy transition is gradually unfolding across key sectors of the economy with residents, businesses and institutions adopting electrified technologies such as electric vehicle (EVs), heat pumps, solar panels and energy storage systems. Toronto Hydro must sustain, expand and modernize the grid to be ready and equipped to serve customers' growing demand for safe and reliable electricity during this transition." Please provide all assumptions Toronto Hydro has made regarding the adoption of EV, heat pumps, solar panels and energy storge systems in its service territory for the 2025-2029. Please specify how this impacts Toronto Hydro's capital and programs in each year and provide the corresponding impact on the revenue requirement in each year.

RESPONSE:

Toronto Hydro's Peak Demand Forecast outlined in Exhibit 2B, Section D4 at page 4 provides the assumptions for the EV forecast. The capital programs that are primarily affected by the System Peak Demand Forecast are (i) Stations Expansion at Exhibit 2B, Section E7.4, and Load Demand at Exhibit 2B, Section E5.3. It is not possible to isolate the specific impact of EVs on the proposed expenditure levels in these programs because the Peak Demand Forecast and underlying investment plan, represents an aggregate view of system need. EV Demand represents just one of a combination of drivers that influence investment levels in various geographic regions of the Toronto Hydro Grid.

Given uncertainty with respect to the uptake of heat pumps, Toronto Hydro did not model heat electrification as an individual driver in its Peak Demand Forecast for this rate period.

Please see the response to 1B-CCC-13 for (i) information about the adoption of DERs, including solar panels (which are captured under renewables) and energy storage systems, and (ii) a list of the affected capital and operations work programs.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-30

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 11

Preamble:

Toronto Hydro commissioned an industry leading consumer choice modelling Future Energy Scenarios study to assess the impacts of different energy transition scenarios on Toronto Hydro's distribution system. The Future Energy Scenarios conclude that system peak demand could grow significantly or more moderately depending on technology, policy and consumers choices that will be made in the future. Toronto Hydro's evidence is that it must ensure the grid is ready ahead of when demand increases (to avoid under-served customers) and also be reasonably cautious in building new capacity for the future. Please explain how this study directly impacted Toronto Hydro's capital and operating plans for the period 2025-2029

RESPONSE:

Toronto Hydro augmented its decision-making process with the results of a Future Energy Scenarios model to understand the impact of different policy, technology and consumer behavior drivers; and used the Future Energy Scenarios to stress-test whether the utility's capacity plan can accommodate energy transition needs (e.g., building heating electrification) in the early part of the next decade, if required. The Future Energy Scenarios reveal that the impact of building electrification in the next two decades could be significant from a system peak demand perspective, but that there are notable differences (driven by policy, technology and consumer-behaviour choices) as to when and how building electrification could unfold. Practically, this meant that Toronto Hydro decided to take a "wait and see approach" to investments in new capacity for accommodating wide-scale building electrification in the mid-2030s and beyond. For more information on Toronto Hydro's capacity planning and electrification process please refer to Exhibit 2B Section D4. For more information on the Future Energy Scenarios, please refer to Appendix A and B of the same schedule.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-31

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 11

The evidence refers to Enbridge Gas Inc's Pathways to Net Zero, National Grid's Future Grid Plan and Eversources' Electric Sector Modernization Plan. Please indicate to what extend these studies has impacted or informed Toronto Hydro's capital and operating plans for the period 2025-2029.

RESPONSE:

These studies did not impact Toronto Hydro's capital and operating plans for the period 2025-2029.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-32

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 24

Please explain why a 0 percent productivity factor continues to be appropriate? How does this provide a benefit to Toronto Hydro's ratepayers.

RESPONSE:

Toronto Hydro continues to rely on the OEB policy with respect to the productivity factor of 0%. The combined X-Factor, inclusive of the productivity factor, the empirical stretch/efficiency-factor and the PIM, applies a 0.75% stretch to the utility's revenues each year over the 2026-2029 period. As detailed in the response to interrogatory 1B-Staff-03(b), the combined X-factor provides customers a total rate reduction benefit of $81.5 million over the rate term, in addition to the benefits associated with achieving the PIM targets, as set out in Exhibit 1B, Tab 3, Schedule 1 at pages 57-58.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-33

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 24

To what extent has Toronto Hydro seen the use of a Revenue Growth Factor (or a similar mechanism) - which enables year over year rate increases to fund incremental revenue requirement to both capital and OM&A investments in other performance based rate plans. Please provide examples and context.

RESPONSE:

Please refer to the expert evidence at Exhibit 1B, Tab 2, Schedule 1, Appendix A at:

- Page 6: Jurisdictions, such as UK and New York, have recognized the need to ensure adequate cost recovery of capital and OM&A costs as part of their forecasted multi-year revenue requirements.
- Page 14: The RGF, which includes forecasted capital and OM&A expenditures is generally consistent with 1) the 'building blocks' approach used in jurisdictions such as the UK, Australia, Philippines, and Malaysia, and 2) the 'stair-step' approach utilized by New York utilities.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-34

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 25

Please explain how Toronto Hydro arrived at a 2% annual inflation factor adjustment for its Revenue Growth factor.

RESPONSE:

Please refer to interrogatory 1B-Staff-92(a).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-35

Reference: Exhibit 1B, Tab 2, Schedule 1, Table 3, Page 25

Table 3 - 2026-2029 Revenue Growth Factor sets out the proposed RGF for each year. Did Toronto Hydro consider smoothing the revenue requirement adjustments over the five-year period? If not why not? Why is the adjustment so much larger in 2028? What would be the downside of having a more consistent adjustment each year?

RESPONSE:

The Revenue Requirement for 2028 is larger than the increases in other years because of PILs/taxes. More specifically, the increase is primarily attributed to the expiration of the accelerated CCA rules on December 31, 2027.[1]

Toronto Hydro considered smoothing the revenue requirement, but ultimately decided not to pursue this option because it was able to achieve the same outcome by adjusting the clearances of Group 2 rate riders.

Smoothing rates through rate riders is the preferred solution for two reasons: (1) it is a familiar approach that has been used in previous applications, and (2) it is less burdensome (i.e. more efficient) to implement from a regulatory accounting perspective because it doesn't require new accounts to be created to reconcile timing-related difference as a result of the advancement/deferral of revenue adjustments needed to enable smoothing.

[1] Exhibit 6, Tab 2, Schedule 1 (Updated December 19, 2023), Page 5

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-36

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 22, Table 4

Please provide the actual Toronto Average Blended Salary Increase for 2023 and the forecast level for 2024.

RESPONSE:

Please see response to interrogatory 1B-Staff-93.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-37

Reference: Exhibit 1B, Tab 2, Schedule 1 p.35

Preamble:

Toronto Hydro is proposing a Demand-Related Variance Account (DRVA) to record the demand driven revenue requirement impacts arising from variances in actual versus forecast capital and operational expenditures for certain demand-based programs and the revenue impacts arising from variances in forecast versus actual billing determinants over the rate period. The Council is interested in understanding the scope of the DRVA;

QUESTION (A):

a) For each year 2020-2024 please provide the forecast and actual expenditures for the following capital and operating programs: Customer Connections, Customer Operations, Stations Expansion, Load Demand, Non-Wires Solutions, Generation Protection Monitoring and Control and Externally-initiated Plant Relocations and Expansions. Also, please provide the forecast and actual revenue requirement that would have been dealt with through the DRVA Expenditure sub-account had one been in place for that period;

RESPONSE (A):

Please see below Table 1 for Actuals/Bridge Capital Expenditures and Table 2 for Actuals/Bridge Operating Expenditures. In responding to this interrogatory Toronto Hydro has only included OM&A segments that would have been dealt with through the DRVA expenditure sub-account had one been in place for that period.

Table 1: Actuals/Bridge Capital Expenditures that would have been subject to the DRVA sub-account (in $ millions)

Programs	Actuals				Bridge
	2020	2021	2022	2023	2024
Customer Connections	35.6	92.4	76.1	86.8	78.2
Stations Expansion	18.2	50.3	47.5	10.4	16.1
Load Demand	24.0	29.7	30.8	26.7	23.2
Non-Wires Solutions[1]	1.0	0.5	0.1	0.0	0.6
Generation Protection Monitoring & Control[1]	0.8	0.8	0.1	0.2	7.8
Externally Initiated Plant Relocations & Expansions	8.7	9.3	12.9	16.0	13.0

Table 2: Actuals/Bridge Operating Expenditures that would have been subject to the DRVA sub-account (in $ millions)

OM&A Segments[2]	Actuals				Bridge
	2020	2021	2022	2023	2024
Customer Connections, Exhibit 4, Tab 2, Schedule 8, Section 5	3.7	1.6	1.6	3.1	3.6
Key Accounts, Exhibit 4, Tab 2, Schedule 8, Section 6	-	0.5	0.8	0.8	1.2
Flexibility Services, Exhibit 2B, Section E7.2	0.4	0.2	0.2	0.8	0.8

Please see Table 3 for approved Capital Expenditures and Table 4 for approved Operating Expenditures that would have been dealt with through the DRVA expenditure sub-account had one been in place for that period.

Table 3: Approved Capital Expenditures that would have been subject to DRVA sub-account (in $ millions)

Programs	Approved				
	2020	2021	2022	2023	2024
Customer Connections	40.1	40.9	41.7	42.6	43.4

[1] 94% of the Renewable Enabling portions of these investments will be provincially funded and not included in the DRVA
[2] Only includes segments associated with the DRVA

Programs	Approved				
	2020	2021	2022	2023	2024
Stations Expansion	19.5	40.0	49.3	12.5	15.2
Load Demand	11.3	11.4	18.5	22.6	23.6
Non-Wires Solutions[3]	1.0	3.7	3.8	1.0	1.0
Generation Protection Monitoring & Control[3]	3.7	2.3	2.4	2.5	2.7
Externally Initiated Plant Relocations & Expansions	11.4	20.8	4.6	4.7	4.5

As noted in Toronto Hydro's response to interrogatory 4-SEC-89(a), the total OM&A cost approved by the OEB for 2020 was $266.7 million, which was lower than the 2020 test year OM&A funding requested by Toronto Hydro.[4] The OEB approved OM&A on an envelope basis and therefore, Toronto Hydro cannot provide a breakdown by the specific programs or segments such as Customer connections. However, in order to provide a directional view of the segments that would have been dealt through the DRVA expenditure sub-account had one been in place for that period, Toronto Hydro has used its 2020 test[5] costs for Customer Connections, Key Accounts and Flexibility Services and have escalated it by the OEB approved Custom Price Cap Index ("CPCI") formula[6] for 2021-2024 using OEB's prescribed rates.

Table 4: Approved* Operating Expenditures that would have been subject to the DRVA sub-account (in $ millions)

OM&A Segments	Approved*				
	2020	2021	2022	2023	2024
Customer Connections	3.2	3.3	3.3	3.4	3.6
Key Accounts	-	-	-	-	-
Flexibility Services	0.8	0.8	0.8	0.9	1.0

[3] 94% of the Renewable Enabling portions of these investments will be provincially funded and not included in the DRVA
[4] See also 1B-SEC-8 for a discussion of adjustments for Account 4380 with respect to the OEB-approved 2020 OM&A budget.
[5] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 8
[6] EB-2018-0165, Ontario Energy Board, Decision and Order (December 19, 2019)

Toronto Hydro is unable to produce the revenue requirement that would have been subject to the sub-account during 2020-2024 within the timelines of providing the IR response, but undertakes to provide the information prior to the Technical Conference.

QUESTION (B):

b) For each year 2025-2029 please provide the proposed revenue requirement for each of the programs listed in a). In effect, what is the proposed revenue requirement that will be the subject of the DRVA Expenditure Variance sub-account?

RESPONSE (B):

Please see below table 5 for proposed revenue requirement for each of the programs:

Table 5: 2025-2029 Revenue Requirement associated with DRVA Programs (in $ millions)[7]

	2025	**2026**	**2027**	**2028**	**2029**
Customer Connections	9.7	16.4	23.8	33.0	40.8
Stations Expansion	0.3	2.2	3.6	4.1	4.3
Load Demand	2.5	5.2	8.4	12.0	15.2
Non-Wires Solutions	0.2	0.9	1.1	1.6	1.9
Generation Protection Monitoring & Control	0.0	0.0	0.1	0.1	0.2
Externally Initiated Plant Relocations & Expansions	4.6	5.3	6.5	7.9	9.0
Customer Operations	4.7	4.8	5.2	5.4	5.7
Total Revenue Requirement	**22.0**	**34.8**	**48.5**	**64.1**	**77.1**

QUESTION (C):

c) For the period 2020-2024 please provide the forecast and actual revenue that would have been dealt with through the DRVA Variance sub-account had one been in place for that period

[7] Rounding variances may exist

RESPONSE (C):

Please refer to 1B-SEC-16 -Table 2.

QUESTION (D):

d) For each year 2025-2029 please provide the forecast revenue that will be the subject of the DRVA Revenue Variance sub-account.

RESPONSE (D):

Please refer to 1B-SEC-16-Table 1.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-38

Reference: Exhibit 1B, Tab 3, Schedule 1, Pages 2-6

Toronto Hydro's position is that the Performance Incentive Mechanism (PIM) provides ratepayers a significant $65 million upfront benefit and shifts risk to the utility for delivering key outcomes that matter to customers;

QUESTION (A):

a) Please provide examples of such an approach being adopted by other utilities;

RESPONSE (A):

Toronto Hydro's expert Scott Madden provides examples of performance incentives adopted in other jurisdictions, with all associated details and references, in Exhibit 1B, Tab 2, Schedule 1, Appendix B. Jurisdictions where such incentives have been implemented include UK, Hawaii, Rhode Island, and New York.[1]

QUESTION (B):

b) How did Toronto Hydro arrive at the .6%?

RESPONSE (B):

Please Toronto Hydro's response to 1B-VECC-3.

QUESTION (C):

c) Please explain how the $65 million was calculated.

RESPONSE (C):

Please see Toronto Hydro's response to 1B-Staff-3 (c).

QUESTION (D):

d) Please provide evidence to demonstrate that the targets established for each metric reflect, challenging, but achievable outcomes;

RESPONSE (D):

The requested evidence is provided Exhibit 1B, Tab 3, Schedule 1. In section 2 of that narrative, from pages 8-56, Toronto Hydro provides a detailed explanation of each metric including historical results (where available), the rationale for featuring the metric on the Custom Scorecard and for adopting the proposed target, and a summary of the key investments in the plan that enable the utility to achieve the targets.

QUESTION (E):

e) Toronto Hydro has proposed a process whereby the finalization of the targets takes place in a second phase of this proceeding that can be run in parallel with the Draft Rate order process. If agreement cannot be reached through the "settlement-like process" parties would have an opportunity to make submissions to the OEB. Would Toronto Hydro support a discovery stage as part of this process? If not, why not?

RESPONSE (E):

At this stage, Toronto Hydro is unable to assess if and to what extent a further discovery stage would provide value to the process. Toronto Hydro trusts that if a phase 2 is granted, the OEB will contemplate the procedural steps necessary based on the specifics known at that time, and the parties will have the opportunity to make submissions in that regard.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-39

Reference: Exhibit 1B, Tab 3, Schedule 3, Page. 15

QUESTION :

Toronto Hydro has set out 2020-2024 “Productivity Achievements”. The evidences states that in total, over the current rate period the utility implemented over 30 distinct productivity initiatives which yield material benefits for ratepayers. These benefits include over $23 million in costs that the utility expects to avoid or reduce by the end of the rate term, resulting in a 2025 rebasing revenue requirement that is approximately $5.7 million lower. Please provide a table setting out each of these initiatives and the associated cost avoidance/benefits where these can be quantified. Please reconcile these amounts with the $23 million and the $5.7 million. Please include all assumptions.

RESPONSE:

Please see Toronto Hydro’s response to 1B-AMPCO-07.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-40

Reference: Exhibit 1B, Tab 3, Schedule 3, Page 15

Toronto Hydro has set out its Productivity Achievements for the period 2020-2024. Please provide a complete list of productivity initiatives planned for 2025-2029. Please set out the expected annual savings for each initiative.

RESPONSE:

Please see Toronto Hydro's response to interrogatory 1B-SEC-25.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-41

Reference: Exhibit 1B, Tab 4, Schedule 1, Page 6

In 2022 Toronto Hydro launched the Etobicoke Demand Response Pilot in Partnership with Power Advisory LLC and Toronto Metropolitan University Centre for Urban Energy. What was the overall cost of the pilot and how was it funded? Are there any costs associated with the pilot in 2025? If so, what are the costs?

RESPONSE:

Please see the evidence in Exhibit 2B, Section E7.2 at pages 12-13 for information about the Etobicoke Demand Response pilot. Please see the response to interrogatory 1B-CCC-42 for information about the cost of the pilot and how it was funded. There are no costs associated with this pilot beyond 2025.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-42

Reference: Exhibit 1B, Tab 4, Schedule 1, Pages 1-12

QUESTION:

Tonto Hydro has set out strategies and initiatives undertaken by Toronto Hydro during the 2020-2024 period. These include:

- Innovation @TH
- System Observability: Network Condition Monitoring and Control (NCMC)
- System Controllability: Reclosers Pilot
- Etobicoke Demand Response Pilot
- Battery Energy Storage Systems
- Future Energy Scenarios Modelling Tool
- Electric vehicles (EV) Demand Response
- Process Automation
- Customer Experience and Service Tools
- Workforce Development and Upskilling

For each of these strategies/initiatives/pilots please provide the following:

a) The cost of each and how it was funded (through rates, other sources of funding etc.)
b) An indication as to whether the strategy, initiative/pilot costs were forecast and if so, what the forecast costs were
c) An indication as to whether the strategies/initiatives/pilots will continue and if so, the expected annual cost
d) The cost reductions associated with these strategies/initiatives/pilots and whether those cost savings have been embedded in the rate plan forecasts.

RESPONSE:

Appendix A to this response includes a table with a breakdown of the initiatives by rate period. With respect to question (d), quantified efficiency benefits (i.e. cost reductions or avoidances) are provided below for the initiatives where it is possible to quantify this information. Toronto Hydro confirms that material cost reductions are embedded in the forecasts, where appropriate.

- **Etobicoke Demand Response Pilot**
    - **2020-2024:** Please see Exhibit 2B, Section E7.2.1.4 and Toronto Hydro's response to interrogatory 2B-SEC-73.
    - **2025-2029**: Please see Exhibit 1B, Tab 3, Schedule 1 at pages 51 to 52 and the response to 1B-Staff-49 for a quantification of benefits associated with Toronto Hydro's target to procure 30MW on non-wires system capacity through its Flexibility Services program as described in Exhibit 2B, Section E7.2.
- **System Observability: Network Condition Monitoring and Control ("NCMC"**)
    - **2020-2024:** Please see the evidence in Exhibit 2B Section E7.3.3 for details on benefits and cost savings seen to date as part of the NCMC program.
    - **2025-2029**: Please see the evidence in Exhibit 2B Section E7.3.3 for details on benefits and cost savings forecasted as part of the NCMC program. As a result of the implementation of NCMC, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs in that program by approximately $300 per vault starting in 2027. At the end of the NCMC program (i.e. once all vaults are commissioned), this will result in approximately $275,000 in maintenance costs avoided each year. These costs savings are reflected in the Preventative and Predictive Underground Line Maintenance program outlined in Exhibit 4, Tab 2, Schedule 2.
- **System Controllability: Reclosers Pilot**
    - **2020-2024:** The goal of the reclosers pilot was to confirm intended coordination and reliability benefits that Toronto Hydro could achieve with the piloted recloser

technologies. As the primary driver is reliability improvements, there are no specific cost reduction planned as part of the reclosers pilot.

