RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-117

Reference: Exhibit 2A, Tab 1, Schedule 2, OEB Appendix 2-BA

a) Please provide appendix 2-BA for 2019 actuals. Please ensure to reconcile any differences between closing 2019 balances and opening 2020 balances, as provided in reference 2.

RESPONSE:

Please refer to Appendix A to this response for 2019 actuals. The difference between closing 2019 balances and opening 2020 balances is related to the disallowance from rate base of $4 million associated with the Enterprise Resource Planning ("ERP") Phase 1 project.[1]

[1] EB-2018-0165, OEB Decision and Order (December 19, 2019) at page 69.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-118

References: **Exhibit 2A, Tab 4, Schedule 2, Appendix A - OEB Appendix 2-D Overhead Costs_Redacted**
Exhibit 2A, Tab 4, Schedule 2

a) Please provide a variance analysis of OEB-approved overhead costs in Toronto Hydro's last CIR and actuals as provided in reference 1 for the years 2018-2023. If any of the variances result in a +10% difference, please explain in detail.

RESPONSE:

In preparing its response, Toronto Hydro identified a data entry error in populating data in OEB Appendix 2-D (Exhibit 2A, Tab 4, Schedule 2). The corrected OEB Appendix 2-D is appended to this interrogatory response, and has been updated to include: 2023 actuals, and an updated 2024 bridge year forecast reflecting the impact of the Cloud and Locates DVAs as set out in the DVA Continuity appended to interrogatory 9-Staff-349. Toronto Hydro confirms that this error was isolated to OEB Appendix 2-D.

In its Decision, the OEB approved the 2020 Test Year for Overhead Costs.[1] The 2021-2023 forecast in Table 1 was determined by escalating the test year by I-X, where "I" is the OEB approved inflation for the respective years and "X" is the 0.6 percent stretch factor. Table 1 compares this forecast with the actual capitalized OM&A for 2018-2023.

Table 1: Total Capitalized OM&A Funded/Actuals ($ Millions)

	2018	2019	2020	2021	2022	2023
Total Capitalized OM&A Funded	(115.2)	(124.7)	(122.3)	(124.2)	(127.6)	(131.5)
Total Capitalized OM&A Actuals	(115.2)	(125.2)	(122.3)	(112.7)	(124.9)	(137.8)
Variance (%)	**0%**	**0%**	**0%**	**-9%**	**-2%**	**5%**

[1] EB-2018-0165, Exhibit U, Tab 2, Schedule 3, Appendix A – OEB Appendix 2-D (April 30, 2019).

Toronto Hydro did not experience any material variance greater than +/- 10% for total capitalized OM&A between OEB-approved overhead costs in Toronto Hydro's last CIR and actuals. However, variance analysis of the three subcomponents of the OM&A is summarized below:

1. **Labour Capitalization**

Table 2: Labour Capitalization Funded/Actuals ($ Millions)

	2018	2019	2020	2021	2022	2023
Labour Capitalization Funded	(101.4)	(109.8)	(106.1)	(107.7)	(110.7)	(114.1)
Labour Capitalization Actuals	(101.4)	(109.4)	(106.1)	(95.2)	(105.3)	(115.2)
Variance	**0%**	**0%**	**0%**	**-12%**	**-5%**	**1%**

In 2021, capitalized labour was 12 percent lower than funded. This is attributed to the lower number of internal resources allocating their time to capital projects as a result of lower staffing levels due to challenges beyond Toronto Hydro's control such as COVID-19 and other external factors; as well as resources balancing for capital work execution.

2. **Vehicle Capitalization**

Table 3: Vehicle Capitalization Funded/Actuals ($ Millions)

	2018	2019	2020	2021	2022	2023
Vehicle Capitalization Funded	(4.2)	(3.9)	(3.8)	(3.9)	(4.0)	(4.1)
Vehicle Capitalization Actuals	(4.2)	(3.6)	(3.8)	(5.5)	(5.5)	(4.7)
Variance (%)	**0%**	**-7%**	**0%**	**42%**	**39%**	**15%**

As described in Exhibit 2A, Tab 4, Schedule 2 in Section 1.3 at page 3, Toronto Hydro updated its approach for the calculation of available hours to deduct leaves and time not spent working on specific operating or capital jobs from total working hours. This resulted in the variances observed in 2021-2023.

3. Material Handling On-cost

Table 4: Material Handing On-Cost Funded/Actuals ($ Millions)

	2018	2019	2020	2021	2022	2023
Material Handling On-cost Funded	(9.6)	(11.0)	(12.4)	(12.6)	(12.9)	(13.3)
Material Handling On-cost Actuals	(9.6)	(12.3)	(12.4)	(12.0)	(14.1)	(17.9)
Variance (%)	**0%**	**12%**	**0%**	**-5%**	**9%**	**34%**

In 2019 and 2023, capitalized material on-costs increases are attributed to higher material throughput and material handling costs. These increases were 12 percent ($1.2 million) and 34 percent ($4.6 million), respectively to support the material requirement for the capital program.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-119

References: **Exhibit 2A, Tab 2, Schedule 1, Appendix C - OEB Appendix 2-BB - Useful Life Comparison**
Exhibit 9, Tab 1, Schedule 1, Appendix A - Calculation of Useful Life Change Impacts

QUESTION (A):

a) Please provide the $ amount change in depreciation expense for 2023 and 2024 associated with the asset useful lives that changed when Toronto Hydro applied Concentric's depreciation methodology.

RESPONSE (A):

Please see Table 1 below.

Table 1: Depreciation and Amortization Expense ($ Millions)

	2023 Bridge	2024 Bridge
Depreciation and Amortization Expense (without UL changes)	276.1	291.6
Depreciation and Amortization Expense (with UL change)	229.0	237.2
Difference	**(47.1)**	**(54.4)**

QUESTION (B)

b) Please provide a variance analysis of historical depreciation expense to approved depreciation expense for 2018-2023 by asset class. If any variances are greater than +10%, please provide a detailed explanation.

RESPONSE (B):

Please refer to Appendix A to this response for a comparison of historical depreciation expense[1] to approved depreciation expense.[2]

[1] Exhibit 2A, Tab 1, Schedule 2, OEB Appendix 2-BA
[2] EB-2018-0165, Draft Rate Order (February 12, 2020), Schedule 2, pages 1-5; and Exhibit U, Tab 2, Schedule 1, Appendix B, (April 30, 2019)

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-120

Reference: Exhibit 2B, Section E4, Appendix B – OEB Appendix 2-AA – Program Summary

$	2025	2026	2027	2028	2029
AFUDC	6.3	7.0	8.7	10.3	12.0

a) Please confirm the interest rate applied to the eligible capital amounts.

RESPONSE:

The interest rate applied to eligible capital amounts is 4.02 percent.

Toronto Hydro notes that the interest rate in Exhibit 5, Tab 1, Schedule 2, Appendix 2-OA is 4.04 percent. The misalignment of the rates is attributed to the timing of when the capital plan was finalized, which used a preliminary forecast of the interest rate at the time. Upon finalization of the interest rate, owing to the immaterial impact to the 2025-2029 capital expenditures and revenue requirement, no further changes were made. The impact is approximately $0.2 million less in AFUDC costs over the 2025-2029 period ($0.04 million per year), which has an immaterial impact to revenue requirement.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-121

References: **Exhibit 2B, Section A, PDF Page 2 of 356**
Alectra Utilities 2020-24 Distribution System Plan, Exhibit 4, Tab 1, Schedule 1, Pages 17, 186, 211, PDF Pages 37, 205, 231 of 1007
Hydro Ottawa Distribution Revenue Requirement & Rate Application, Exhibit 4, Tab 1, Schedule 8, Page 4, PDF Page 88
Hydro Ottawa Distribution Revenue Requirement & Rate Application, Exhibit 1, Tab 3, Schedule 3, Attachment A, Page 22, PDF Page 1408

Preamble**:**

Please see the table below that shows a subset of utility parameters per 1,000 customer basis for Toronto Hydro and several of its peers.

Utility	# of Customers	Service Area sq. km	# of Employees	# of Terminal Stations	# of Municipal Substations	# of Poles	Circuit kms Overhead Wires	Circuit kms Underground Wires	# of Distribution Transformers
Toronto Hydro	790,000	631.1	1,245	37	139	183,620	15,393	13,765	61,300
# per 1,000 customers		0.80	1.58	0.047	0.18	232	19.5	17.4	77.6
Alectra	950,000	1924	1600	14	155	130,000	16400	22,000	125,000
# per 1,000 customers		2.03	1.68	0.015	0.16	137	17.3	23.2	131.6
Ottawa	340,000	1,116	720	18	88	49,247	5609		45414
# per 1,000 customers		3.28	2.12	0.053	0.26	145	16.5	-	133.6
Enwin	88,000	120	198	11	50	20,293	2,703	1965	6713
# per 1,000 customers		1.36	2.25	0.125	0.57	231	30.7	22.3	76.3
Brantford	39,300	74	60	3		10,021	254	229	5,063
# per 1,000 customers		1.88	1.53	0.076	-	255	6.5	5.8	128.8
Synergy	56,000	441	129	3	7	23,391	993	277	7673
# per 1,000 customers		7.88	2.30	0.054	0.13	418	17.7	4.9	137.0
Hydro One (Distribution)	1,400,000	961,142	9,300		1000	1,600,000	113,000	10000	522,000
# per 1,000 customers		686.53	6.64	-	0.71	1,143	80.7	7.1	372.9

QUESTION (A):

a) Please review and update this table with corrected Toronto Hydro information if necessary.

RESPONSE (A):

Please see Tables 1 to 3 below.

Table 1: Utility Parameters for Toronto Hydro and its Peers

	# of Customers	Peak Load *(MW)*	Service Area *(sqkm)*	# of FTE	OH Primary *(km)*	UG Primary *(km)*	Poles	Distribution Transformers
Alectra Utilities Corporation	1,076,537	5,407	1,924	1,466	7,192	14,492	130,909	124,955
Brantford Utilities	111,044	519	636	183	1,275	853	31,721	13,595
ENWIN Utilities Ltd.	91,128	465	121	169	682	480	20,299	7,723
Hydro One Networks Inc.	1,440,085	6,821	961,143	4,927	114,165	10,576	1,600,000	522,000
Hydro Ottawa Limited	358,901	1,280	1,116	616	2,763	3,463	50,000	47,400
Synergy North Corporation	57,088	172	441	128	993	277	22,362	7,670
Toronto Hydro-Electric System Limited	790,699	4,276	630	1,245	4,052	6,611	183,620	61,300

Table 2: Utility Parameters for Toronto Hydro and its Peers per 1000 Customers

	# of Customers	Service Area *(sqkm)*	# of FTE	OH Primary *(km)*	UG Primary *(km)*	Poles	Distribution Transformers
Alectra Utilities Corporation	1,076,537	1.79	1.36	6.68	13.46	121.60	116.07
Brantford Utilities	111,044	5.73	1.65	11.48	7.68	285.66	122.43
ENWIN Utilities Ltd.	91,128	1.33	1.85	7.48	5.27	222.75	84.75
Hydro One Networks Inc.	1,440,085	667.42	3.42	79.28	7.34	1,111.05	362.48
Hydro Ottawa Limited	358,901	3.11	1.72	7.70	9.65	139.31	132.07
Synergy North Corporation	57,088	7.72	2.24	17.39	4.85	391.71	134.35
Toronto Hydro-Electric System Limited	790,699	0.80	1.57	5.12	8.36	232.22	77.53

Table 3: Utility Parameters for Toronto Hydro and its Peers per MW

	Peak Load *(MW)*	Service Area *(sqkm)*	# of FTE	OH Primary *(km)*	UG Primary *(km)*	Poles	Distribution Transformers
Alectra Utilities Corporation	5,407	0.36	0.27	1.33	2.68	24.21	23.11
Brantford Utilities	519	1.23	0.35	2.46	1.64	61.16	26.21
ENWIN Utilities Ltd.	465	0.26	0.36	1.47	1.03	43.66	16.61
Hydro One Networks Inc.	6,821	140.90	0.72	16.74	1.55	234.56	76.52
Hydro Ottawa Limited	1,280	0.87	0.48	2.16	2.71	39.07	37.04
Synergy North Corporation	172	2.57	0.75	5.78	1.61	130.24	44.67
Toronto Hydro-Electric System Limited	4,276	0.15	0.29	0.95	1.55	42.94	14.33

QUESTION (B)

b) Please discuss the ability of utilities serving more densely populated service areas to achieve more optimal utilization of assets relative to utilities serving less densely populated service areas.

RESPONSE (B):

The discussion on the relative costs of serving more densely versus less densely populated service areas, specifically within the context of the City of Toronto, is thoroughly examined in the Econometric Benchmarking Study of Toronto Hydro's Total Cost and Reliability Metrics, Exhibit 1B, Tab 3, Schedule 3, Appendix A. Further insights into urban-specific challenges are outlined in the Productivity section, Exhibit 1B, Tab 3, Schedule 3 at pages 2-9.

When evaluating asset utilization across utilities serving areas of varying population densities, it's crucial to consider factors that influence operational efficiency and asset deployment. Utilities in densely populated areas, such as Toronto Hydro, encounter unique challenges in optimizing asset utilization. These challenges include serving a diverse mix of customer classes, accommodating higher customer loads, meeting elevated reliability standards, and managing the complexities of urban infrastructure demands.

Toronto’s downtown core serves many unique customers that require elevated reliability and service continuity, e.g., buildings that house major economic and governmental institutions, hospitals and emergency rooms, universities and research facilities, etc. To meet these reliability requirements Toronto Hydro operates one of the largest secondary networks in North America. Secondary networks, due to their complexity and redundancy, require more infrastructure per unit of load, but they significantly improve reliability and quality of service in highly dense areas where outages have serious consequences.

Customers in densely populated areas typically exhibit higher peak loads and consumption compared to those in less densely populated areas. Toronto Hydro, for instance, records the highest peak load and consumption per customer among the utilities identified in the preamble, with the load being 17% higher than average. Urban customer density areas also require higher reliability, power quality and flexibility to support the critical nature of loads and more rigorous maintenance practices. Urban and densely populated areas benefit from redundant system designs, allowing load to be served by multiple feeders and enhancing service levels, which is achieved at the expense of increased infrastructure per customer and load. Higher reliability requirements lead to lower asset utilization factors.

In addition, the expectation of higher growth rates in urban areas also necessitates addressing future space constraints within utility planning. Toronto's downtown core, for example, saw a significant population increase of about 16% over five years, from 2016 to 2021, as noted in Exhibit 1B, Tab 3, Schedule 3, pp. 2-3. Increased population density heightens challenges related to rights of way and congestion with other utility providers, influencing the required size and scale of assets and built-in additional capacity.

The following bullets provide additional thoughts on the nuances required in comparing utilization rates ranging from rural zones to metro downtown core areas:

- In rural areas, service is typically provided through overhead lines with a radial design and smaller-sized distribution transformers feeding individual farms or residences. Consequently, utilities encounter longer lines and a higher number of distribution transformers per customer.
- Suburban areas are served by 3-phase overhead and underground feeders, likely featuring larger conductors and higher capacity distribution transformers to accommodate increased loads. On average, each transformer serves a greater number of homes and small business customers. Enhanced reliability requirements necessitate additional circuits and switches within the system. Although utilities may install a higher asset count per customer, these assets are of higher capacity, facilitating load accommodation and enabling switching capabilities.
- Urban settings predominantly utilize underground 3-phase lines with large conductors, encased in concrete ducts and run through cable chambers. Transformation equipment, often situated in underground vaults, is sized for higher customer loads. Utilities will ensure that there is enough spare capacity available on the feeders to reroute power in case of a failure in one part of the network. In urban environments, utilities might observe a lower transformer count per customer or per unit of load, although circuit length and pole counts

may increase due to larger loads and heightened reliability demands. Many transformers must have a higher capacity compared to suburban and rural settings to manage larger loads. The grid also incorporates additional civil infrastructure, including vaults, chambers, and ducts, alongside a high number of protection and load transfer equipment. It's notable that customers may own equipment at supply points, resulting in fewer distribution transformers per customer and per unit of load.

- The downtown core is almost exclusively served by underground infrastructure, with many customers connected to a secondary network. Transformers are of a significantly larger size to serve residential and commercial towers and high-rise buildings. The high loads, interconnected feeders, and the use of dual and secondary networks lead to lengthier primary and secondary underground circuits. Feeders and equipment are housed in multi-duct banks, vaults, and chambers. The system extensively employs network protectors and switches to ensure resilient and highly reliable service delivery to critical loads. Utilities typically install more expensive, high-capacity, and complex underground equipment, along with additional lines, to ensure sufficient redundancy in the system for load switching within a sophisticated network design. However, this typically results in a lower asset count per customer or per unit of load compared to other customer density settings.

In conclusion, utilities serving more densely populated areas need to account for factors negatively impacting asset utilization: higher customer loads, increased reliability standards, and needs to accommodate potential demand growth within scarce land.

QUESTION (C):

c) Please compare and contrast Toronto Hydro’s customer density and asset utilization relative to its Ontario peers.

RESPONSE (C):

The econometric study, detailed in Exhibit 1B, Tab 3, Schedule 3, Appendix A, investigates the impact of serving a densely populated service territory using the urban core variable. The study found that

Toronto Hydro's costs, when accounted for the urban core variable, were 28% below the expected benchmark for the period from 2020 to 2022. In general, the lower costs reflect a better utilization of available resources and infrastructure by Toronto Hydro when compared to its peers.

Part b) of the question discussed the challenges related to direct comparison of the asset utilization in the highly densely populated area, such as Toronto Hydro service territory with urban and downtown core settings, to its less densely populated Ontario peers.

Generally, within the service territory of Toronto Hydro, when compared to its peers in Ontario, the utility would anticipate:

- A lower count of distribution transformers per service, albeit with higher capacity;
- Longer underground circuits per customer and per unit of load when including secondary circuits (secondary network area);
- A number of poles and length of overhead infrastructure similar to that of other urban-based utilities, with the exception of those serving rural areas;
- Significantly more extensive and complex underground infrastructure, featuring multi-duct banks, vaults, and cable chambers;
- Higher counts of switching and protection equipment;
- Unique infrastructure, such as underground stations and vaults situated well below the surface.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-122

Reference(s): Exhibit 2B, Section A, Page 6
RRR Data, 2022

<u>Preamble:</u>

Figure 1 in Reference 1 indicates unknown causes of outage make ups 7% of outage causes from 2018 - 2022.

From the RRR data filed by Toronto Hydro, the contribution of unknown outage cause is increasing with time.

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
SAIFI - Unknown	0.21	0.32	0.30	0.29	0.31	0.54	0.39	0.49

QUESTION (A):

a) How did Toronto Hydro restore the outages where the cause was unknown?

RESPONSE (A):

Please refer to Toronto Hydro's response to interrogatory 2B-EP-27.

QUESTION (B):

b) Please explain the increase in unknown outages and what Toronto Hydro is doing to improve this measure.

RESPONSE (B):

Please refer to Toronto Hydro's response to interrogatory 2B-EP-27.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-123

Reference: Exhibit 2B, Section A, Page 15

Preamble:

Toronto Hydro states: "Toronto Hydro now incorporates climate data projections into its equipment specifications and station load forecasting."

QUESTION (A):

a) Does Toronto Hydro update the depreciation rates of assets to reflect climate hardening activities it has undertaken? If yes, please provide examples. If no, please explain why not.

RESPONSE (A):

Response from Concentric:

Concentric considered all factors when selecting average service life and Iowa curve recommendations, including forces of retirement such as weather-related events and third-party contacts/strikes, as estimated based on peer utilities, the professional judgement of Concentric personnel, and discussions with operations and management staff from Toronto Hydro. In discussions with Toronto Hydro staff, Concentric was informed of the types of assets currently being retired and the materials and types of assets being installed. Attention was paid to circumstances where assets being removed are being replaced with significantly different assets, and the rationale for the change. While the depreciation study did not consider system hardening as a separate factor in the selection of average service lives, the changes in asset types and expected lives of assets installed in more recent years was considered. It should be noted that system hardening is occurring throughout the North American electric industry. As such, in addition to system hardening being part of discussions with operations and maintenance staff, it is reflected in the asset lives selected by peer utilities, which form the basis of the peer review.

Response from Toronto Hydro:

As described in Exhibit 2A, Tab 2, Schedule 1, Section 3.1, Toronto Hydro has incorporated the recommendations of Concentric Advisors, ULC ("Concentric") in its depreciation rates effective January 1, 2023.

QUESTION (B):

b) Does Toronto Hydro update the useful lives of assets to reflect climate hardening activities it has undertaken? If yes, please provide examples. If no, please explain why not.

RESPONSE (B):

Toronto Hydro did not specifically consider climate hardening activities to update useful lives; however, Toronto Hydro routinely considers updates to its useful lives as new information becomes available, including the information produced by Concentric as part of the Depreciation Study, which includes peer utility and operation experience that integrates climate hardening considerations as per response to part (a).

QUESTION (C):

c) Please explain how Toronto Hydro determined asset hardening needed to be done to preserve asset life and provide examples of analyses.

RESPONSE (C):

In June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol. The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Toronto Hydro utilized climate data projections for temperature, rainfall, and freezing rain in its equipment specifications. For example, revision to submersible transformer specification to require stainless steel construction, revision to network transformer specification to require thicker walls and increased paint specifications for corrosion mitigation, and revision to padmount, poletop, and vault transformers specification to handle overload conditions. In 2022, this study was updated, please refer to Exhibit 2B, Section D2, Appendix A.

Further to this study, Toronto Hydro monitors changes to industry codes, standards, and regulations for alignment on asset hardening requirements. For example, in February 2023 the Canadian Standards Association (or CSA Group) updated CSA C22.3 No. 1:20, Overhead Systems and CSA C22.3 No. 7:20, Underground systems, with new requirements for Climate Change Adaptation. Toronto Hydro strives to meet and surpass these new requirements. For more information see Exhibit 2B, Section D2.1.2 Climate and Weather at page 10.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-124

References: **Exhibit 2B, Section A, Page 2**
Exhibit 2B, Section E6.1, Page 6
Exhibit 1B, Tab 5, Schedule 1, Appendix A

Preamble:

Toronto Hydro's recent customer engagement demonstrated that residential customers' first priority is controlling rates, their second priority is maintaining reliability, and their third priority is investing in new technologies that reduce rates or reduce their exposure to long duration outages due to extreme weather. Toronto Hydro's capital expenditures are targeting improved SAIDI, which excludes the MEDs that residential customers consider a priority.

QUESTION (A):

a) Please describe how Toronto Hydro planned to achieve the first priority of lowest possible rates and the second priority of maintaining reliability in light of its targeted SAIDI improvement.

RESPONSE (A):

To clarify, customers' first priority was found to be the delivery of electricity at reasonable distribution rates, not the "lowest possible" rates. See Exhibit 1B, Tab 5, Schedule 1, page 5.

As mentioned in Exhibit 1B, Tab 5, Schedule 1, Customer Engagement at page 8, "Phase 2 solicited detailed customer feedback on the $5.9 billion draft plan and the associated price impacts, providing the utility additional insight about customers' preferences relative to the investment plan priorities, options and outcomes. This feedback: (i) confirmed that Toronto Hydro found a suitable balance between price and other key outcomes of its 2025-2029 investment plan, (ii) supported the refinement and finalization of the plan, and (iii) informed the development of the 2025-2029 custom scorecard presented in Exhibit 1B, Tab 3, Schedule 1."