- **2025-2029**: Although Toronto Hydro expects to continue pilots for specific recloser technologies, reclosers that have completed the pilot phase are included in the System Enhancements program.[1] As with the pilots, the reclosers planned as part of this program are driven by reliability and are intended to support Toronto Hydro's improvement target for outage duration.[2] Please refer to Toronto Hydro's response to 2B-Staff-246(a) for an estimation of economic benefits associated with the reduction of "customer minutes out" in the 2025-2029 rate period under the proposed Contingency Enhancement Program.

- **Process Automation**
  - **2020-2024** : Please see Exhibit 1B, Tab 3, Schedule 3 for evidence relating to productivity initiatives undertaken in the current rate period, many of which are tied to process automation. Please refer to Toronto Hydro's response to interrogatory 1B-AMPCO-7 for the quantified benefits per initiative.
  - **2025-2029:** Please refer to the evidence Exhibit 1B, Tab 3, Schedule 1, subsection 2.4.1 "Efficiency Achievements" at pages 41-44. As noted in the response to interrogatory 1B-SEC-25, Toronto Hydro intends to continue to focus on process automation (i.e. digitization, robotics and predictive analytics) to drive continuous improvement in productivity and to meet the proposed Efficiency Achievements target in the next rate period.
- **Customer Experience:**
  - **2020-2024**: Please refer to the evidence Exhibit 4, Tab 2, Schedule 14, subsection 4.2 "Cost Control and Productivity Measures" at pages 11-14, which discusses numerous achievements that improved customer experience and convenience through enhancements to online and self-service tools, while generating significant process

[1] Exhibit 2B, Section E7.1.
[2] Exhibit 1B, Tab 3, Schedule 1, at p. 8-15.

efficiencies and cost avoidance through the automation of manual processes and streamlining operational tasks.

- **2025-2029**: Please refer to evidence on the Customer Relationship Management segment of the Customer Care program in Exhibit 4, Tab 2, Schedule 14 at pages 34-46 (especially pages 39-41) and the Key Accounts segment of the Customer Operations program in Exhibit 4, Tab 2, Schedule 8 at pages 22-27. Through the adoption of modern technology and continuous engagement with its diverse customer base, including the unique needs of key accounts (e.g. hospitals, public service providers, and large users) Toronto Hydro intends to continue delivering strong customer service and drive continuous improvement in meeting customers' evolving expectations.

Initiative	2020-2024 Costs	Funding Source	Continuation	2025-2029 Costs
Innovation @ TH	Approximately $750,000	Self-Funded	Yes. Please see Exhibit 1B, Tab 2, Schedule 2	$16M[1]
System Observability: Network Condition Monitoring and Control (NCMC)	$56.8M	Rates	Yes. please see Exhibit 2B, Section 7.3	$6M
System Controllability: Reclosers	$19.9M	Rates	Yes. Please see Exhibit 2B, Section E7.1	$132M
Etobicoke Demand Response Pilot	$4M	Rates ($2M) + IESO Grid Innovation Fund ($2M)	Yes. Please see Exhibit 2B, Section E7.2	$5.7M
Future Energy Scenarios Modelling Tool	$1.026M[2]	Rates	Yes. Please see Exhibit 2B, Section D5.	$72,000
Workforce Development & Upskilling	Not possible to quantify as these costs are embedded in program budgets.	Rates	Yes. Please see the OM&A and Workforce evidence in Exhibit 4, Tabs 1, 2 and 4.	Not possible to quantify as these costs are embedded in program budgets.

[1] Toronto Hydro is proposing to allocate the equivalent of 0.3% of its total revenue requirement to the Innovation Fund, which is approximately $16 million based on the pre-filed revenue requirement. For more information on the Innovation Fund proposal, please refer to Exhibit 1B, Tab 4, Schedule 2.
[2] Please refer to Toronto Hydro's response to interrogatory 2B-Staff-156 part (c).

Initiative	2020-2024 Costs	Funding Source	Continuation	2025-2029 Costs
EV Demand Response	$287,000	Rates	Yes. Please see Exhibit 1B, Tab 4, Schedule 2, Appendix A.	n/a[3]
Process Automation	$32M	Rates	Yes. Please see Exhibit 2B, Section 8.4 and Exhibit 4, Tab 2, Schedule 17.	$50M[4]
Customer Experience	$28.5M	Rates		$25M[5]

[3] Pilot projects as part of the Innovation Fund will be scoped-out (i.e. designed and budgeted) once the OEB has approved the proposal. For more information on the Innovation Fund proposal, please refer to Exhibit 1B, Schedule 4, Tab 2.
[4] This is a high level estimate and may change since Toronto Hydro will assess and evaluate each individual project through its Enterprise Technology Portfolio (ETP) Framework as described in the IT Investment Strategy at Exhibit 2B, Section D8.5.3, pp. 18-21
[5] *Ibid.*

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-43

Reference: Exhibit 1B, Tab 4, Schedule 1, Pages 13-20

Preamble: Toronto Hydro has stated that Innovation has shaped its Application and the 2025-2029 investment plan that underpins it. The Council would like have a better understanding of the costs included in the Application that are related to "innovation" over and above the "Innovation Fund". Toronto Hydro refers to several innovation initiatives:

- Grid Modernization Strategy
- Local Demand Response
- Renewable Enabling Investments
- Enterprise Technology Portfolio
- Regulatory Innovation

For each of these initiatives provide the following:

QUESTION (A):

a) The annual cost of these initiatives for each year of the plan

RESPONSE (A):

Please see the summary table below for a list of the programs that map to each of the referenced initiatives with evidentiary references and a breakdown of the related annual costs.

For the Grid Modernization Strategy, this is an overarching framework that encompasses many programs and initiatives throughout the application as set out in Exhibit 2B, Section D5. As described in interrogatory 1B-CCC-44, the overall cost of this strategy is estimated to be in the range of $550-$600 million over the 2025-2029 period, representing an average annual spend of

$110-$120 million. This amount includes some of the expenditures listed in other parts of the following table.

Toronto Hydro notes that the costs reproduced below are the costs related to the program/segment overall, which in some cases include costs beyond the scope of "innovation" where it isn't possible to disaggregate innovation-specific costs from other cost drivers in the program.

Table 1: Innovation-Related Programs 2025-2029

Initiative	Relevant Programs	Annual Costs ($ Millions)				
		2025	2026	2027	2028	2029
Grid Modernization Strategy [1]	**See Exhibit 2B, Section D5** Relevant Programs include: • **System Enhancements** (2B, E7.1) • **Metering (AMI2.0)** (2B, E5.4) • **Asset & Program Management – System Planning** (4, T2, S9) • **Control Center** (4, T2, S7) • **Network Condition Monitoring and Control** (2B, E7.3)	110.0 - 120.0	110.0 - 120.0	110.0 - 120.0	110.0 - 120.0	110.0 - 120.0
Enterprise Technology Portfolio	**IT Software Enhancements** (2B, E8.4)	38.6	40.6	41.0	33.3	34.8
	IT OM&A (Cloud) (2B-Staff-263)	5	5.5	6	6.5	7
Renewable Enabling Investments[2]	**Network Condition Monitoring and Control** (2B, E7.3)	4.2	0.2	0.4	0.6	0.6
	Energy Storage (2B, E7.2)	3.6	3.6	7.5	3.8	4.0
	Station Expansion – Sheppard TS (2B, E7.4)	-	0.5	4.5	5.0	5.0
Local Demand Response	**Non-Wires Solution** (2B, E7.2) **Asset and Program Management – Local Demand Response** (4, T2, S9)	0.2	0.9	1.1	1.6	1.9
Regulatory Innovation	**Innovation Fund** (1B, T5, S2)	2.9	3.1	3.2	3.5	3.6

[1] Average annual costs. All IT Software related investments that support Grid Modernization are included within the Enterprise Technology Portfolio.
[2] Please see Exhibit 2A, Tab 5, Schedule 1

QUESTION (B):

b) The annual benefit expected and information on the extent to which the benefits are factored into the revenue requirement for each year.

RESPONSE (B):

The table below provide a concordance to the evidence where benefits associated with the initiatives are presented. Specific projects under these initiatives and related programs will be scoped through annual planning processes as part of the execution of the 2025-2029 Investment Plan and implementation of the OEB's decision in this rate application.

Table 2: Innovation-Related Program Benefits

Initiatives	Programs	Benefits
Enterprise Technology Portfolio	**IT Software** (Exhibit 2B, E8.4)	Toronto Hydro intends to leverage technology to achieve various performance targets and benefits as outlined in the 2025-2029 Custom Scorecard at Exhibit 1B, Tab 3, Schedule 1.
	IT OM&A (Cloud) (2B-Staff-263)	
Grid Modernization Strategy	**System Enhancements** (Exhibit 2B, Section E7.1)	Please see Exhibit 2B, Section D5, page 17 for the estimated lifetime operational cost savings from the deployment of SCADA switches.
		Please see the response to 2B-Staff-246 for quantified reliability benefits. Toronto Hydro also integrated the reliability benefits associated with new SCADA switches and mid-line reclosers as part of its Reliability Projection ("RP") Methodology. A detailed description of this methodology is available in 2B-SEC-42 a) and a forecast of reliability performance for 2025-2029 is available in 2B-SEC 42 c). In addition, Toronto Hydro estimated the benefits of the implementation of FLISR across the Horseshoe region based on preliminary network simulations. Please see the quantification of anticipated improvements in 2B-Staff-162 a).
Local Demand Response	**Non-Wires Solutions**	Please see the Non-Wires Solutions metric and target in Exhibit 1B, Tab 3, Schedule 1 at page 66.

QUESTION (C):

c) An indication as to whether or not external funding was sought and/or obtained either through the OEB, IESO or NRCan

RESPONSE (C):

Please see Toronto Hydro's response to 1B-Staff-10 for list of the types of initiatives/projects that Toronto Hydro has previously sought external funding for. Toronto Hydro notes that opportunities for external funding for the next rate period must be determined on the basis of specific projects, which will be scoped through annual planning processes as part of the execution of the 2025-2029 Investment Plan and implementation of the OEB's decision in this rate application.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-44

Reference: Exhibit 1B, Tab 4, Schedule 1, Page 12

Toronto Hydro is undertaking a Grid Modernization strategy to make investments it deems necessary to ready the grid for decarbonization and energy transformation while enhancing the value that the system provides to customers through improved reliability, resilience and efficiency outcomes:

QUESTION (A):

a) What is the overall cost of this strategy and the annual costs for each year of the rate plan term?

RESPONSE (A):

The overall cost associated with the programs and initiatives that map to the Grid Modernization Strategy is estimated to be in the range of $550-$600 million over the 2025-2029 period. This includes the investments and capability building initiatives described throughout Section D5. Note that while modernization is an element of many of the investment programs discussed under the Grid Modernization Strategy, it is not the sole purpose of the programs. The same costs are responsive to other drivers, for example, failure risk and compliance (e.g., renewal of smart meters under AMI 2.0) and capacity (e.g., flexibility services).

QUESTION (B):

b) Are the ADMS, OMS and FLISR systems considered part of the Grid Modernization strategy and the overall business case?

RESPONSE (B):

Yes. All three initiatives are enabled by the broader ADMS project as described in Exhibit 2B, E8.4, Appendix A.

QUESTION (C):

c) Please explain, in detail, the extent to which Toronto Hydro collaborated with other utilities in terms of developing its Grid Modernization strategy. For example, both PUC Distribution Inc. and Elexicon Energy Inc. have undertaken similar projects. Has Toronto Hydro consulted with either PUC Distribution Inc. or Elexicon regarding their projects. If not, why not?

RESPONSE (C):

Toronto Hydro did not consult with the specified utilities in the development of the 2025-2029 Grid Modernization Strategy. However, as discussed in Exhibit 2B, Section D5.1.1, the strategy is informed by Toronto Hydro's extensive first-hand knowledge of the sector and the successes and leading examples of peer utilities in various progressive jurisdictions. Toronto Hydro regularly engages with industry peers on strategic and operational subjects, including through direct, informal engagement, as well as through engagements facilitated by consultants, industry groups and associations.

The Grid Modernization Strategy is also based on Toronto Hydro's extensive knowledge of the unique challenges and opportunities for its own system and operations. As further outlined in D5.1.1, Toronto Hydro has developed a grid modernization strategy which addresses emerging challenges and opportunities in a manner that leans first and foremost into the deployment of proven technologies (e.g., reclosers, switches, smart meters, analytics). From a materiality perspective, most of these investments are a continuation or renewal of programs that Toronto Hydro has been rolling-out at a gradual pace over the last two decades (e.g., remote-operable switches; smart meters), while others (e.g., achieving "self-healing" grid operations) represent the culmination of transformational efforts that have been a part of the utility's long-term modernization roadmap for many years.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-45

Reference: Exhibit 1B, Tab 4, Schedule 1, Pages 15-16

Please provide the overall cost of the nine energy storage systems being put into place to enable the connection of forecasted renewable growth on nine high priority feeders. What is the definition of a "high priority feeder"? Are these being put in place primarily to enable the connection of renewable DER facilities? If so, how are they funded (through rates generally or by the owners of DER facilities)?

RESPONSE:

As described in Exhibit 2B, Section 7.2.2, over the 2025-2029 period, Toronto Hydro plans to invest $22.5 million to deploy nine Energy Storage Systems (ESS) with an aggregated capacity of 10.2MW on nine distribution feeders. These ESS installations are intended for renewable enablement, correcting destabilized grid parameters than can result from high amounts of generation on one feeder.[1] ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio (MLGR). "High-priority feeders" are feeders that exceed optimal MLGRs, as defined in IEEE Standard P1547.2/D6.5 and National Renewable Energy Laboratory's High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook).

Toronto Hydro confirms that its ESS program targets the enablement of REG connections and does not contemplate additional use cases to support the distribution system. As such, the utility is seeking treatment of these costs as eligible investments for provincial rate recovery under section

[1] Seguin, R., Woyak, J., Costyk, D., Hambrick, J., & Mather, B. (2016). (tech.). High-Penetration PV Integration Handbook for Distribution Engineers (pp. 4–26). Oak Ridge, Tennessee: Office of Scientific and Technical Information.

79.1 of the *Ontario Energy Board Act, 1998.*[2] For further details, please refer to Exhibit 2A, Tab 5, Schedule 1 (updated January 29, 2024).

[2] Cost Recovery re Section 79.1 of the Act, O. Reg. 330/09, at s. 1(2).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-46

Reference: Exhibit 1B, Tab 4, Schedule 2

Toronto Hydro is proposing an Innovation Fund to support the design and execution of innovation pilot projects over the 2025-2029 rate period. The pilot projects undertaken through the Innovation Fund would be focussed on testing new technologies, advanced capabilities and alternative strategies that enable electrification grid readiness and are responsive to the OEB's expectations with respect to facilitation DER integration, as expressed in the Framework for Energy Innovation. The fund amounts to approximately $16 million over the 2025-2029 rate period:

QUESTION (A):

a) Please explain, in detail, the extent to which Toronto Hydro intends to collaborate with other utilities regarding its innovation Fund pilots;

RESPONSE (A):

As indicated in the description of the Governance Framework for the Innovation Fund at page 10 of Exhibit 1B, Tab 4, Schedule 2 , Toronto Hydro would engage with external stakeholders to inform the pilot project selection process, including other utilities as relevant. In these engagements, Toronto Hydro would canvass ideas and solutions that are being considered in the sector to help gain a better understanding of pilot projects that may be technically feasible and advisable. This feedback would be used as input into the pilot selection process, the output of which will identify the selected projects and key details about the projects, including the rationale for selecting them. Furthermore, and as noted on page 16 of the referenced evidence, in order to contribute to broader knowledge sharing with the electricity sector, Toronto Hydro intends to share its pilot project learnings with the OEB Innovation Sandbox team, so it can then be shared with industry stakeholders that include other Ontario utilities.

QUESTION (B):

b) With respect to the pilots that may prove to be less fruitful than others will ratepayers be responsible for the costs of those pilots? If so, why?

RESPONSE (B):

Toronto Hydro is requesting funding for the Innovation Fund which is purposefully not conditional on the ultimate degree of success for individual pilot projects. Inherent in the pursuit of innovative solutions, which Toronto Hydro is doing consistent with provincial and OEB policy objectives, is the risk that some efforts will be more or less successful than others, but also the understanding that there is value in the learning that comes from the efforts regardless of the outcome. Furthermore, if funding were to be conditional on the outcome of efforts to innovate, this could have a chilling effect on the pursuit of innovative solutions and is likely to encourage spending on projects that are mature, or where the beneficial outcomes are more proven or certain. These are the very aspects that the proposed Innovation Fund is designed to overcome.

QUESTION (C):

c) What specific type of projects will be prioritized?

RESPONSE (C):

The prioritization of pilot projects takes place at two stages of the Governance Framework, namely: (i) the application of defined characteristics to determine specific areas for innovation (at the conceptual level), and (ii) the pilot selection phase (at the scoping level).

As described in the referenced evidence at pages 6-8, Toronto Hydro has identified certain characteristics for the pilot projects that will be supported by the Innovation Fund. Those characteristics include that the projects will explore distribution capabilities associated with adapting to fundamental change in the energy sector, as identified in or related to certain expectations of the OEB set out in the FEI report, and the projects will have the potential to deploy solutions that are innovative because they use new technology or existing technology in new ways, they involve innovative business practices and relationships, or they involve enhancing distribution services in ways that benefit customers.

In parallel, through its Grid Modernization Strategy, Toronto Hydro identified certain high-potential areas of innovation that present tangible opportunities to begin designing and executing projects rather than undertaking a “blank page” ideation phase. Toronto Hydro assessed these areas of innovation for the characteristics mentioned above and concluded that they are aligned with these characteristics (Exhibit 2B, Schedule D5).

The pilot project concepts identified for the 2025-2029 rate period, which would involve testing new distribution capabilities by deploying pilot projects that have the potential to be scaled up into standard capital or operational work programs, are: (a) Flexible Connections, (b) Electric Vehicle Commercial Fleet Charging, (c) EV Demand Response, and (d) Advanced Microgrids. Further details about how each of the pilot project concepts meets the defined characteristics are set out in Appendix A of the referenced evidence.

Individual projects will be selected and scoped out during the Pilot Selection and Design Phases of the Governance Framework (Section 4.1). In these Phases, the Innovation Fund team will prioritize projects that have potential business value, execution feasibility, opportunity for scalability, and opportunity to leverage external funding. The Pilot Selection phase will also be informed by external stakeholder engagement, as further described in Exhibit 1B, Tab 4, Schedule 2.

QUESTION (D):

d) Does Toronto Hydro expect there to be a prudence review of the costs and benefits of the pilots it plans to undertake? If not, why not?

RESPONSE (D):

No. As explained in the rationale for the Innovation Fund at pages 2-6 of the referenced evidence, the Innovation Fund has been designed to overcome certain challenges that act as barriers to innovation for regulated distributors. These challenges include having to demonstrate, in rate applications, the prudency of innovation-driven pilot projects on the basis of costs and benefits which are not always certain at the outset, and which projects are early stage, exploratory and/or developmental in nature. To overcome this obstacle, Toronto Hydro is requesting approval of the Innovation Fund proposal effectively on the basis of the rigorous internal Governance Framework that will be used to ensure the associated funds are prudently deployed. Additionally, the proposal includes a variance account to track Toronto Hydro’s expenditures, which will return any unspent funding back to ratepayers. See Proposed Rate Treatment (Section 5) of the referenced evidence, and Exhibit 9, Tab 1, Schedule 1 for more information on the proposed Innovation Fund Variance Account (IFVA).

QUESTION (E):

e) What type of reporting will Toronto Hydro undertake regarding the pilots that will be funded through its Innovation Fund?

RESPONSE (E):

At pages 8-16 of the referenced evidence, the Governance Framework for the proposed Innovation Fund refers to three types of reports that will be produced, for different purposes, including the pilot selection report, milestone reports, and the pilot evaluation and learnings report. The pilot selection report will identify the selection of projects and key details about the projects, including the rationale for selecting them. The milestone reports will be produced throughout the lifecycle of each project and are intended for internal management purposes to monitor progress and expenditures. Lastly, the pilot evaluation and learnings report is intended to capture the learnings, reflecting on the achievement of desired outcomes, including learning objectives, that are set at the outset of each pilot project during the design phase of the Governance Framework. Crucially, this report will assess and determine the future of each pilot project as described in Section 4.2 (Pilot Execution & Evaluation Phases) of Exhibit 1B, Tab 4, Schedule 2. The pilot evaluation and learning report will be shared with the OEB’s Innovation Sandbox, and the key takeaway from this report could then be shared with industry stakeholders.

QUESTION (F):

f) Please provide copies of all of the research Toronto Hydro undertook to inform the level of funding requested;

RESPONSE (F):

Please see Toronto Hydro's response to interrogatory 1B-DRC-06 part d).

QUESTION (G):

g) Please explain how the $16 million will be recovered over the rate plan term.

RESPONSE (G):

As stated in the Innovation Fund evidence at pages 16-17, Toronto Hydro proposes to recover the funds through an Innovation Fund rate rider. For more details on the rate rider, please refer to Toronto Hydro's response to interrogatory 9-Staff-342 part a).

In addition, Toronto Hydro proposes to establish a new variance account, the Innovation Fund Variance Account, to record variances between amounts collected by the rate rider and amounts actually deployed for and used in carrying out pilot projects.
More information on the Innovation Fund Variance Account can be found in Exhibit 9, Tab 1, Schedule 1, and on the Innovation Fund rate rider in Exhibit 9, Tab 3, Schedule 1.

QUESTION (H):

h) Does $16 million represent a cap? Is it comprised of both capital and OM&A costs?

RESPONSE (H):

The $16 million does not represent a cap. As explained in the Innovation Fund evidence, the proposed Innovation Fund reflects a level of investment identified based on comparative jurisdictional research. This amount represents approximately 0.3% of the 2025-2029 revenue requirement outlined in Exhibit 6, and reflects the low end of the range of utility investment in comparable innovation and research and development activities, with average utility spending at 0.5% to 1% of revenue. As part of the Innovation Fund proposal, Toronto Hydro proposed a *symmetrical* variance account to track actual revenue requirement (whether capital or OM&A related) against the forecasted amount that will be recovered through the Innovation Fund rate rider. Toronto Hydro intends to clear the balance in the variance account in its next rebasing application.

QUESTION (I):

i) When does Toronto Hydro expect to have its work plan for designing and implementing the selected pilot(s) completed?

RESPONSE (I):

As stated in the evidence at page 11, the completion of the work plan is marked by approval of the steering committee. Before this can happen, the pilot project owners need to compile pilot project scopes (including outcomes and milestones), budgets, and work plans for managing the process. These activities occur in the second phase of the internal Governance Framework – the design phase. It is Toronto Hydro's intention to begin undertaking the activities described in the Governance Framework, beginning with the pilot selection phase, after the OEB renders its Decision and Rate Order for the 2025-2029 Custom Rate Application. Once the pilot selection phase has been completed, Toronto Hydro will proceed with the pilot design phase. Given that pilot projects may require multiple years of testing, Toronto Hydro will endeavour to complete the design phase within the first 18 months of the rate period.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-47

Reference: Exhibit 1B, Tab 4, Schedule 2, Appendix B - NRCan letter

QUESTION:

Did Toronto Hydro seek funding from NRCan for its Innovation Fund? If not, why not? Does it expect to do so in the future? If not, why not?

RESPONSE:

As stated in the Innovation Fund evidence, Toronto Hydro intends to apply for NRCan funding to support Innovation Fund pilot projects if and when they are eligible under NRCan program rules. In January 2024, Toronto Hydro submitted an Expression of Interest to NRCan's Smart Grid Demonstration program. The EOI included submissions on two projects to be considered for funding through NRCan's Smart Grid Demonstration program. One of the projects submitted is included in the Innovation Fund. The NRCan program could provide funding for other potential pilots projects under the EV Commercial Fleet Charging or EV Demand Response areas of innovation. For a complete list of external funding that Toronto Hydro has applied for in the last few years, please see Toronto Hydro's response to interrogatory 1B-Staff-10. The referenced NRCan letter is the result of Toronto Hydro's engagement with NRCan in connection with the Innovation Fund proposal. In response, NRCan shared with Toronto Hydro the referenced letter.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-48

Reference: Exhibit 1B, Tab 5, Schedule 1, Page 4

With respect to customer engagement Toronto Hydro undertook a two-phased approach to inform its rate Application. First, prior to embarking on the business and investment planning process, it obtained a "genuine" understanding of its customers' needs and priorities and used this feedback to set strategic direction for the investment priorities of it plan. Second, after the 2025-2029 draft plan was prepared Toronto Hydro went back to its customers to obtain feedback on the draft plan. The utility considered this feedback in refining and finalizing its plan.

QUESTION (A):

a) If customers' top priorities are price and reliability, what has Toronto Hydro done to address the pricing issue in any significant way?

RESPONSE (A):

As noted in the evidence in Exhibit 2B, Section E2.1 finding balance between price and progress towards outcomes that customer expect was a key focus throughout Toronto Hydro's integrated planning process. To achieve this balance, Toronto Hydro constrained its initial capital plan by approximately $480 million from the beginning to the end of the process. Similarly, the OM&A plan detailed in Exhibit 4 was also constrained by approximately $40 million through the course of the planning process. This was primarily achieved through the iterative review of the workforce plan as described in the response to interrogatory 4-CCC-58(d). Finally, price was also a consideration in the Performance Incentive Mechanism (PIM) described in Exhibit 1B, Tab 3, Schedule 1, which provides customers an upfront rate reduction benefit of approximately $65 million over the rate term by shifting financial risk to the utility for delivering performance outcomes that customers value.

QUESTION (B):

b) Toronto Hydro states that "…on average 84% of customers surveyed supported the draft plan and the associated rate impacts." Were customers given the 7.5% annual distribution rate impact numbers? If not, why not? Does imply that they support annual increases in the revenue requirement as proposed?

RESPONSE (B):

Please see the response to interrogatory 1B-Staff-39(b). Toronto Hydro would like to clarify that the proposed average annual distribution rate impact is 7%.

QUESTION (C):

c) What specific changes did Toronto make to its investment plan in Phase 2. How did Toronto Hydro decide on a $70 million reduction to its overall plan?

RESPONSE (C):

As noted in the timeline provided in the response to interrogatory 2B-SEC-32, the last step in Toronto Hydro' integrated business planning process is the refinement and finalization of the plan based on the results of the Phase 2 engagement. The evidence in Exhibit 2B, Section E2 at pages 9-11 describes the changes that Toronto Hydro made to the plan in more detail. Please also refer to Toronto Hydro's response to interrogatory 2B-SEC-54 for a breakdown by program of the changes which were made to the draft capital plan in the last step of the process.

QUESTION (D):

d) What is the revenue requirement impact for each year and the rate impact each year for residential customers of reducing the overall capital plan by $70 million?

RESPONSE (D):

Please see Table 1 and Table 2 below for revenue requirement reduction and residential rate impact respectively for each year as a result of reducing the overall capital plan by $70 million.

Table 1: Revenue Requirement Change – CE Phase 2 Refinements to the Final Plan (in $ millions)

	2025	2026	2027	2028	2029	2025-2029
Revenue Requirement	(0.3)	(0.7)	(1.3)	(2.0)	(3.0)	(7.3)

Table 2: % Residential Customer Rate Impacts associated with CE Phase 2 Refinements to the Final Plan

	2025	2026	2027	2028	2029	2025-2029
Residential Rate Impact %	0.0%	(0.1%)	(0.1%)	0.0%	(0.1%)	(0.1%)

QUESTION (E):

e) Please define “social permission”;

RESPONSE (E) – PREPARED BY INNOVATIVE:

“Social permission”, as it relates to this application, is defined in Toronto Hydro’s Customer Engagement Executive Summary, which is filed at Exhibit 1B, Tab 5, Schedule 1, App A at page 1. That definition is provided below:

Social permission is the percentage of customers who responded to Toronto Hydro’s draft plan by indicating either: (1) they think Toronto Hydro should accelerate spending beyond the level in the draft plan to deliver better system outcomes, (2) they support the proposed rate increase that is reflected in the draft plan, or (3) they feel that the proposed rate increase in the draft plan is necessary, even though they don’t like the proposed increase.

QUESTION (F):

Did Innovative discuss the Performance Incentive Mechanism as part of the customer engagement process? Were customers told Toronto Hydro would have an opportunity to “earn back” the $65 million?

RESPONSE (F):

No. The 2025-2029 Custom Scorecard and associated Performance Incentive Mechanism (PIM) was developed after Phase 2 Customer Engagement. Toronto Hydro had to finalize its plan, including making adjustments based on the results of Phase 2, in order to confirm the $65 million incentive and the scorecard measures and targets.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-49

Reference: Exhibit 1B, Tab 5, Schedule 1, Page 13

Preamble:

Toronto Hydro undertook application-specific customer engagement through Innovative Research. In addition, Toronto Hydro states that ongoing customer and stakeholder engagement activities occur in the normal course of business as part of Toronto Hydro's robust and sophisticated customer research and response model.

QUESTION (A):

a) What is expected to be the overall cost of the Innovative Research work specific to this Application? Please provide a detailed breakdown;

RESPONSE (A):

Please see table 1 below:

Table 1: Innovative Project Phase Costs

Phase	Costs (before HST)
Phase 1	$284,250
Phase 2*	$476,411
Total	$760,661

*As of the end of 2023.

QUESTION (B):

b) What is the annual cost of ongoing customer engagement activities included in the rate plan revenue requirements?

RESPONSE (B):

Please see the summary table below for a list of the programs that map to the on-going customer engagement initiatives referred to Exhibit 1B, Tab 5, Schedule 1 and a breakdown of the related annual costs. Toronto Hydro notes that the costs in this table are related to the program/segment overall, which include costs beyond the scope of "on-going customer engagement" because it is not possible to disaggregate customer engagement costs from other drivers in the program.

Table 2: On-going Customer Engagement

Program /Segment	Description of Activities	Annual Costs ($ Millions)				
		2025	2026	2027	2028	2029
Customer Operations – Key Accounts Segment (Exhibit 4, Tab 2, Schedule 8 at Page 22)	Proactive and responsive engagement activities with Key Account customers. Please refer to for more information.	1.5	1.5	1.7	1.8	1.9
Customer Operations – Customer Connections Segment (Exhibit 4, Tab 2, Schedule 8 at Page 16)	Communications with customers relating to connection and upgrade requests, from intake through the completion process, and general inquiries.	3.2	3.3	3.5	3.6	3.8
Customer Care - Customer Relationship Management Segment (Exhibit 4, Tab 2, Schedule 14 at Page 34)	Communications across various channels to provide customers information in relation to service offerings and the utility's operations.	14.7	15.7	16.1	16.9	17.5
Customer Care - Collections Segment (LEAP) (Exhibit 4, Tab 2, Schedule 14 at page 26).	Application of financial assistance programs such as the Low-Income Energy Assistance Program ("LEAP") and Ontario Energy Support Program ("OESP").	10.2	10.9	11.0	11.3	11.6

<table>
<tr><th rowspan="2">Program /Segment</th><th rowspan="2">Description of Activities</th><th colspan="5">Annual Costs ($ Millions)</th></tr>
<tr><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th></tr>
<tr><td>Public, Legal and Regulatory Affairs – Communications and Public Affairs Segment (Exhibit 4, Tab 2, Schedule 18 at page 28)</td><td>Includes channels that facilitate two way communication with customers such as costs for surveys, focus groups, and the Customer Advisory Panel. This also includes town halls and other communications with customers regarding planned capital work.</td><td>6.6</td><td>6.9</td><td>7.1</td><td>7.3</td><td>7.6</td></tr>
<tr><td rowspan="2">Asset and Program Management – System Planning Segment (Exhibit 4, Tab 2, Schedule 9 at Page 12)</td><td>The utility uses the City of Toronto’s development pipeline to engage large customers and developers with upcoming projects to understand their needs, determine their load requirements and timelines, provide technical guidance, explore innovation opportunities, and provide support in understanding the connection process. For more information, about development planning please see coordinate planning Exhibit 2B, Section B.</td><td rowspan="2">8.4</td><td rowspan="2">9.1</td><td rowspan="2">9.5</td><td rowspan="2">10.0</td><td rowspan="2">10.3</td></tr>
<tr><td>Toronto Hydro participates in the Regional Planning process which includes community and stakeholder engagement, including webinars, led by the IESO.</td></tr>
</table>

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-50

Reference: Exhibit 1B, Tab 5, Schedule 3, Page 1

Please file Toronto Hydro's responses to matters raised in letters of comment filed with the OEB during the course of the application.

RESPONSE:

Please see Appendix A

Re: Toronto Hydro 2025–2029 Rate Application Letters of Comment

Dear Valued Customer,

Thank you for your letter of comment regarding Toronto Hydro's 2025–2029 rate application and investment plan. Customer letters are an important part of the rate application process and we appreciate you taking the time to provide your feedback.

The Ontario Energy Board (OEB) received 22 letters of comment in total. Many of the letters focused on similar themes, including that:

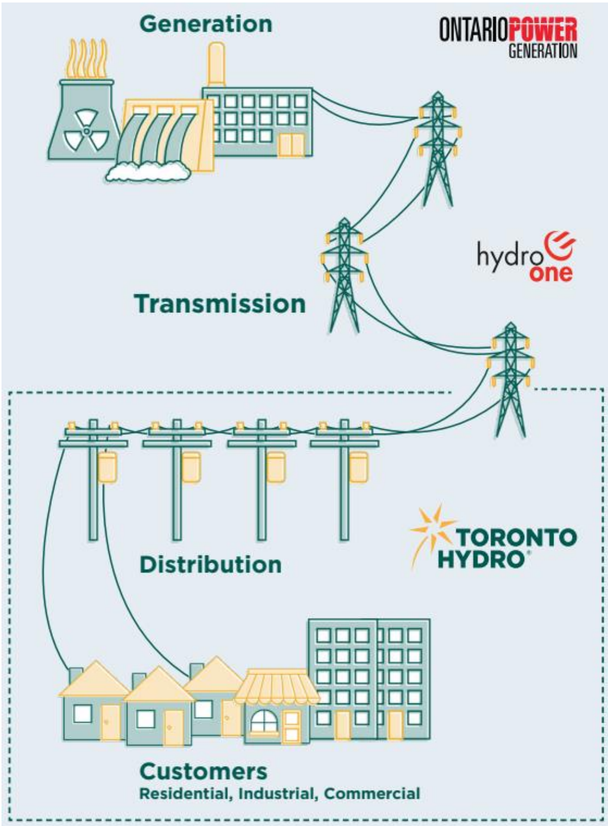
- Customers need clarity about what portion of their electricity bill goes to Toronto Hydro
- Customers believe the required electricity infrastructure already exists, so additional investment isn't required
- Customers are struggling with the cost of living and can't afford additional rate increases
- Customers want Toronto Hydro to explore other solutions rather than increasing costs

This letter represents Toronto Hydro's response to the comments raised and is divided into the following sections:

1. Electricity 101: Toronto Hydro's Role in the Electricity System
2. Toronto Hydro Bill Breakdown
3. Toronto Hydro's Investment Needs
4. Toronto Hydro's Operating Environment
5. Customer Engagement and Business Planning
6. Timing and Pace of Investment
7. Supporting Electrification
8. Affordability and Cost-of-Living Challenges
9. Our Productivity and Performance
10. Additional Resources

1. Electricity 101: – Toronto Hydro's Role in the Electricity System

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**:



Generation: Generation is the process of creating electricity from sources such as nuclear power, hydroelectric, natural gas wind and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.

Transmission: Once electricity is generated, it must be sent to urban and rural areas across the province. This happens by way of high-voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution: Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to customers. Toronto Hydro does not generate or transmit electricity — we own and operate the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.

2. Toronto Hydro Bill Breakdown

Toronto Hydro recognizes that there is some confusion among customers about how their electricity bill is distributed among the different parties involved in the electricity system, including what portion goes to Toronto Hydro and how Toronto Hydro spends the money we receive.

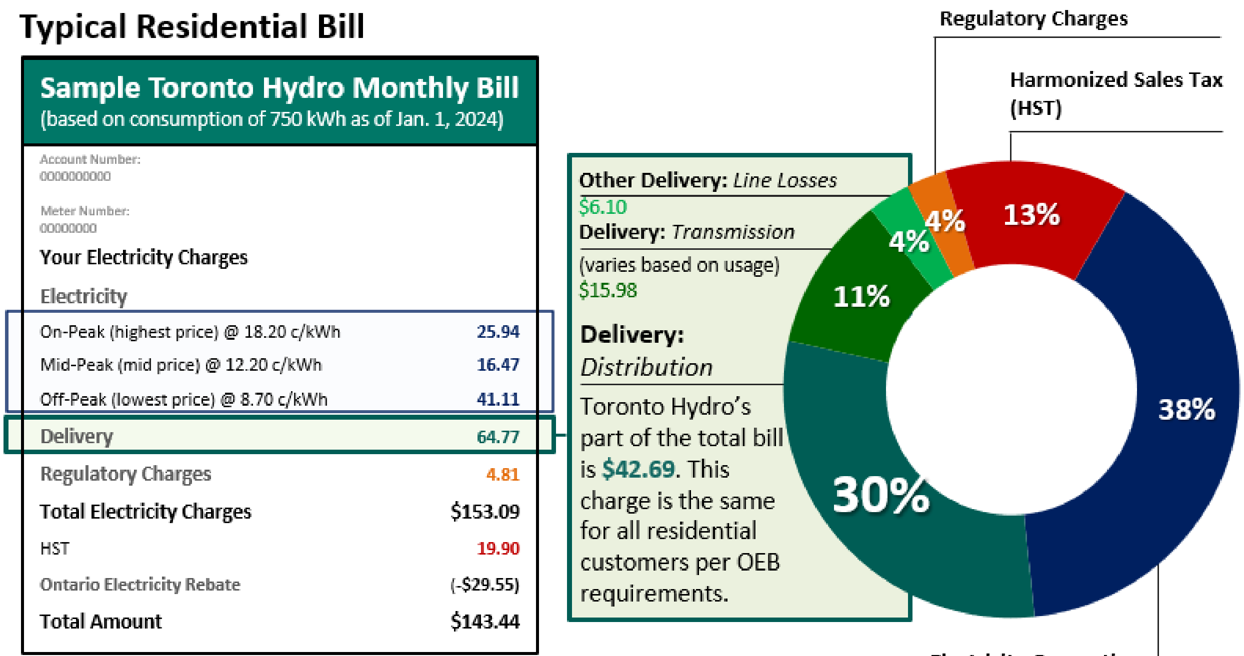
While the electricity bill you receive comes from Toronto Hydro, we actually collect payment for the entire electricity system. **Only about 30% of your electricity bill goes to Toronto Hydro** to pay for the local distribution grid. For example, if the typical monthly residential bill is $143.44**,** the **Delivery Charge** would be **$64.77** and would include:

- Toronto Hydro's Distribution: $42.69
- Hydro One's Transmission: $15.98
- Other Delivery including Line Losses (which is electricity lost during transmission): $6.10

The **remaining 70% of the bill** goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies. Included in this amount is the 40% of your total bill that covers electricity generation costs. This is the part of your bill that changes based on your consumption. In other words, if you take steps to conserve energy, these actions will only impact 38% of your bill. For the typical residential customer, this amount is approximately $53.97.