Toronto Hydro's 2025-2029 Distribution System Plan ("DSP") was tailored to meet customers' needs and preferences, including prioritizing investments for reliability. As mentioned in Exhibit 1B, Tab 3, Schedule 1 at page 9, "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 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."

As mentioned in Exhibit 1B, Tab 3, Schedule 1 at page 16, "Toronto Hydro's projection indicates that the investment plan is roughly sufficient to maintain Outage Frequency as measured by the custom SAIFI Defective Equipment metric over the 2025-2029 period, with some risk of deterioration relative to the five-year historical baseline (2018-2022). The target to maintain (rather than improve) Outage Frequency recognizes 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."

Regarding the exclusion of MEDs from the SAIDI performance metric, please see response 1B-Staff-90, part (b).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-125

Reference: Exhibit 2B, Section B, page. 2

<u>Preamble:</u>

Toronto Hydro indicates that as part of proactive customer engagement, large customers and developers with upcoming projects are engaged to understand their needs and timelines and these engagements enable Toronto Hydro to incorporate anticipated connections into its Peak Demand Forecast with a higher degree of confidence.

QUESTION:

a) Given the emergence of new electrification trends such as commercial electric vehicle charging, building electrification etc., please confirm if Toronto Hydro has evolved its proactive customer engagement processes to engage a broader range of customers.

   i. If yes, please explain how Toronto Hydro has evolved its proactive customer engagement processes to engage prospective customers that are interested in connecting loads for electrification trends such as commercial electric vehicle chargers, building electrification etc.

RESPONSE:

Yes, Toronto Hydro continually evolves its proactive customer engagement practices as customer needs and new environmental factors such as electrification emerge. Through the Key Accounts segment's operational and senior leader customer engagements, Toronto Hydro ascertains future electrification and decarbonization plans from Key Account customers and supports customers to develop strategies to achieve their future decarbonization goals. This information is shared with internal stakeholders such as System Planning. Please also refer to the evidence on ongoing customer engagement,[1] the Key Accounts segment of the Customer Operations program,[2] and the Customer Relationship Management segment of the Customer Care program.[3]

[1] Exhibit 1B, Tab 5, Schedule 1, p. 13-23.
[2] Exhibit 4, Tab 2, Schedule 8, p. 22-25.
[3] Exhibit 4, Tab 2, Schedule 14, p. 34-43.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-126

Reference: Exhibit 2B, Section C, Pages 5-6

QUESTION (A):

a) Please confirm that the existing outage management system underreported scheduled outages.
   i. If not confirmed, please reconcile with the stated text "Increased number of scheduled outages reported".
   ii. Would the same underreporting issues apply to unscheduled outages?

RESPONSE (A):

Confirmed.

In addition to the impact on scheduled outages, the new Oracle Utility Analytics solution captures an increased number of unscheduled outages affecting a smaller number of customers. However, these additional outages have an insignificant impact on overall SAIDI and SAIFI performance.

QUESTION (B):

b) Please explain how Toronto Hydro is ensuring that historical underreporting of outages does not drive increased reliability spending that is unnecessary to maintain actual reliability.

RESPONSE (B):

Historical underreporting of outages has had no bearing on the 2025-2029 expenditure plan. The reporting issue is primarily a factor for Scheduled Outages.

QUESTION (C):

c) Has the historic increase in sectionalization enabled Toronto Hydro to reduce the impact (customer minutes out) of scheduled outages? Please explain.

RESPONSE (C):

In general, increased ability to sectionalize provides more options to minimize the customer impact of scheduled outages. Scheduled outages are confined to as narrow an area as possible to allow crews to work safely. This is achieved by utilizing permanent switches where available, and by installing temporary switches where permanent switches are not available. Because temporary switches are installed when permanent switches are not present, the impact of increased sectionalization on customer minutes out due to scheduled outages is marginal.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-127

Reference: Exhibit 2B, Section C, p. 5, 12

Preamble:

Toronto Hydro notes that the "recent rise in reliability impacts was caused by a range of factors. The predominant cause for the increase in SAIFI was unknown impacts, which consist of outages that have no apparent cause."

QUESTION (A):

a) Will Toronto Hydro's upgrade from the existing Outage Management System to Oracle's Network Management System facilitate improved identification of these "unknown impacts"?

RESPONSE (A):

Unknown outages, typically brief due to temporary faults, are hard to diagnose precisely. Despite enhanced identification, tracking, and reporting from Oracle's Network Management System ("NMS") and Utility Analytics ("OUA'), these tools cannot identify the root causes of such outages. For more details, please refer to Toronto Hydro's responses to 2B-EP-27.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-128

Reference: Exhibit 2B, Section C, Page 22

Preamble:

With respect to Figure 22 in Reference 1.

QUESTION (A):

a) Do Toronto Hydro's overhead conductor system failures primarily comprise splice and termination failures?
   i. If yes, please quantify the percentage of conductor failures that are due to conductor splice and termination failures.
   ii. If no, please explain where conductor splice and termination failures are tracked,
   iii. If no, please explain what typical overhead conductor failures are.

RESPONSE (A):

In general, interruptions stemming from 'overhead conductors' (shown in Figure 22) are a mix of both conductor and connection failures (including line clamps, splices, and terminations). Conductor failures could be related to issues like metal fatigue, or physical damage, while connection failures may be associated with problems in splices, terminations, or other points where the conductor is connected.

i. The majority of these failures can be attributed to connection failures rather than conductor failures. Toronto Hydro does not track overhead conductor failures with sufficient granularity to determine the percentage of failures that are due to termination or splices.

QUESTION (B):

b) What percentage of conductor system failures represent actual conductors failing between conductor splices and/or terminations. If Toronto Hydro does not have accurate numbers, please provide an estimate.

RESPONSE (B):

Due to limited data granularity, along with inherent difficulty in ascertaining the exact location of mid-span conductor failure from an interruption reporting perspective, Toronto Hydro is unable to provide an accurate percentage breakdown of actual conductors failing between splices and/or terminations. Toronto Hydro estimates that the majority of interruptions related to overhead conductors are driven by connection failures (line clamps, splices, and terminations). Please refer to the response to part (c) for more information on how Toronto Hydro is mitigating conductor, cable, and accessory failures.

QUESTION (C):

c) What is Toronto Hydro’s standard practice to mitigate conductor splice and termination failures?

    iv. Please provide the average cost of replacing only a conductor splice, the average cost of replacing only a termination, and the average cost of following Toronto Hydro’s standard practice.

RESPONSE (C):

Toronto Hydro employs robust asset lifecycle optimization policies and practices to minimize failures and maximize the value derived from individual assets throughout their lifecycles, as outlined in Exhibit 2B, Section D3.1. By conducting overhead line patrols and infrared scans of overhead primary lines as described in Exhibit 4, Tab 2, Schedule 1, Toronto Hydro can proactively detect evident signs of conductor splice and termination defects before they result in failures. These signs may include cracked or deteriorated connections, damaged or exposed insulation, or thermal anomalies. Toronto Hydro also mitigates failures by adhering to the latest construction standards, complying with *Ontario Regulation 22/04*,[1] conducting field audits, and implementing asset management investment plans to replace overhead infrastructure that is at higher risk of failure.

iv. Toronto Hydro replaces terminations and conductor splices reactively following a failure, or as part of a larger capital project. Due to limited data granularity and the bundling of this type of work with other work, Toronto Hydro is unable to provide the average cost of replacing only a conductor splice or termination. In general, replacing assets reactively is more expensive than replacing them as part of a planned project.

[1] O. Reg. 22/04: Electrical Distribution Safety, under Electricity Act, 1998, S.O. 1998, c. 15, Schedule. A.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-129

References: **Exhibit 2B, Section D1, Page 12**
Exhibit 2A, Tab 2, Schedule 1, Appendix D, Rate Base
Exhibit 2B, Section D3, Appendix A, Page 2
Exhibit 2B, Section E6.6, Page 22

Preamble:

With regards to the above references, please answer the following questions:

QUESTION (A):

a) Please define useful life in terms of the causes of retirement that useful life includes and does not include.

RESPONSE (A):

As discussed in Toronto Hydro's response to interrogatory 2B-Staff-131, Toronto Hydro's useful lives for asset management purposes were originally adopted on the basis of the mean useful life from a study conducted by Kinectrics for Toronto Hydro on asset useful lives. These were reviewed as part of the Depreciation Study completed by Concentric Inc. Toronto Hydro made adjustments to align its useful lives to Concentric's findings, where appropriate, resulting in changes to useful lives for a subset of asset types. Please see part (b) below for Concentric's response regarding causes of retirement. For a more detailed discussion regarding the determination of depreciation life versus useful life (i.e. failure curves), please see Toronto Hydro's response to interrogatory 2B-Staff-131.

QUESTION (B):

b) Please compare and contrast the causes of asset retirement as they pertain to useful life and depreciation life.

RESPONSE (B):

Response provided by Concentric:

The depreciable life of assets is based upon a detailed retirement rate analysis which includes all historical retirements through the period available to Concentric, an analysis of Canadian peer electric utilities, discussions with Toronto Hydro operations and management personnel, and the professional experience of Concentric. The depreciable life is inclusive of factors such as retirements due to the age of assets, economic forces of retirement, changes in legislation, and other retirements beyond the control of Toronto Hydro.

Response provided by Toronto Hydro:

For a detailed discussion regarding depreciation life versus failure curves, please see Toronto Hydro's response to interrogatory 2B-Staff-131.

QUESTION (C):

c) Please explain why depreciation life is always (except in exceptional circumstances) less than useful life.

RESPONSE (C):

Please see Toronto Hydro's response to interrogatory 2B-Staff-131.

QUESTION (D):

d) For asset classes with useful life estimates, please provide a table showing the useful life and depreciation life of those asset classes, and for those with equal depreciation life and useful life, please explain why they are equal.

   i. Please explain how Toronto Hydro updates its useful life expectations when actual failure rates deviate from expected failure rates (e.g., power transformers Reference 4).

RESPONSE (D):

Please see Table 1 below identifying major asset classes with useful life estimates and the depreciation life of those asset classes.

Table 1: Comparison of asset useful life and depreciation life expectations.

Major Asset Classes	Asset Useful Life	Dep. Life	Reason if Equal
Overhead Primary Conductor	60	60	Minor adjustment to Useful life in review of Concentric Study
Overhead Secondary Conductor	60	60	Minor adjustment to Useful life in review of Concentric Study
Overhead Switch	30	30	Change driven by input from Concentric Study based on the impact of increasing technologies impacting useful life of asset class and input from operational and management staff.
Overhead Transformer	35	35	Toronto Hydro's useful life was originally set at 35 years based on 2009 Kinectrics Study[1]
Poles (Wood Poles)	45	45	Toronto Hydro's useful life is based on 2009 Kinectrics Study
UG Primary Cable - Concrete, Conduit	50	50	Toronto Hydro's useful life is based on 2009 Kinectrics Study
UG Primary Cable - DB Jacketed	40	20	
UG Primary Cable - DB Unjacketed	20	20	Minor adjustment to useful life in review of Concentric Study
UG Primary Cable - PILC	65	65	Change driven by input from Concentric Study, peer Canadian utilities generally had service life in the range of 30-60 years, and historical retirement data also indicated shorter life expectation.

[1] Toronto Hydro Electric System Useful Life of Assets, Kinectrics (August 28, 2009)

Major Asset Classes	Asset Useful Life	Dep. Life	Reason if Equal
UG Secondary Cable - DB	23	23	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
UG Secondary Cable - Conduit	60	60	Change driven by input from Concentric Study based on discussions with operational staff and a comparison with peer utilities.
Underground Switch	40	40	Change driven by input from Concentric Study, impacting only air-insulated pad-mounted switches (resulting in an increase in useful life).
Underground Transformers	30	30	Change driven by input from Concentric Study based on discussions with operational and management staff.
Underground Network Units	35	35	Change driven by input from Concentric Study, increase in useful life based on operational and management experience.
Stations - Switchgear Enclosures	50	50	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Stations - DC Batteries	10	10	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Stations - Power Transformers	45	45	Toronto Hydro's useful life is based on 2009 Kinectrics Study, minor change (1 year) based on input from Concentric Study.
Circuit Breakers	45	45	Minor changes driven by input from Concentric Study impacting two subtypes (Airblast and Air Magnetic) only. Aligns useful life estimates with remaining breaker types.
Civil - Network Vaults	60	60	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study

Major Asset Classes	Asset Useful Life	Dep. Life	Reason if Equal
Civil - Network Vaults - Roof	25	25	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Civil - Cable Chambers	65	65	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Civil - Cable Chambers - Roof	25	25	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Civil- Underground Vaults	60	60	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Meters	15	15	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study
Automatic Transfer Switch (ATS) & Reverse Power Breaker (RPB)	40	40	Toronto Hydro's useful life is based on 2009 Kinectrics Study, no change due to Concentric Study

i. Please see Toronto Hydro's response to interrogatory 2B-Staff-131, part (a).

QUESTION (E):

e) For each of the assets listed in Table 1: Material Refinements to ACA Asset Models, please explain why updates to the Depreciation Study by Concentric triggered revisions to the useful life values used by the asset managers at Toronto Hydro.

ii. For each of the assets listed in Table 1, what information did Concentric have about Toronto Hydro's assets that Toronto Hydro did not have?

iii. Did Toronto Hydro hire Concentric for its expertise in determining asset depreciation lives, or its expertise in assessing asset condition and the resulting useful life?

RESPONSE (E):

Please see Toronto Hydro's response to interrogatory 2B-Staff-131 part (a), for details regarding Toronto Hydro's updates to useful lives and the broader use of this information in asset management.

ii. Concentric leveraged their extensive professional experience in conducting service life studies along with information from peer utilities in North America in addition to asset and financial data that was available from Toronto Hydro.

iii. Toronto Hydro hired Concentric for its expertise in estimating the service life of assets for the purpose of depreciation. Toronto Hydro's engineers have sufficient expertise and first-hand knowledge of the system to determine the appropriate timing for asset replacements. As discussed in Toronto Hydro's response to interrogatory 2B-Staff-131 part (a), service life estimates and useful life of assets are inter-related and as such the results of the Depreciation Study are an important consideration in reviewing useful life estimates.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-130

References: Exhibit 2B, Section D1, Page 12
Exhibit 2B, Section D5, Page 15-16

QUESTION (A):

a) When leveraging risk-based decision making to ensure System Renewal investments are sufficient to maintain historical reliability, please explain how SCADA operated switch investments in self-healing grids changes the consequence of asset failures and the resulting risk calculations?

RESPONSE (A):

SCADA operated switch investments and related investments in self-healing grid capabilities are expected to reduce the consequence of asset failure in specific circumstances due to increased operational flexibility and automated switching operations for faster restoration of customers in unaffected parts of a feeder during an outage event.

While the reduction in consequence of failure through the implementation of self-healing grids will result in an overall reduction of risk, Toronto Hydro does not expect to have self-healing functionality implemented and operational until 2030. Therefore, the change in risk profile due to self-healing capabilities in the horseshoe system is not expected within this rate period.

Toronto Hydro recognizes that the installation of SCADA switches on horseshoe feeders does provide an immediate reliability benefit due to remote switching capabilities and increased operational flexibility (although not the more significant improvement expected through automated self-healing capabilities). These benefits are considered in Toronto Hydro's plans to maintain reliability and are integrated into the projections that underpin its performance incentives for SAIFI and SAIDI as detailed in Exhibit 1B, Tab 3, Schedule 1.

QUESTION (B):

b) When leveraging risk-based decision making please confirm that when 2100 or 1400 customer group line segments are sectionalized into 700 customer group segments the consequence of individual asset failure decreases relative to the pre-sectionalized configuration.

   i. If confirmed, please explain what change would need to occur to the probability of asset failure to maintain a constant overall risk profile when consequence of failure is reduced?

   ii. If not confirmed, please explain what happens to the consequence of asset failure post-sectionalization?

   iii. In either case, please explain the process Toronto Hydro uses to adjust the acceptable probability of failure (or useful life or acceptable asset condition) to maintain a constant overall risk profile when consequence of asset failure changes.

RESPONSE (B):

Confirmed, when group line segments are sectionalized into 700 customer group segments, the consequence of individual asset failure decreases relative to the pre-sectionalized configuration.

i. If the consequence of failure is reduced through enhancement, the probability of failure would need to increase (i.e. the asset would need to be older, in worse condition, or otherwise more likely to fail) for the risk value to remain the same.

ii. Please see response to (i) above.

iii. Probability and consequence are assessed independently and combined to assess risk within Toronto Hydro’s planning processes. A reduction in the consequence of failure on a particular feeder may cause Toronto Hydro to opt to maintain assets longer and accept a higher probability of failure in favour of making investments on a part of the system that carries greater risks.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-131

References: Exhibit 2B, Section D1, Page 17
Exhibit 2B, Section D2, Pages 20, 43
Exhibit 2B, Section D3, Page 29

Preamble:

Given the large percentage of Toronto Hydro assets that are beyond their useful lives and given Toronto Hydro's historically improving SAIDI and SAIFI metrics, it is possible that Toronto Hydro has incorrectly estimated the useful lives of some of its asset classes.

QUESTION (A):

a) Please describe the process that Toronto Hydro uses to update its useful life expectations based on actual asset performance.

RESPONSE (A):

Toronto Hydro does not agree with the premise outlined in the preamble of this question with respect to the relationship between the referenced useful life metrics and SAIDI and SAIFI performance. Regardless of where the useful life values are set, the application of prudent asset management principles would dictate that a utility should always be operating a substantial percentage of assets beyond useful life. Toronto Hydro does not replace individual assets simply because the age of the asset has exceeded the useful life value. As discussed in detail in Toronto Hydro's response to interrogatory 2B-SEC-44, the utility makes replacement decisions on the basis of probability of failure, consequence of failure, and various system design considerations, as part of a programmatic asset management approach tailored to the specific realities of Toronto Hydro's dense urban environment. The specific drivers of historical reliability improvements are discussed in Exhibit 2B, Section E2.2.1.

To update its useful life expectations, Toronto Hydro relies on the judgement and expertise of its own engineering and operational experts, with support from industry-standard studies completed by leading experts. The utility's asset useful lives for asset management purposes were originally adopted on the basis of the mean useful life from a study conducted by Kinectrics for Toronto Hydro on asset useful lives, to which Toronto Hydro subject matter experts contributed. These were reviewed as part of the Depreciation Study completed by Concentric Inc., filed in Exhibit 2A, Tab 2, Schedule 1, Appendix D. Toronto Hydro made adjustments to its useful lives where appropriate, based on Concentric's results, which themselves were informed by Toronto Hydro subject matter experts.

Depreciation Life vs. Failure Curves

In 2B-Staff-129, OEB Staff requests a discussion regarding the differences between useful life values determined for depreciation purposes versus those developed for asset management purposes, and postulates that depreciation life values are almost always less than useful life values used in asset management. Toronto Hydro assumes that OEB Staff is referring to the difference between average service lives determined on the basis of a broader set of retirement causes (for depreciation purposes) as compared to average service lives calculated on the basis of what Toronto Hydro would call "failure curves," i.e. probability of failure curves created on the basis of the utility's failure data (as opposed to retirement data).

Toronto Hydro agrees with the view that, in theory, a useful life value based purely on failure data would, in many (but not all) cases, be equal to or greater than the depreciation useful life. However, the extent to which this would in fact be the case across all asset classes, and the magnitude by which the depreciation and useful life values would actually vary from one another in each instance, would be dependent on the specific asset type and the utility's asset management practices.

Assessing the actual differences between depreciation life and useful life on an objective basis requires developing asset failure curves. The development of failure curves using a utility's own failure data continues to be an area of development and exploration for many distribution utilities like Toronto Hydro. While the statistical approaches to developing the useful life of an asset class are fairly established (and not dissimilar from developing the survival curves used for depreciation), the volume of data and quality of data required to produce a failure curve remains a barrier. Specifically, this requires many years of appropriately structured and labeled failure data that can be tied directly to underlying assets and their attributes at the time of failure. For most utilities, blended asset failure datasets of this nature are, at best, limited to around 10 years of history (as compared to useful life of distribution assets themselves, which are typically around the 30-50-year range). Furthermore, the quality of this data over the available period varies significantly, especially as utilities have progressed from early implementations of data and work management systems to more mature and advanced digital tools in recent years. The reality is that the systems which capture outage data and corrective action data were historically designed with the primary goal of optimizing the efficiency of field operations and were not intended to provide the very high level of data quality and granularity necessary to develop predictive failure curves with ease. As Toronto Hydro gains experience with the more advanced Oracle Utility Analytics ("OUA") interruption tracking system, the utility expects the level of data quality regarding asset failures to improve.

Application of Useful Lives in Asset Management at Toronto Hydro

Toronto Hydro's existing useful life values are appropriate for use in asset management. By leveraging the Kinectrics and Concentric studies, Toronto Hydro ensures alignment of useful life assumptions with broader industry knowledge for major asset classes for the purpose of driving asset management decisions. On this point, it is important to underscore exactly how useful life values factor into the utility's asset management decisions.

- **Assets Past Useful Life:** As noted earlier in this response, Toronto Hydro does not replace assets simply because they have exceeded their useful life values. While the utility does make reference to the percentage of Assets Past Useful Life ("APUL") throughout the Distribution System Plan, this measure is offered as a simplified, directional indicator of changes in asset demographics over long periods of time, and does not directly inform the selection of assets by system planners. To the limited extent that APUL has been used to frame investment pacing decisions for 2025-2029, it is with regard to particular spikes in asset need that are expected over the longer-term (e.g., network units in 2030-2034).

Note that age and APUL are distinct measures. In some cases, Toronto Hydro's evidence highlights issues with the age demographics of certain asset classes (for example, stations power transformers and direct-buried cables). In these examples, the population of concern is not the general population of assets past useful life, but a subset of assets operating well beyond useful life (for example, stations power transformers operating beyond a target maximum age of 65 years).

- **Asset Condition Assessment ("ACA"):** Asset useful life is an input into the ACA methodology, along with inspection information and other asset characteristics to determine the overall condition of the asset. In this context, the useful life is used as a calibration factor within the model to represent a central point in time where the utility can expect to begin to see increased deterioration. When assets with ACA models are being targeted for replacement as part of discrete capital projects, these decisions are made on the basis of the health score. Importantly, the asset useful life on its own will not increase the asset health score of an asset beyond the HI3 band. There must be a verifiable condition present to push the asset into HI4 and HI5.

Toronto Hydro encourages all parties to review the detailed program-level evidence regarding asset needs and investment pacing decisions in Exhibit 2B, Section E6. Additional information regarding expected changes in asset demographics over the 2025-2029 period with investment is provided in Toronto Hydro's response to interrogatory 2B-SEC-44.

QUESTION (B):

b) For all asset classes with ACA data provide the following data in an MS Excel worksheet:

i. Useful life used in this filing.
ii. Useful life used in the previous distribution system plan.
i. For any useful lives that were updated, please explain the primary driver of the update.
iii. Assets Past Useful Life (APUL) percentage for this filing
iv. APUL percentage in 2017
v. Forecast APUL percentage in 2029
vi. Presence or absence of a probability of failure curve, and the year in which Toronto Hydro plans to either update the curve or create it for the first time.
i. For all the probability of failure curves, please indicate if the curves are based on Toronto Hydro specific data or 3rd party data.

RESPONSE (B):

Please see Toronto Hydro’s response attached, 2B-Staff-131 App A ACA Demographics and Corresponding Useful Lives.