The diagram below provides a breakdown of a typical residential bill:

Typical Residential Bill



Note: For time of use Off-/Mid-/On-peak split 63%/18%/19% according to the OEB rate model.
The Sample Bill is based on the OEB rates effective January 1, 2024.

3. Toronto Hydro's Investment Needs

The Delivery Charges found on your bill help fund Toronto Hydro's distribution system. For 2025 to 2029, we developed an investment plan to get the grid ready to serve the city's evolving electricity needs, including increased development from population and economic growth, as well as increased electrification and digitization. Our plan will help ensure that our grid and operations will remain safe, reliable and environmentally responsible.

Specifically, Toronto Hydro's 2025–2029 investment priorities include:

- **Sustainment and Stewardship:** These are investments to renew aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable grid.
- **Modernization**: These are investments to develop advanced technological and operational capabilities that will make the system better and more efficient over time
- **Growth and City Electrification**: These are necessary investments to connect customers (including distributed energy resources) and build the capacity to serve a growing and electrified local economy
- **General Plant**: These are investments in our vehicles, work centres and information technology infrastructure to keep the business running and reduce our greenhouse gas emissions

4. Toronto Hydro's Operating Environment

In developing the investment priorities that formed the basis of our 2025–2029 plan, we aimed to address certain needs and challenges of delivering safe, reliable and clean electricity, including:

- **Powering a mature and growing urban city**: We serve Canada's largest and North America's second fastest growing city (by population). We also operate in a dense urban environment, which makes it more complicated and more expensive for us to plan and build infrastructure. As Toronto continues to grow, we need to prepare the grid to power new condo towers, residential communities and businesses.
- **Fixing and replacing equipment in poor condition:** A large percentage of our grid was installed in the 1950s and 60s, and approximately a quarter of the utility's grid equipment continues to operate past useful life. We need to continue monitoring the condition of our grid and replace equipment most at risk to keep it safe and reliable for customers.
- **Keeping up with how customers use electricity:** Customers are increasingly adopting electrified technologies like electric vehicles and heat pumps for their day-to-day energy needs, and using new technologies like solar panels and battery storage to manage their energy usage. We need to upgrade our equipment and modernize our grid to keep up with these changes.
- **Responding to extreme weather and cybersecurity threats:** Extreme weather events such as extreme heat, high winds, flooding and ice storms are becoming more common due to climate change. In addition, cybercrime is on the rise across Canada. We need to invest in making our grid and operations more resilient against these emerging threats.

5. Customer Engagement and Business Planning

In preparing our plan, we recognized that we needed to balance addressing the operating challenges with price and other outcomes that customers value. Toronto Hydro has a robust planning process, which ensures that customer feedback informs our multi-year investment priorities.

During our planning process, we heard from over 37,000 customers across two phases of customer engagement:

- **Phase 1:** In 2022, we started preparing our plan by asking customers about their needs and preferences for electricity distribution services. Based on the Phase 1 Engagement and system conditions, we developed an initial plan that targeted certain short and long term goals.
- **Phase 2:** In March 2023, we went back to our customers with this draft plan — via a comprehensive online survey — to get feedback and to ask customers how the plan could better meet their needs and preferences.

With unprecedented levels of participation (more than 33,000 customers completed the survey), **84% of respondents supported our proposed plan** or one that does even more to improve services.

6. Timing and Pace of Investment

We understand that there are concerns about affordability, and questions regarding whether our proposed investments can be delayed until economic conditions improve.

Toronto Hydro's investment planning and rate application process operates on a five-year cycle. This means we only go to the OEB approximately every five years with an investment plan to ask for updated rates.

As described in this letter, there are certain investments which are necessary to renew aging equipment and prepare for increased growth in the city. These investments cannot happen quickly — particularly in a densely populated and congested city like Toronto. Building new powerlines and stations takes years of planning and construction. There are also equipment and resource constraints that limit how quickly we can build a bigger grid. That's why we need to start investing now to get the grid ready for future growth.

If we were to put off these investments, this could lead to lower reliability, lower service levels for customers looking to connect to the grid, and reduced efficiency. In addition, if we wait to make these proactive investments, we will likely have to spend even more to catch up on work that needs to be done, instead of spending more gradually. That's why we need to start investing in least-regrets investments now so as not to risk the safety, security, reliability and resiliency of the grid.

In the long term, increasing the utilization of the electricity system (through increasing the number of total users as well as the amount of electricity used by individual users) could help to bring down costs for individual customers.

7. Supporting Electrification

We understand that there are concerns that increased electricity rates will disincentivize customers from switching to electric vehicles (EVs) and heating. The rates we're proposing are necessary for making the investments needed to ensure the grid is ready when increased electricity demand materializes.

In addition, as customers increasingly turn to electricity for more of their day-to-day energy needs, it's expected that they will spend less of their income on energy over the long term as increased electricity costs are more than offset by savings from reducing or eliminating their use of fossil fuels, such as gasoline and natural gas.

Finally, there are a number of financial incentives available for EVs and electric heating, such as the Government of Canada's Incentives for Zero-Emission Vehicles Program[1] and the City of Toronto's Home Energy Loan Program.[2]

8. Affordability and Cost-of-Living Challenges

While our proposed rate increases are necessary for ensuring system safety and reliability and addressing the investment needs and challenges described in this letter, we recognize that there are some customers for whom rate increases will be particularly challenging.

[1] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/incentives-zero-emission-vehicles/program-overview
[2] https://www.toronto.ca/services-payments/water-environment/environmental-grants-incentives/home-energy-loan-program-help/help-terms-and-conditions/

A number of financial assistance programs are available to eligible customers, with support ranging from helping customers reduce their electricity usage to on-bill credits that help offset monthly charges. The following programs are available to eligible customers:

- The City of Toronto's **Emergency Energy Fund (EEF)** assists customers with energy-related emergencies to reconnect, prevent disconnection or assist in payment of energy arrears
- The OEB's **Ontario Electricity Support Program (OESP)** provides an on-bill credit each month to qualifying households
- The Independent Electricity System Operator's **Energy Affordability Program** offers support to income-eligible electricity consumers by helping them to better manage their monthly electricity costs and to increase their home comfort
- The OEB's **Low-income Energy Assistance Program (LEAP)** provides a one-time emergency grant to help customers pay their electricity bill

To learn more about these assistance programs, visit **torontohydro.com/help**.

Additionally, as part of our commitment to improving how these programs work, Toronto Hydro is requesting enhancements to the LEAP program for the 2025-2029 rate period. Through these various enhancements, we're aiming to increase the average annual number of customers assisted to approximately 1,900 per year (or more than 9,000 over the entire five-year period).

We're also committed to working with the OEB, governments and other stakeholders to find additional targeted solutions that will help customers who need it most.

9. Our Productivity and Performance

Toronto Hydro always strives to provide value to our customers. Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and completing construction work in the city. Despite this, we're always looking for ways to minimize costs and rate increases by finding productivity and efficiencies in our plans and work. For example, as part of reducing our facilities footprint in the city, we consolidated from seven operating centres down to four. As part of this consolidation, the utility sold properties, and are returning proceeds of close to $200 million to customers by the end of the decade resulting in an annual credit of approximately $132 on the average residential customer's bill from 2016 to 2029.

During our business planning process, we asked external experts to assess our performance, including benchmarking with respect to our productivity, reliability, and cost efficiency. The results of those studies, which were publicly filed as part of our application, demonstrate that our performance on these measures is similar or better than our peer utilities.[3]

This also applies to employee compensation. Toronto Hydro balances cost-effectiveness with the need to attract and retain the talent required to provide service in an increasingly complex and dynamic operating environment. Toronto Hydro has external consultants who benchmark our total compensation, and we've been found to be within a market-competitive range in the energy market.

[3] For more information on Productivity initiatives, please see Exhibit 1B, Tab 3, Schedule 3.

In addition, our 2025–2029 plan is focused on delivering results that matter to customers like you. To help ensure that we achieve these outcomes, we'll be holding ourselves financially accountable through a framework that tracks and reports our performance on 12 distinct measures. This performance framework provides customers with an upfront rate reduction benefit of $65 million that we will only earn back if we achieve certain objectives.

10. Additional Resources

To learn more about Toronto Hydro's 2025–2029 rate application and investment plan, please refer to the following:

- Our 2025–2029 Rate Application
- 2025–2029 Rate Application Executive Summary (PDF, 894 KB)
- 2025–2029 Rate Application Customer Summary (PDF, 1.5 MB)
- Our 2025–2029 Investment Plan

RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCMBC-1

Reference: Exhibit 1B, Tab 1, Schedule 3, Page 9, Table 9: OM&A 2020-2029 Cost Drivers

QUESTION (A) :

a) Please explain the reason for the $9.5 million Distribution Operations cost driver in 2024.

RESPONSE (A):

Programs contributing to $9.5 million variance in Distribution Operation cost driver in 2024 are summarized in Table 1 below. Please refer to the program narrative for additional details.

Table 1: Distribution Operations cost driver in 2024

Distribution Operations	**2024 Bridge**	**Reference**
Preventative and Predictive Overhead Line Maintenance	0.7	Exhibit 4, Tab 2, Schedule 1
Preventative and Predictive Underground Line Maintenance	(0.2)	Exhibit 4, Tab 2, Schedule 2
Preventative and Predictive Station Maintenance	0.5	Exhibit 4, Tab 2, Schedule 3
Corrective Maintenance	0.7	Exhibit 4, Tab 2, Schedule 4
Emergency Response	2.7	Exhibit 4, Tab 2, Schedule 5
Disaster Preparedness Management Program	0.5	Exhibit 4, Tab 2, Schedule 6
Control Centre Operations	0.5	Exhibit 4, Tab 2, Schedule 7
Customer Operations	0.2	Exhibit 4, Tab 2, Schedule 8
Asset and Program Management	0.5	Exhibit 4, Tab 2, Schedule 9
Work Program Execution	0.9	Exhibit 4, Tab 2, Schedule 10
Fleet and Equipment Services	0.4	Exhibit 4, Tab 2, Schedule 11
Supply Chain Services	2.1	Exhibit 4, Tab 2, Schedule 13
Total Cost Driver	**9.5**	

QUESTION (B):

b) Please explain the reason for the $13.9 million Distribution Operations cost driver in 2025.

RESPONSE (B):

Programs contributing to $13.9 million variance in Distribution Operation cost driver in 2025 are summarized in Table 2 below. Please refer to the program narrative for additional details.

Table 2: Distribution Operations cost driver in 2025

Distribution Operations	2025 Forecast	Reference
Preventative and Predictive Overhead Line Maintenance	1.2	Exhibit 4, Tab 2, Schedule 1
Preventative and Predictive Underground Line Maintenance	0.7	Exhibit 4, Tab 2, Schedule 2
Preventative and Predictive Station Maintenance	1.0	Exhibit 4, Tab 2, Schedule 3
Corrective Maintenance	3.9	Exhibit 4, Tab 2, Schedule 4
Emergency Response	2.8	Exhibit 4, Tab 2, Schedule 5
Disaster Preparedness Management Program	0.1	Exhibit 4, Tab 2, Schedule 6
Control Centre Operations	0.4	Exhibit 4, Tab 2, Schedule 7
Customer Operations	(0.1)	Exhibit 4, Tab 2, Schedule 8
Asset and Program Management	0.2	Exhibit 4, Tab 2, Schedule 9
Work Program Execution	0.8	Exhibit 4, Tab 2, Schedule 10
Fleet and Equipment Services	0.2	Exhibit 4, Tab 2, Schedule 11
Supply Chain Services	2.7	Exhibit 4, Tab 2, Schedule 13
Total Cost Driver	**13.9**	

RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCMBC-2

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 25, Table 3: 2026-2029 Revenue Growth Factor

QUESTION:

What is the main reason for the large increase in the Revenue Growth Factor from 2.62% in 2027 to 7.43% in 2028?

RESPONSE:

The primary reason for the increase in the Revenue Growth Factor from 2.62% to 7.43% is an increase in PILs. Specifically, PILS are increasing over this period primarily due to a lower Capital Cost Allowance (CCA) compared to 2027 as the accelerated CCA rules are ending as at December 31st, 2027.

RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCMBC-3
Reference: Exhibit 1B, Tab 2, Schedule 1, Page 26

Preamble:
"Substituting the labour component of the inflation factor with a Toronto-specific index is responsive to the consideration that labour is a key cost driver within the utility's plan, and a Toronto-specific labour index could be more suitable to account EB-2023-0195 Toronto Hydro Rates Application - CCMBC Interrogatories for the localized inflationary cost pressures that the utility faces in the 2025-2029 rate period."

QUESTION (A):

a) Please confirm that Toronto Hydro proposes that ratepayers bear the risk of inflation.

RESPONSE (A):

Toronto Hydro's proposed approach to inflation is consistent with standard incentive regulation under Price Cap IR, which adjust rates annually by an OEB approved inflation-factor. Rates include the impacts of each year's Inflation Factor adjustment, while the utility is responsible for managing variances between actual inflation and the rate adjustments resulting from the Inflation Factor. Toronto Hydro is also responsible for managing the impacts, and bearing the risk of revenue reductions imposed by the X-Factor during the 2025 to 2029 period.

QUESTION (B) – (D):

b) Does the Toronto-specific labour index only cover the City of Toronto, or does it cover a larger area?
c) What percentage of Toronto Hydro employees are residents of the City of Toronto?

d) Do the businesses and manufacturers operating in Toronto face the same inflationary cost pressures as Toronto Hydro?

RESPONSE (B-D):

Please see Toronto Hydro's response to 1B-Staff-93.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1B-DRC-1

References: **Exhibit 1B, Tab 5, Schedule 1, Appendix A**
Exhibit 2B, Section E8.4

<u>Preamble:</u>

THESL engaged Innovative Research Group Inc. ("IRG") to assist in meeting THESL's customer engagement commitments and develop a comprehensive customer engagement study. The work was carried out in two phases. The first phase assessed customers' needs and preferences in relation to THESL's programs and services for the 2025-2029 rate period. During the second phase, customers provided detailed feedback on the $5.9 billion draft plan and the associated price impacts.

QUESTION (A):

Please provide a copy of all written instructions provided by THESL to IRG in relation to IRG's customer engagement mandate for the Application and the report provided in Exhibit 1B, Tab 1, Schedule 1, Appendix A.

RESPONSE (A):

Please see 1B-SEC-11 at Appendix A for the retainer that established IRG's mandate pursuant to which the customer engagement was performed.

QUESTION (B):

Please provide a copy of all written instructions provided by THESL to IRG in relation to customer engagement with respect to consumer choice in integrating technologies like distributed energy resources ("DERs"), electric vehicles ("EVs"), solar power, and battery storage.

RESPONSE (B):

Toronto Hydro did not provide written instructions to IRG beyond the retainer outlined in the utility's response to 1B-SEC-11.

QUESTION (C):

Please describe all measures undertaken by THESL and IRG to invite and ensure the participation of EV stakeholders and other DER customers (including EV drivers, owners of DERs, EV associations, and DER industry associations) in customer engagement activities.

RESPONSE (C) – PREPARED BY TORONTO HYDRO:

Toronto Hydro undertook a two-phased approach to customer engagement through which it gathered feedback from nearly 37,000 customers – the utility's largest and most comprehensive customer engagement to date. For its Phase 2 engagement specifically, customers with an email address on file received an email invitation. Toronto Hydro also informed residential and small business customers about an open access version of the survey through bill inserts, social and traditional media as well as Toronto Hydro's website. This approach resulted in a broad engagement with the opportunity for all customers, including EV stakeholders and DER customers, to participate and provide valuable input into Toronto Hydro's planning process. The success of these efforts in ensuring that EV stakeholders and DER customers were engaged is clear in the response to the question at Exhibit 1B, Tab 5, Schedule 1, Appendix A at pages 286/365, where when customers were asked if they ever considered shifting from one energy source to another (with examples given such as switching to a heat pump or an electric vehicle) 20% of residential customers and 28% of small business customers said they had either done it or were actively taking steps in this direction.

QUESTION (D):

Please provide any and all notes from IRG's customer engagement relating to EVs and DERs that are supplementary to the reports provided in Exhibit 1B, Tab 1, Schedule 1, Appendix A.

RESPONSE (D) – PREAPRED BY INNOVATIVE:

There are no additional notes from IRG's customer engagement relating to EVs and DERs that are supplementary to the reports provided in Exhibit 1B, Tab 5, Schedule 1, Appendix A.

QUESTION (E and F):

Please discuss how the outcomes and priorities of customers have changed compared to historical equivalents and discuss any trend lines in customer priorities related to the adoption and integration of technologies like DERs, EVs, solar power, and battery storage.

Please discuss how the outcomes and priorities of customers have changed compared to historical equivalents and discuss any trend lines in customer priorities related to the energy transition and THESL's net zero commitments. As part of your answer please discuss any work done by THESL or IRG on the substantive knowledge of customers and what they understand their understanding of the energy transition.

RESPONSE (E AND F):

RESPONSE – PREPARED BY INNOVATIVE:

The focus of this engagement was to understand Toronto Hydro customers' current preferences. There was no time series analysis of change in customers' views on outcomes and priorities conducted for this application.

The surveys conducted for this engagement do not presume any knowledge about the energy transition. Each question provides enough background information for customers to provide meaningful responses. The questions were tested with customers to ensure they felt there was enough information. There is a diagnostic question at the end of the survey to double check whether customers felt there was too little, too much or the right amount of information. Most customers indicated the survey had the right amount of information.

The Phase 1 survey did include two awareness questions. The first asked about customer familiarity with the primary sources of GHG emissions, and the second asked customers about their familiarity with the role of an expanded and modernized grid to implement the City of Toronto's Net Zero Strategy. The results show a wide range of knowledge about primary sources of GHG emissions, confirming other publicly released research on energy transition knowledge by INNOVATIVE. For example, on Exhibit 1B, Tab 5, Schedule 1, Appendix A at page 113 of the Phase One Residential Report, 55% of residential customers report being at least somewhat familiar with the primary sources of GHG emissions.

RESPONSE – PREPARED BY TORONTO HYDRO:

In the last five years, Toronto Hydro has observed many Key Account customers move from planning and finalizing their Environmental Social and Governance (ESG) goals to adoption of decarbonized projects. Many of these projects are either in the design/construction phase or already energized. This transition has been led by the Municipal, Academic, Schools and Social Services, and Hospitals (MASH) sector and Toronto Hydro anticipates that this will continue through the 2024-2029 period. For example, identifiable EV specific projects over the 2022-2024 period include over 400 on and off-street EV charging stations in garage lots, surface level lots and pole-mounted stations across the City of Toronto. This rate of electrification within the City of Toronto is expected to grow and increase throughout the 2024-2029 period together with ongoing new building construction electrification requirements for commercial, residential and mixed-use developments.[1]

The utility also generally anticipates growth in Renewable Distributed Energy Resources. Specifically, the utility currently projects that the total number of renewable DER connections[2] will

[1] Exhibit 2B, Section E5.1.4.1 at Page 22

[2] Renewable: consists of DER based on renewable technologies, such as solar photovoltaic, wind turbine and bio-gas generators;

grow from about 2280 connections in 2023 to nearly 4,500 by the end of 2029 – an increase of roughly 67 percent.[3]

[3] Exhibit 2B, Section E2.1.3.2 at Page 15

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1B-DRC-2

References: Exhibit 1B, Tab 1, Schedule 1, pp.58-59
Exhibit 2B, Section E3

Preamble:

THESL notes that "[c]ustomers are showing a continued interest in participating in the electricity system as both consumers and producers of power." THESL further notes that "[e]quipment that has a high number of DER connections is more likely to experience unstable conditions that pose significant reliability and safety risks to the system and its users."