QUESTION (C):

c) Please explain why Toronto Hydro has selected asset age as its “comprehensive indicator of failure risk across the system” rather than performing an actual risk assessment based on actual asset condition (currently Toronto Hydro’s proxy for probability of failure) and consequence of failure.

RESPONSE (C):

“Comprehensive” in this context refers to the fact that Toronto Hydro does not have a condition model for all of its major asset classes, and therefore the APUL metric is more inclusive of the utility’s broader asset base.

“[…] indicator of failure risk” is meant to convey the simple fact that, in the broadest sense, age is correlated with probability of failure, and to the extent that the probability of failure is changing over time across the utility's asset base, this a directional indicator of potential changes in the level of investment required to manage asset risk.

Please refer to Toronto Hydro's response to interrogatory 2B-AMPCO-18 for details regarding the current status of Toronto Hydro's implementation of the Probability of Failure and Consequence of Failure components of the Condition Based Risk Management framework.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-132

References: Exhibit 2B, Section D2, Page 10
Exhibit 2B, Section E6.5, Page 37

QUESTION (A):

a) Please confirm that the historically achieved reduction in risk and the recommendation by the consultant to not relax Toronto Hydro's existing adaptation measures means that those adaptation measures meet or exceed Toronto Hydro's requirements.
   i. If confirmed, please explain why a new budget line item of $85.9 for "Overhead Infrastructure Resiliency" is being introduced in this test period.
   ii. If not confirmed, please explain what adaptation measures are in excess of the recommended adaptation measures and why.

RESPONSE (A):

Toronto Hydro confirms that the adaptation measures described in Exhibit 2B, Section D2, page 10 meet Toronto Hydro's requirements in respect of equipment specifications and design practices. Where equipment has been replaced or installed since the adaptation measures were established, it is to the new requirements.

The Overhead Infrastructure Resilience segment is an example of where these adaptation measures are being deployed. This segment is a reintroduction and expansion of work done through the Overhead Infrastructure Relocation Program in Toronto Hydro's 2015-2019 DSP to improve the resiliency of the overhead system through targeted relocations and undergrounding of overhead assets that are at risk of adverse weather, as well as, tree contacts, animal contact, foreign interference and/or in areas that are difficult to access. Targeted assets also include obsolete designs, which are no longer aligned with Toronto Hydro's current planning and work practices, but which are not currently addressed through other capital programs. For details of the needs driving this segment, please see Exhibit 2B, Section E6.5, page 26-33 and 37-38.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-133

Reference: Exhibit 2B, Section D2, Page 25

Preamble:

Regarding “Obsolete and deteriorating overhead accessories” and example of catastrophic failure of a porcelain insulator.

QUESTION (A):

a) Please explain how the risk of failure is high when the reason given relates solely to the typical probability of failure (i.e. the probability of electric tracking) and not typical consequence of failure.
    i. What is the typical failure mode of an insulator.
    ii. What is the typical consequence of an insulator failure.

RESPONSE (A):

i) Typical failure modes of an insulator include:
    a. Electrical tracking due to contamination build up - porcelain insulators are more susceptible to contamination build up than polymeric type insulators due to the material properties;
    b. Cracking and shattering of the insulator due to age, contamination, and even sudden temperature changes – this only applies to porcelain insulators.

ii) Typical consequence of an insulator failure include:
    a. Electrical tracking, leading to flashovers, pole fires, and outages;
    b. Cracking and shattering (for porcelain insulators only), releasing porcelain shards which can cause damage to nearby equipment, public property, and put the general public at risk.

It is the combination of the higher probability of failure with the potential to fail in a catastrophic manner as described in Exhibit 2B, Section D2 at page 25, that leads to the high risk of failure for porcelain insulators.

QUESTION (B):

b) Of all the failures in the past 5 years, what percentage resulted in a catastrophic failure that caused property damage or human injury, and what percentage did not?
    i. Please explain why a single incident of property damage is the consequence used to justify the insulator replacement program.
    ii. Please provide the risk comparison between the typical insulator failure risk (i.e. typical failure probability and typical consequence of failure) versus the risk of property damage failure (i.e. single/exceptional occurrence and property damage consequence) as measured on Toronto Hydro's risk matrix.

RESPONSE (B):

Toronto Hydro does not have detailed records specifically related to porcelain insulator failure. The information collected within Toronto Hydro's interruption tracking system does not have sufficient granularity to distinguish catastrophic and normal failure modes for this asset type.

i) Please note that Toronto Hydro is not proposing a dedicated insulator replacement program for the 2025-2029 period. Toronto Hydro will typically replace these obsolete insulators upon failure, during overhead rebuilds, or in tandem with reactive or corrective work performed on related assets such as poles or overhead conductors. As discussed in Exhibit 4, Tab 2, Schedule 1, Toronto Hydro maintains porcelain insulators by regularly washing high priority locations to reduce contamination and minimize failure risk due to tracking.

ii) As per response above, Toronto Hydro does not have the granularity within its information systems to perform a comparative risk analysis. For a broader discussion on how Toronto Hydro assesses the risk of asset failures, please see Toronto Hydro's response to interrogatory 2B-SEC-44.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-134

References: **Exhibit 2B, Section D2, Table 2, Page 27**
Exhibit 2B, Section D2, Table 3, Page 33
Exhibit 2B, Section D2, Table 4, Pages 40, 41
Exhibit 2B, Section D2, Table 5, Pages 46, 47
Exhibit 2B, Section D2, Table 6, Page 49
Exhibit 2B, Section D3, Appendix B, Page 19

QUESTION (A):

a) Please update Table 2 through Table 6 indicated in the references above to show the following columns with equivalencies determined by Toronto Hydro's risk matrix:
   i. Typical Failure Mode(s)
   ii. Probability of the Typical Failure Mode
   iii. Consequence of the Typical Failure Mode
   iv. Exceptional Failure Mode(s) (or Catastrophic Failure Mode(s))
   v. Probability of the Exceptional Failure Mode (or Catastrophic Failure Mode)
   vi. Consequence of the Exceptional Failure Mode
   vii. Locations of the Typical and Exceptional Failure Modes on Toronto Hydro's risk matrix.

Please note if Toronto Hydro does not have the probabilities of the typical and exceptional failure modes, then please provide an estimate of those values or an estimate of the relative probabilities of those values (e.g., the typical mode is 100 times more likely than the exceptional).

RESPONSE (A):

The tables referenced by the question provide common root causes of failure by asset class. Toronto Hydro does not compute average probabilities or average consequences for the various root causes of failure. The utility's approach for calculating Probability of Failure ("PoF") for risk quantification purposes is largely grounded in its application of the Condition Based Risk Management ("CBRM") framework. As discussed in Exhibit 2B, Section D3, Appendix C, at page 14:

> *THESL have defined three failure modes depending on the asset deterioration stage and corresponding remedial action as listed in Table 6. These failure modes have been applied in the ACA methodology for the derivation of probability of failure and consequence of failure values. The three failure modes align with both THESL's established practices and the principles of the CNAIM methodology and are considered to be appropriate for the evaluation of asset PoF and CoF.*

The three failure modes are Incipient, Degraded, and Outage (Catastrophic). These failure modes are differentiated by the type of action that they trigger. For example, significant corrosion on a padmount transformer will trigger reactive replacement, which by definition is a "Degraded" failure mode. Incipient and Degraded failure data is assembled primarily by leveraging corrective work order data (i.e., asset repairs and reactive replacements), where as Outage failure data is assembled primarily from outage event and emergency response records. Toronto Hydro determined the PoF for these failure modes by leveraging its records of historic failure in the manner described in Exhibit 2B, Section D3, Appendix B, page 15. Ultimately, Toronto Hydro will apply the composite probability of failure for these failure modes, which tracks with the specific health score for an asset, in its risk-based value framework. For reference, Table 1 below provides the range of PoF values for each Health Index band for each asset class where existing data is currently sufficient to calculate PoF.

1 **Table 1: PoF Ranges by Health Index Band**

Assets	PoF Ranges				
	HI1	HI2	HI3	HI4	HI5
SCADAMATE Switches	0.9%	0.9% to 1.82%	1.9% to 2.78%	2.89% to 4.79%	4.95% to 8.97%
Wood Poles	0.03%	0.03% to 0.07%	0.07% to 0.1%	0.11% to 0.17%	0.18% to 0.33%
Network Transformers	1.06%	1.06% to 2.16%	2.26% to 3.29%	3.43% to 5.67%	5.86% to 10.64%
Submersible Transformers	1.5%	1.5% to 3.05%	3.19% to 4.65%	4.84% to 8.01%	8.28% to 15.03%
Vault Transformers	0.34%	0.34% to 0.69%	0.72% to 1.05%	1.09% to 1.81%	1.87% to 3.4%
Padmount Transformers	0.63%	0.63% to 1.27%	1.33% to 1.94%	2.01% to 3.33%	3.45% to 6.25%
SF6 Insulated Padmount Switch	2.26%	2.26% to 4.58%	4.79% to 6.99%	7.27% to 12.04%	12.45% to 22.58%
Air Insulated Padmount Switch	3.56%	3.56% to 7.22%	7.55% to 11.02%	11.46% to 18.98%	19.62% to 35.59%
SF6 Insulated Submersible Switch	0.88%	0.88% to 1.79%	1.87% to 2.73%	2.84% to 4.71%	4.87% to 8.83%
Air Insulated Submersible Switch	0.44%	0.44% to 0.89%	0.93% to 1.36%	1.42% to 2.34%	2.42% to 4.39%
Station Power Transformers	2.73%	2.73% to 5.53%	5.79% to 8.45%	8.79% to 14.55%	15.04% to 27.28%
AirBlast Circuit Breaker	0.5%	0.5% to 1.01%	1.05% to 1.54%	1.6% to 2.65%	2.74% to 4.96%
Air Magnetic Circuit Breaker	0.24%	0.24% to 0.48%	0.51% to 0.74%	0.77% to 1.27%	1.32% to 2.39%
Oil Circuit Breaker	0.99%	0.99% to 2.02%	2.11% to 3.08%	3.2% to 5.31%	5.48% to 9.95%
Oil KSO Circuit Breaker	1.45%	1.45% to 2.94%	3.08% to 4.49%	4.67% to 7.74%	8.% to 14.5%
SF6 Circuit Breaker	1.89%	1.89% to 3.84%	4.01% to 5.86%	6.1% to 10.09%	10.43% to 18.92%
Vacuum Circuit Breaker	0.71%	0.71% to 1.44%	1.5% to 2.19%	2.28% to 3.78%	3.91% to 7.09%

Please see response to 2B-AMPCO-18 part (a) regarding the current status of Toronto Hydro's ongoing work to develop the Consequence of Failure component of the CBRM framework.

Please see Exhibit 2B, Section D3.2.1.3 regarding how Toronto Hydro intends to combine Probability of Failure and Consequence of Failure into a quantified risk value within the Engineering Asset Investment Planning ("EAIP") tool.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-135

Reference: Exhibit 2B, Section D2, Page 42

QUESTION (A):

a) Toronto Hydro notes that it owns "approximately 139 MSs". What is the exact number of MSs owned by Toronto Hydro?

   i. If an actual number is not available, please explain why not.

RESPONSE (A):

At the time of filing, the actual number of MSs owned was 139. The term "approximately" was used as Toronto Hydro was in the process of decommissioning one MS.

QUESTION (B):

b) If there is a decommissioning plan, please provide the number of stations operational at the time of responding to IRs, and the plan for decommissioning over the forecast period.

RESPONSE (B):

Yes, Toronto Hydro has a decommissioning plan. At this time, there are 138 MSs in-service. Please see the table below summarizing the utility's decommissioning plan for the 2025-2029.

Table 1: Number of Municipal Stations to be Decommissioned over 2025-2029

	2025	2026	2027	2028	2029
Municipal Stations	3	5	1	2	6

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-136

Reference: Exhibit 2B, Section D2, Page 11

QUESTION (A):

a) Does Toronto Hydro routinely compare the costs of rehabilitation and replacement to extend the operating life of assets found to be in poor condition?
If so, please provide some representative costs for asset classes conducive to rehabilitation.

RESPONSE (A):

No. Toronto Hydro does not routinely compare the costs of rehabilitation and replacement for assets operating in poor condition during its capital planning process. In general, many assets that are in poor condition will be:

- older assets which are built to an older standard and it would not be prudent to be refurbishing non-standard equipment, and/or
- not repairable to a state that is safe to crews and the public, and/or
- costly to repair.

Some examples include:

- Transformers and switches which will often have corrosion that requires the full replacement of the enclosure/tank (Costly Repair)
- Civil structures like vaults which have major structural deficiencies that cannot be safely patched/repaired (Unsafe Repair) (See Exhibit 2B Section E6.4 Page 12)
- Rotting wood poles which cannot be repaired (Unsafe repair)

Furthermore, Toronto Hydro's Corrective Maintenance Program (Exhibit 4 Tab 2 Schedule 4) will undertake actions to address deficiencies that will extend the operating life of the assets.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-137

Reference: Exhibit 2B, Section D2, Page 18

QUESTION (A):

a) Are priority deficiencies only evaluated for assets found to be in HI5 condition, or are they evaluated for a broader range of asset conditions? Please explain.

RESPONSE (A):

The assigned priorities (P1-P4) are dependent on various factors such as the severity of the issue (e.g. leaking transformer), location (e.g. main trunk versus lateral/sub-lateral), number of customers potentially affected, etc. Toronto Hydro also takes into consideration environmental, safety, and reliability impacts. The priorities are assigned based on inspection results and deficiencies identified by our crews or others on any of our assets and are not limited to assets found to be in HI5 condition.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-138

References: Exhibit 2B, Section D2, Page 23

QUESTION (A):

a) Please indicate the assessed health index ratings that would trigger pole replacement.

RESPONSE (A):

There is no health score that automatically triggers asset replacement. Please see response to part (b) for more information.

QUESTION (B):

b) How does Toronto Hydro prioritize pole replacements given that it replaces poles that have different health indices?

RESPONSE (B):

As discussed in Exhibit 2B, Section E6.5 at pages 16 to 21, Toronto Hydro prioritizes replacing poles that are in HI4 and HI5 condition, with a focus on parts of the system where the consequence of failure is high and where historical performance has been poor. Other factors that drive pole replacement within the System Renewal programs include the application of construction and design standards at the project planning and design stage, voltage conversion requirements, efficiencies that can be achieved by grouping assets into area rebuilds, the presence of obsolete equipment (e.g., box construction), and on-the-ground field conditions and design factors.

QUESTION (C):

c) How does Toronto Hydro determine the appropriate economic trade-off between the value to customers of the foregone lost service life due to replacing poles and pole top transformers before they fail against the risks associated with running these assets to failure?

RESPONSE (C):

The goal of minimizing an asset's total lifecycle cost while ensuring safe and reliable asset performance is embedded in Toronto Hydro's Reliability Centered Maintenance practices, its risk-based asset replacement and project planning approaches, and its iterative, outcomes-oriented Investment Planning & Portfolio Reporting process, all of which are described in Exhibit 2B, Section D3. Generally, when it comes to system renewal work, planners are expected to justify their proposed capital projects on the basis of value-for-money, i.e., whether the project is scoped to address sufficient failure risk and contribute meaningfully to system performance objectives. These principles are applied during a planner's desktop analysis when, for example, deciding which assets to address, and whether to address those assets through a spot replacement approach versus a broader area rebuild approach. Engineering managers are tasked with reviewing planner scopes and challenging assumptions to ensure asset lifecycle planning principles are applied consistently and that, ultimately, assets which are serviceable are not being replaced prematurely.

During the lead-up to its 2020 CIR, the utility moved toward its current approach of emphasizing measurable customer-focused outcomes and targets (as opposed to opaque cost-benefit metrics). This approach is built upon (i) industry-leading customer engagement, (ii) an iterative capital planning process that produced verifiable trade-offs within top-down financial constraints, and (iii) parametric five-year program estimates built upon a combination of historical unit and project costs, leading indicators such as asset condition demographics, and historical and forecast performance trends.

Beginning in 2021, Toronto Hydro – with encouragement from the OEB's Decision in the utility's 2020 CIR[1] – began the process of implementing an industry-leading Engineering Asset Investment Planning ("EAIP") tool (ultimately, Copperleaf C55). As part of this project, the utility has set-out to

[1] EB-2018-0165, Decision and Order (December 19, 2019) at pages 90-94.

develop an industry-leading Value Framework that leverages the asset-by-asset outputs of its Condition-Based Risk Management framework to assign a consistent, objective measure of value to individual projects developed by system planners. These value measures will be leveraged within the EAIP tool to run value-maximizing optimizations on the utility's execution work program, and will provide planners with an additional tool for assessing and demonstrating the economic value of their projects, consistent with the principles of asset lifecycle management. (Toronto Hydro expects this tool to be fully implemented and embedded in planning processes in time for its next major capital planning cycle in 2025.)

With respect to the overhead assets referenced in this question, note that Toronto Hydro generally does not prioritize pole top transformers for proactive replacement, except where the units are at risk of containing PCBs and as part of larger proactive area rebuild projects when there are economies of scale. For a general discussion of overhead asset replacement prioritization practices, please refer to Exhibit 2B, Section D3, Table 2.

QUESTION (D):

d) Please provide the benefit-cost analysis that Toronto Hydro used to evaluate its proposed proactive wood pole and pole top transformer replacement programs.

RESPONSE (D):

Per the discussion provided in response to part (c), Toronto Hydro does not reduce its five-year System Renewal investment programs down to a single benefit-cost analysis metric. The utility's 2025-2029 expenditure plan for the Overhead System Renewal program was developed based on various considerations including asset condition demographics, reliability performance trends, voltage conversion needs, and environmental and safety risks. The forecast benefits of this program with respect to reliability outcomes are captured within the SAIDI/SAIFI forecasts found in Exhibit 1B, Tab 3, Schedule 1, along with an overall benefit-cost analysis of Toronto Hydro's proposed reliability investments as a whole.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-139

Reference: Exhibit 2B, Section D3 p.6

QUESTION (A):

a) What has changed such that Toronto Hydro is adding concrete and steel poles to its dedicated pole inspection program in 2025?

RESPONSE (A):

Please refer to Toronto Hydro's response to 2B-PWU-10.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-140

Reference: Exhibit 2B, Section D3, Appendix B

Preamble:

Appendix B provides the ACA Summary for 2017, 2022 and the Forecast for 2029 year end if no investments are made.

QUESTION (A):

a) For both tabs in Appendix B, please provide Forecasts for 2029 YE under the following scenarios.
    i. If the proposed capital and maintenance plans are implemented
    ii. If Toronto Hydro's capital program was reduced by 25%
    iii. If Toronto Hydro's capital program amounts for 2025 was approved, and Toronto Hydro was to operate under a Price Cap IR regulatory framework for the forecast period.

RESPONSE (A):

For part (i), please refer to Toronto Hydro's response to interrogatory 2B-SEC-44. For (ii) and (iii), please refer to interrogatory 1B-SEC-21.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-141

References: **Exhibit 2B, Section D3, Appendix A, Pages 4, 6**

QUESTION (A):

a) How many SF6 switches broken down by category (e.g., insulated padmount) are planned to be replaced in the planning period?

RESPONSE (A):

Toronto Hydro has forecasted to replace 116 padmount switches based on the preliminary selection of areas targeted as per the drivers mentioned in Section E6.2.3.3. For these Horseshoe system assets, Toronto Hydro does not yet have the discrete project details for projects in later years of the plan, which would be necessary to break these switches down further into sub-categories. The utility will be prioritizing higher-risk air-insulated switches. With respect to the Downtown underground system, Toronto Hydro plans to replace four URD submersible SF6 switches in the 2025-2029 period.

QUESTION (B):

b) Please explain why it was prudent to have 1 Hi4 and 16 Hi5 SF6 insulated padmount switches in 2022.
   i. Please explain why it is now necessary to replace switches that have effectively the same health rating in 2029 as they did in 2022?

RESPONSE (B):

The 17 SF6 insulated padmount switch units in HI4/5 in 2022 were addressed for repair or replacement through corrective maintenance and reactive capital programs in 2023. The next inspection cycle of these units in 2024 will result in updates to their Health Scores as per the action taken. Please see Exhibit 2B, Section E6.2.3 for a detailed discussion regarding the need for investment in padmount switches and the focus on air-insulated switches. Please refer to 2B-SEC-44 for a comprehensive discussion regarding expected changes in asset demographics over the 2025-2029 period.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-142

References: **Exhibit 2B, Section D3, Page 6**
Exhibit 2B, Section D3, Pages 12, 13

Preamble:

With regards to Toronto Hydro's asset replacement programs for poles.

QUESTION (A) AND (B):

a) Similar to submersible transformers, please explain why Toronto Hydro chose to inspect all poles on an 8-year cycle, rather than only inspecting those poles approaching or past their useful lives (or previously identified as being in poor condition) more frequently?
b) Why does Toronto Hydro not inspect poles on a cycle time that is tied to actual asset condition (or age if condition is not known)?

RESPONSE (A) AND (B):

Please refer to Toronto Hydro's response to interrogatory 2B-PWU-10.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-143

References: Exhibit 2B, Section D3, Pages 15, 16

QUESTION (A):

a) Please provide the list of asset classes that are considered critical spares.

RESPONSE (A):

The following asset classes have equipment listed as critical spares:

- Overhead transformers
- Overhead distribution poles
- Overhead primary conductors
- Overhead secondary conductors
- Overhead switches
- Overhead insulators
- Padmounted transformers
- Submersible transformers
- CRD transformers
- Building vault transformers
- Padmounted switches
- Underground cables
- Network transformers
- Stations bus disconnect switches
- Stations DC batteries and chargers

QUESTION (B):

b) For each of the critical spares asset classes please describe the long-term asset retirement strategies in terms of the expected natural failure rate, planned retirement rate, risk profile over time, and role that critical spares play in achieving that strategy.

RESPONSE (B):

Toronto Hydro is unable to provide the information requested. In the utility's experience, the multi-decade, asset-class-specific plans requested by OEB Staff are of limited value (and unnecessary) in determining effective and actionable asset investment strategies and business plans for Toronto Hydro's service territory and system. Over the last 20 years, the utility has developed an asset management and program delivery approach that is performance-based, programmatic, integrated and flexible. Toronto Hydro's programmatic System Renewal evidence found in Section E6 provides detailed justifications for the level of investment required to achieve the outcome objectives associated with the Distribution System Plan. Please see Toronto Hydro's response to 2B-SEC-44 for further discussion regarding the key considerations driving the asset management strategies for a majority of asset classes.

Toronto Hydro maintains critical spares for a large set of key assets across its system. The utility uses critical spares to allow the utility to repair or replace an asset under outage or emergency conditions in a timely manner, ultimately impacting Toronto Hydro's ability to minimize the duration of outages to its customers. The availability of critical spares is reflected in Toronto Hydro's historical interruption statistics and thus informs Toronto Hydro's risk analysis via the reliability projection methodology.

QUESTION (C):

c) Please explain why a "wall" or "wave" within a 10 to 15-year period is the optimal window within which to manage asset demographics for long lived assets.

RESPONSE (C):

As stewards of the system, Toronto Hydro must take into account rate impacts, supply chain risks, and execution limitations when dealing with asset "walls" or "waves". To clarify, Toronto Hydro does not aim to manage an asset class within a 10 to 15-year window for long-lived assets. Rather, if it becomes aware of a large proportion of assets within an asset class reaching end-of-life (i.e. a "wall" or "wave" of assets reaching end of life) within the next 10 to 15 years, it will attempt to smooth out the renewal over a longer time period to minimize inefficiencies of having to replace a large amount of assets in a short period of time. This approach allows the utility to manage execution challenges and reduce rate volatility for its customers.

QUESTION (D):

d) Please explain why asset management strategies such as Critical Spares cannot also extend the replacement lifespan over which a subset of assets can be replaced.

RESPONSE (D):

Critical spares serve as vital lifelines for Toronto Hydro, ensuring a consistent level of service continuity when faced with asset failures. The availability of critical spares is already reflected in Toronto Hydro's historical outage statistics and by extension its assumptions regarding the future consequence of failure for key assets. A greater reliance on critical spares to extend replacement lifespans would in effect mean running a greater share of assets to failure, which would result in reliability performance deterioration and greater inefficiencies related to reactive (as opposed to planned) replacement.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-144

References: **Exhibit 2B, Section D3, Page 24**
Exhibit 2B, Section D5, Page 20
Exhibit 2B, Section D5, Page 38
Exhibit 2B / Section D5 / p. 69

Question (A):

a) Please explain from a risk perspective why Advance Metering Infrastructure (AMI) meters cannot be run to fail (i.e. replaced reactively) and provide the business case justifying asset retirement before failure.

RESPONSE (A):

Toronto Hydro anticipates that replacing AMI meters reactively by employing a run to fail approach would pose significant operational, customer and regulatory compliance risks and forestall the achievement of expected benefits from the installation of newer meters compared to mass meter replacement, as discussed below and in program evidence.[1]

Reactive meter replacement involves replacing individual meters after they have become defective (e.g. due to loss of communication or a blown fuse). Reactive replacement always involves a degree of billing accuracy risk, due to the lag between meter failure and the execution of replacement in the field. When meters fail, customer consumption data is lost on the failed meter, and depending on the number of failed meters at any one time requiring reactive replacement, customer consumption data may not be captured for extended periods of time. Where replacement is not or cannot be completed in a timely manner, it can result in delayed billing and/or the need to estimate

[1] Exhibit 2B, Section E5.4, subsection E5.4.3.3 "Failure Risk", at p. 9-10.

customer consumption and demand, which in turn may adversely affect billing accuracy.[2]

The age of Toronto Hydro's metering assets exacerbates the risks discussed above, and the extensive number of first-generation meters in the system results in a high exposure risk should mass failure of a component begin to occur. As a larger subset of the meter population ages and approaches end of life ("EOL"), the probability of meter failures increases,[3] which further drives the need for reactive meter replacement. By 2025, approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their EOL, increasing the likelihood of meter failures and hindering Toronto Hydro's ability to meet the OEB-prescribed billing accuracy target of 98%.[4] In this context, relying on reactive replacements to achieve AMI 2.0 would place significant constraints on Toronto Hydro's resources and reduce efficiencies compared to mitigating these risks through a large-scale deployment.

Toronto Hydro's AMI 2.0 initiative is also driven by metering technology obsolescence. As noted in the Metering program evidence, a significant portion of Toronto Hydro's residential and small commercial meters were installed between 2006 and 2008.[5] Due to rapid advancements in technology, these first-generation smart meters have become outdated and obsolete.[6] Meter manufacturers continuously update their product with new features, abilities, communication upgrades, and storage capacity improvements. In the past 18 years, Toronto Hydro has utilized Honeywell Elster as its AMI provider. During that period, meters have gone through five generations and two communication network upgrades. The key functionalities that Toronto Hydro plans to adopt through the AMI 2.0 initiative, as part of its Grid Modernization strategy, can only be realized with the installation of fifth generation meters in the utility's system. Obsolete meters will become

[2] Exhibit 2B, Section E6.7, subsection E6.7.3.2 "Reactive Capital", at p. 13.
[3] Exhibit 2B, Section E5.4. subsection E5.4.3.3 "Failure Risk", at p. 9-10.
[4] Exhibit 2B, Section E5.4, Table 2, at p. 2.
[5] *Supra* footnote 3.
[6] Exhibit 2B, Section E5.4, subsection E5.4.3.4 "Business Operations Efficiency & Reliability" at p. 10-13.

inhibitors to fully utilizing new features and capabilities, the benefits of which are listed in 2B-Staff-194. Therefore, replacing the entire fleet of meters is the optimal solution that leads to operational improvements and facilitates the integration of key Grid Modernization initiatives, including voltage monitoring, distributed energy resource integration, electric vehicle load forecasting, and more efficient outage detection and response.

QUESTION (B):

b) Please provide the asset age demographics (by age, asset count and asset condition) for residential and small commercial AMI meters currently in service.

RESPONSE (B):

Table 1: Residential & Small Commercial AMI Meter Asset Age Demographics

Meter Age *	Number of Residential and Small Commercial AMI meters
19	38
18	5,566
17	177,604
16	176,685
15	125,208
14	37,001
13	30,404
12	11,281
11	3,580
10	3,118
9	17,538
8	16,147
7	25,410
6	39,649
5	31,177
4	16,967
3	38,033
2	12,119
1	23,463
0	6,651

Table 1 - Note: * Data used from 2023 Year End

Toronto Hydro operates its meters on a pass or fail basis and does not use an asset health index band for this type of asset. Meters that are suitable for service have a working display, are able to accurately measure consumption, and have a working communication module. None of these functions can be partially working or have any other intermediate health status that can be measured.

QUESTION (C):

c) Based on useful life and actual failure data to date, what is the expected natural failure rate for AMI meters in each year of the planning period?

RESPONSE (C):

Please refer Table 7 on page 13 of Exhibit 2B, Section E6.7, subsection E6.7.3.2, which indicates the natural failure rate for all meters, including AMI meters.

QUESTION (D):

d) Please provide the planned retirement pacing (in dollars and number of units) by year for AMI meters as per the above plan to replace $248.1M worth of AMI meters during the planning period.

RESPONSE (D):

Toronto Hydro notes that the AMI 2.0 initiative will only cover residential and small commercial and industrial meter replacements, for which the 2025-2029 cost is estimated at $201.6 million of the $248.1 million Program cost, as indicated in Table 6 in Exhibit 2B, Section E5.4, at page 17.

For the number of meters to be replaced under the AMI 2.0 initiative, please refer to the below table:

Table 2: Number of Meters to be Replaced under AMI 2.0 Initiative

	2025	2026	2027	2028	2029	Total
Residential and Small C&I Meter Replacement	157,893	173,710	179,708	68,985	0	**580,296**

QUESTION (E):

e) What is the value of AMI 2.0 meters that are planned to be replaced in advance of their natural failure rate in each year of the planning period.

RESPONSE (E):

The table below shows the derecognition value of AMI meters that Toronto Hydro plans to replace in advance of their natural failure rate (before end of life) in each year of the 2025-2029 rate period over the course of the AMI 2.0 program.

Table 3: Derecognition Value of AMI Meters Planned for Replacement

$ (Millions)	2025	2026	2027	2028	2029
AMI Meter Derecognition Values	$3.33	$3.09	$2.89	$0.98	$0.00

QUESTION (F):

f) Please explain why AMI 2.0 needs to be done in advance of DER penetration increases rather than selectively around areas where DER penetration may cause voltage concerns.

RESPONSE (F):

To successfully enable key AMI 2.0 functionalities such as feeder voltage monitoring due to increasing DER penetration, Toronto Hydro must make wholesale changes to an area and convert the area onto the AMI 2.0 communication network. While newer AMI 2.0 meters are capable of communication on the existing network, older obsolete meters cannot communicate on the new network. If Toronto Hydro were to perform spot replacements of meters to enable a single use case, the utility would lose communication with all other meters in the area, resulting in significant impacts to customer billing and utility operations. In order to successfully transition to AMI 2.0 technology and associated functionalities, a critical mass of meters at a system level must be implemented to ensure successful billing. For further details on penetration requirements at a system level to achieve the benefits of AMI 2.0, please refer to Toronto Hydro's response to 2B-Staff-194.

QUESTION (G):

g) What level of AMI 2.0 penetration is required on a feeder to provide adequate voltage violation and overloading monitoring?

   i. Why cannot a comparatively few AMI 2.0 meters scattered amongst existing AMI meters provide adequate feeder monitoring?

RESPONSE (G):

Please refer to the response to subpart (f).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-145

Reference: Exhibit 2B, Section D3, Page 40

Preamble:

In section D3, Toronto Hydro notes that it "considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level and considers the risks facing individual asset classes and risks relevant to investment programs."

QUESTION (A):

a) Please provide the ERM risk results in tabular format for each of the past 5 years and yearly projections for the test period.

RESPONSE (A):

To clarify, the ERM process is a corporate risk framework, not an asset risk framework. It does not comprehensively deal with granular asset risks in a manner that lends itself to the tabulation of results. Rather, as discussed further in Exhibit 2B, Section D3 at page 41, lines 10-18, the ERM helps to identify and manage corporate risks that emerge from the asset base, such as non-energy mitigating cable chamber lids.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-146

Reference: Exhibit 2B, Section D3, Appendix B, Page 8

Preamble:

Regarding the asset health methodology of Toronto Hydro's wood pole assets.

QUESTION (A):

a) Please provide the basis for selecting a useful life of 45 years.

RESPONSE (A):

The useful life of 45 years was adopted on the basis of the mean useful life from a study conducted by Kinectrics for Toronto Hydro on asset useful lives. This was reviewed as part of the Depreciation Study completed by Concentric Inc., filed in Exhibit 2A, Tab 2, Schedule 1, Appendix D, and was maintained at 45 years. The value recommended from Concentric Inc. has been informed by review of Toronto Hydro's data, consultations with Toronto Hydro operational, engineering, and management staff and assessment of service lives utilized by peer Canadian electric distribution utilities.

QUESTION (B):

b) Please confirm that Normal Expected Lives as used in the Reference is the same as "useful life" as used by Toronto Hydro in this filing.
   i. If not confirmed, please explain the differences between Normal Expected Lives and useful life.

RESPONSE (B):

Confirmed.

QUESTION (C):

c) Please explain why Toronto Hydro has not re-calibrated the useful life (or Normal Expected Life) of wood poles despite evidence that the useful life (or Normal Expected Life) is too low, thus resulting in elevated health scores.

RESPONSE (C):

Toronto Hydro's useful life for wood poles was set on the basis described in response to part (a), and the utility believes this useful life is reasonable based on current information. The utility does not, at present, have a valid statistical basis on which to set the useful life differently, and from a governance and consistency perspective, is unwilling to make arbitrary changes to core modelling assumptions. Potential changes of this nature require thorough study, exploration and iteration by data analysts and engineers. Toronto Hydro, recognizing early-on the unique issues with the wood pole model, has implemented a number of changes to improve and temper the behaviour of the model. This is explained in detail in the referenced report. For further discussion regarding the behaviour of the wood pole model, please refer to 2B-Staff-226, part (b). For a discussion regarding the application of wood pole condition results in Toronto Hydro's 2025-2029 investment plan, refer to 2B-SEC-44. Finally, for a broader discussion regarding useful lives, please see response to 2B-Staff-131, part (a).

QUESTION (D):

d) What percentage of Wood Poles have health score collars applied to the final health score determination?

   i. Does this percentage imply a problem with the underlying health score formulation?

   ii. If no, at what percentage would a problem with the underlying health score formulation likely exist, and why?

RESPONSE (D):

As explained by EA Technology on page 9 of the referenced report:

> "Just over 2% of the asset population have health score values set through condition collars, mainly due to moderate pole separation (cracks and pole top feathering). This shows a considered approach to the setting of condition collars to identify assets with issues requiring intervention.
>
> The CNAIM methodology includes an additional (reliability) modifier to reflect any issues or observations that are not reflected in the observed and measured condition modifiers. THESL have used this methodology feature in the wood pole model and applied a collar of 7.25 to assets that have been confirmed to be in a poor condition by inspectors in the field. This is considered to be an appropriate use of the reliability modifier mechanism to directly impact asset health where information is available."

The purpose of collars in the methodology is to ensure that an asset's health score represents the correct level to reflect the condition when the Condition Input Factors are not strong enough to achieve the correct anticipated level of health score. While a high rate of collar applications would warrant further examination, there is no specific value at which the application rate would inherently represent a problem with the underlying health score formulation.[1]

[1] To illustrate this point: if 100 wood poles were condemned by a field inspector, but the condition methodology without a collar was assigning a score of less than 7.25 to 90 of those poles, then 90% of the 100 poles would require application of a collar to ensure a minimum health score of 7.25. This would be an appropriate result.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-147

Reference: Exhibit 2B, Section D3, Page 15

Preamble:

Toronto Hydro states, "Where appropriate, Toronto Hydro undertakes targeted refurbishments in the field to maximize the serviceable life of existing assets. For example, as mentioned above, the utility will rebuild a deteriorated vault roof, extending the useful life of the entire vault."

Has Toronto Hydro considered utilizing pole stubs to extend the life of wood poles that have ground line rot but are otherwise in good condition? If not, please explain why not. If yes, what were the results?

RESPONSE:

Toronto Hydro does not utilize pole stubs to extend the life of wood poles as the additional costs or risks associated with this approach outweigh any possible benefits from cost savings. These include:

1. Due to the nature of the environmental loading (as per CSA C22.3 No1-20: Overhead Systems) acting on overhead pole lines, and the physical properties of hydro poles, the maximum stress on the pole occurs close to the groundline of the pole. A location-specific customized structural design would be required for each location depending on the type of pole stubbing method selected, and the overhead framing configuration on the pole.
2. Primary, secondary, and communication risers would not be able to be maintained on these poles due to the mechanical means by which pole stubbing is installed.
3. Climbing access needs to be maintained on poles and access would be limited by pole stubbing installations.
4. Industry standard pole loading software is not capable of modelling these kinds of reinforcement methods.

5. Poles are considered a piece of major distribution equipment as defined by Electrical Safety Authority ("ESA") in their "Technical Guideline for Section 6. Approval of electrical equipment". A pole with rot identified near the ground line of the pole may indicate that there is also deterioration of the pole beneath the ground line resulting in a poorly performing pole foundation.
6. Pole stubbing may not be compatible with foundation requirements for the type of existing pole foundation: direct buried, direct buried with concrete reinforcing, poor soil, sloped terrain, proximity to foundations or retaining walls, reinforced sidewalk bays, or legacy foundation installations.
7. In relation to hydro poles, the *Accessibility for Ontarians with Disabilities Act, 2005*[1] ("AODA") requires minimum distances to be maintained around poles in areas accessible by members of the public. Pole stubbing activities would require additional footprint around existing pole locations, and this may not be possible for existing pole locations due to space restrictions.

[1] *Accessibility for Ontarians with Disabilities Act*, 2005, S.O. 2005, c. 11.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-148

Reference: Exhibit 2B, Section D3, page. 45

Preamble:

Toronto Hydro uses peak demand forecasting to identify capacity constraints at substations and undertake planning to accommodate the forecasted growth.

QUESTION (A):

a) Please provide a table listing all Toronto Hydro's stations and show the forecast capacity constraints in each station for each of the next 20 years for the summer and winter peaks.

RESPONSE (A):

Please see the Excel file attached as an appendix to this IR showing the stations with forecasted capacity constraints in the next 20 years in Summer and Winter.

QUESTION (B):

b) Please provide a table of the restricted feeders and the substations they are located within, and the capacity deficit for each restricted feeder for each of the next 20 years.

RESPONSE (B):

Compared to stations buses, feeder loading is much more dynamic in nature, as load can swing from feeder to feeder frequently due to various capital and customer work, customer supply schemes and contingency situations from both planned and unplanned work. To ensure that customers can connect to the grid in a timely and efficient manner, Toronto Hydro proactively manages feeder capacity constraints through the Load Demand program. As defined in Exhibit 2B, Section E5.3, feeders that are identified as highly loaded based on standard planning practices are considered for relief. Feeders are not considered restricted from accepting load, as required expansion or enhancement work will be conducted to accommodate any customer load. Due to the dynamic nature of managing capacity constraints at the feeder level, the process of identifying feeder load level transfers and other investments to address restricted feeder capacity is a continuous one and Toronto Hydro does not forecast capacity deficits for feeders in the manner requested (i.e. over a 20-year period). With this context in mind, Exhibit 2B Section E5.3 pages 14-15 identifies the current plan for relief of highly loaded feeders in both the Horseshoe and Downtown systems.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-149

Reference: Exhibit 2B, Section D3, Page 45

Preamble:

Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centres, (ii) electrification of transportation, and (iii) Municipal Energy Plans.

QUESTION (A):

a) Please provide an overview and justification for why these three specific drivers were considered.

RESPONSE (A):

The noted drivers were selected as the most impactful and discrete near and medium-term growth drivers that the utility must consider in identifying the minimum investments necessary in the 2025-2029 rate period to ensure that the system is ready and able to serve customers in the next decade. These needs are specifically:

i. Data Centers are large point loads that frequently can result station overloading.
ii. Electrification of Transportation is expected significant to impact system-wide load growth, especially transit corridors.
iii. Municipal Energy Plans: Toronto Hydro must prepare the distribution system for the City's plans. Large loads reported by City or City Consultants, require capacity planning.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-150

References: Exhibit 2B, Section D3, Page. 53

Preamble:

Toronto Hydro indicated that "The various risk analyses presented in Section D3.2 and Section D3.3 drive the overall investment required to manage the distribution system."

QUESTION:

a) Please provide a table showing the pre-investment and post-investment risks and the costs of mitigation for each of the risk analyses presented in section D3.2 and D3.3.

RESPONSE:

- **Quantified Risk-based Analysis:** As detailed in D3.2.1.3, Toronto Hydro is currently in the process of developing and implementing a custom value framework as part of its Engineering Asset Investment Planning ("EAIP") system, which will allow the utility to establish quantified value (inclusive of risk mitigation benefits) associated with asset failure. For details regarding the progress and completion expectations for the EAIP tool, please see 2B-AMPCO-20.
- **Reliability Projections:** Exhibit 1B, Tab 3, Schedule 1, Pages 8 to 21 provide both the current and forecasted reliability performance for Outage Duration and Outage Frequency (with comparisons to an "IRM"-level of funding), along with key programs within the expenditure plan that contribute to these measures.[1] For long-term planning, reliability projections are useful in understanding the risk that reliability performance could deteriorate under different investment scenarios.

[1] Note that these reliability projections have been updated in response to 2B-SEC-42, part (c).

- **Worst Performing Feeder:** Worst Performing Feeder measures (e.g., FESI) are highly volatile measures of granular, feeder-level performance and cannot be forecasted with current modelling capabilities. Worst Performing Feeder measures are leveraged to monitor the ongoing performance of the system and identify problem areas at risk of especially poor reliability performance.
- **Enterprise Risk Management:** Enterprise Risk Management is an embedded, qualitative aspect of business planning and the Investment Planning & Portfolio Reporting process. Please see response to 2B-Staff-145 regarding the interplay between the corporate ERM and the Asset Management System. Where applicable, for each asset management-related risk monitored within the ERM system (e.g., PCBs, box construction), Toronto Hydro has developed a 2025-2029 investment plan that is calibrated to prevent risk from escalating beyond acceptable tolerances.
- **Priority Deficiencies:** As discussed in Exhibit 2B, Section E3.2, Toronto Hydro applies a prioritization framework to identify urgent repairs and corrective actions. The utility does not forecast priority deficiencies by risk category as part of long-term investment planning. Underlying trends in priority deficiencies are considered when developing long-term expenditure plan levels in programs, including Reactive Capital (Exhibit 2B, Section 6.7) and Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4).
- **Legacy Assets:** Please see Toronto Hydro's response of 2B-AMPCO-26 for a comparison of forecasted 2024 and 2029 results for key legacy assets. The reduction of legacy assets is driven by capital program investments within the System Renewal category.
- **Generation and Load Capacity Risk Assessments:** Please refer to Toronto Hydro's detailed evidence provided in Exhibit 2B, Sections D4, E3, E5.3, E5.5, and E7.4 for detailed discussions regarding the utility's peak demand and distributed generation forecasts, the risks associated with these increases in demand, and the expected impact that the planned investments will have on mitigating these risks.

Please see Toronto Hydro's response to 2B-SEC-44 for a comprehensive discussion on how asset health, performance, criticality, executability, and other asset management considerations together inform the pacing of Toronto Hydro's renewal investments in the 2025-2029 Distribution System Plan.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-151

References: Exhibit 2B, Section D3, Appendix A

QUESTION (A):

a) Why is a minimum H of 4 the appropriate choice for calculating Probability of Failure (PoF).

RESPONSE (A):

Toronto Hydro referred to Ofgem's CNAIM framework in implementing its own Condition Based Risk Management framework ("CBRM") in 2017. Inherent to the methodology, assets with a health score of 0.5 are in new or like new condition, while a health score of 5.5 represents the point at which the first significant signs of deterioration would be expected. By setting a minimum asset health score ("H") of 4 in the calculation of probability of failure ("PoF"), the same PoF is given to all assets before reaching the point where significant signs of deterioration are expected.

QUESTION (B):

b) Does setting a minimum H score constrain PoF so that it is not suitably close to 0 for assets in the best condition?

RESPONSE (B):

Setting a minimum H score in the PoF calculation is a provision for constant PoF for the lowest health scores. The PoF associated with H scores less than this limit relate to installation issues or random events instead of condition and are calibrated using asset failure data (i.e., through constants k, c in the formular). The minimum H score is a transition from constant PoF to a controlled exponential relationship.

QUESTION (C):

c) For wood poles and power transformers asset classes, please provide a table showing the range of PoF for each health score and health index.

RESPONSE (C):

Please see Table 1 below.

Table 1: Wood Pole and Power Transformer PoF Ranges

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	PoF Range – Wood Poles	PoF Range – Station Power Transformers
HI1	≥ 0.5	< 4	0.03%	2.73%
HI2	≥ 4	< 5.5	0.03% to 0.07%	2.73% to 5.53%
HI3	≥ 5.5	< 6.5	0.07% to 0.10%	5.79% to 8.45%
HI4	≥ 6.5	< 8	0.11% to 0.17%	8.79% to 14.55%
HI5	≥ 8	≤ 10	0.18% to 0.33%	15.04% to 27.28%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-152

Reference: Exhibit 2B, Section D3, Appendix A

Preamble:

In Table 2, Health Index bands and definitions, Toronto Hydro sets ranges for each HI band.

QUESTION (A):

a) Please explain how the health score ranges are mapped onto the different health indices.

RESPONSE (A):

Health Score ranges are mapped onto the different health indices as a way of representing the key stages of an asset's lifecycle. Toronto Hydro adapted Ofgem's Common Network Asset Indices Methodology ("CNAIM") approach in implementing its Condition Based Risk Management framework ("CBRM") in 2017. The following mapping is inherent to the methodology:

- An asset with a health score of 0.5 has new or like new condition. A health score that is less than 4.0 has the same Probability of Failure ("PoF") as an asset that is new.
- Assets with a health score of 4.0 will begin to have a PoF related to its health score. A health score of 5.5 represents the point at which first significant signs of deterioration would be expected. This is where the PoF of the asset is approximately double that of a new asset.
- A health score of 10 represents the worst current condition of an asset, where the PoF is 10 times that of a new asset. A health score of 15 represents the worst future condition of an asset.

Figure 1 below, taken from CNAIM, illustrates where the health index bands lie on a typical asset health / PoF curve.