QUESTION (A):

Please elaborate on what THESL means by customers are interested in participating as both consumers and producers and that reliability and safety risks associated with equipment that has a high number of DER connections.

RESPONSE (A):

Some customers in Toronto Hydro's service territory choose to install Distributed Energy Resources (DERs), enabling them to produce electricity for their own consumption. As noted in Exhibit 2B Section E5.1.3.2, as of the end of 2022, Toronto Hydro connected 2,185 Renewable DERs, 28 Energy Storage and 116 Non-Renewable DER connections from customers and developers under a variety of technologies and applications with a total connected capacity of 304.94 MW. As noted in Exhibit 2B Section E7.2.2, an increase in generation projects can lead to a fundamental change in the power flow conditions at the distribution system and how they need to be managed. This has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of renewable energy generation is known to cause issues in distribution system planning and operations such as unintentional islanding and overvoltage on feeders.

QUESTION (B):

Please provide details as to the areas in THESL's service territory experience the highest reliability and safety risks associated with DER connections (such as neighbourhood, number of DERs connected, overview of risks and reliability issues, customer concerns, etc.). If THESL is unable to provide further details, please explain why not and whether such information may be obtained in this proceeding or subsequent proceedings.

RESPONSE (B):

Please see Table 1 in Exhibit 2B, Section E3.3 for the areas that pose the highest risk for DER connections, due to the lack of fault level capacity on the bus associated with these stations. Further intake of DERs could put the stations and feeders in these areas at risk of exceeding the allowable fault limits, which could be detrimental to the equipment's rating. The safety and reliability risks associated with DER connection are detailed in the evidence at Exhibit 2B Section E3.

QUESTION (C):

What, if any, are factors that THESL believes will influence customer choice as the "key driver of DER demand", in addition to the economic and policy considerations listed, both for the period 2024-2029 and beyond.

RESPONSE (C):

Toronto Hydro believes that customers' choices regarding Renewable DER, Non-renewable DER and Energy Storage Facilities are shaped by a combination of technological, social, environmental, and policy factors. Below is a list of some of factors that can influence customer choice as the key driver of DER demand in the future.

- **Technological Advancements**: Advances in technology can make DERs more attractive and cost-effective for consumers. This includes technology that integrates DER into smart homes and buildings, allowing for better control, automation, and optimization of energy usage.
- **Energy Independence, Security and Resilience**: Consumers may choose DERs to gain greater control over their energy costs and to mitigate concerns about energy security and resilience.

This is particularly true to larger rotation-based generation facilities that could support their load or parts of it.

- **Environmental & Social Factor**: A growing awareness of climate change, along with peer influence and community norms in that respect can drive more customers to choose DERs to reduce their carbon footprints.
- **Government Incentives & New Business Models**: In addition to broader policy considerations, specific incentives, subsidies, and regulations can impact the attractiveness of DER for customers. The emergence of new business models, such as community-based energy projects, can provide customers with new options and incentives for adopting DER.

QUESTIONS (D) AND (E):

d) What are the consequences if DER growth rates exceed THESL's forecasts and more closely approximate the highest projection scenarios from the FES Report? Please include in your response a discussion on what challenges will this present in terms of THESL's ability to meet the higher demand and any consequences it may have on THESL's ability to meet demand past 2030 if demand continues to accelerate more quickly than anticipated.

e) What additional investments beyond those set out in E3.3.1 would THESL propose to accommodate the highest projections from the Future Energy Scenarios Report?

RESPONSE (D) AND (E):

It is important to note that highest level of DER uptake in FES is aligned with the Net Zero 2040 projections in TransformTO and is significantly more aggressive than any other scenario. It is based on the theoretical potential of solar generation in Toronto and hence represents an upper bound where 100% of suitable buildings install solar PV. For more information, please see Section 4.4 of Exhibit 2B Section D4 Appendix B.

Should the DER growth rate more closely resemble the highest projection scenario in the FES report, consequences would include more constrained feeders on the distribution network (due to short-circuit capacity), issues with existing protection systems, as well as voltage regulation issues due to large amounts of DERs. As discussed in Exhibit 2B, Section E3, Toronto Hydro already faces DER hosting capacity limitations in a small percentage of areas on its system. In any scenario that involves DER growth, the number of restrictions can be expected to grow over time. Furthermore, the more rapid the uptake is of DERs, the sooner these limitations will be encountered and the more widespread they will become.

One benefit of a scenario-based model such as FES is that the utility can track developments as they occur and determine which scenario is more closely being followed, and plan the necessary investments accordingly to ensure that the utility is able to meet demand.

As summarized in Exhibit 2B, Section E3, Toronto Hydro has put forward a plan to address existing and anticipated DER hosting capacity restrictions in alignment with its DER forecast for 2025-2029. With respect to the longer-term, as discussed in detail in Section D5.2.2, an important stream of the utility's Grid Modernization Strategy is the Grid Readiness portfolio (and related innovation projects), which includes targeted investments to explore and demonstrate solutions and capabilities that could become part of Toronto Hydro's toolkit for cost-effectively facilitating and integrating a much higher penetration of DERs beyond 2030. If the rate of DER uptake significantly outpaces that reflected in Toronto Hydro's DER forecast, it will likely be necessary to increase the scope of investment in the solutions summarized and Section E3. A higher rate may also encourage a more accelerated pace of modernization and innovation investment to advance Grid Readiness capabilities.

Toronto Hydro is proposing the use of a Demand Variance Account to account for a scenario where significantly more than planned electrification drivers materialize.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1B-DRC-3

References: **Exhibit 1B, Tab 1, Schedule 1, p.50**
Exhibit 2B, Section 5.5

Preamble:

THESL notes that its "investment plan makes the minimum investments necessary (the "least regrets investments" to maintain key outcomes in the near-term while also making paced and deliberate progress in readying the grid and utility operations of the future, regardless of the path the energy transition takes."

QUESTION (A):

a) Please discuss the time horizon considered by THESL in its investment plan to support its "least regrets investments" approach and explain what is meant by "near-term" and "readying the grid and utility operations of the future".

RESPONSE (A):

In the context of making "least regrets" investment decisions, the "near-term" refers to Toronto Hydro's 2025-2029 Distribution System Plan period (and the utility's decision to largely prioritize modernization investments that will have immediate benefits to customers in this period), while "readying the grid and utility operations for the future" means making investments in the 2025-2029 period that will build toward certain more advanced capabilities that will be required in the next decade and beyond as the pace of change related to the energy transition is expected to accelerate.

For more information about the least regrets planning approach, please refer to Exhibit 2B, Section D4 starting on page 9. Please also refer to the response to interrogatory 1B-PP-05-part (a) for more context on "readying the grid and utility operations of the future".

QUESTIONS (B):

b) Please discuss the disadvantages and downside risks to THESL's distribution system, customers, investments in DERs, infrastructure, and/or workforce of underinvesting in electric vehicle infrastructure and DER connection and adoption infrastructure if a higher electrification scenario materializes compared to the one relied upon in the Application and THESL's investment plan. Please also discuss the implications of underinvestment over the rebasing period (2025-2029), mid-term (2030-2040), and long-term (2040 onwards).

RESPONSE (B):

Toronto Hydro's "least regrets" investment plan for 2025-2029 is designed to prepare the grid and operations for the level of growth anticipated in the utility's 10-year Peak Demand Forecast and its DER forecast. The utility is also proposing a Demand-Related Variance Account ("DRVA") to protect ratepayers, the utility and its shareholder, from structural unknowns in forecasted costs and revenues related to demand growth in a time of unprecedented change and transformation in the economy and energy system. Please see Exhibit 1B, Tab 2, Schedule 1 starting on page 35 for detailed evidence with respect to the need and scope of the proposed DRVA.

Hypothetically, if a much higher electrification scenario occurs and Toronto Hydro fails to make the necessary investments in a timely manner, this would have negative impacts on the various topics listed in DRC's question. Some of the key impacts are summarized below by time period.

<u>Rebasing Period (2025-2029)</u>

1. **Distribution System:** Underinvestment in infrastructure to support EVs, DERs and various other drivers of demand could lead to increased strain on the system. This could result in more frequent outages, reduced reliability, and lower service quality. Toronto Hydro could face higher operational costs and emergency repairs due to the inadequacy of the current infrastructure to handle peak loads.
2. **Customers:** Lack of access to adequate EV charging capacity could slow down the adoption of electric vehicles.

3. **Investments in DERs:** Underinvestment could hinder the integration of DERs, affecting local energy generation and storage solutions. This could result in lost opportunities for customers to reduce energy costs and emissions, and for the broader grid to benefit from more distributed energy production.
4. **Workforce:** Insufficient investment could result in a workforce that is ill-prepared for the evolving energy landscape, lacking skills in new technologies and customer service demands associated with EVs and DERs, as well as missed opportunities to build and apply efficiency-enhancing digital solutions including data analytics.

Mid-Term (2030-2040)

1. **Distribution System**: Continued underinvestment could lead to chronic underperformance of the grid, with aging infrastructure unable to cope with the growing electrification needs. This may necessitate costly, large-scale emergency upgrades to prevent system failures.
2. **Customers**: As electrification demands increase, customers could face significant power quality issues, such as voltage fluctuations and reliability problems. This could lead to public dissatisfaction and loss of trust in Toronto Hydro.
3. **Investments in DERs**: A lack of robust DER-supporting infrastructure could result in missed opportunities for reducing peak loads and improving grid resiliency, leading to higher operational costs and electricity rates. Toronto Hydro would find itself turning away large volumes of prospective DER projects.
4. **Infrastructure**: Persistent underinvestment could make the grid increasingly vulnerable to extreme weather events and cyberattacks, jeopardizing security and reliability at the same time that customer expectations for service reliability would be increasing.
5. **Workforce**: A workforce not scaled or trained to meet the demands of a rapidly evolving energy sector could lead to inefficiencies and increased costs, further impacting Toronto Hydro's ability to meet customer needs and regulatory requirements.

Long-Term (2040 Onwards)

1. **Distribution System:** The long-term consequences of underinvestment could include a severely degraded and unreliable grid, unable to support the electrification needs of the city, resulting in economic and social impacts.
2. **Customers:** Long-term underinvestment could lead to significant disparities in service quality, with some customers having access to reliable and modern energy services while others do not.
3. **Investments in DERs**: Failure to invest adequately could result in a significant lag in the adoption of clean energy technologies, impacting environmental goals and leading to higher greenhouse gas emissions.
4. **Infrastructure:** The gap between the infrastructure needs and the actual state could widen, making it increasingly difficult and expensive to catch up with necessary upgrades and innovations.
5. **Workforce:** A long-term lack of investment in workforce development could result in a significant skills gap, undermining Toronto Hydro's ability to innovate in the evolving energy market.

QUESTION (C):

c) Similarly, please discuss any disadvantages where a lower electrification scenario materializes.

RESPONSE (C):

In the case where a significantly lower electrification scenario materializes, accompanied by overinvestment along various time horizons as highlighted above, the central disadvantage would be the risk of underutilized or stranded assets and technological obsolescence leading to increased electricity rates for customers. These risks, as well as the risks discussed in response to parts (b) and (c) of this question emphasize the importance of flexibility, accurate demand forecasting, and adaptive planning in Toronto Hydro's investment strategies to mitigate financial risks and system performance risks, ensure customer satisfaction, and align with broader environmental and policy objectives.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1B-DRC-4

Reference: Exhibit 1B, Tab 1, Schedule 1, pp. 12-13

<u>Preamble:</u>

THESL is seeking to grow its workforce by approximately 25 percent "to have the required resourcing capacity and capabilities to sustain foundations of a safe and reliable grid and meet the imperatives of an urban city and customers who are increasingly relying on electricity to expand, digitize and decarbonize their footprint."

QUESTION (A):

a) Please identify in the record THESL provides details of how technological advancement will require training their workforce over the course of years to ensure THESL is able to sustain a safe and reliable grid as the energy transition accelerates.

RESPONSE (A):

Please see Exhibit 4, Tab 4, Schedule 3, Pages 8-13.

QUESTION (B):

b) Please confirm and comment on whether the anticipated widespread adoption of DERs and EVs over the next five years and beyond will require investments in THESL's workforce and please discuss what will be involved in training the workforce for your proposed approach (timeframes, new approaches, etc.)

RESPONSE (B):

Please see part a) above and Exhibit 4, Tab 4, Schedule 3, pages 22-25.

QUESTION (C):

c) Please comment on what training, programs, and investments will be needed if a more ambitious energy transition and DER adoption scenario occurs over the next five years and beyond. In your response, please comment on what training and upgrading of workforce skills will be needed to ensure that THESL's workforce is able to meet the challenges of an accelerated energy transition in this and the next decade and how does this compare to THESL's current approach and the approach proposed in the Application.

RESPONSE (C):

Please see response to part b above.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1B-DRC-5

References: Exhibit 1B, Tab 2 – 4

Exhibit 2B, Section E7.2

Preamble:

THESL notes that the Investment Plan optimizes near-term system capacity through, among others, the targeted use of non-wires solutions including grid-side technologies such as renewable enabling energy storage systems. THESL notes that for the proposed Non-Wires Solutions Program will focus on developing a scalable, demand-driven, energy storage system (“ESS”) strategy that is responsive to distribution system needs and supports THESL’s pathway to renewable integration and electrification.

QUESTION (A) :

Please indicate whether EV batteries are expressly and/or implicitly, included in THESL's definition of ESS and, if so, how?

RESPONSE (A):

Toronto Hydro’s ESS strategy focuses on Toronto Hydro owned and operated, front-of-the-meter assets. As such, customer owned EV batteries are not part of this particular strategy. However, as a non-wires solution, EV batteries could play a role in the future. Please see the response to part (b).

QUESTION (B) :

Please explain how THESL proposes to optimize efficiencies from the many EV batteries and charging infrastructure in its systems?

RESPONSE (B):

The non-wires solutions (NWS) considered for the 2025-2029 rate period have been outlined in detail in Exhibit 2B Section E7.2. Toronto Hydro's use of NWS is targeted and focuses on credible capital deferral opportunities, and thus, the application of these solutions is limited to instances where such deferral opportunities can be identified and measured.

The use case identified at this time is limited to bus-level load transfer deferral or avoidance. This can be achieved through the procurement of dispatchable demand response from aggregators or customers. Toronto Hydro is agnostic to the technology (type of DER) or approach (load curtailment) utilized by aggregators or customers to deliver this demand response capacity. Participants are compensated based on measured and verified performance, utilizing the methodology outlined in IESO's Market Manual 12 – Issue 16.

When Toronto Hydro runs its LDR procurements, aggregators are invited to offer capacity. If the volume of electric vehicles (EVs) with bi-directional chargers reaches levels where the capacity could be aggregated to provide meaningful capacity, aggregators will be welcome to bid this capacity into the LDR process. If the cost of such capacity is competitive, Toronto Hydro will work with these aggregators to leverage the devices mentioned.

QUESTION (C) :

Please itemize all of the benefits that an EV ESS may have and provide THESL's rationale for not pursuing any specific EV ESS projects at this time given the stated benefits.

RESPONSE (C):

Toronto Hydro is open to procuring services from EV ESS if and when such devices can be aggregated to provided meaningful capacity to the grid. Toronto Hydro runs open DR procurements and invites interested aggregators to provide capacity from such devices if and when it is available.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1B-DRC-06

Reference: **Exhibit 1B, Tab 4, Schedule 1**
Exhibit 1B, Tab 4, Schedule 2

Preamble:

THESL indicates that its innovation activities include integrating DERs, preparing for electrification by augmenting the capacity planning process with new scenarios-based modelling, launching an internal sandbox initiative, conducting an EV "smart charging" pilot with both Plug 'n' Drive and Elocity. THESL is also proposing to establish a $16 million Innovation Fund to support the design and execution of innovative pilot projects over the 2025-2029 rate period.

QUESTION (A):

a) Please comment on whether the Innovation Fund will be dedicated solely to DER-related projects and whether there will be opportunities for further stakeholder participation regarding the allocation of funding for projects under the Innovation Fund.

RESPONSE (A):

The Innovation Fund will not be dedicated solely to DER-related projects. Rather, it will be dedicated to pilot projects that are aligned with the OEB's expectations for electricity distributors as set out in the FEI report and the Filing Requirements, including but not limited to developing capabilities to prepare for the impact of DERs on distribution systems. For more information on the types of projects that the Innovation Fund will focus on please see the Areas of Innovation (Section 3) and Pilot Selection and Design Phases (Section 4.1) of the Innovation Fund evidence found in Exhibit 1B, Tab 4, Schedule 2. Please also refer to Toronto Hydro's response to interrogatory 1B-CCC-46.

Decisions with respect to selection of projects and resulting allocation of funding under the Innovation Fund will be overseen by the Innovation Fund steering committee. As noted in the Pilot

Selection and Design Phases (Section 4.1) of the referenced evidence, stakeholder participation will inform the Pilot Selection phase by canvassing ideas and solutions to help Toronto Hydro gain a better understanding of what is feasible, what has potential business value, and what presents opportunities for scalability to leverage external funding.

QUESTION (B):

b) How does the proposed allocation of $16 million the Innovation Fund compare with total dollar amount funding in comparable jurisdictions?

RESPONSE (B):

Please refer to Toronto Hydro's response to interrogatory 1B-DRC-06 part (d).

QUESTION (C):

c) What types of projects will be eligible for funding under the Innovation Fund and what types of projects will be unable to access funding as a result of allocating only 0.3% of revenue as opposed to up to 1%?

RESPONSE (C):

Toronto Hydro would like to clarify that funding for the proposed Innovation Fund is not an allocation of revenue. Rather, Toronto Hydro has determined the amount of funding requested for this proposal, based on the top-down assumption of 0.3% of revenue requirement. This amount reflects the low end of the range identified in the utility's research as noted above and will be recovered through a rate rider as explained in the response to interrogatory 9-Staff-342.

The types of pilot projects to be supported by the proposed Innovation Fund will be determined based on the parameters set out in the evidence, as applied through the Governance Framework. For information on how Toronto Hydro will select and prioritize projects, see response to 1B-CCC-46 and Sections 3 (Areas of Innovation) and 4.2 (Pilot Selection and Design Phases) of the Innovation Fund proposal found in Exhibit 1B, Tab 4, Schedule 2.

QUESTION (D):

d) Please provide any and all analysis, reports, studies, presentations, data or other documentation with respect to developing the proposal for the Innovation Fund, including all THESL's research regarding utility investments across comparable innovation initiatives and research and development activities (i.e., the range from 0.3 to 1 percent of revenues).