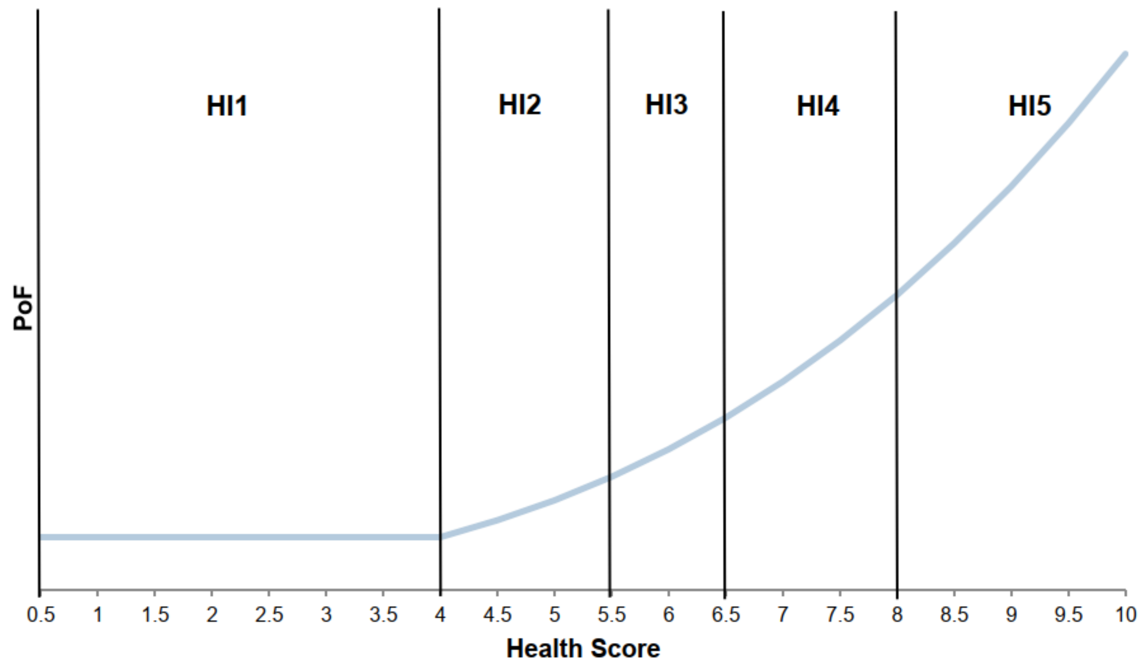

Figure 1: Mapping of Health Index Bands to Probability of Failure/Health Score[1]

QUESTION (B):

b) Please explain why the future forecast range of health scores is different (upper limit of 15) than the current range for those assets (upper limit of 10).

RESPONSE (B):

The cap on the future health score is extended to 15 in order to provide room for assets that are currently in poor condition to continue deteriorating in the future health score model. If this extension was not provided, assets would cluster around the maximum score of 10, which would

[1] https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/dno_common_network_asset_indices_methodology_v2.1_final_01-04-2021.pdf, page 29, Figures 3

reduce the ability to differentiate between assets that are projected to be in relatively better or worse condition in the future.

QUESTION (C):

c) Why can't assets with a health score greater than 10 be in service today?

RESPONSE (C):

Please see response to part (b). Toronto Hydro's CBRM methodology is based on the CNAIM Framework. The CNAIM Framework adopts a standardized 0 to 10 scale for the current health score. As such, the calculated current health score cannot go beyond 10.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-153

References: **Exhibit 2B, Section D4, p. 2**
Exhibit 2B, Section D4, Appendix B, p. 2
NOTE: The report did not provide page numbers so OEB staff is unsure what constitutes Page 1 of Appendix B.
Exhibit 2B, Section D2, p. 6

Preamble:

Toronto Hydro is planning expenditures on the basis of being a summer peaking utility when its studies indicate that it is moving towards becoming a winter peaking utility in the 2030s.

QUESTION (A) AND (B):

a) Please explain why using the Summer Peak to drive the investment in long lived (multi-decade) assets is the prudent choice when the FES clearly indicates in all cases that Toronto Hydro is a Winter Peaking utility in the 2030s and beyond.

b) Please explain how Toronto Hydro's plans can be optimal if it is using a summer peak for planning purposes when it is becoming a winter peaking utility.

   i. Is Toronto Hydro only planning investments for the 2025-2029 period, and how does this summer peaking planning strategy reconcile with the "least regrets" strategy it purports to use?

   ii. How was the shift from summer to winter peaking accounted for in long-term regional planning with the IESO given that those forecasts are for 20 years?

RESPONSE (A) AND (B):

Please see Exhibit 2B, Section D4 at pages 8-12. Unlike the 10-year System Peak Demand forecast that Toronto Hydro has relied upon to prepare the investment plan in this application, the outputs of the Future Energy Scenario (FES) model do not predict what is likely to occur in the future.

Rather, the FES provide insight into future possible pathways of decarbonization, and were used to evaluate the System Peak Demand forecast and resulting capacity investments from a "least regrets" perspective. To that end, although the FES model suggests that Toronto Hydro will be a winter peaking utility the 2030s, Toronto Hydro expects to remain a summer peaking utility in the 2025-2029 rate period. This is because the 10-year System Peak Demand forecast, which underpins this rate application does not include the impact of wide-scale building electrification, as the policy and consumer-behaviour drivers of this type of demand remain uncertain.

To stress test the System Peak Demand forecast against the least regrets planning philosophy, Toronto Hydro assessed whether the utility could accommodate a growing winter peak (driven by building electrification) in the 2025-2029 rate period, if needed. To that end, the utility looked at scenarios of forecasted building heating loads derived from the FES outputs, and concluded that the capacity investment plan can meet higher levels of building heating loads (which contribute to winter peak) should this driver of electrification materialize at a faster pace than expected in the 2025-2029 rate period. This analysis gave Toronto Hydro confidence that the investments in system capacity that the utility proposes to make in the 2025-2029 rate period are least regrets to address growth and electrification drivers that the utility faces in this decade and the early part of the next decade. That being said, it is possible that the utility could be faced with incremental capacity constraints at a localized level as a result of accelerated transportation and building electrification demand in the next rate period. To address this challenge, the utility proposes a Demand Related Variance Account (DRVA) to track variances in actual versus forecasted expenditures in a number of demand-related investment programs. For more information about this proposal please refer to Exhibit 1B, Tab 2, Schedule 1 at pages 35-47.

The long-term regional planning process is underway and expected to wrap-up in the summer of 2024.[1] As part of this process, the IESO is considering the impact of electrification on both summer and winter forecasts over the longer-term outlook of 20 years. To consider the longer-term winter

[1] https://www.ieso.ca/Get-Involved/Regional-Planning

peak impact of electrification, Toronto Hydro layered heating load to its base 10-year System Peak Forecast to derive a long-term 20-year scenario.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-154

Reference: Exhibit 2B, Section D4, Pages 10-18

Preamble:

Toronto Hydro discusses the primary drivers of capacity needs and related investments over the 2025-2029 rate period, including customer connections, electrification of transit, electric vehicles, hyperscale data centres and Municipal Energy Plans and has shown the anticipated impact of these drivers relative to base load. Specific areas of Toronto Hydro's service territory are highlighted where significant load growth is expected, including: Port Lands, East Harbour, Horseshoe East (including the Golden Mile) and Horseshoe West (including Downsview).

QUESTION (A):

a) Please identify how Toronto Hydro adopted the direction from the OEB's January 2023 Framework for Energy Innovation both in how it investigated the use of third party owned DERs to meet planning needs as well as meaningfully investigated a market-driven solution before building/owning the solution themselves.

RESPONSE (A):

Toronto Hydro has been actively pursuing and deploying non-wires solutions since 2018 (at Cecil TS) and continues to build on this experience with the Etobicoke project in the Manby/Horner area of its grid. For the 2025-2029 rate period Toronto Hydro set an ambitious target to triple the amount of flexible system capacity to be procured from market-based providers. Procuring this capacity could help avoid about 25 percent of the total load required to be transferred in the targeted station areas. The history of this work, as well as the future plans are outlined in detail in the evidence at Exhibit 2B Section E7.2. For additional information about Toronto Hydro's 30 MW non-wires system capacity please see the response to 1B-Staff-88.

QUESTION (B):

b) Please explain in detail how Toronto Hydro is responding to the policy direction outlined in the OEB's Framework for Energy Innovation?

RESPONSE (B):

As noted in the response to part (a), Toronto Hydro has developed a plan to procure and leverage services from DERs with an ambitious target of 30 MW. In addition, Toronto Hydro has also put forward: (i) a Benefit Cost Analysis and an incentive proposal (as outlined Exhibit 1B, Tab 3, Schedule 1) that aligns with the OEB's policy direction; and (ii) an Innovation Fund proposal to explore more nascent areas of DER integration, enabling further development of capabilities in the area of DER integration. For more information on how innovation has shaped the 2025-2029 rate application, including integrating policy directives from the FEI report, please see Exhibit 1B, Tab 4, Schedules 1 and 2.

QUESTION (C):

c) Please list all non-wires solutions Toronto Hydro has considered for the areas identified to see significant load growth over the near and medium term, including grid modernization, geo-targeted conservation and demand management programs and discuss the decision factors for each, including benefit-cost analysis for various options to address these areas with non-wires solutions.

RESPONSE (C):

Please see the responses above. Toronto Hydro's use of non-wires solutions focuses on practical applications where i) capital avoidance or deferral opportunities can be identified and measured, and ii) non-wires solutions can be deployed with confidence that critical customer outcomes (i.e., reliability and cost-effectiveness) can be maintained.

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 have well-developed tools for grid observability and for DER monitoring and forecasting. Toronto Hydro is making significant efforts to improve grid observability, control and automation through *Intelligent Grid* and *Grid Readiness* initiatives, several of which could significantly improve monitoring capabilities for DERs (discussed in detail in Exhibit 2B, Section **Error! Reference source not found.** and D5.2.2).

QUESTION (D):

d) Please discuss and provide any analysis conducted of how expanded EV charging, predominantly during off-peak hours, could potentially lower costs for utility customers due to greater utilization and revenues from existing distribution system assets.

RESPONSE (D):

As noted in Exhibit 2B, Section D5.2.2.5, Toronto Hydro partnered with Plug'n Drive and Elocity Technologies to trial an EV Smart Charging Pilot aimed at understanding EV charging patterns and behaviours in Toronto and gathering information to assist in the development of future EV programs. Benefits of this pilot include supporting the development of additional tools for EV owners to monitor, schedule, and control their charging sessions, and collecting data and insights to understand impacts of EV charging on the distribution grid.

Third party aggregators what have developed controllability are free to participate in the LDR programs. Toronto Hydro is agnostic to the technology used to bid capacity into the program. Further details can be found in Exhibit 2B, Section 7.2.

QUESTION (E):

e) Please discuss and provide any analysis conducted that indicates when various aspects of Toronto Hydro's system would require capital upgrades to support various EV and DER adoption levels.

RESPONSE (E):

Toronto Hydro's System Peak Demand forecast in Exhibit 2B, Section D4 and the Customer and Generation Connections forecasts presented in Exhibit 2B, Section E5.1 consider growth, electrification and DER adoption rates that also underpin investment needs in the following capital expenditure programs: Load Demand, Stations Expansion, GMPC, Connections and Renewable Enabling Energy Storage Systems.

Toronto Hydro has conducted area-specific analyses in select neighborhoods to evaluate the impact of increased number of residential service upgrades on the local distribution system. This assessment aimed at visualizing and understanding the impact of these upgrades on the system, and to identify necessary alternatives. The conclusion drawn from these analyses to date is that Toronto Hydro will likely not need to do a complete overhaul of its distribution system to accommodate these connections. Rather, it is necessary to make investments to improve grid observability in order to monitor the loading conditions on primary and secondary system assets, helping to inform decision making (please see Intelligent Grid, Exhibit 2B, D5.2.1, p. 10-12 for details). Examples of such decisions include, but are not limited to, installation of upgraded or additional transformers, upsizing of buses and transferring loads among nearby feeders, busses or stations.

While Toronto Hydro's capacity plan ensures that the distribution system is adequately sized, external factors such as government incentives or market evolution could further accelerate customer adoption of electric vehicles or other fuel switching technologies. To that end, Toronto Hydro proposes a flexibility mechanism (known as a variance account) to reconcile differences between forecasted and actual demand-driven costs and revenues.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-155

Reference: Exhibit 2B, Section D4, p. 11

Preamble**:**

With regards to "Figure 4: Toronto Hydro System Peak Demand Forecast by Driver".

QUESTION(A):

a) Does Toronto Hydro consider DERs a negative peak demand or a source of capacity supply?

RESPONSE (A):

Toronto Hydro's System Peak Demand Forecast is a gross forecast. As a result, Figure 4 only displays drivers of load growth.

QUESTION (B):

b) Are DERs considered a negative energy load or a source of energy generation?

RESPONSE (B):

DERs are not considered negative energy load or energy generation as far as the peak demand forecast is concerned.

QUESTION (C):

c) Please restate Figure 4 from Reference 1 and provide tabular data so that System Peak Demand Forecast by Driver is stated in MW.
    i. If applicable, update Figure 4 to show DERs separately.

RESPONSE (C):

Toronto Hydro produces its System Peak Demand Forecast in apparent power, MVA. Please see the response provided to interrogatory 2B-SEC-46 part (b) for the requested tabular data in MVA. Regarding DERs, please see the response provided to part (a) above.

QUESTION (D):

d) Please provide a new figure and provide tabular data that shows System Energy by Driver in GWh or MWh, and as applicable show DERs separately.

RESPONSE (D):

Toronto Hydro is unable to provide the requested information as the utility's Peak Demand Forecast does not reflect a forecast of Energy Delivery (i.e. is not forecast using GWh or MWh). Please refer to the response provided to part b) above with respect to DER.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-156

References: **Exhibit 2B, Section D4, Appendix A**
Exhibit 2B, Section D4, Appendix B

Preamble:

Toronto Hydro has explained the "Future Energy Scenarios tool" and provided an appendix with an explanation of its outputs and a detailed report from the consultant that performed the study.

QUESTION (A):

a) Please confirm that the Future Energy Scenarios tool is not an internal tool, and more akin to a service purchased from a consultant. Please elaborate.

RESPONSE (A):

As noted in Exhibit 2B, Section D4, Appendix A, Section 1.3 (page 3), Toronto Hydro engaged a leading UK consultant, Element Energy, to develop the Future Energy Scenarios modelling tool. This model is now available as a software tool for internal business users at Toronto Hydro.

QUESTION (B):

b) Please provide the "Business Case" or similar document produced by the business unit that "uses" the Future Energy Scenarios tool to justify its acquisition or development. Please provide any other documentation used by or presented to Toronto Hydro decision makers to release the funding to acquire / develop the tool.

RESPONSE (B):

In the development of the Climate Action Plan in 2021-22, Toronto Hydro leaders engaged in numerous conversations about the energy transition. Through these conversions, a need was identified for greater strategic insight into the wide range of potential peak demand scenarios associated with various external perspectives on the likely future of the energy system. This need was investigated by looking at tools and best practices from other jurisdictions, including the work undertaken by Element Energy in the UK. A decision to procure a third-party service to develop this capability was made late in 2021 (background presentation setting out the context, purpose and target benefits attached as Appendix A), following which Toronto Hydro undertook a competitive process to procure the services. Element Energy was the successful vendor of that process, and the scope of work (attached as Appendix B) initiated the work with Element on this project.

QUESTION (C):

c) Please provide a brief summary of the benefits and costs for this tool, as portrayed to Toronto Hydro decision makers at the time of deciding to pursue this tool. Please reference the material from part b).

RESPONSE (C):

A brief summary of the expected benefits can be found in Appendix A to the response to part (b). The estimated cost was $990,000 for the model development and implementation project, plus annual maintenance costs of $36,000 per year for three years. The final cost of development and implementation was $1.29 million. Project variances were due to greater than anticipated stakeholder engagement efforts in the design of the scenario worlds and unforeseen challenges with model configuration.

Future Energy Scenarios - Proposal

26 July 2021

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Context

- Ontario's energy system is set to undergo a revolution as it becomes increasingly decarbonized, decentralized, and digitized

- These changes are driven by national, provincial and municipal 2050 Net Zero targets, specifically focusing on the electrification of transport and heating, as well as increasing the penetration of renewable distributed generation

- Toronto Hydro and its distribution system will play a central role in enabling the achievement of 2050 Net Zero targets

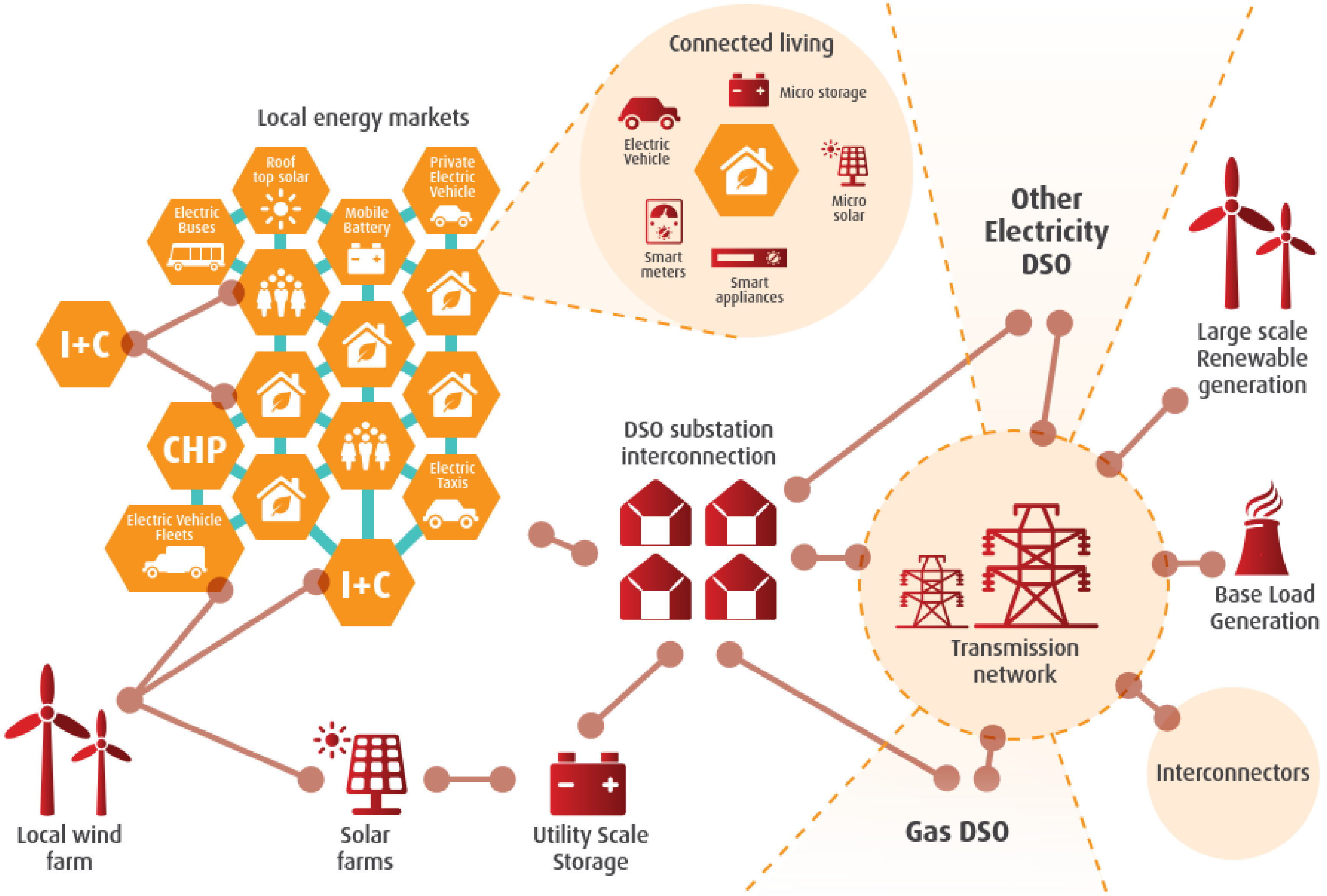
- In this context, long-term, scenarios-based forecasting will play an increasingly significant role in planning, including the development and justification of plans within regional resource and infrastructure planning and regulatory processes.

Future of the energy system (2030? 2050?)

Decarbonization
- Electrification of Heat and Transport
- Increased Distributed Renewable Generation
- Micro generation and storage
- Grid Scale Storage

Digitalization
- Grid IT/OT
- Smart Homes
- Virtual Power Plants
- Flexible Connections

Decentralization
- Microgrids
- Local Energy Markets
- Community Energy



Source: UK Power Networks, Future Smart Consultation Report

Purpose of the Future Energy Scenarios Study

- To provide Toronto Hydro and its stakeholders with an in-depth understanding of the way in which local electricity demand, consumption, and generation (including distributed resources) will change in the future, in order to:
  1. plan efficient and timely network capacity investments (including NWAs);
  2. develop a grid modernization plan to enable and optimize increasing levels of DERs, EVs, NWAs, etc.;
  3. develop a common strategic outlook to support different forecasting needs across the company, including load forecasting and revenue forecasting.

- Despite national, provincial and municipal clarity on achieving Net Zero by 2050, there is still significant uncertainty on how this ambitious goal will be achieved.

- Furthermore, the uptake of DERs such as EVs will likely cluster in certain geographic locations, and it is vital to capture these locations and better understand constraints.

- A Future Energy Scenarios study will capture this future uncertainty, as best as possible, and increase the robustness of Toronto Hydro's investment strategy

Target Benefits

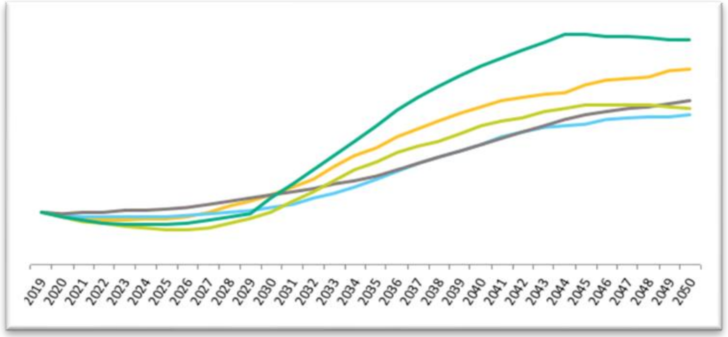
Creating a single Future Energy Scenarios report that models demand, consumption, and generation (including DERs) from today to 2050 as it pertains to Toronto Hydro’s service territory will allows us to:

- Demonstrate reasonable and efficient investment plans in the 2025-2029 Rate Application
- Enable better decision making and strategic planning for both capacity-driven investment and other grid modernization investments
- Develop a Toronto Hydro position on the 2050 energy system, consistent across various business units, including revenue and connections forecasting
- Inform decisions on R&D projects and support effective implementation of the UoF strategy
- Enhance customer and stakeholder engagement activities

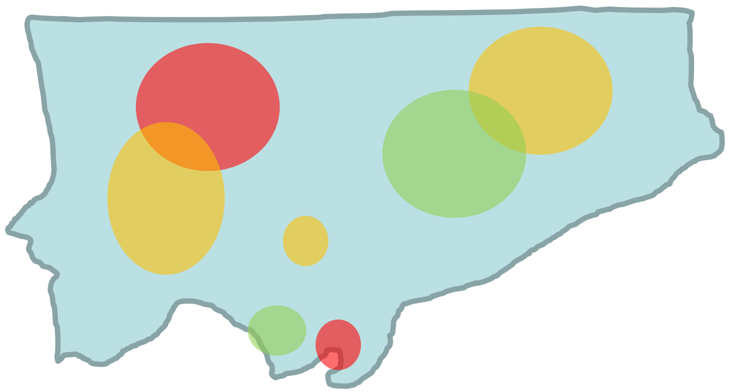
Scope

1. 2050 Demand & Generation Scenarios

- Domestic housing stock
- Industrial and commercial floorspace
- Distributed generation (BTM and FTM)
- Electric Vehicles
- Decarbonized heating (heat pumps)
- Battery storage
- Energy efficiency measures (CDM)
- Demand side response (flexibility)



2. Geospatial Disaggregation



Disaggregate network level forecasts down to an appropriate geospatial resolution to enable investment planning activities

3. Integrate into Business Processes

Strategic Investment Planning:

- Inform capacity driven investment planning programs; "least regret investment"
- Inform intelligent grid projects and strategic targeting of enhanced monitoring and control
- Align with regional planning process

Stakeholder Engagement & CIR Filing 2025-2029:

- Inform stakeholder engagement activities with customers; *bring them along on the journey*
- Solidify a Toronto Hydro position on a plausible future energy system
- Drive discussion on role of LDCs in the future energy system with OEB and policy makers

Agreement for Professional Consulting Services

THIS AGREEMENT is made this 7th day of February, 2022,

BETWEEN:

Toronto Hydro-Electric System Limited,

a corporation incorporated under the laws of Ontario

(hereinafter called "Toronto Hydro")

and

Element Energy Limited,

a limited company incorporated under the laws of England and Wales

(hereinafter called the "Consultant")

[redacted]

[redacted]

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SCHEDULE A

SERVICES AND RATES

1. Services to be Performed

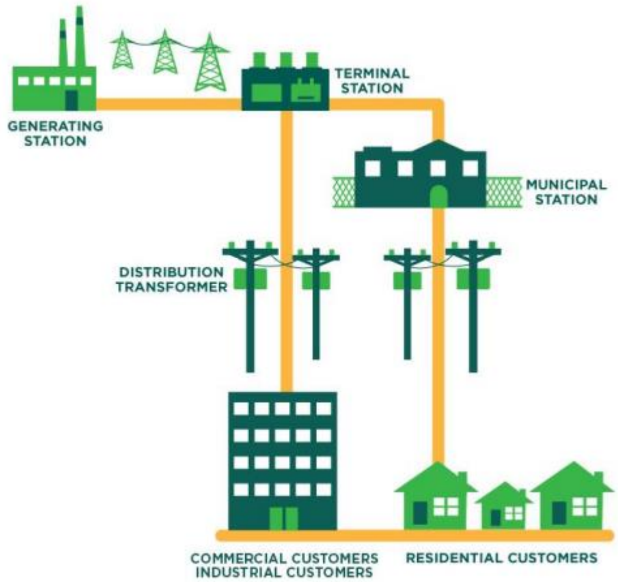
(a) Future Energy Scenarios Model

Toronto Hydro requires the development of a future energy scenarios model that produces scenario-based 2050 forecasts for peak load (kVA), generation (kW), and energy consumption (kWh). The model will be used to understand the range of possible future energy scenarios in order to inform capacity-driven investment, grid modernization investment, as well as revenue forecasting.

Toronto Hydro is supplied electricity from Hydro One Networks Inc. (HONI) at 230kV, 115kV, 27.6kV, or 13.6kV at 37 Terminal Stations (TS) located across the City of Toronto. Electricity is then delivered to end-users through the distribution system. Refer to Figure 1 below for a basic structure of the electricity system infrastructure. The future energy scenarios must be modelled, at a minimum, at the 37 Terminal Stations and associated buses. A more granular geospatial resolution may also be considered. The project is proposed to be carried out in two phases, as described in the following sections. Any alternative approaches should be described in detail and provided in addition to proposed approach. If alternative approaches are included, a clear justification of why the approach is more favourable to Toronto Hydro is required.

The Consultant shall designate a primary contact who will delegate work to its team as requested by Toronto Hydro, and is the key contact person for managing the working relationship with Toronto Hydro.

Figure 1. Basic electricity system infrastructure



Phase 1: Energy Scenario Development & Stakeholder Engagement

This phase requires the development of a minimum of 3 and up to 5 future energy scenarios. The future energy scenarios must model the base load as well as the uptake of the key drivers listed in table 1 below up to 2050. The model must not rely on pre-existing Toronto Hydro models and must build up these models using a bottom-up approach and aggregate up to the terminal station bus level.

The forecasts for technology uptake must be built using the Consultant's own models, tools and methodologies. It is preferred that technology uptake scenarios are modelled bottom-up, using consumer choice modelling by analyzing economic and demographic data and leveraging publicly available data for the City of Toronto. This requirement will enable Toronto Hydro to increase the sophistication of its modelling practices and future-proof the model for when Toronto Hydro chooses to model at a more granular geospatial resolution.

Table 1. Key drivers required for the future energy scenarios model

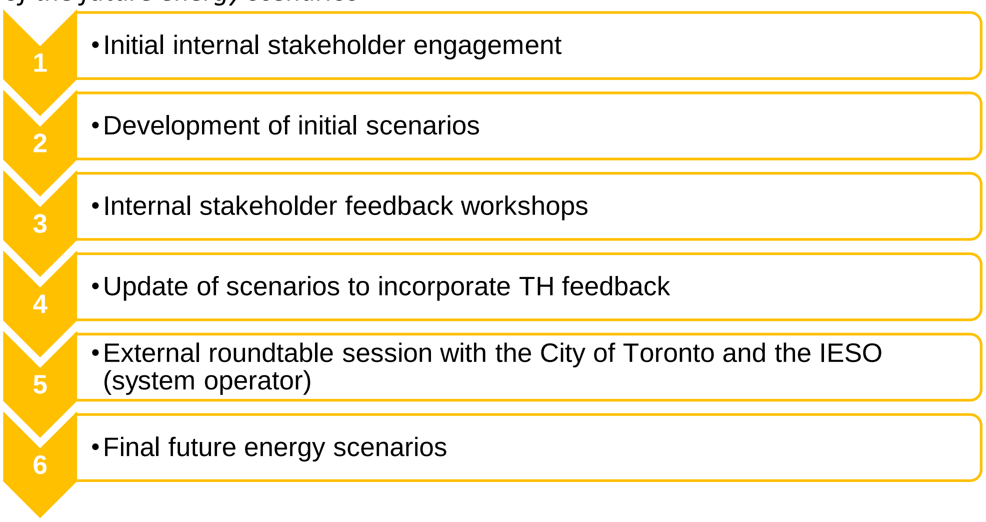
No.	Key Driver
1	Residential housing growth
2	Industrial & Commercial growth broken down by type (retail, office, industrial etc.)
3	Electric vehicle uptake by type (light duty private, fleet, buses, taxis etc.)
4	Distributed generation by type and size (solar, wind, bio-gas, diesel, and natural gas/CHP must all be considered)
5	Appliance growth by type
6	Conservation demand management driven by province wide programs and by natural customer choices (also referred to as energy efficiency)
7	Decarbonized heating (air source and ground source heat pumps)
8	Domestic and grid-scale Battery Energy Storage Systems (BESS)
9	Customer flexibility (services available to manage network constraints, such as vehicle to grid, smart EV charging and other demand side response technology)
10	Any other key drivers deemed important for the Toronto Hydro service area as part of the

	research and stakeholder engagement activities in this phase

(b) Stakeholder Engagement

The scenarios must be designed through continuous engagement with internal project stakeholders to seek agreement on assumptions and projections. The Consultant is also required to support some external stakeholder engagement to meet, at a minimum, the level of engagement outlined in figure 2 below. The timing of the roundtable sessions with external stakeholders will be determined by Toronto Hydro in accordance with its regulatory stakeholder engagement process.

Figure 2. Minimum level of internal and external stakeholder engagement required for the development of the future energy scenarios



Phase 2: Network Data Cleansing and Modelling

This phase requires the cleansing of Toronto Hydro network and customer data, as well as the modelling of the future energy scenarios. This requires:

- Cleansing and analyzing network load, energy and generation data.
- Cleansing and analyzing network topology and connectivity data.
- Cleansing and analyzing customer connection requests data for inclusion in the forecast (for first 1-5 years).
- Producing annual and monthly peak demand (kVA), energy consumption (kWh), generation (kW) and customer number forecasts from 2022 to 2050. Coincident and non-coincident peak demand should be calculated. Forecasts are required at the following levels:
    - Total distribution system, aggregate and by customer class
    - By each terminal station bus level, aggregate and by customer class
    - By each key driver, aggregate and by customer class
        - For EVs, Distributed Generation, and Heat Pumps, forecasts should also include the volume of each type of technology

The following data sets provided by Toronto Hydro will aid the Consultant with this task. The Consultant must specify any other data sets required outside of the list below. The Consultant should assume an extensive level of cleansing required for most of the data sets provided.

- Complete network topology of all transformer stations per voltage level and their associated feeders, along with the number, location and type of customers connected.
- Hourly monitored demand data for all substations for the most recent full year.
- List of known distributed generation and energy storage installations across the network with technology type, start year, and connectivity to the network.
- Hourly monitored generation data for large-scale distributed generation installations, where available.
- Total units distributed (kWh) annually and hourly by customer class for the most recent full year
- Customer numbers by customer class.

(c) Non-Functional Requirements

- The future energy scenarios model must be agile, enabling Toronto Hydro to quickly and easily change parameters and assumptions for each scenario, without having to re-configure the model each time.
- The model must be designed in a manner that allows Toronto Hydro to update various elements of the model internally, without the reliance on the Consultant. Training for the model must be included in the Consultant's proposal.
- The model must be easy to use and include a functional user interface
- The model must be delivered with a detailed user manual explaining the inner mechanics of the model.
- The model must provide visual graphs and charts that are useful for communicating the output of the model in a stakeholder friendly manner. At a minimum, the visuals should include:
    - Each of the technology drivers, aggregated and by single driver, at a network level and at each substation, from current year to 2050.
    - The base load, aggregated and by type of customer, at a network level and at each substation, from current year to 2050.
    - Each of the future energy scenarios.
- If the proposed model is cloud-based, the Consultant must meet Toronto Hydro's IT Security standards for how the model is hosted and updated in the future.
- Toronto Hydro will own all rights, title, and interest, including without limitation, all intellectual property rights in the information provided by Toronto Hydro to the Consultant as part of this project, including any output of the model.

(d) Project Management Requirements

The Consultant is required to participate in weekly project meetings through video conferencing with the core internal Toronto Hydro team, and to provide project status updates at these meetings in an agreed upon format. They must also participate in internal workshops with a wider group of internal stakeholders as and when required, through virtual video conference calls or in-person.

(e) Project Deliverables

The project Deliverables shall include:

- The Future Energy Scenarios model that meets the requirements outlined in earlier sections.

- A detailed user manual for the model that outlines the inner mechanical workings of the model and that may be used for training of Toronto Hydro staff.
- A detailed internal-facing final report that outlines all of the modelling assumptions, input data, modelling methodologies, as well as the results from the project.

The Consultant may also be required to deliver, at Toronto Hydro's request, an external-facing report that meets regulatory requirements and appropriately describes the results of the future energy scenarios model. The Fees for this additional Deliverable shall be in accordance with the rates set out below..

(f) Annual Update and Maintenance of Model

The Consultant must outline the recommended level of model maintenance and updates, and the pricing for this activity on an annual basis. These costs should be separated and will not be considered as part of the initial project execution but will be taken into consideration when assessing the suitability of the model for Toronto Hydro. Should Toronto Hydro require the Consultant to provide annual updates, Toronto Hydro may do so as part of this Agreement at its own discretion.

(g) Participation in Toronto Hydro's Regulatory Application Process

The Consultant must be available to speak to the work carried out as part of this project in a regulatory proceeding as required by the Ontario Energy Board and as directed by the Toronto Hydro Regulatory team.

(h) Weather Correction of Network Data

The Consultant will provide a weather correction service (i.e. correcting hourly true demand data for each network asset, or on other such frequencies as requested by Toronto Hydro) as part of Phase 1 and Phase 2. The Fees for such service shall be a lump-sum, as more particularly set out in section 2(a) of this SCHEDULE A below.

2. <u>Rates</u>

a) Model Fees

In exchange for the Services set out in Section 1 of this SCHEDULE A (and in particular, subsections (a), (b), (c), (d), (e), and (h) thereto), Toronto Hydro shall pay the Consultant the following Fees on a milestone basis, as more particularly set out in the tables below:

Phase 1		
Milestone #	**Description**	**Fixed Cost/Fee ($)**
MS 1:	Kick-off meeting	[redacted]
MS 2:	Initial round of stakeholder engagement conducted	[redacted]
MS 3:	Final round of stakeholder engagement (internal and external) completed	[redacted]
MS 4:	Final scenarios with associated documentation to Toronto Hydro	[redacted]

Total		[redacted]

Phase 2		
Milestone #	**Description**	**Fixed Cost/Fee ($)**
MS 1:	Kick-off meeting	[redacted]
MS 2:	Present proposed approaches for customer archetypes, geographical distributions, profile shapes and load factors to Toronto Hydro	[redacted]
MS 3:	Provide preliminary model outputs to Toronto Hydro for review	[redacted]
MS 4:	Final EELG model with associated documentation to Toronto Hydro	[redacted]
Total		[redacted]

	Total Project Cost (Phase 1 and Phase 2):	$[redacted]
Weather Correction of Network Data		
Rate	Weather correction (annual or on a frequency prescribed by Toronto Hydro)	[redacted]

Project Total	$[redacted]

b) <u>Annual Maintenance</u>

<u>In addition to the Fees set out in subsection 2(a) above, should Toronto Hydro elect to exercise the Renewal Terms of this Agreement, Toronto Hydro shall further pay to the Consultant, the following Fees for the Services set out in subsection 1(f) of this SCHEDULE A above. The Fees indicated below shall be payable on the commencement of each Renewal Term:</u>

Annual Maintenance		
Year	**Description**	**Annual Fixed Cost/Fee ($)**
1	Year 1	[redacted]
2	Year 2	[redacted]
3	Year 3	[redacted]
Maximum Possible Total		[redacted]

c) Consultant Rate Card

In addition to the Fees further set out above, where Consultant shall be required to assist Toronto Hydro with respect to any external discussions, at Toronto Hydro's sole option and request, as more particularly set out in section 1 of this SCHEDULE A above (in particular, subsections (e) and (g) thereto), Toronto Hydro shall compensate the Consultant on an hourly basis in accordance with the following rates for each of Consultant's personnel:

Rate card		
Rate ID	**Role / Description**	**Hourly rate ($)**
Rate 1:	Partner	[redacted]
Rate 2:	Principal Consultant	[redacted]
Rate 3:	Senior Consultant	$[redacted]
Rate 4:	Consultant	[redacted]

SCHEDULE B

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-157

References: Exhibit 2B, Section D4, Appendix B

<u>Preamble:</u>

Toronto Hydro's Future Energy Scenarios utilizes a multitude of external data sources

QUESTION(A):

a) Please complete the following table:

Data Source	Model Input that uses the source	Date that source was published

RESPONSE FROM TORONTO HYDRO (A):

Please see the tables provided in Toronto Hydro's response to interrogatory 2B-Staff-159, part a) and 2B-PP-36, part c). The date for each of the sources is provided within the reference.

QUESTION (B):

b) What is the time period over which Element Energy performed its work to run their model. Please explain the instances where Element Energy did not use the most recently available information. For example, staff note Element Energy references the "City of Toronto 2012 Growth Plan" in Figure 21, where the City of Toronto has published more recent growth plans[1]

[1] The City of Toronto's Official Plan Review notes a 2019 growth plan that came into effect and other related strategies and assessments available since the 2012 Growth Plan. The City's Official Plan Review website is available at https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/official-plan-review/

RESPONSE FROM ERM (B):

The first phase of the project, which included all information and data gathering, was conducted between January and July 2022. The data referenced was provided to Element Energy by the City of Toronto and was the latest information available at the time.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-158

References: **Exhibit 2B, Section D4, Appendix A**
Exhibit 2B, Section D4, Appendix B
Exhibit 2B, Section D4, Figure 5
Exhibit 2B, Section D4

Preamble**:**

Figure 3 from Reference 1 is reproduced below.

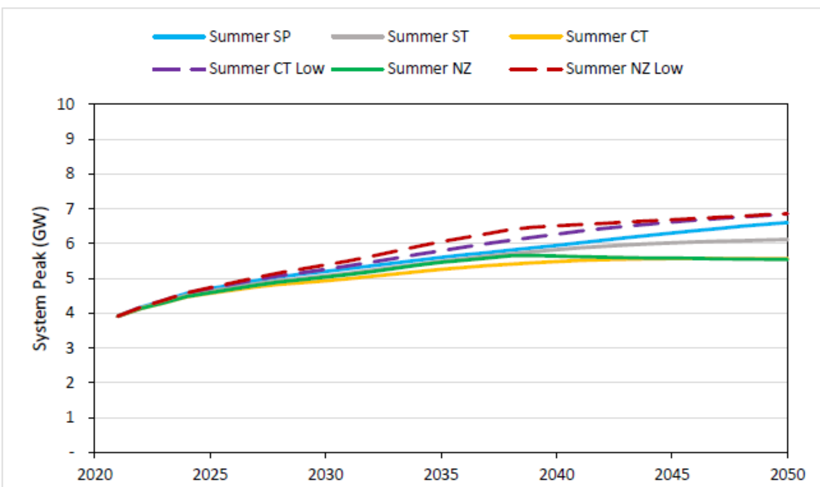
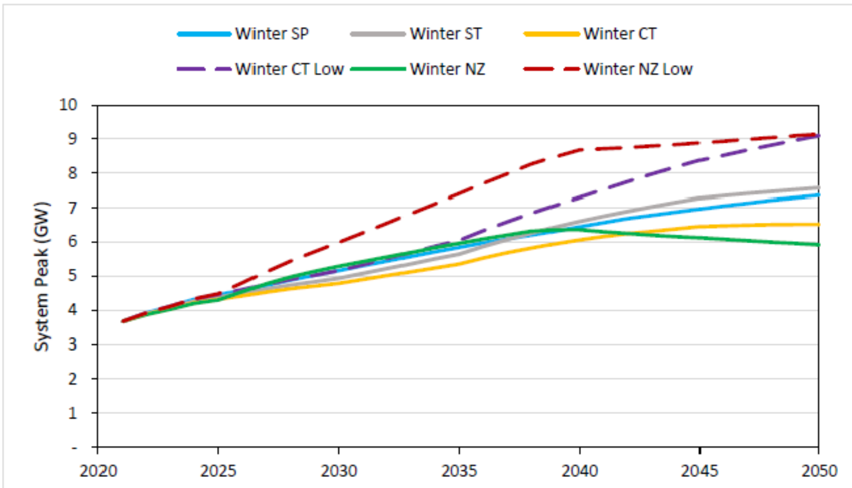
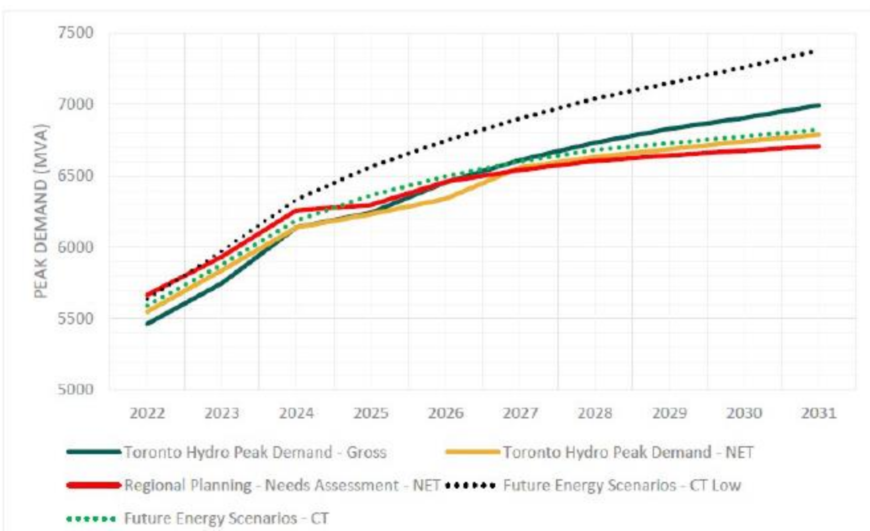


Figure 4 from Reference 1 is reproduced below.



Reference 3 is reproduced below.



1 **QUESTION (A):**

2 a) Please complete the following table for all the years shown in Figure 3 above, with MW
3 values:

Summer System Peak for Scenario Worlds

Peak Load (MW)	SP	ST	CT	CT-low	NZ	NZ-low
2021						
2022						
2023						
2024						
2025						
Through to						
2050						

RESPONSE (A):

Please see Table 1.

Table 1. Summer System Peak (Coincident) for Scenario Worlds (MW)

	SP *(MW)*	ST *(MW)*	CT *(MW)*	CT Low *(MW)*	NZ *(MW)*	NZ Low *(MW)*	Stations *(MVA)*
2021	3,912	3,912	3,912	3,912	3,912	3,912	n/a
2022	4,170	4,144	4,135	4,170	4,135	4,170	n/a
2023	4,366	4,323	4,298	4,368	4,298	4,369	4,905
2024	4,574	4,514	4,472	4,579	4,481	4,589	5,080
2025	4,706	4,632	4,575	4,718	4,591	4,737	5,229
2026	4,817	4,737	4,664	4,842	4,695	4,879	5,383
2027	4,936	4,842	4,753	4,967	4,801	5,024	5,475
2028	5,042	4,931	4,827	5,077	4,896	5,159	5,659
2029	5,123	4,999	4,878	5,166	4,966	5,272	5,835
2030	5,201	5,069	4,932	5,257	5,036	5,385	5,941
2031	5,282	5,148	4,994	5,360	5,109	5,504	6,029
2032	5,363	5,232	5,060	5,467	5,194	5,635	6,136
2033	5,445	5,318	5,128	5,577	5,290	5,779	n/a
2034	5,526	5,405	5,196	5,688	5,380	5,919	n/a
2035	5,604	5,486	5,258	5,793	5,463	6,051	n/a
2036	5,674	5,565	5,316	5,899	5,525	6,169	n/a
2037	5,740	5,637	5,365	5,998	5,586	6,286	n/a
2038	5,809	5,704	5,409	6,093	5,648	6,405	n/a
2039	5,877	5,766	5,449	6,185	5,657	6,471	n/a
2040	5,948	5,823	5,483	6,271	5,644	6,515	n/a
2041	6,021	5,878	5,515	6,355	5,625	6,548	n/a
2042	6,094	5,922	5,537	6,430	5,608	6,582	n/a
2043	6,166	5,960	5,552	6,498	5,596	6,616	n/a
2044	6,237	5,994	5,563	6,562	5,586	6,651	n/a
2045	6,305	6,024	5,573	6,620	5,581	6,685	n/a
2046	6,371	6,045	5,574	6,670	5,573	6,719	n/a
2047	6,433	6,065	5,573	6,719	5,566	6,754	n/a
2048	6,497	6,082	5,570	6,766	5,559	6,790	n/a
2049	6,553	6,100	5,570	6,810	5,553	6,825	n/a
2050	6,606	6,118	5,571	6,854	5,547	6,859	n/a

QUESTION (B):

b) Please complete the following table for all the years shown in Figure 4 above, with MW values:

Winter System Peak for Scenario Worlds

Peak Load (MW)	SP	ST	CT	CT-low	NZ	NZ-low
2021						
2022						
2023						
2024						
2025						
Through to						
2050						

RESPONSE (B):

Please see Table 2.