RESPONSE (D):

Please see the detailed evidence in Exhibit 1B, Tab 4, Schedule 2. Attached as an appendix to this response, Toronto Hydro has provided a table summarizing the research conducted with respect to the Innovation Fund. Internal documentation relating to the development of the proposal is not relevant because it reflects considerations that are draft in nature, and which provide no further probative value to assessing the merits of the Innovation Fund proposal detailed in the evidence.

QUESTION (E):

e) Please discuss the findings of THESL's research regarding comparable innovation investments including which jurisdictions were considered, the types of projects that received funding, and any lessons learned from these projects and broader innovation funding and investments.

RESPONSE (E):

Toronto Hydro summarized the findings of its jurisdictional research in pages 5-6 (Rationale for the Innovation Fund) of Exhibit 2B, Tab 4, Schedule 2. Additionally, please see response to part (d) above for a description of Toronto Hydro's analysis.

QUESTION (F):

f) When selecting projects to fund through the Innovation Fund, will THESL look at what pilots and program successfully implemented by comparable utilities and then propose pilots that potential partners could assist with as part of THESL's services? If not, why not.

RESPONSE (F):

Please see Toronto Hydro's response to interrogatory 1B-CCC-46 part (a).

QUESTION (G):

g) Please discuss and elaborate on why pilots specific to THESL are necessary or helpful as opposed to considering the outcomes of innovation projects by comparable utilities (Ontario or otherwise) then applying the outcomes and learnings to THESL's services.

RESPONSE (G):

As stated in the Innovation Fund evidence, adopting solutions implemented by other utilities is not a "cut-and-paste" exercise as it requires further in-depth exploration and testing. Each distributor and each distribution system have different operating characteristics, and this is particularly true for Toronto Hydro and its urban distribution system which serves a diverse customer base and reflects the amalgamation of six different municipal utilities. In the Pilot Selection and Design Phases (Section 4.2), Toronto Hydro intends to engage external stakeholders to inform pilot selection. Included in the list of external stakeholders are other Ontario distributors, who will be canvassed on their experience and knowledge.

QUESTION (H):

h) Why were these specific attributes for DERs selected?

RESPONSE (H):

As stated in the referenced evidence, the need for the Innovation Fund proposal is driven by multiple imperatives, including meeting the OEB's expectations for electricity distributors to be prepared for the impacts of DERs on the distribution system. Other imperatives that more broadly underpin the need for the Innovation Fund include developing capabilities to adapt to the changing energy landscape, such as the energy transition and electrification of key economic sectors utilizing space heating and transportation.

QUESTION (I):

i) Please identify the senior utility leaders who will oversee the Innovation Fund and the selection of projects and discuss how interested stakeholders will be able to assist with generating creative and innovative projects and whether funding will be available to ensure adequate stakeholder participation?

RESPONSE (I):

The Innovation Fund evidence indicates the four-phase process outlined in the Governance Framework will be overseen by a steering committee of senior utility leaders and managed by pilot project 'owners' whose business responsibilities correspond to the Area of Responsibility of the pilot project that has been designated by the steering committee. The senior leaders and project owners will be determined upon approval of the Innovation Fund proposal and other material requests outlined in this rate application.

The evidence further outlines that the steering committee will have a supervisory role over the management of the pilot project team, as it will be responsible for making key decisions such as approving project scopes and budgets. The project owners will be responsible for managing the day-to-day activities of designing, executing, and reporting on the pilot projects.

Since stakeholder participation is embedded into the pilot selection phase, it is part of the Innovation Fund and will be allocated resources to support undertaking stakeholder engagement activities. The format and other specifics of stakeholder engagement will be determined upon approval of the Innovation Fund proposal. For details on the role of stakeholder participation in the Governance Framework, please see Toronto Hydro's response to interrogatory 1B-CCC-46 part (a).

QUESTION (J):

j) Please discuss and provide further examples of what the ideas and projects put forward through the Sandbox and what information and data are being shared with THESL employees overseeing the operation and implementation of the Sandbox. Please also discuss how the outcomes of the Sandbox are being communicated and shared with relevant and interested stakeholders. If information is not readily available or shared with stakeholder, please explain why not and what mechanisms exist (or should exist) to share such information in a timely and meaningful way.

RESPONSE (J):

Examples of ideas that have been submitted are detailed in Exhibit 1B, Tab 4, Schedule 1 at pages 2 and 3. The outcomes of projects are shared through internal communications channels, including but not limited to: employee roadshows, employee intranet, electronic notice boards and through other employee engagement avenues. For more information about how Toronto Hydro is leveraging its experience and learnings with the sector in terms of developing DER integration capabilities for peak management purposes, please also see Toronto Hydro's response to 1B-Staff-40(b).

Jurisdiction	Innovation Investments	Level of Funding
NV-RME (Norwegian Energy Regulatory Authority)	Targets projects that test out new, innovative solutions connected to flexibility, aggregation, and new tariffs to improve pricing signals.[i]	0.3% of asset base[ii]
Ofgem	Eligibility requirements include: (1) facilitate energy system transition and/or benefit consumers in vulnerable situations; (2) potential to deliver a net benefit to customers; (3) Involve research, development or demonstration (e.g. new technology, new methodology, novel arrangement or operational practice); (4) develop new learning; (5) must be innovative (e.g. unproven business case entailing a degree of risk); (6) not lead to unnecessary duplication.[iii]	0.5%-1% of base revenues - Network Innovation Allowance[iv]
New York Public Services Commission (NYPC)	Reforming Energy Vision (REV) projects that explore reshaping utility business practices to encourage new roles and business models for electric utilities, including:[v] • DER integration and consumer behaviours and expectations around distributed generation and other new types of technologies such as energy efficiency and demand response; • Advance the concept of the utility as a distribution platform company, which through incentives and price signals encourages technological innovation; • Leveraging collaboration and experts to understand specific technology challenges and identify potential solutions to address them.	0.5% of total revenue requirement or $10 million annually - Reforming Energy Vision (REV) Demonstrations[vi]
Australia Energy Regulator	Researching, developing or implementing demand management capability or capacity. Eligible projects must be innovative, meaning: new or original concepts, including new or original ways of building or developing capability and capacity to undertake, facilitate or utilize demand management; or	0.75-1% of Annual Revenue Requirement (ARR) under Demand Management Innovation Allowance Mechanism[viii]

Jurisdiction	Innovation Investments	Level of Funding
	technology not previously implemented; or focused on customers in a market that has not been exposed to the technology[vii]	
California Public Utilities Commission	EPIC-4 funding streams include: accelerate advancements in renewable generation technologies; create a more nimble grid to maintain reliability for 100% clean energy; increase value of DER; improve customer value of energy efficiency and electrification technologies, etc.[ix]	$13.61 USD per customer annually – EPIC (Electric Program Investment Charge)[x]
Minnesota Public Utilities Commission	Remove barriers to entry for renewable energy technologies, including economic barriers from competing against conventional energy sources, targeting areas of energy productions, research and development projects, and educational research initiatives[xi]	$9.12 USD per customer annually – Renewable Development Fund (RDF)[xii]
Massachusetts Department of Public Utilities	Utilities to propose projects focused on testing, piloting, and deploying RD&D projects that modernize the grid and employ new technologies including for optimizing system performances through grid visibility, command and control, and self-healing, optimize system demand, and interconnection and integrate DERs as part of Grid Modernization Plan.[xiii]	Eversource: $14.26 USD per customer annually[xiv]
Enbridge Energy Transition Technology Fund (Proposed in EB-2022-0220)	Advance research, development, and commercialization of low-carbon technologies that reduce GHG emissions, including RNG and low-carbon fuels; emissions reduction through end-use (including hydrogen); Carbon Capture Utilization & Sequestering (CCUS)[xv]	$5 million CAD annually / $25 million total over 5 years; approx. 0.4% of revenue requirements proposed for test year (2024)[xvi]
Hydro-Quebec	n/a	Spends 1% of total revenues on R&D[xvii]
Ontario Power Generation	n/a	Spends 0.7% of total revenues on R&D[xviii]

[i] Mechanisms to support innovation in Norwegian electricity networks – R&D funding and the Norwegian regulatory sandbox framework, available at: https://www.nve.no/media/13166/regulatory-mechanisms-to-support-innovation.pdf.
[ii] *Ibid.*
[iii] RIIO-2 NIA Governance Document, available at: https://www.ofgem.gov.uk/publications/riio-2-nia-governance-document-0.
[iv] Coyne, J.M., Yardley, C.Y., Pryciak, J., and Yachtew, A., "Should Ratepayers Fund Innovation?" in *Energy Regulation Quarterly,* Volume 6, Issue 3 (September 2018), available at: https://energyregulationquarterly.ca/articles/should-ratepayers-fund-innovation#sthash.vqAJd1el.L7VqGOUc.dpbs.
[v] National Association of State Utility Consumer Advocates, et al. "The Role of Innovation in the Electric Utility Sector," *Future Electric Utility Regulation,* Report No. 13 (April 2022), available at: https://eta-publications.lbl.gov/sites/default/files/feur_13_-_innovation_20220511final.pdf.
[vi] *Supra* note iv.
[vii] Australia Energy Regulatory, Decision – Demand Management Innovation Allowance Mechanism expenditures (July 2023), available at: https://www.aer.gov.au/system/files/AER%20-%20Decision%20to%20approve%20DMIAM%20expenditures%20FY20%20FY21%20FY22%20-%20July%202023_0.pdf.
[viii] *Supra* note iv.
[ix] California Energy Commission, The Electric Program Investment Charge 2021-2025 Investment Plan (EPIC 4 Investment Plan), available at: https://www.energy.ca.gov/publications/2021/electric-program-investment-charge-proposed-2021-2025-investment-plan-epic-4.
[x] *Supra* note iv.
[xi] *Ibid.*
[xii] *Ibid.*
[xiii] *Ibid.*
[xiv] *Ibid.*
[xv] EB-2022-0220 at Exhibit 1, Tab 10, Schedule 7.
[xvi] *Ibid.*
[xvii] "Canada's Top 100 Corporation R&D Spenders in 2022", available at: https://researchinfosource.com/top-100-corporate-rd-spenders/2022/list.
[xviii] *Ibid.*

RESPONSES TO ENVIRONMENTAL DEFENCE INTERROGATORIES

INTERROGATORY 1B-ED-1

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 10

QUESTION (A):

a) Enbridge's Pathways to Net Zero forecasts a tripling of demand whereas Toronto Hydro and the IESO forecast demand doubling. Please explain why Enbridge comes up with a significantly different figure and discuss which one Toronto Hydro believes is correct.

RESPONSE (A):

Toronto Hydro's Future Energy Scenarios ("FES") should not be confused with a forecast. The outputs of FES are based on contrasting future scenario worlds (essentially "what if" scenarios), implemented via technology uptake and consumer behaviour models, and applied geospatially to Toronto Hydro's unique service territory, customer base, and distribution network. These scenario worlds were chosen with the intention of demonstrating a reasonable range of potential outcomes over the long-term, at the network level of Toronto Hydro's distribution system (as opposed to the Ontario bulk system in the IESO's study, for example).

In general, it is important to bear in mind that these studies are approaching different subjects (e.g., peak demand ranges in FES vs. costed GHG reduction pathways in Enbridge's study), at different levels of granularity (e.g., Toronto vs. provincial), using distinct modelling approaches, assumptions and data sources. For these reasons, a simple comparison between Toronto Hydro's Future Energy Scenarios and the referenced Enbridge and IESO studies is not feasible. The analysis in the Future Scenarios provides a reasonable outlook into the future possible system demands the utility faces in a range of credible energy transition scenarios.

RESPONSES TO ENVIRONMENTAL DEFENCE INTERROGATORIES

INTERROGATORY 1-ED-02

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 34

QUESTION (A):

a) Toronto Hydro states that its proposed Innovation Fund "is the low end of a range found in research of comparable ratepayer-funded initiatives aimed at facilitating innovation by utilities and regulatory bodies in other jurisdictions, as well as general data on utility spending for research and development activities." Please provide this analysis.

RESPONSE (A):

Please see Toronto Hydro's response to interrogatory 1B-DRC-06 part d).

QUESTION (B):

b) If Toronto Hydro were to set its Innovation Fund budget at the mid-range of comparable initiatives, what would the budget be?

RESPONSE (B):

If Toronto Hydro was to fund its Innovation Fund through a rate rider based on the mid-range of what it found in its research, Toronto Hydro would calculate an amount equal to 0.5% of its Revenue Requirement instead of 0.3%, which would result in approximately $27 million of funding for the Innovation Fund.

QUESTION (C):

c) What additional activities would Toronto Hydro undertake with a mid-range Innovation Fund budget?

RESPONSE (C):

The activities described in the four phases of the Governance Framework present a methodology, which is flexible with respect to budget, since it provides a roadmap for implementation rather than setting the scope of work. In contrast, the areas of innovation that can be addressed and the pilot projects that can be undertaken in connection with areas of innovation are affected by budget. Since Toronto Hydro has proposed the Innovation Fund to be at the low end of the range of funding found in its research, it has not considered what additional activities it might be able to undertake with a mid-range budget. However, the effect of a larger budget would likely be that Toronto Hydro could propose more areas of innovation and/or more pilot projects or larger scale pilot projects within the planned areas of innovation.

QUESTION (D):

d) How will the Innovation Fund rate rider be charged to residential customers - variable or fixed?

RESPONSE (D):

The Innovation Fund Rate Rider will be charged to residential customers as a fixed charge, consistent with the Distribution Revenue rate design for these classes. For a breakdown of how the Innovation Fund Rate Rider will be collected over the rate period, see Exhibit 9, Tab 3, Schedule 1 (Rate Rider Table).

QUESTION (E):

e) Is Toronto Hydro open to other Ontario utilities participating in its Innovation Fund pilots and benefiting from the results?

RESPONSE (E):

Please see Toronto Hydro’s response to interrogatory 1B-CCC-46 part a).

RESPONSES TO ENVIRONMENTAL DEFENCE INTERROGATORIES

INTERROGATORY 1B-ED-3

Reference: Exhibit 1B, Tab 3, Schedule 1, Page 38

QUESTION (A):

a) Please provide a table listing each building owned by Toronto Hydro, how they are heated, their approximate annual gas consumption, the age of any fossil fuel heating equipment, the approximate life left in any fossil fuel heating equipment, the annual fossil fuel costs (all inclusive, including commodity, delivery, and fixed charges), and the annual incremental electricity costs that would arise were the fossil fuel equipment with an appropriate electric heat pump.

RESPONSE (A):

All of Toronto Hydro's station buildings rely on electric heating and therefore, the following information relates to the utility's four work centres only, which rely on a mix of fuel sources, including fossil fuel. Please refer to the appendix to this response, which lists the fossil fuel heating equipment currently in service in the utility's 4 work centres, remaining useful lives of the assets, annual fuel costs, and gas consumption.

Toronto Hydro is unable to reliably estimate incremental electricity costs from replacing fossil fuel equipment with electric heat pumps since asset replacements may not be always like for like. For example, capacity limitations might require replacing one fossil fuel unit with multiple electric heat pumps or the addition of supplemental heating sources such as electric baseboard heaters. Moreover, heating system efficiencies vary across assets and work centres, adding to the difficulty of estimating incremental electricity costs.

QUESTION (B):

b) If any of its fossil fuel heating equipment reaches the end of its life within the rate term, will Toronto Hydro replace it with electric or fossil fuel equipment?

RESPONSE (B):

Yes, Toronto Hydro plans to replace poor condition end of life fossil fuel heating equipment in its buildings with electric or hybrid equipment, in accordance with prudent asset management practices under the utility's Facilities Asset Management Strategy[1] and with a view to successfully executing the Net Zero 2040 Strategy.[2]

As shown in the response to part (a), the majority of fossil fuel heating equipment coming at end of life in the 2025-2029 rate period are located at the 500 Commissioners work centre, where the utility expects to focus most of its investments.

[1] Exhibit 2B, Section D6.
[2] Exhibit 2B, Section D7.

RESPONSES TO ENVIRONMENTAL DEFENCE INTERROGATORIES

INTERROGATORY 1B-ED-4

Reference: Exhibit 1B, Tab 3, Schedule 1, Page 47

QUESTION (A):

For historic and planned LDR, please indicate (i) the percent which also provides demand response for provincial capacity purposes, (ii) the percent that involves gas-fired generation, (iii) the percent that involves storage, (iv) the percent that involves the purchase of DR from a pre-existing DER.

RESPONSE (A):

(i) Historically and currently, the capacity that has been utilized by Toronto Hydro for its LDR program has not been, and is not, simultaneously committed to the IESO's Capacity Auction. The LDR program only simulates providing demand response for provincial capacity purposes for the purposes of the Grid Innovation Fund pilot project as described in Section E7.2.1.4. of the Non-Wires Solutions program found at Exhibit 2B, Section E7.2.

(ii) Between 2018-2020, 87% of the demand response capacity committed to Toronto Hydro's LDR program involved the use of gas-fired generation. From 2020-2024, 0% of the demand response capacity committed to Toronto Hydro's LDR program relies on gas-fired generation.

(iii) Toronto Hydro has not yet received any DR capacity from storage resources, despite the fact that storage resources are eligible for participation.

(iv) All of the DERs that have been involved in provided DR capacity to Toronto Hydro existed prior to the launch of the procurements.

RESPONSES TO ENVIRONMENTAL DEFENCE INTERROGATORIES

INTERROGATORY 1B-ED-5

Reference: Exhibit 1B, Tab 3, Schedule 1, Page 50

QUESTION (A):

Please quantify the benefits of the proposed NWAs to electricity customers as a whole on a best-efforts basis.

RESPONSE (A):

The rate-payer benefits associated with the NWS program is outlined in detail in Exhibit 1B, Tab 3, Schedule 1 at pages 49-55.

QUESTION (B):

Please provide the underlying calculation spreadsheets for the benefits-cost analysis of the proposed LDR Flexible System Capacity, including any DCF spreadsheets. Please include the lifetime savings.

RESPONSE (B):

Please see the response to interrogatory 1B-Staff-49.

RESPONSES TO ENVIRONMENTAL DEFENCE INTERROGATORIES

INTERROGATORY 1B-ED-6

Reference: Exhibit 1B, Tab 4, Schedule 1, Page 15

QUESTION (A):

a) How many and what percent of Toronto Hydro customers are unable to connect a DER to the system due to capacity constraints?

RESPONSE (A):

Currently, there are five station buses unable to host DERs. This represents approximately 5 percent of Toronto Hydro's system. Please refer to Table 1 of Exhibit 2B, Section E3.3.

QUESTION (B):

b) Please estimate how many and what percent of Toronto Hydro customers will still be unable to connect a DER to the system due to capacity constraints by 2029 after additional investments by Toronto Hydro?

RESPONSE (B)

Toronto Hydro's proposed investments in Generation Protection, Monitoring and Control (GPMC) (Exhibit 2B, Section E5.5) and Stations Expansion (Section E7.4) target all system restrictions preventing the connection of DERs to the system. In addition, system capacity investments through the Load Demand (Exhibit 2B, Section E5.3) and Non-Wires Solutions (Section E7.2) programs are intended to alleviate expected system constraints to connecting DERs by 2029, such as improving minimum generation to load ratio (MLGR).

QUESTION (C):

c) Please provide a table showing the Toronto Hydro feeders, whether they are constrained, how many customers are attached to each, whether the constraint is short-circuit or thermal, and whether the constraint will be eliminated or lessened within the rate term.

RESPONSE (C):

Please see Table 1 in Exhibit 2B, Section E3.3.