Table 2. Winter System Peak (Coincident) for Scenario Worlds (MW)

	SP *(MW)*	ST *(MW)*	CT *(MW)*	CT Low *(MW)*	NZ *(MW)*	NZ Low *(MW)*	Stations *(MVA)*
2021	3,671	3,672	3,671	3,671	3,671	3,671	n/a
2022	3,920	3,896	3,886	3,920	3,876	3,920	n/a
2023	4,114	4,072	4,046	4,116	4,029	4,117	4,812
2024	4,318	4,260	4,217	4,324	4,197	4,332	4,988
2025	4,451	4,378	4,320	4,465	4,302	4,481	5,142
2026	4,577	4,494	4,420	4,603	4,541	4,804	5,290
2027	4,730	4,622	4,531	4,760	4,778	5,134	5,383
2028	4,890	4,739	4,631	4,905	4,981	5,443	5,537
2029	5,028	4,834	4,707	5,030	5,143	5,724	5,642
2030	5,163	4,934	4,788	5,163	5,288	5,996	5,699
2031	5,303	5,075	4,901	5,335	5,424	6,266	5,740
2032	5,441	5,218	5,014	5,512	5,559	6,546	5,795
2033	5,578	5,364	5,129	5,694	5,697	6,834	n/a
2034	5,713	5,508	5,241	5,876	5,834	7,117	n/a
2035	5,843	5,646	5,353	6,052	5,963	7,401	n/a
2036	5,979	5,874	5,535	6,334	6,092	7,702	n/a
2037	6,091	6,072	5,686	6,587	6,208	7,980	n/a
2038	6,206	6,259	5,825	6,832	6,320	8,260	n/a
2039	6,322	6,436	5,951	7,069	6,360	8,482	n/a
2040	6,446	6,601	6,065	7,298	6,363	8,682	n/a
2041	6,570	6,753	6,163	7,521	6,305	8,711	n/a
2042	6,687	6,891	6,245	7,748	6,252	8,747	n/a
2043	6,781	7,027	6,312	7,967	6,206	8,790	n/a
2044	6,874	7,157	6,385	8,177	6,162	8,835	n/a
2045	6,966	7,275	6,453	8,375	6,124	8,887	n/a
2046	7,054	7,345	6,478	8,526	6,083	8,934	n/a
2047	7,137	7,411	6,499	8,676	6,043	8,989	n/a
2048	7,218	7,470	6,511	8,822	6,002	9,044	n/a
2049	7,292	7,523	6,516	8,960	5,962	9,096	n/a
2050	7,363	7,577	6,518	9,101	5,921	9,144	n/a

QUESTION (C):

c) Please add the summer and winter peak system load forecasts that underly the investment plan, as shown in Reference 3 to the tables of a) and b), acknowledging that the forecasts of Reference 3 may not be performed through to include 2050.

RESPONSE (C):

Please refer to Tables 1 and 2 as provided above. Please note that the graph referenced in Reference 3 was updated on January 29, 2024.

QUESTION (D):

d) Reference 2 states that the "steady progression" (SP) scenario world is aligned with the TransformTO "Business as Planned" scenario. With Reference 4, Toronto Hydro states that its system peak demand forecast is generally aligned with the Consumer Transformation (CT) scenario. Please articulate the key differences and similarities, as they relate to Toronto Hydro's investment plan, between the SP scenario, the CT scenario, and the forecasts that underly the proposed investment plan in this proceeding.

RESPONSE (D):

The key assumptions used for the SP and CT scenarios are explained in Exhibit 2B, Section D4, Appendix B, Section 2 (pages 3 – 7) while the description of the process for the forecasts that underly the proposed investment plan can be found in Exhibit 2B, Section D4.1.1 (pages 2 – 6).

QUESTION (E):

e) Please articulate how the Future Energy Scenarios (FES) tool has informed system planning for the rate period of this application. How did the FES tool inform capital investments and operations and maintenance plans for this period? How will the FES tool continue to be used moving forward?

RESPONSE (E):

Please refer to response in 3-Staff-274 g), 1B-CCC-30 and Exhibit 2B, Section D4, Appendix A, Section 1.3 (page 4). The FES tool continues to be valuable because it allows Toronto Hydro to identify investments that would be required to reinforce the grid in different scenarios. This capability supports Toronto Hydro's least regrets planning philosophy in that it allows the utility to stress test its Peak Demand Forecast against plausible scenarios to ensure that the utility (1) does not overbuild the system and (2) does not become a barrier to particular decarbonization pathways.

The FES tool may be updated on an as-needed basis when material new information is released.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-159

Reference: **Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October, 2012**
Exhibit 2B, Section D4, Appendix B

Preamble:

Reference 1 states that "the output of any methodology will need to be transparent, robust and reproducible, and include forecast information from independent and authoritative sources where these are publicly available."

None of the links in the footnotes in Reference 2 are functioning hyperlinks.

QUESTION (A):

a) Please provide all the links in the report as attachments to the response to this interrogatory. Where the footnote references a data file, provide as xlsx/csv file where it is available in that format from the source.

RESPONSE FROM ERM (A):

Section	Section Heading	Provided Link(s)
Executive Summary	N/A	CER, Canada's Energy Future, 2021 IESO, Annual Planning Outlook, 2022 City of Toronto, TransformTO, 2021
3.2	Local Factors and Customization to Toronto	City of Toronto, About Toronto Neighbourhoods, 2022. *Note that since the time of analysis, some neighbourhoods have been split up because of very high population growth. Effective after April 12, 2022, the number of neighbourhoods in Toronto is 158.*

4.1.1	Core Demand - Archetype Definitions	Statistics Canada, The Census of Population – Neighbourhood Profiles, 2016 Natural Resources Canada, Survey of Household Energy Use Data Tables, 2015 North American Industrial Classification System NAICS & SIC Identification Tools | NAICS Association
4.1.2	Core Demand - Building Stock	Watson & Associates, City of Toronto Development Charge Background Study, 2008 Toronto Data Management Group, Traffic Zones Boundary Files, 2006 (Toronto Hydro's network area covers 677 traffic zones). City of Toronto, SmartTrack Stations Program, 2021
4.1.3	Core Demand - Core Electrical Efficiency	National Resources Canada, Canada-wide Energy Use Dataset | Energy Efficiency Trends Analysis Tables, 2000 – 2018 National Resources Canada, 2015 Survey of Household Energy Use (SHEU-2015) Data Tables , 2015 National Resources Canada, Energy Star | Choosing and Using Appliances With EnerGuide, 2013 Natural Resources Canada, Residential Sector Canada Table 37: Appliance Stock by Appliance Type and Energy Source Toronto Public Health, Protecting Vulnerable People from Health Impacts of Extreme Heat, July 2011 Natural Resources Canada Comprehensive Energy Use Database (2000 – 2018) | Commercial/Institutional Sector – Ontario Natural Resources Canada, Canada-wide Energy Use Database (2000 – 2018) | Total End-Use Sector - Energy Use Analysis Efficiency Canada and Carleton University, Canada's Climate Retrofit Mission, June 2021 City of Toronto, City of Toronto NetZero Existing Buildings Strategy and Technical Appendix, 2021
4.1.4	Core Demand - Flexibility Measures	Ontario Energy Board (OEB), Frequency of Regulated Price Plan Switching Under Consumer Choice, 2021
4.2.2	Low Carbon Heating - Policy Assumptions	The Independent Electricity System Operator, Pathway to Decarbonization – Assumptions for Feedback, March 2022
4.2.3	Low Carbon Heating - Thermal Efficiency	Natural Resources Canada, National Energy Use Database – Ontario, 2018 The City of Toronto, Net Zero Existing Buildings Strategy, May 2021
4.2.4	Low Carbon Heating - Uptake	The Canadian Gas Association, Potential Gas Pathways to Support Net Zero Buildings in Canada, October 2021

	Modelling Results	
4.3.1	Electrification of Transport - Modelling Approach	Government of Canada, Incentives for Zero-Emissions Vehicles (iZEV), April 2022 Statistics Canada, Vehicle registrations by type of vehicle, September 2020 Ontario Data Catalogue, Vehicle Population Data 2016, March 2019 Statistics Canada, New zero-emission vehicle registrations, January 2022 Toronto Transit Commission, Service Summary 2021, January 2022
4.3.2	Electrification of Transport - Cars and Light Trucks	Canada Energy Regulator, Canada's Energy Future, 2021 Bloomberg NEF, Electric Vehicle Outlook, 2021
4.3.3	Electrification of Transport - Medium- and Heavy-Duty Trucks	Government of Canada, Incentives for Medium- and Heavy-Duty Zero-Emission Vehicles Program, July 2022 California Air Resource Board, Medium- and Heavy-Duty ZEV requirement, 2020
4.3.4	Electrification of Transport - Buses	Toronto Transit Commission, TTC Green Initiatives, 2022
4.3.5	Electrification of Transport - Rail	The City of Toronto, Transit Expansion, June 2022
4.3.6	Electrification of Transport - Charging Distribution	Element Energy and WSP Parsons Brinckerhoff, Plug-in electric vehicle uptake and infrastructure impacts study, 2016 Element Energy, Electric Vehicle Charging Behaviour Study, 2019 Statistics Canada, 2021 Census of population, 2021 Toronto Metropolitan University, Household car ownership, 2018 City of Toronto Open Data Portal, Land use zoning by-law, 2022 Element Energy for Transport & Environment, Battery electric HGV adoption in the UK: barriers and opportunities, November 2022
4.3.7	Electrification of Transport - Smart Charging and Vehicle-to-Grid	Element Energy, V2GB – Vehicle to Grid Britain Requirements for market scale-up (WP4), June 2019 Bauman, J. et. al., Residential Smart-Charging Pilot Program in Toronto: Results of a Utility Controlled Charging Pilot, June 2016 IAEE, Driver Experiences with Electric Vehicle Infrastructure in Ontario, Canada and the Implications for Future Policy Support, Fourth Quarter 2020 FleetCarma, Charge the North, 2019
4.4.1	Electricity Generation -	IESO, Active Generation Contract List, June 2021

	Modelling Approach	
4.4.2	Electricity Generation - Solar Photovoltaics	NREL, Solar Futures Study, 2021 OEB, Electricity Rates, 2022 IESO, microFiT Program, 2022 IESO Capacity Auction, 2022 City of Toronto, Physical area of parking lots, 2019
4.4.4	Electricity Generation - Non-Renewables	Ontario Clean Air Alliance, Ontario Municipalities that have endorsed gas power phase-out, March 2021
4.5.1	Energy Storage - Domestic Battery Storage	NREL, Cost Projections for Utility-Scale Battery Storage: 2021 Update, June 2021 KPMG, Development of decentralized energy and storage systems in the UK, October 2016
4.5.2	Energy Storage - Industrial and Commercial Battery Storage	IESO, Hourly Ontario Energy Price, 2022 IESO, Industrial Conservation Initiative Backgrounder, July 2022 IESO, Ancillary Services, 2022

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-160

Refences: **Exhibit 2B, Section D5, Page 4**
Exhibit 2B, Section D5, Page 69

Preamble:

Regarding Toronto Hydro's forecasted DER penetration, DER caused potential complexity to system operations, and DER hosting and load capacity map.

QUESTION (A):

a) Please provide Toronto Hydro's DER connection policies that are being put into place to limit the complexity and instability caused by DERs?

RESPONSE (A):

Toronto Hydro has clear DER connections guidelines, as outlined in Toronto Hydro's Conditions of Service Reference 3 document. By following these guidelines and working with its customers through the DER Connections process, Toronto Hydro ensures that safety, technical and operating requirements are satisfied with respect to DER connections. This helps the utility manage potential complexities that may be introduced to the grid.

QUESTION (B):

b) Is Toronto Hydro implementing policies to incentivize DER development in areas where the grid has excess capacity, and disincentivize DERs in areas with restricted capacity?
   i. If yes, please provide documentation.
   ii. If no, please explain why this is prudent from a ratepayer and legislative perspective.

RESPONSE (B):

Toronto Hydro supports DER connections in accordance with the Distribution System Code (DSC) and plans to incent DER development by providing customers with better visibility and essential information regarding available capacity (Hosting Capacity Assessment and Maps – Exhibit 2B, Section D5.3.4) so that customers can be well informed about system constraints when planning their DER projects. In addition, through an expanded Local Demand Response initiative as part of the Non-Wires Solution program (Exhibit 2B, Section E7.2) Toronto Hydro continues to offer financial incentives (i.e. capacity payments) for DER resources that can offer demand response services to the grid. This offering includes the development of online DR Capacity Auction tool to make it easier for customers and aggregators to participate in Local DR.

QUESTION (C):

c) Who bears the cost of expenditures needed to enable DER connections on feeders that do not have excess hosting capacity?

   i. Why is this prudent from a ratepayer perspective?

RESPONSE (C):

In accordance with section 3.3.3 of the DSC, system enhancements costs are borne by the distributor rather than by individual customers. Distribution investments to connect, or enable the connection, of Renewable Energy Generation ("REG") facilities to Toronto Hydro's distribution system are eligible for provincial rate recovery under section 79.1 of the *Ontario Energy Board Act, 1998*. Please see Exhibit 2A, Tab 5, Schedule 1 for more information.

QUESTION (D):

d) Does the Hosting Capacity Analysis (HCA) discourage or otherwise inhibit potential DER candidates from connecting to the grid in areas that have capacity constraints? Please discuss.

   i. If not, what is the value to ratepayers of the expenditures required for the HCA?

RESPONSE (D):

Yes. A public-facing HCA map or data portal can potentially discourage DER candidates from connecting to the grid in areas with capacity constraints. This is because the map may show that the local grid cannot support additional DERs without significant upgrades or modifications. Knowing this, potential candidates might choose not to invest in DERs in these areas due to the anticipated costs, delays, or uncertainties associated with grid upgrades.

Conversely, a HCA map can also empower DER candidates by providing them with preliminary information about the grid's capacity. This transparency enables them to make more informed decisions regarding where and how to invest in DER technologies. For example, they might decide to install DER in areas with more capacity or consider smaller systems that fit the existing grid capabilities.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-161

Reference: Exhibit 2B, Section D5.2.1, Page 11

<u>Preamble:</u>

Toronto Hydro writes that it is "adding more sensors, relays and monitoring technology at specific nodes across the distribution grid, including customer meters. These assets will provide additional data collection points across the grid, which Toronto Hydro will leverage to improve overall situational awareness ("grid transparency"), facilitate quicker fault location, and gain access to important insights at the edge of the grid."

QUESTION (A):

a) Please provide several representative examples where Toronto Hydro is proposing to put these sensors and relays and explain why they are being proposed for these locations relative to the rest of Toronto Hydro's territory.

RESPONSE (A):

To clarify, the reference to "specific nodes" is intended to convey the fact that there are various locations within the design of the distribution system (as opposed to the geography) where certain sensors and technologies can provide value. Some examples include:

- AMI 2.0 meters, which provide observability and control at the customer-level;
- Network Condition Monitoring and Control technologies, which provide observability and control on Toronto Hydro's network system; and
- Stations Digital Relays, which provide observability and control at the stations level.

For a comprehensive overview of how these technologies support Toronto Hydro's Grid Modernization Strategy, and how the utility is pacing and prioritizing deployment, please refer to Exhibit 2B, Section D5.2.1 and Sections E5.4, E6.6, and E7.3.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-162

Reference: Exhibit 2B, Section D5.2.1.2, p. 14

Preamble:

"One of the most significant objectives for Toronto Hydro's Grid Modernization Strategy in the 2025-2029 rate period is to advance the ongoing process of readying Horseshoe system feeders for the transition to a self-healing operation beginning in 2030."

QUESTION (A):

a) Please quantify the anticipated improvement in SAIDI and SAIFI after Toronto Hydro transitions to self-healing operations in the Horseshoe region.

RESPONSE (A):

Based on preliminary network simulations, Toronto Hydro estimates that a successful full-scale implementation of Fault Location, Isolation, and Service Restoration ("FLISR"), otherwise referred to as Distribution Automation ("DA"), across the Horseshoe region could deliver improvements in the range of 20% and 25% for SAIDI and SAIFI, respectively.

QUESTION (B):

b) If Toronto Hydro anticipates a material improvement in SAIDI and SAIFI due to self-healing operations, please reconcile the associated investments against Toronto Hydro's strategy of maintaining historic reliability.

RESPONSE (B):

Toronto Hydro expects to realize the improvements from automated FLISR beginning in 2030. Please see response 1B-Staff-175 for more information on Toronto Hydro's reliability objectives related to modernization more broadly.

QUESTION (C):

c) Why is the horseshoe the area of focus versus the downtown or other parts of Toronto?

RESPONSE (C):

Toronto Hydro's Horseshoe and Downtown systems are fundamentally different in design. The Horseshoe area is configured as an open-loop primary system, with many feeder ties (including intra- and inter-station feeder ties) and sectionalizing points which are SCADA-enabled. The Horseshoe system also has a high proportion of overhead feeders, which are exposed to the elements. By contrast, the Downtown system is largely a combination of dual-radial and networked configurations, which are designed to provide a very high degree of day-to-day reliability for high density areas and critical loads. The Horseshoe system, due to its various design features, is substantially less reliable on a day-to-day basis, and is also more exposed to major reliability events due to high winds and ice accumulation. In fact, the Horseshoe system accounts for 76% of total system SAIDI and 89% of total system SAIFI on average.

The system design differences stem from the fundamental trade-off between cost and reliability in distribution system design. The density and criticality of loads in the Downtown area (combined with the fact that space for utilities is at a premium in the urban core) justifies a higher-cost, largely underground system, whereas this is less the case in the comparatively lower density Horseshoe area of the city. FLISR implementation represents an opportunity for Toronto Hydro to stack a proven and cost-effective digital enhancement on top of the existing features of the Horseshoe system in order to deliver a necessary step-change improvement in the long-term reliability, resiliency, and operational efficiency of this system. For more details on FLISR, please refer to Section D5.2.1.2 and D5.3.2.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-163

References: Exhibit 2B, Section D5.2.1.2, Page 15
Exhibit 1B, Tab 3, Schedule 3, App A, Page 30

Preamble:

Toronto Hydro states that a U.S. Department of Energy report on FLISR implement found that "FLISR reduced the number of Cis ("Customers Interrupted") by up to 45 percent and reduced the CMIs ("Customer Minutes of Interruption") by up to 51 percent for a relevant outage event." The footnote indicates that the time basis of calculating momentary outages in the study is different than that used by Toronto Hydro.

QUESTION (A):

a) Please quantify the reported improvement in Toronto Hydro's FLISR metrics if Toronto Hydro uses the same metric definition as in the U.S. Department of Energy Study.

RESPONSE (A):

As detailed in Exhibit 2B, Section D5.2.1.2, Toronto Hydro anticipates substantial benefits from the introduction of automatic FLISR starting in 2030. See response to interrogatory 2B-Staff-162, part (a) for anticipated benefits of a full-scale implementation of FLISR across the Horseshoe Region.

It is important to note that the level of benefits achieved from automatic FLISR will ultimately depend on the specific technical and operating realities with respect to integrating FLISR into Toronto Hydro's existing distribution system. The utility will have a more accurate expectation of likely benefits once it has made substantial progress on the "manual FLISR" implementation planned for the 2025-2029 rate period.

The maximum benefits cited from the U.S. Department of Energy report were derived from feeder-level data collected from 266 FLISR events observed over the course of a year. By comparison, Toronto Hydro evaluated the expected impact of FLISR on its system-wide reliability statistics, meaning that the benefits are statistically diluted by including outages that would not be impacted by FLISR (see 2B-Staff-162 for more information).

QUESTION (B):

b) Please update Table 11 in Reference 2 (PDF Page 364/1113) based on using the same definition of SAIFI for Toronto Hydro and its peers.

RESPONSE (B):

Please note the reliability benchmarking results provided in Table 11, and others in the Reliability Benchmarking Study prepared by Clearspring Energy Advisors, are based on different interruption reporting practices, which are not applied to Toronto Hydro and other distributors in Ontario. Most notably, Toronto Hydro and its peer distributors in Ontario and across Canada follow a one-minute threshold for sustained interruptions, which differs from the predominant five-minute interruption definition used in the US for sustained interruptions, as detailed in Exhibit 1B, Tab 3, Schedule 3, App A, Pg. 25. Based on available data, Toronto Hydro is not able to reproduce Table 11 on a one-minute sustained interruption threshold, however, in order to maintain consistency with the benchmarking approach, it provided its interruption data on a 5-minute sustained interruption threshold, which underpins the information provided in Table 11.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-164

References: **Exhibit 2B, Section D5.2.2, Page 28**
Exhibit 2B, Section D5.2.2, Page 35
Exhibit 2B, Section E3, Page 14

<u>Preamble:</u>

Toronto Hydro states, in Table 3. Grid Readiness Program Summaries, Technology - Grid protection, Monitoring and Control, "Toronto Hydro has identified and forecasted a number of stations with short circuit capacity limits, capping the amount of DER connections. Additionally, several feeder circuits have surpassed the recommended generation to minimum load ratio..."

QUESTION (A):

a) Which stations have been identified and forecasted to experience short circuit capacity limits in the planning period?

RESPONSE (A):

Please see Exhibit 2B, Section E5.5 at page 7, Table 4.

QUESTION (B):

b) Please expand Table 3 from the second reference to include columns that indicate for each station:

   i. the first year in which its short circuit capacity will be exceed in its present configuration,
   ii. the year in which the bus-tie reactors will be installed,
   iii. the new short circuit capacity once bus tie reactors are installed, and
   iv. the first year in which that capacity will again be exceeded.

RESPONSE (B):

Please see updated Table 3 below.

Table 3: Locations of Proposed Bus Tie Reactors (2025-2029)

Station Name	Bus	Forecasted Year of Capacity Exhaustion	Planned Installation Year	Bus-tie Reactor Size*	Forecasted Year of Capacity is to be exceeded**
Cecil	CE-A1A2	2025	2027	To Be Determined	To Be Determined
Esplanade	X-A1A2	2025	2028	To Be Determined	To Be Determined
Leslie	51-BY	2025	2029	To Be Determined	To Be Determined
Richview	88-BY	2023	2025	To Be Determined	To Be Determined
Runnymede	11-JQ	2025	2026	To Be Determined	To Be Determined
Woodbridge	D6-BY	2023	2029	To Be Determined	To Be Determined

Notes:
(*) – To be determined after HONI study.
(**) – To be determined after bus-tie reactor size is determined.

QUESTION (C):

c) What is the lead time required to acquire and install each of the bus tie reactors planned for the upcoming test period?

RESPONSE (C):

Lead time estimates varies from 1 to 2 years. This includes the feasibility study, procurement, installation and commissioning of the projects.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-165

Reference: Exhibit 2B, Section D5.2.2.4, Page 42

Preamble:

Toronto Hydro states, "As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid with a total capacity of 304.9 MW."

QUESTION (A):

a) Please provide a table that breaks down the DERs connected to Toronto Hydro's system by technology (CHP, solar PV, battery, etc.) type, capacity (MW), customer class, and connected station.

RESPONSE (A):

Please see Tables 1-14 below.