QUESTION (D):

d) The application states: "Toronto Hydro plans to deploy nine energy storage systems, with an aggregate capacity of 10.2 MW, to enable the connection of forecasted renewable growth on nine high-priority feeders." Approximately how many customers will be impacted by this investment? Please list the relevant feeders, the nature of the restriction, and how many customers will be able install DERs due to the lifting of the restriction.

RESPONSE (D):

Please refer to Exhibit 2B Section E7.2 Table 20 for the nine planned ESS projects at respective priority feeders with an aggregate capacity of 10.2MW, intended to enable an aggregate renewable generation capacity of 6.12MW. The planned investments do not directly correlate to an impacted number of customers, which will depend on the size of the DERs as they materialize. Toronto Hydro's proposed investments will relieve minimum load to generation ratio (MLGR) restrictions.

QUESTION (E):

e) Does Toronto Hydro provide flexible hosting capacity? If not, when will it do so?

RESPONSE (E):

At this time, Toronto Hydro does not provided flexible connections. However, this is a capability that the utility has put forward as a pilot project concept that could be supported by its proposed Innovation Fund (see Exhibit 1B, Tab 4, Schedule 2, Appendix A, pages 2-3 for more details). Toronto Hydro also notes that flexible hosting capacity arrangements have been proposed as part of the OEB's Distributed Energy Resources (DER) Connections Review. On January 29, 2024, the OEB introduced a proposal for a new section 6.2.4.1A of the Distribution System Code, which will outline how distributors can establish specific system or operating conditions and/or contractual terms that will require the output or operation of the proposed embedded generation facility to be varied.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-1

Reference: **Exhibit 1B, Tab 1, Schedule 1, Section 2.3.2 Complex Operating Conditions, Table 1: Ontario Cities Population Density**

Preamble:

The population density of Etobicoke, North York, and Scarborough is similar to the population density of Mississauga, Brampton, Vaughan, Richmond Hill, Markham, Pickering, Whitby, and Oshawa.

QUESTION (A):

a) Please expand Table 1 to show the population densities of Etobicoke, North York, Scarborough, Mississauga, Brampton, Vaughan, Richmond Hill, Markham, Pickering, Whitby and Oshawa and file it.

RESPONSE (A):

Cities	Population (People)	Land Mass (km^2)	Population Density (People/km^2)
Toronto[1]	2,794,356	631.1	4,428
Ottawa	1,017,449	2788.2	365
Mississauga	717,961	292.74	2,453
Brampton	656,480	265.89	2,469
Hamilton	569,353	1118.31	509
Richmond Hill	202,022	100.79	2,004
Vaughan	323,103	272.44	1,186
Markham	338,503	210.93	1,605
Pickering	99,186	231.10	429

[1] Toronto Hydro notes that the municipality of City of Toronto already includes the boroughs of Etobicoke, North York, and Scarborough.

Cities	**Population (People)**	**Land Mass (km^2)**	**Population Density (People/km^2)**
Whitby	138,501	146.69	944
Oshawa	175,383	145.72	1,204

QUESTION (B) :

b) Please confirm that there are large areas of agricultural land within city limits of Hamilton and Oshawa.

RESPONSE (B):

Toronto Hydro is familiar with the characteristics of its service territory and the boundaries of the City of Toronto, but does not have similar detailed data regarding the municipal boundaries and service territories applicable to all other utilities.

QUESTION (C) :

c) What is the population density of Mississauga if the land occupied by Pearson Airport is excluded.

RESPONSE (C):

Please see part b) above.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-2

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 2.3.2 Complex Operating Conditions and Table 2

Preamble:

"The density of Toronto Hydro's service territory is unique even within an international context due to the ever-increasing number of high-rise buildings."

QUESTION (A):

a) Please provide Toronto Hydro's definition of a high-rise building.

RESPONSE (A):

Please see footnote 28: "High-rise building is a multi-floor building of at least 12 stories or 35m in height. As per data from SkyscraperPage, Global Cities & Buildings Database https://skyscraperpage.com/cities/#notes".

QUESTION (B):

b) Table 2 indicates that there are 2,598 high rise buildings in Toronto. How many of those buildings use natural gas for space and water heating? How many of those buildings have a natural gas or diesel emergency power generator?

RESPONSE (B):

Toronto Hydro does not track this type of data.

QUESTION (C):

c) Please list the cost impacts that construction of high-rise buildings imposes on Toronto Hydro.

RESPONSE (C):

High-rise buildings are not tracked distinctly from other types of connection projects. Customer connections costs are evaluated in accordance with DSC Section 3 Connection and Expansions, and evaluated based on the new customer's connection and expansion asset requirements. If new facilities must be constructed to the main distribution system in order to connect the Customer, those facilities (expansion) are evaluated via the prescribed economic evaluation in DSC Appendix B. The economic evaluation determines the amount of capital contribution that will be required by the Customer for the expansion work. The customer is responsible for the connection asset costs (connection from the main distribution system to the customer's demarcation point) less the basic connection allowance.

QUESTION (D):

d) Does Toronto Hydro believe that existing ratepayers should subsidize developers of high-rise buildings? Please explain your answer.

RESPONSE (D):

Toronto Hydro is licensed by the Ontario Energy Board ("OEB") to supply electricity to Customers as described in the Electricity Distribution License issued to Toronto Hydro on October 17, 2003 by the OEB. Additionally, there are requirements imposed on Toronto Hydro by the various codes referred to in the Distribution License and by the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, including the Distribution System Code. As a licensed distributor of electricity, Toronto Hydro is obligated to connect customers to its distribution system and must adhere to the laws, regulations, and codes to effect customer connections. This includes cost allocation and treatment of service connections in a manner compliant with the laws, regulations and codes.

QUESTION (E):

e) Are developers of high-rise buildings required to pay contributions in aid of construction to offset the costs they impose on Toronto Hydro? If the answer is yes, please explain how these contributions are assessed and the total amount collected by Toronto Hydro in the most recent year for which a total amount is available. If the answer is no, please explain why not.

RESPONSE (E):

Please refer to Toronto Hydro's response to parts c) and d) above.

With regards to the total amount of contributions collected by Toronto Hydro, by year, please refer to Exhibit 2B, Section E5.1, Table 9, pages 18-19.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-3

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 2.3.2 Complex Operating Conditions

Preamble:

"In addition to high-rise buildings, this growth is also driving the development of sustainable new housing communities through the redevelopment of areas such as Downsview, the Golden Mile and the Port Lands, some of which are planned as net zero communities and to meet the highest performance measures of the Toronto Green Standard."

QUESTION (A):

a) Please provide Toronto Hydro's definition of "sustainable new housing communities."

RESPONSE (A):

Sustainable new housing communities in this context refers to new developments that have been approved by the City of Toronto Planning that conform to current and future versions of the Toronto Green Standard (TGS).

QUESTION (B):

b) Please file the Toronto Green Standard and identify the "highest performance measures."

RESPONSE (B):

The Toronto Green Standard (TGS) is owned and managed by the City of Toronto. More information may be found on the City of Toronto website - https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/. Performance targets are established based on type of development, this framework can be found on the above website.

QUESTION (C):

c) Does Toronto Hydro audit claims of measurement of highest performance under the Toronto Green Standard?

RESPONSE (C):

The Toronto Green Standard is audited and enforced by the City of Toronto. More information may be found on the City of Toronto website - https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/.

QUESTION (D):

d) Do sustainable new housing communities impose additional costs on Toronto Hydro than do existing communities?

RESPONSE (D):

Sustainable new housing communities do not incur additional costs nor are they treated differently from other customers. The supply of electricity or related services by Toronto Hydro to any customer are subject to the same assessment and requirements outlined in Toronto Hydro's Conditions of Service, which comply with the requirements of the Distribution System Code.

QUESTION (E):

e) Does Toronto Hydro believe that ratepayers in existing communities should subsidize ratepayers in new sustainable communities? Please explain your answer.

RESPONSE (E):

There is no cross subsidy, please refer to response d) above. As a licensed distributor of electricity, Toronto Hydro is obligated to connect customers to its distribution system and must adhere to the laws, regulations, and codes to effect customer connections. This includes cost allocation and treatment of service connections in a manner compliant with the laws, regulations and codes.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-4

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 2.3.4 Extreme Weather

Preamble:

"Extreme weather amplifies the challenge of distributing electricity to a mature, dense and rapidly growing urban city. Heat, high winds, heavy rainfall, freezing rain and heavy snowfall can cause major system damage and result in prolonged power outages. As evidenced by recent events (outlined in Table 3 below), extreme weather has become a regular operating condition that the utility must consider and manage in its day-to-day operations and long-term planning activities. With the frequency and intensity of adverse weather increasing due to climate change, Toronto Hydro's grid and operations must become more resilient to this challenge."

QUESTION:

Please provide Toronto Hydro's definitions of "extreme weather," "averse weather," "climate change" and "prolonged power outage."

RESPONSE:

Toronto Hydro defines "extreme weather" and "adverse weather" as rain, ice storms, snow, winds, extreme temperatures (heat and cold), freezing rain, frost, or other extreme weather conditions that are likely to affect grid operations.

The utility uses the Intergovernmental Panel for Climate Change's ("IPCC") definition of climate change as "a change in the state of the climate that can be identified (e.g., by using statistical tests) by changes in the mean and/ or the variability of its properties and that persists for an extended period, typically decades or longer."[1]

[1] https://www.ipcc.ch/site/assets/uploads/sites/4/2022/11/SRCCL_Annex-I-Glossary.pdf

Prolonged power outage refers to an interruption in electric service that lasts longer than typical outages at the distribution level and can extend from several hours to days or even weeks.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-5

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 2.3.1 Technology Advancements

Preamble:

"Integrating DERs into the grid provides customers more tools to actively manage their energy needs and enables the grid to be supplied by locally-generated renewable electricity resources. To advance these outcomes, Toronto Hydro must address the significant challenge of accommodating electrons that flow bidirectionally within a grid that was not built for this type of supply and demand. Equipment that has a high number of DER connections is more likely to experience unstable conditions that pose significant reliability and safety risks to the system and its users. Toronto Hydro monitors all DER connections closely for these factors to ensure that the grid remains safe and reliable for customers, and is building advanced grid capabilities to mitigate against these risks and enable DER adoption by customers in the future."

QUESTION (A):

a) Please confirm that customers who own DER's impose additional costs on Toronto Hydro.

RESPONSE (A):

Confirmed. There are additional costs associated with enabling DER connections. Some of these costs are eligible investments for provincial rate protection pursuant to *Ontario Regulation 330/09*, as outlined in Exhibit 2A, Tab 5, Schedule 1.

QUESTION (B):

b) Does Toronto Hydro require new customers who are installing DER's to pay a contribution to offset the costs they impose on Toronto Hydro?

RESPONSE (B):

Yes. Toronto Hydro complies with the requirements of the Distribution System Code to determine the capital contributions that must be paid by DER customers connecting to the grid.

QUESTION (C):

c) Does Toronto Hydro believe that customers who do not own DERs should subsidize customers who own DERs? Please explain your answer.

RESPONSE (C):

It is not within Toronto Hydro’s purview to comment on the cost allocation rules in the Distribution System Code, or the OEB’s policy objectives with respect to DER integration. Toronto Hydro notes that investments in Grid Modernization to develop advanced grid capabilities that can support and enable DER adoption by customers in the future, also provide value to load customers in terms of reliability, resiliency and efficiency benefits. Please see Exhibit 2B, Section D5 for more information.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-6

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 2.3.2 Workforce Challenges

Preamble:

"Over this period, as Toronto Hydro's replenished a large wave of retirements, it also right-sized its workforce through continuous improvements in productivity, including harmonizing key jobs to create a more agile compliment of staff, and automating manual processes to increase employee output levels"

QUESTION (A):

a) Please provide Toronto Hydro's definition of "right-sized."

RESPONSE (A):

Please refer to 1B-CCC-14 (b)

QUESTION (B):

b) Does the quoted paragraph indicate that Toronto Hydro has increased or decreased the total number of its employees? Please explain your answer.

RESPONSE (B):

Please refer to 1B-CCC-14 (b)

QUESTION (C):

c) On the average, is the compensation of a newly hired young and inexperienced employee higher or lower than of an old and experienced employee who is retiring? Please explain your answer.

RESPONSE (C):

Please refer to 4-CCMBC-18.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-7

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 3.3 Plan Validation and Finalization, Table 4: Summary of 2025-2029 Proposed Distribution Rate Change

QUESTION (A):

a) Are the amounts shown in Table 4 up to date? If the answer is no, please file the table with the current amounts.

RESPONSE (A):

Toronto Hydro confirm the amounts in Table 4 are up to date.

QUESTION (B):

b) Please expand Table 4 to show percentage rate increases (not bill impacts as shown in Exhibit 1B, Tab 1, Schedule 3, Page 1, Table 1 or Page 3, Table 3 which mask rate increases with other factors) for each year and the average. If such a table is elsewhere in the filing, please provide the reference.

RESPONSE (B):

Please refer to Exhibit 8, Tab 1, Schedule 1, Page 14-16, Table 5.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-8

Reference: **Exhibit 1B, Tab 1, Schedule 1, Section 4.2 Growth and City Electrification, Table 6: City Growth and Electrification Capital Programs**

QUESTION (A):

a) Is Toronto Hydro charging developers for the costs of relocations to accommodate new high-rise developments? Please discuss.

RESPONSE (A):

If a customer requests that a Toronto Hydro owned asset be relocated, Toronto Hydro applies Distribution System Code Section 3.1.10 – "Where a customer requests the relocation of a distributor-owned asset, the distributor shall recover from that customer the cost of relocating that asset, except to the extent recovery is limited under law."

QUESTION (B):

b) Is Toronto Hydro sharing the costs of relocations for road widening, LRT construction, waterfront reconstruction construction with the City of Toronto, Metrolinx, Waterfront Toronto, and other agencies? Please discuss.

RESPONSE (B):

Please refer to Exhibit 2B, Section E5.2, pages 5-8 for details of cost apportionment between Toronto Hydro and third parties requesting relocation of utility assets to accommodate the maintenance and improvement of public infrastructure.

QUESTION (C):

c) Is Toronto Hydro following the OEB's Distribution System Code in determining the need for contributions for new loads? Please discuss.

RESPONSE (C):

Yes, please refer to Toronto Hydro's response to interrogatory 1B-EP-2 parts (c) and (d).

QUESTION (D):

d) Are the amounts shown in Table 6 net of contributions or are the gross amounts?

RESPONSE (D):

Toronto Hydro confirms that the amounts shown in Table 6 are net of contributions. Please refer to Exhibit 2B, Section E5.1.4.1, Table 9 for the gross, contribution and net Customer Connections expenditures and Exhibit 2B, Section E5.2.4, Table 4 for Externally Initiated Plant Relocations & Expansions expenditures.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-9

Reference: Exhibit 1B, Tab 1, Schedule 1, Section 4.3 Grid Modernization

<u>Preamble:</u>

"The system provides a holistic view of the grid and encompasses advanced applications such as Outage Management System (OMS), Fault Location Isolation and Service Restoration (FLISR), Volt/Var Optimization, which allow swift detection and response to outages and grid disturbances, and enable reliable and efficient management of DERs by optimizing voltage levels and reactive power flows throughout the distribution system."

QUESTION (A):

What percentage of expenditures on OMC, FLISR, and Volt/Var Optimization are required to enable reliable and efficient management of DERs and what percentage of expenditures are required for other reasons? Please explain your answer.

RESPONSE (A):

Toronto Hydro's investments in Outage Management System (OMS), Fault Location Isolation and Service Restoration (FLISR), and Volt/Var Optimization applications are intended to reduce the frequency and duration of outages, improve grid resiliency, enhance the efficiency of outage response, and optimize the distribution system. As such, they are independent of the uptake of DERs or the need to enable DER management.

QUESTION (B):

Are customers who own DER's required to pay a contribution to offset the expenditures that are required to serve them? If the answer is yes, please provide the total amount that is expected to be collected in 2025 from customers who own or rent DER's. If the answer is no, please explain why not.

RESPONSE (B):

No. Customers are only required to pay a capital contribution for project expenses and operational costs to facilitate the DER connection. Toronto Hydro recovers the cost of this connection in accordance with the Distribution System Code.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-10

Reference: Exhibit 1B, Tab 1, Schedule 3, Page 5, Table 5: Customer and Load Growth Changes for 2018-2029

QUESTION (A):

a) Please confirm that Toronto Hydro's evidence as presented in Table 5 shows that electrification will result in a reduction in load. Please explain your answer.

RESPONSE (A):

Toronto Hydro does not confirm that the evidence in Table 5 proves electrification will lead to a decrease in load. Please see response to interrogatory 1B-PP-18.

QUESTION (B):

b) Please confirm that Toronto Hydro is proposing to spend more and more money to deliver less and less electricity. Please explain your answer.

RESPONSE (B):

Toronto Hydro does not confirm this statement. Exhibits 2B and 4 contain detailed evidence of the needed and prudent investments for Toronto Hydro to sustain the distribution system, modernize the grid, connect new customers and DERs, and invest in its workforce in order to provide safe and reliable service in an increasingly complex environment. Further, Toronto Hydro's multi-variate regression analysis forecasting customer and load growth, which explicitly includes historical and forecast CDM assumptions, shows modest growth in system-wide consumption and demand. This customer and load forecast is a separate exercise from Toronto Hydro's peak demand forecast for system planning purposes. That peak demand forecast informs "the planning of capital work programs mainly at the distribution station level (e.g., feeder level) to meet capacity need. The peak demand forecast considers localized growth and density intensification from new high-rise developments, EVs, and other large connections that are driving the need for investments."[1]

[1] Exhibit 3, Tab 1, Schedule 1, p.18

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-11

Reference: Exhibit 1B, Tab 1, Schedule 3, Page 10, Table 10: Proposed Capital Structure and Cost of Capital Parameters

QUESTIONS (A) AND (B):

a) Is Toronto Hydro proposing to use the same 40% deemed equity thickness as the other 57 distributors regulated by the OEB? Please explain your answer.

b) Is Toronto Hydro proposing to use the same 9.36% deemed return on common equity as the other 57 distributors regulated by the OEB? Please explain your answer.

RESPONSE (A) AND (B):

Please see the response to interrogatory 5-Staff-315. Toronto Hydro intends to update the deemed return on equity rate at the time of the DRO based on the Cost of Capital parameters which will be issued by the OEB in the fall of this year.

QUESTION (C):

Does the recent OEB decision in the EB-2023-0143 Getting Ontario Connected Variance account that allowed.

RESPONSE (C):

Toronto Hydro cannot respond because this question is incomplete.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-12

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 2

Preamble:

"The current custom rate framework, which was established in the 2015-2019 Rate Application (EB-2014-0116), provided stability and flexibility as Toronto Hydro grappled with the significant challenge of renewing a rapidly deteriorating distribution system. The 2025-2029 Custom Rate Framework detailed in this schedule is structurally consistent with the rate framework approved by the OEB in past applications, with purposeful evolutions to achieve the objectives summarized below.

Provide multi-year funding certainty and flexibility for Toronto Hydro to:

(i) continue to sustain a reliable grid and safe and effective operations; and

(ii) address current and emerging (externally-driven) needs and challenges that the utility faces in delivering its services and preparing the grid for the energy transition."

QUESTION (A):

a) Please explain why the current rate framework should be changed if it provided "stability and flexibility." Does Toronto Hydro no longer need stability and flexibility?

RESPONSE (A):

As noted in the referenced evidence, Toronto Hydro maintained various components of its prior Custom IR rate framework which facilitate the continuation of stability and flexibility. For a detailed explanation of the rationale for evolving the current rate framework please refer to section 2 of the referenced evidence starting on page 12. With respect to funding implications specifically, Table 2 of the evidence outlines the ROE implications of continuing with the current rate framework.

QUESTION (B):

b) Does Toronto Hydro still have a "rapidly deteriorating distribution system"? If the answer is yes, why has Toronto Hydro management failed to stop the deterioration since the current custom rate framework was established?

RESPONSE (B):

Please refer to Exhibit 2B, Section E2.2.1, which provides an overview of the current condition and reliability performance of Toronto Hydro's distribution asset populations. While the current state of different asset classes varies, in the broadest terms, Toronto Hydro's significant capital investments since 2015 have resulted in stable or improving asset condition and age demographics, and improvements in reliability. Toronto Hydro's 2025-2029 System Renewal plan is built from the bottom up to ensure the utility will continue to make the minimum investment necessary to maintain current levels of asset risk and recent historical reliability performance.

QUESTION (C):

c) Please explain what is meant by the term "structurally consistent" and how it differs from the meaning of the word "consistent"?

RESPONSE (C):

"Structural consistency" generally refers to the uniformity, coherence, or stability of a system, or framework concerning its underlying structure. In the noted reference, "structural" refers to foundational components of the 2025-2029 custom rate framework. Please refer to pages 5 and 6 of the Rate Framework evidence (Exhibit 1B, Tab 2, Schedule 1) for a summary the components of the proposed rate framework, a comparison to the 2020-2024 custom rate framework and an explanation of how the proposed rate framework aligns with the RRF and OEB Rate Handbook.

QUESTION (D):

d) Does the 2025-2029 Custom Rate Framework meet the OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 3, Incentive Rate Setting Applications? If the answer is no, please explain why not.

RESPONSE (D):

The premise of this question not consistent with the Chapter 3 Filing Requirements which state at page 1: "*These filing requirements set out the OEB's expectations for electricity distributors' annual rate adjustment applications in between cost of service (CoS) applications under Price Cap IR, or the Annual IR Index, also known as IRM applications.*"

QUESTION (E):

e) Does "multi-year funding certainty" provide more funding certainty than Price Cap IR used by most Ontario Distributors? If the answer is yes, why should Toronto Hydro have more funding certainty than other distributors? If the answer is no, please explain why not?

RESPONSE (E):

Relative to the funding that is available to Toronto Hydro specifically under Price Cap IR, the proposal in this application provides adequate funding certainty. Please refer to 1B-Staff-12 for a breakdown of the revenue differences between Price Cap IR and the proposed custom index. Please refer to the response to 1B-Staff-15 for the implications of Price Cap IR on utility financial performance (ROE).

Toronto Hydro is unable to comment on the funding adequacy of Price Cap IR for other utilities. Such a determination needs to be made on the specific facts and circumstances of each utility in question.

QUESTION (F):

f) Does the proposed 2025-2029 Custom Rate Framework increase or decrease the earnings risk of Toronto Hydro compared to its current rate framework? Please explain your answer.

RESPONSE (F):

The structure of the proposed 2025-2029 Custom Rate Framework places more risk on the utility than the structure of the 2020-2024 Custom Rate Framework. This is because, considering Toronto

Hydro's total cost benchmarking results relied on in this Application, the X-factor applicable under the 2020-2024 Custom Framework would have been approximately 0.45 % (i.e. 0.15% empirical stretch plus a 0.3% incremental stretch factor applied to capital), which is less than the 0.75% combined X-factor proposed in the 2025-2029 Custom Framework. Furthermore, the net difference between the two stretch factors (i.e. 0.3%) represents an amount that the utility would have been able to recover in rates under the 2020-2024 Custom Framework. However, under the 2025-2029 Custom Framework, Toronto Hydro has placed that amount at risk (as an upfront discount for ratepayers for the 2025-2029 rate period) pending the achievement of target performance objectives as outlined in the Custom Scorecard and accompanying PIM evidence in Exhibit 1B, Tab 3, Schedule 1.

QUESTION (G):

g) Does the proposed 2025-2029 Custom Rate Framework allow Toronto Hydro to have a higher or a lower earnings risk than Ontario distributors who use the Price Cap IR rate setting method? Please explain your answer.

RESPONSE (G):

For the reasons noted in part (f), all other things equally considered, Toronto Hydro assumes a greater level of earnings risk.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-14

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 12

Preamble:

"As illustrated in Figure 1 below, the continuation of a custom-rate setting approach is necessary for Toronto Hydro as funding derived from the OEB's standard Price Cap and IRM framework is insufficient to fund the plan's imperatives of system stewardship, growth and electrification, and modernization."

QUESTION (A):

a) Does Toronto Hydro believe that OEB's standard Price Cap IRM framework is inadequate to fund "imperatives of system stewardship, growth and electrification, and modernization" of electricity distributors and should be changed? Please explain your answer.

RESPONSE (A):

Within the context of Toronto Hydro's investment needs, Price Cap IR is inadequate to fund "imperatives of system stewardship, growth and electrification, and modernization." Please see the response to 1B-Staff-3(b) as it relates to funding under Price Cap IR.

The RFF provides a Custom IR approach for utilities that are in Toronto Hydro's circumstance, for whom Price Cap IR is insufficient. Toronto Hydro declines to comment on whether Price Cap IR should be changed, as the question is not relevant to this Custom IR proceeding.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-15

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

<u>Preamble:</u>

"Under a standard IRM scenario, Toronto Hydro's 2025-2029 capital investment plan would be underfunded by approximately 35 percent or $1.5 billion. 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, along with increases in safety and environmental risks and reactive replacement costs due to increasing numbers of asset failures."

QUESTIONS (A):

a) Please file the calculation that shows the derivation of the "8 percent deterioration in system reliability".

RESPONSE (A):

The 8 percent deterioration in system reliability was calculated as the percentage difference between 2018-2022 SAIDI (Excluding Loss of Supply, Major Events, and Scheduled Outages) of 48.16 and the projected 5-year rolling average at the end of the rate period under the IRM scenario of 51.91 minutes (see Figure 1 in Exhibit 1B, Tab 3, Schedule 1). For more details on Toronto Hydro's reliability projection models, please refer to interrogatory 2B-SEC-42.

QUESTION (B):

b) Would the "8 percent deterioration in system reliability" be experienced throughout the Toronto Hydro service area? If the answer is no, please provide the percentage of deterioration in each area.

RESPONSE (B):

Toronto Hydro's reliability projection methodology is not currently designed to forecast reliability for sub-divisions of the system. The eight percent deterioration is a system-wide average.

QUESTION (C):

c) Is Toronto Hydro claiming that only unconstrained spending can prevent a deterioration in system reliability?

RESPONSE (C):

No. Toronto Hydro's 2025-2029 Investment Plan establishes the necessary level of funding to manage System Reliability over the next rate period. It is not unconstrained. Key investments in expanding, modernizing, and sustaining the foundations of the grid will be critical for System Reliability, supporting the utility's objective of improving Outage Duration and maintaining Outage Frequency measures (see Exhibit 1B, Tab 3, Schedule 1, Pg. 8 to 21).

QUESTION (D):

d) If $1.5 billion spending is required to prevent any deterioration in system reliability, what would be the percentage of deterioration if only $1.0 billion was spent?

RESPONSE (D):

Toronto Hydro has not assessed this specific scenario, as doing so would require a complete re-evaluation of the 2025-2029 Investment Plan, program by program. However, based on similar 'envelope funding' scenarios requested by Intervenors, Toronto Hydro has produced additional reliability scenario projections (Outage Duration and Outage Frequency) over the 2025-2029 period for comparison purposes. Please refer to Toronto Hydro's response to interrogatory 1B-SEC-21.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-16

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 21

Preamble:

"Toronto Hydro proposes a shift in its rate-setting approach from price-cap to a revenue-cap model. Rather than escalate rates themselves each year, and use a simplistic g-factor to account for expected billing determinant growth, Toronto Hydro proposes to escalate revenue requirement each year, and design rates for each revenue requirement on the basis of forecasted customer and load growth over the rate term."

QUESTION (A):

a) Please confirm that under a price-cap model, a utility bears the load forecast risk while under a revenue-cap model a utility does not bear the load forecast risk. Please explain your answer.

RESPONSE (A):

Under a Price Cap model and the Revenue Requirement Cap applied for by other utilities regulated by the OEB, both the utility and ratepayers bear any risk or reward associated with variances in billing determinants. To the degree billing determinants exceed forecast, customers bear this risk and the utility experiences reward. Should billing determinants fall short of forecast, the utility bears the risk and customers experience reward.

However, under a true revenue cap model as proposed by Toronto Hydro, actual revenues collected are trued-up against forecast revenue requirement, as determined via annual CRCI escalations inclusive of the RGF values approved in the rebasing year. The true-up is completed on the basis of weather-normalized billing determinant variances.

QUESTION (B):

b) Please confirm that the proposed revenue cap model lowers the business risk of Toronto Hydro compared to the Ontario distributors that use the standard OEB price-cap model. Please explain your answer.

RESPONSE (B):

No. For information about the business risks that Toronto Hydro faces, please see the response to interrogatory 5-Staff-315.

The use of a revenue cap model inclusive of a true-up mechanism addresses uncertainty associated with billing determinants growth for *both* ratepayers and the utility. Conversely, this approach also neutralizes the opportunity for either party to benefit from billing determinant variances. The inclusion of this mechanism is an important component of Toronto Hydro's rate framework "…*to protect ratepayers, the utility and its shareholder, from structural unknowns in forecasted costs and revenues related to demand growth in a time of unprecedented change and transformation in the economy and energy system*."[1]

[1] Exhibit 1B, Tab 2, Schedule 1, p.4

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-17

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 23

Preamble:

"The C-factor is an attrition relief mechanism that implements additional rate escalations 1 each year, beyond those provided for through base rates escalated at inflation less productivity, to account for the utility's growing capital-related revenue requirement as a result of implementing the multi-year capital investment plan known as the DSP."

QUESTION:

The term "attrition relief mechanism" is not commonly used by the OEB. The noun attrition means a decrease in number size or strength. What is decreasing at Toronto Hydro that would require a relief mechanism?

RESPONSE:

As described in the reference above, attrition relief refers to a mechanism (such as the C-Factor or the Revenue Growth Factor) which mitigates the attrition of funding in rates relative to the utility's prudent and necessary costs (i.e. revenue requirement).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-18

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 29

Preamble:

"In addition to the efficiency-factor, Toronto Hydro's rate framework proposes a proactive 0.6 percent performance incentive factor that further reduces revenues by approximately $65 million over the rate term, providing customers an additional upfront rate reduction."

QUESTION (A):

a) Why would a reduction in revenues provide customers a rate reduction in a revenue-cap plan or does Toronto Hydro actually mean a reduction in revenue requirement?

RESPONSE (A):

Through the Custom Revenue Cap Index, the X-factor reduces the revenue (and thus rates) that the utility is able to collect through rates over the 2026 to 2029 period. Toronto Hydro's revenue requirement remains unaffected by this input, as it reflects Toronto Hydro's costs to fund the 2025-2029 Investment Plan featured in Exhibits 2B and 4. Please see the response to 1B-Staff-3 for more information about the revenue reduction/deficiency imposed by the rate framework.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-19

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

Preamble:

"To implement the PIM, Toronto Hydro proposes a new deferral account - the Performance Incentive Mechanism Deferral Account (PIM-DA) - to record the PIM earnings. This account would be brought forward for review and disposition in the utility's next rebasing application, based on known (or forecasted) performance results for the 2025-2029 rate period."

QUESTION:

Will the entries in the PIM-DA be audited by an independent external auditor? If the answer is no, please explain why not.

RESPONSE:

As with all other DVAs, entries in the PIM-DA would be reviewed by an external auditor to obtain reasonable assurance that the financial statements are free from material misstatement.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-20

Reference: Exhibit 1B, Tab 2, Schedule 1, Page 34

Preamble:

"In alignment with the OEB's statutory objective to facilitate innovation in the electricity sector, Toronto Hydro proposes to establish an Innovation Fund to support the design and execution of innovative pilot projects over the 2025-2029 rate period."

QUESTION (A):

a) Please provide Toronto Hydro's definition of "innovative pilot projects."

RESPONSE (A):

A pilot project is an exploratory project designed to test the feasibility, viability, and effectiveness of a particular concept, strategy, technology, or process before full-scale implementation. The goal of a pilot project is to gather data, identify potential challenges, and assess the practicality of the proposed solution or idea. As stated on page 7 of the referenced evidence, Toronto Hydro employs the same definition of innovation as the OEB does in section 2.1.7 of the Filing Requirements. Thus, "innovative pilot projects" refers to exploratory projects that have the potential to deploy innovative solutions in line with the considerations and parameters described in the Innovation Fund evidence, particularly in section 3 (Areas of Innovation).

QUESTION (B):

b) Please confirm that ratepayers will bear the risk that innovative pilot projects might deliver no benefits to ratepayers.

RESPONSE (B):

Please see Toronto Hydro's response to interrogatory 1B-CCC-46 part (b).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-21

Reference: Exhibit 1B, Tab 2, Schedule 1, Pages 35 to 37

Preamble:

"Subject to OEB approval, Account 1508 - Demand-Related Variance Account (DRVA) would record: (i) the demand-driven revenue requirement impacts arising from variances in actual versus forecast capital and operational expenditures for certain demand-based programs (the Expenditure Variance Sub-Account); and (ii) the 1 revenue impacts arising from variances in forecast versus actual billing determinants over the rate period (the Revenue Variances Sub-Account)."

QUESTION (A):

a) Does the proposed Demand Related Variance account increase or decrease the business risk of Toronto Hydro? Please explain your answer.

RESPONSE (A):

As noted in the DRVA evidence filed at Exhibit 1B, Tab 2, Schedule 1 starting on page 35, this rate application is being filed during a time of unprecedented change and transformation, as customers, communities and governments at all levels are actively embarking on an energy transition to mitigate the existential and economic impacts of climate change. Decarbonization is expected to create new roles for electricity, including as an energy source for transportation and building heating systems. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g., the pace and adoption of electrified technologies such as EVs and heat pumps; the role of low-emission gas; and the scale of local vs. bulk electricity supply).

The DRVA mitigates the impact of heightened uncertainty and associated forecasting risk associated with forecasting customer demand during this period of unprecedented change and transition. In doing so, the DRVA negates the prospect of either ratepayers or the utility losing or benefiting from structural unknowns (i.e. changes in policy, technology and consumer behaviour related to the energy transition) that may lead to material demand-related variances in costs or revenues in the next rate term.

As noted in the response to interrogatory 5-EP-34(c), a variance account does not lower utility risk because the recovery of any amounts tracked in a variance account is subject to regulatory prudence review upon disposition of the account.

QUESTION (B) :

b) Is Toronto Hydro assuming that all capital project variances including variances caused by poor project management would be recorded in the DRVA?

RESPONSE (B):

Toronto Hydro respectfully notes that the premise of this question is unfounded by evidence. Over the last two custom incentive rate period, the utility has demonstrated prudent delivery of its capital work program within reasonable margins of variance on total in-service additions (see 9-Staff-339). As noted above, and as is the case with any DVA that tracks variances from forecasted costs, the disposition of DRVA balances would be subject to a prudence review in the 2030 rebasing application.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-22

Reference: **Exhibit 1B, Tab 2, Schedule 1, Pages 46, Demand-Related Revenue Variance Subaccount**

QUESTION:

Does the proposed Demand-Related Revenue Variance account increase or decrease the business risk of Toronto Hydro? Please explain your answer.

RESPONSE:

Please see response to 1B-EP-21(a) with respect to the impact of the DRVA on business risk.

With respect to the DRVA – Revenue Variance Sub-Account, Toronto Hydro notes in the evidence at Exhibit 1B, Tab 2, Schedule 1 page 46: "*With this subaccount, Toronto Hydro's CRCI becomes a true revenue cap model (subject to weather-driven variances) … with the revenue variance sub-account operating similar to a decoupling true-up mechanism.*"

Please see the response to 1B-Staff-37(a) for a further explanation of how the Revenue Variance subaccount operates as a decoupling mechanism. Please see the response to 1B-EP-16 for a discussion of the difference in risk between a price cap and a revenue cap.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 1B-EP-23

Reference: Exhibit 1B, Tab 2, Appendix A and Appendix B, Scott Madden Report

QUESTION (A):

a) The report refers to a few US states. Should the OEB assume that regulatory commissions in the remaining US states have not approved any incentive rate plans that are similar to the plan that Toronto Hydro is proposing. Please explain your answer.

RESPONSE (A) - PREPARED BY SCOTTMADDEN:

No. The OEB should not assume US regulatory commissions not mentioned in the report have not approved rate plans that are similar to the plan that Toronto Hydro is proposing because the report was not intended to be a jurisdiction-by-jurisdiction scan of rate plans. Nor was the report intended to examine changes in ratemaking frameworks and practices over time.

Rather, the report identified ratemaking frameworks and practices of electric utilities that support a clean energy transition, similar to Toronto Hydro. The report focused in large part on electric utilities in jurisdictions leading clean energy transitions, such as Hawaii, New York, and the United Kingdom.

QUESTION (B):

b) Please confirm that regulatory regimes in the United Kingdom, Australia, Philippines, and Malaysia are quite different from the North American cost of service/ rate of return on rate base form of regulation. Please explain your answer.

RESPONSE (B) - PREPARED BY SCOTTMADDEN:

Australia, Philippines, Malaysia and the UK utilize a building blocks method to setting rates. The building blocks method is based on a cost of service (e.g., operating expenses, return on investment, depreciation, and taxes).

QUESTION (C):

c) Please confirm that the Revenue Growth Factor proposed by Toronto Hydro is actually a revenue requirement growth factor.

RESPONSE (C):

Toronto Hydro does not confirm the statement. While the mathematical basis for the Revenue Growth Factor (RGF) is the difference in forecasted revenue requirement from year to year during the rate term, the RGF is subject to the revenue reductions imposed by the X-Factor through the custom index. As noted and shown in the response to 1B-Staff-03(c), through the application of the X-factor, the custom index yields a revenue deficiency of approximately $81.5 million over the rate term, relative to the revenue requirement for the Investment Plan.

The custom index (inclusive of the RGF) does not fund the entirety of the revenue requirement (i.e. costs) that the utility requires to deliver the 2025-2029 Investment Plan; therefore, it is not accurate to characterize the RGF as a revenue requirement growth factor.

QUESTION (D):

d) Please explain how Toronto Hydro's proposed custom IR differs from a multi-year cost of service rate plan.

RESPONSE (D):

Please see response to 1B-Staff-03.

QUESTION (E):

e) Based on Scott Madden's research, is Toronto Hydro's proposed custom IR plan simple or complex?

RESPONSE (E) - PREPARED BY SCOTTMADDEN:

ScottMadden did not evaluate Toronto Hydro's proposed custom IR plan for its relative complexity or simplicity. ScottMadden evaluated Toronto Hydro's proposed custom IR plan for its consistency with other electric utility ratemaking frameworks and practices that support a clean energy transition.

QUESTION (F):

f) Based on Scott Madden's research does Toronto Hydro's proposed custom IR plan provide more or less incentive for productivity improvements than OEB's standard price-cap plan that is used by most Ontario distributors?

RESPONSE (F) - PREPARED BY SCOTTMADDEN:

ScottMadden did not evaluate Toronto Hydro's proposed customer IR plan for its relative incentive for productivity improvements as compared to OEB's standard price-cap plan. ScottMadden evaluated Toronto Hydro's proposed custom IR plan for its consistency with other electric utility ratemaking frameworks and practices that support a clean energy transition.