Table 1: Batteries Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Basin	Commercial / Industrial	0.500
Bridgman	Commercial / Industrial	0.037
	Residential	0.008
Cecil	Commercial / Industrial	2.000
Esplanade	Commercial / Industrial	1.050
Fairchild	Commercial / Industrial	1.000
Finch	Commercial / Industrial	1.498
John	Commercial / Industrial	0.300
Malvern	Commercial / Industrial	5.200
Manby	Commercial / Industrial	2.365
	Residential	0.003
Rexdale	Commercial / Industrial	0.600

Station	Customer Class	Capacity (MW)
Richview	Commercial / Industrial	1.000
	Residential	0.003
Runnymede	Commercial / Industrial	0.999
Scarborough	Commercial / Industrial	0.999
Sheppard	Commercial / Industrial	1.139
Total Battery Capacity (MW)		**18.7**

Table 2: Bi-Fuel (Natural Gas & Diesel) Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Cecil	Commercial / Industrial	1.275
Terauley	Commercial / Industrial	5.400
Total Bi-Fuel (Natural Gas & Diesel) Capacity (MW)		**6.675**

Table 3: Biogas Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Horner	Commercial / Industrial	4.700
Sheppard	Commercial / Industrial	0.500
Total Biogas Capacity (MW)		**5.200**

Table 4: CHP Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Bermondsey	Commercial / Industrial	0.035
Cavanagh	Commercial / Industrial	0.120
Duplex	Commercial / Industrial	0.035
Ellesmere	Commercial / Industrial	0.755
Fairbank	Commercial / Industrial	0.210
Fairchild	Commercial / Industrial	0.146
Finch	Commercial / Industrial	2.528
Horner	Commercial / Industrial	0.397
Leaside	Commercial / Industrial	0.140
Leslie	Commercial / Industrial	0.375

Station	Customer Class	Capacity (MW)
Manby	Commercial / Industrial	0.525
Rexdale	Commercial / Industrial	0.125
Richview	Commercial / Industrial	0.140
Runnymede	Commercial / Industrial	0.490
Scarborough	Commercial / Industrial	0.390
Sheppard	Commercial / Industrial	0.380
Warden	Commercial / Industrial	0.845
Total CHP Capacity (MW)		**7.636**

Table 5: Diesel Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Basin	Commercial / Industrial	5.000
Bathurst	Commercial / Industrial	6.000
Bermondsey	Commercial / Industrial	4.250
Cecil	Commercial / Industrial	1.500
Ellesmere	Commercial / Industrial	5.000
Esplanade	Commercial / Industrial	1.000
Fairbank	Commercial / Industrial	1.350
Fairchild	Commercial / Industrial	0.900
Horner	Commercial / Industrial	1.200
John	Commercial / Industrial	4.050
Leaside	Commercial / Industrial	9.350
Leslie	Commercial / Industrial	7.800
Richview	Commercial / Industrial	1.600
Terauley	Commercial / Industrial	8.550
Wiltshire	Commercial / Industrial	0.500
Total Diesel Capacity (MW)		**58.050**

Table 6: Gas Engine Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Cavanagh	Commercial / Industrial	0.250
Gerrard	Commercial / Industrial	4.233

Station	Customer Class	Capacity (MW)
Total Gas Engine Capacity (MW)		**4.483**

Table 7: Gas Turbine Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Esplanade	Commercial / Industrial	0.750
Total Gas Turbine Capacity (MW)		**0.750**

Table 8: Microturbine Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Agincourt	Commercial / Industrial	0.060
Scarborough	Commercial / Industrial	0.035
Total Microturbine Capacity (MW)		**0.095**

Table 9: Natural Gas Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Agincourt	Commercial / Industrial	0.220
Bathurst	Commercial / Industrial	20.000
Bermondsey	Commercial / Industrial	0.999
Bridgman	Commercial /Industrial	0.355
Cecil	Commercial / Industrial	6.000
Duplex	Commercial / Industrial	0.342
Esplanade	Commercial / Industrial	7.150
Fairbank	Commercial / Industrial	0.340
Fairchild	Commercial / Industrial	1.750
Finch	Commercial / Industrial	6.829
Horner	Commercial / Industrial	4.000
John	Commercial / Industrial	8.500
Leaside	Commercial / Industrial	7.900
Leslie	Commercial / Industrial	1.250
Richview	Commercial / Industrial	0.540
Runnymede	Commercial / Industrial	18.200
Scarborough	Commercial / Industrial	4.099
Strachan	Commercial / Industrial	1.600

Station	Customer Class	Capacity (MW)
Warden	Commercial / Industrial	0.750
Total Natural Gas Capacity (MW)		**90.824**

1 **Table 10: Photovoltaic Connected by Station, Customer Class and Capacity (MW)**

Station	Customer Class	Capacity (MW)
Agincourt	Commercial / Industrial	5.622
	Residential	0.203
Basin	Commercial / Industrial	0.668
	Residential	0.038
Bathurst	Commercial / Industrial	7.115
	Residential	0.503
Bermondsey	Commercial / Industrial	4.299
	Residential	0.387
Bridgman	Commercial / Industrial	0.440
	Residential	0.146
Carlaw	Commercial / Industrial	0.955
	Residential	0.258
Cavanagh	Commercial / Industrial	2.608
	Residential	0.242
Cecil	Commercial / Industrial	0.468
	Residential	0.226
Charles	Commercial / Industrial	0.292
	Residential	0.069
Copeland	Commercial / Industrial	0.208
Dufferin	Commercial / Industrial	1.458
	Residential	0.679
Duplex	Commercial / Industrial	0.198
	Residential	0.151
Ellesmere	Commercial / Industrial	4.837
	Residential	0.401
Esplanade	Commercial / Industrial	0.668
	Residential	0.038
Fairbank	Commercial / Industrial	3.369
	Residential	0.493

Station	Customer Class	Capacity (MW)
Fairchild	Commercial / Industrial	2.801
	Residential	0.488
Finch	Commercial / Industrial	11.702
	Residential	0.491
Gerrard	Commercial / Industrial	0.015
	Residential	0.020
Glengrove	Commercial / Industrial	0.475
	Residential	0.157
Horner	Commercial / Industrial	3.349
	Residential	0.386
John	Commercial / Industrial	0.040
Leaside	Commercial / Industrial	0.919
	Residential	0.441
Leslie	Commercial / Industrial	5.228
	Residential	0.474
Main	Commercial / Industrial	1.274
	Residential	0.265
Malvern	Commercial / Industrial	3.269
	Residential	0.188
Manby	Commercial / Industrial	4.477
	Residential	0.604
Rexdale	Commercial / Industrial	6.251
	Residential	0.223
Richview	Commercial / Industrial	6.018
	Residential	0.409
Runnymede	Commercial / Industrial	2.230
	Residential	0.302
Scarborough	Commercial / Industrial	7.330
	Residential	0.690
Sheppard	Commercial / Industrial	4.990
	Residential	0.841
Strachan	Commercial / Industrial	1.291
	Residential	0.102

Station	Customer Class	Capacity (MW)
Terauley	Commercial / Industrial	0.354
	Residential	0.020
Warden	Commercial / Industrial	3.538
	Residential	0.721
Wiltshire	Commercial / Industrial	0.316
	Residential	0.110
Woodbridge	Commercial / Industrial	0.100
	Residential	0.062
Total Photovoltaic Capacity (MW)		**110.003**

Table 11: Steam Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Cecil	Commercial / Industrial	0.500
Strachan	Commercial / Industrial	0.275
Total Steam Capacity (MW)		**0.775**

Table 12: Turbo Expander Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Leslie	Commercial / Industrial	1.000
Total Turbo Expander Capacity (MW)		**1.000**

Table 13: Underwater Compressed Air Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Strachan	Commercial / Industrial	0.660
Total Underwater Compressed Air Capacity (MW)		**0.660**

Table 14: Wind Turbine Connected by Station, Customer Class and Capacity (MW)

Station	Customer Class	Capacity (MW)
Fairchild	Residential	0.003
Manby	Residential	0.007

Station	Customer Class	Capacity (MW)
Sheppard	Residential	0.003
Strachan	Commercial /Industrial	0.750
Total Wind Turbine Capacity (MW)		**0.763**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-166

Reference: Exhibit 2B, Section D5, Page 59

<u>Preamble:</u>

With regards Toronto Hydro's commentary around AMI 2.0 and future-proofing the meter to provide over-the air updates.

QUESTION (A):

a) Would updating meters after they are sealed require a re-sealing event?

RESPONSE (A):

No, over-the-air firmware upgrades do not require re-sealing.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-167

Reference: Exhibit 2B, Section D5, Page 30

Preamble:

In order to equip customers with easily accessible and up-to-date information as to where DERs can be accommodated most efficiently, Toronto Hydro has proposed a creation of a Hosting and Load Capacity Map (or equivalent data portal) which will provide estimate available capacity for DER interconnection and load capacity at different locations on the network.

QUESTION (A):

a) Please confirm whether the Hosting and Load Capacity map (or equivalent data portal) will provide estimated available capacity for connections other than DERs (for example, load connections such as EV charging connections).

RESPONSE (A):

Toronto Hydro is currently in the planning phases of these projects and assessing the scope and intricacies involved. As stated in Exhibit 2B Section D5.3.4, the utility will explore opportunities to calculate and present complimentary analyses, including load capacity constraints. The utility's priority remains to ensure that any tools or information provided to customers is accurate, reliable, sustainable (i.e., cost-effective), and aligned with Toronto Hydro's commitment to delivering value-for-money.

QUESTION (B):

b) Please confirm how often the data on the Hosting and Load Capacity Map (or equivalent data portal) will be updated.

RESPONSE (B):

As Toronto Hydro is currently assessing the requirements and developing a plan for this project, the utility cannot confirm how often the Hosting and Load Capacity Map would be updated. Toronto Hydro is currently reviewing industry best practices for similar maps and will use the outcome of this review, along with thorough stakeholder and customer engagement, as input to determine the update frequency.

QUESTION (C):

c) Please provide the "Business Case" or similar document produced by the business unit related to the creation of a Hosting and Load Capacity Map (or equivalent data portal). Please provide any other documentation created by Toronto Hydro that provides an overview of the technical requirements of this map or data portal.

RESPONSE (C):

Toronto Hydro has just begun exploring options for the creation of the hosting and loading capacity maps and therefore no "Business Case" or similar document exists. Toronto Hydro is currently reviewing industry best practices for similar maps and will identify next steps including defining the technical requirements.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-168

Reference: Exhibit 2B, Section E1.1, p. 1

Exhibit 1B, Tab 1, Schedule 3, p.5

<u>Preamble:</u>

Toronto Hydro states "In the current rate period, Toronto Hydro's operating parameters shifted from a relatively linear and stable environment to a more dynamic growth-oriented context."

QUESTION (A):

a) Please reconcile the statement above with the negative Total Normalized MVA (% change), and Total Normalized GWh (% change) as shown in Table 5 in Reference 2.

RESPONSE (A):

Reference 1 refers to significant increases in *future* customer demand driven by an unprecedented energy transition that is creating new and expanded roles for electricity within the economy. To gain insight into the challenge posed by the energy transition, 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 study (filed in Exhibit 2B, Section D3) reveals that in the next two-three decades, a significant increase in peak demand across all scenarios is expected to occur, including the least ambitious steady progression scenario that falls short of meeting Net Zero 2050 objectives. This outlook is consistent with other leading studies, such as the Independent Electricity System Operator's ("IESO") Pathways to Decarbonization ("P2D") report, which estimates that in a high-growth scenario, in less than 30 years, Ontario could need more than double its electricity generating capacity.

Reference 2 refers to Toronto Hydro load forecast for billing purposes in the 2025-2029 rate term.

Please see response to 1B-PP-18 for the further details.

QUESTION (B):

b) Is the described shift in operating parameters from "linear and stable" to "more dynamic growth-oriented" a key driver of Toronto Hydro's step-increase in overall capital spending relative to historical spending?

RESPONSE (B):

As noted in Exhibit 2B, Section A at page 2, investing in the performance and long-term viability of an aged, deteriorated, and highly utilized system, while preparing the system to meet the demands of increased electrification, is a key priority of Toronto Hydro's 2025-2029 Distribution System Plan.

As noted in Exhibit 2B, Section E4.2 on page 15, compared to the current 2020-2024 rate period, there is a shift in the 2025-2029 rate period towards System Access and System Service investments to:

i) keep pace with the demands of customers in a city that is growing, digitizing and decarbonizing its economy, and
ii) prepare the grid for the energy transition that is set to unfold over the next two decades by modernizing the utility's infrastructure and operations to improve resiliency, enable DER integration and deliver long-term reliability and efficiency benefits to customers.

Please see Exhibit 2B, Section E4 starting on page 15 for a detailed summary of forecast (2025-2029) vs. historical (2020-2024) expenditures by investment category.

QUESTION (C):

c) Does the shift from "linear and stable" to "more dynamic growth-oriented" materially affect the pace of renewal spending? If yes, please explain why.

RESPONSE (C):

When normalized for inflation, the pace of renewal investment in the next rate period is increasing by approximately 25% compared to historical investment levels (see 2B-Staff-69). As summarized in Exhibit 2B, Section E4.2.2 at page 17, this increase is necessary to manage significant safety, reliability, and environmental asset risks, maintain the system in a state of good repair by managing the overall health demographics of assets, and ensure stable and predictable grid performance for current and future customers. Expansion of capacity as part of renewal projects is not a major incremental driver of the proposed level of System Renewal expenditures in this rate filing.

However, Toronto Hydro expects that the shift to a more dynamic growth-oriented context could place incremental pressures on the System Renewal programs and influence the way renewal projects are prioritized. The utility expects that accommodating neighbourhood-level growth due to electrification will require upgrading the capacity of primary cables and conductors, distribution transformers, secondary buses, and protection schemes, which in turn could have cascading effects such as the need to accelerate voltage conversion projects. When Toronto Hydro replaces an asset or rebuilds an area as part of a planned renewal project, it examines the demand in the area to determine whether the new equipment should be built to a larger standard and whether the feeder more broadly requires reconfiguration or load balancing. In a high electrification scenario, a greater share of the allotted System Renewal funding will need to go toward these expansionary costs, in turn reducing the extent to which expenditures are targeted more narrowly at mitigating asset failure risk. In the long-term, Toronto Hydro cannot neglect asset deterioration and asset failure risk, as this would lead to worsening reliability, heightened safety and environmental risks, and an overall backlog of deteriorating assets that would need to be addressed at higher costs in the future. Therefore, in the long-term, under a high electrification scenario, the utility expects the dual drivers of reliability and growth to result in a higher overall need for System Renewal investment.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-169

Reference(s): **Exhibit 2B, Section E1.1, Page 2**
Exhibit 2B, Section E1.2, Page 4
Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, March 28, 2023, Ontario Energy Board
FRAMEWORK FOR ENERGY INNOVATION: Setting a Path Forward for DER Integration, January 2023, Ontario Energy Board

<u>Preamble:</u>
Toronto Hydro states "Sustainment and Stewardship: Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird."

QUESTION (A):

a) Toronto Hydro is proposing to increase its renewal spending by 35% relative to historical levels (reference 2). Please explain the extent to which this overall increase is being driven by any of the following factors:
   - changes in the rate of deterioration of Toronto Hydro's assets
   - a backlog in historically unaddressed renewal needs
   - a change in the deemed acceptable failure risk threshold for specific asset types
   - other reasons.

RESPONSE (A):
Toronto Hydro continues to face asset demographic challenges in operating a mature distribution system. As summarized in Exhibit 2B, Section A3.1, both condition and age demographics identify a number of critical asset classes with significant investment needs over the 2025-2029 period. These needs are driven by various factors, including those listed in the question above. Through its

investments in Sustainment and Stewardship, Toronto Hydro is aiming to maintain reliability and asset risk current levels. Toronto Hydro has not materially changed its risk threshold for any major asset classes from the previous rate period. However, as part of the utility's strategy for improving resiliency in parts of the overhead system that are critical and vulnerable to increased adverse weather, Toronto Hydro has reintroduced an Overhead Infrastructure Resiliency segment to allow for targeted relocation and undergrounding (Exhibit 2B, Section E6.5), and this partially explains the increase in the Overhead System Renewal program compared to 2020-2024.

The following paragraphs provide a brief summary of the three major drivers of increases in the System Renewal category: inflation; overhead and underground system health and reliability; and asset deterioration in stations.

Inflation

As discussed and illustrated in Exhibit 2B, Section D2.1.3, and as reflected in the unit cost pressures noted in other interrogatory responses (e.g., 2B-Staff-212), Toronto Hydro has dealt with significant inflationary pressures in the current rate period. Calculating the actual amount by which labour and materials inflation has impacted historical costs at the project level is a data-intensive undertaking. However, using the OEB's inflation factor, in combination with Toronto Hydro's forward-looking inflation assumptions, to adjust all of the expenditures in the 2020-2029 period to 2020 dollars, the utility estimates that 60% of the increase in System Renewal expenditures is due to inflation.[1]

Overhead and Underground System Health and Reliability

The condition of Toronto Hydro's overhead and underground systems has deteriorated since 2018. As shown in Table 2 in Exhibit 2B, Section E2, the percentage of assets on the overhead system that are in HI4/HI5 condition has increased from 6% to 9%. While the underground system percentage is stable at 3%, the projected rate of deterioration is higher looking out to 2029 as compared to the equivalent analysis done in 2018 (i.e., seven percentage points vs. four percentage points of

[1] Toronto Hydro applied the 2021-2023 OEB inflation factors to 2020-2022. The OEB's inflation factors lag actual inflation by approximately two years.

deterioration without investment). Toronto Hydro also notes that the most critical asset on the underground system from a reliability perspective is primary cable. This asset class is not reflected in the condition models, and as discussed in Exhibit 2B, Section E6.2, Toronto Hydro has seen a deterioration in reliability performance for this asset type during this rate period, with customer interruptions increasing from a previous low of 105,000 in 2019 to 199,000 in 2022. For more information, please refer to 2B-Staff-211.

Deterioration in asset condition and performance is partly related to the deferral of volumes of work from the 2020-2024 period. This deferral was the result of inflationary pressures, as well as the need to constrain expenditures in the major renewal programs as a means of balancing-out unanticipated cost pressures from demand-related programs. This is discussed in Exhibit 2B, Section E4.1. In recent years (and continuing through 2025), Toronto Hydro has also been focused on removing transformers at risk of containing PCBs from its overhead and underground systems, and this has diminished the utility's ability to target assets and areas of the system in the worst condition and most at risk of failure.

The Horseshoe area renewal programs are the capital programs that have the most significant impact on the day-to-day reliability of the grid. Toronto Hydro has proposed the minimum pace of investment necessary to manage asset risk and maintain reliability performance over the 2025-2029 period. For full details on the programs, please refer to Exhibit 2B, Sections E6.2 and E6.5 For more information on drivers of increases in the Overhead System Renewal program, please refer to 2B-Staff-219. For a comprehensive discussion on expected changes in asset demographics as a result of Toronto Hydro's 2025-2029 investment plan, please refer to 2B-SEC-44.

Asset Deterioration in Stations

Toronto Hydro also intends to accelerate its investment in the Stations Renewal program beyond the pace set during the 2020-2024 period by 61%. This is in response to a considerable backlog of aging and deteriorating assets, with the goal of securing the long-term reliability performance of these critical asset populations. Table 2 in Toronto Hydro's response to 2B-SEC-44 highlights the condition demographics for key station assets. Additionally, the program is experiencing rising unit costs for MS Switchgear, Power Transformers, and MS Primary Supply projects. For more detailed information on the expenditure increases within the Stations Renewal program, refer to Exhibit 2B, Section E6.6.

QUESTION (B) AND (C):

b) Please provide a copy of Toronto Hydro's internal distribution system planning process and identify how it addresses non-wires solutions. What are the planned changes to the planning process to better address identified non-wires objectives as per References 3 and 4.

c) In the present application did Toronto Hydro evaluate Non-Wires Solutions whenever existing traditional "wires" assets (such as poles, conductor systems, underground cable, transformers, switchgear, etc.) were identified as requiring replacement?

   i. If yes, please provide documentation of some representative evaluations that have been undertaken.

   ii. If no, please explain why not, considering the recent guidance in References 3 and 4.

RESPONSE (B) AND (C):

Toronto Hydro's capacity planning process involves a ground up analysis of system capacity needs, driven by load forecasts, as described in Exhibit 2B, Section D4. Planners pre-screen the types of needs that could reliably be addressed by non-wires solutions based on credible opportunities to defer or avoid capital investment through procurement of non-wires capacity. This pre-screening is based on the size of the capacity need and the ability for Toronto Hydro to aggregate sufficient quantities of dispatchable demand response (DR) to meet this need. For example, granular feeder-level issues are difficult to address using NWS, as the total capacity of dispatchable DR on an individual feeder is rarely sizeable enough to meet the need. On the other hand, station level issues are often driven by capacity requirements that are too large to be reliably and cost-effectively met through DR.

Where appropriate use cases have been identified, the planning process includes a consideration of non-wires solutions at the options analysis phase. Figure 1 below provides a high-level summary of this process.

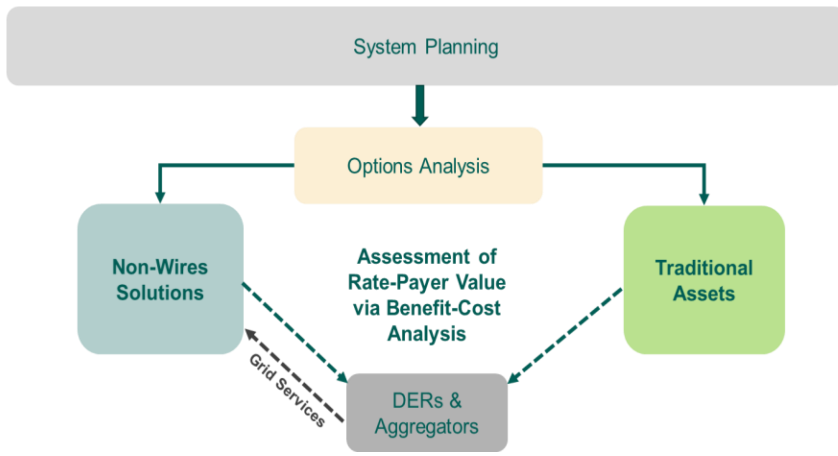


Figure 1. High-level Schematic of Toronto Hydro's Planning Process

Based on experience over the last two rate periods, Toronto Hydro's identified use case of non-wires solutions focuses on capital deferral or avoidance of bus-level load transfers, which can be achieved through the procurement of dispatchable demand response from aggregators or customers. Toronto Hydro also assesses non-wires solutions as alternatives to Station Expansion, as illustrated in the Downsview TS business case at Exhibit 2B, Section E7.2 Appendix A, and discussed in the response to 2B-Staff-253.

In accordance with the use case and the guidance in Reference 3, Toronto Hydro set an ambitious target to procure 30MW of non-wires capacity to defer or avoid approximately 25% of the load transfers that would otherwise be required at the targeted stations in the next rate term. As the NWS market matures, and the ability the procure reliable DER services increases, Toronto Hydro will continue evolve its planning process to identify and develop other credible use cases of non-wires solutions. Please see the responses to 1B-Staff-88 and 1B-Staff-89 for more information.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-170

References: Exhibit 2B, Section 1.1, p. 2

Exhibit 2B, Section E1.2, p. 4

Preamble:

Toronto Hydro states "Modernization: Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time."

QUESTION (A):

a) Does Toronto Hydro quantify the expected value enhancement and system efficiency improvements per dollar spent "developing advanced technological and operational capabilities"?
   i. If yes, please provide documentation of value quantifications of representative modernization investments.
   ii. If no, please explain why Toronto Hydro is confident that all of its planned modernization investments cost effectively add value for ratepayers.

   Contextualize your answer in consideration of the proposed 56% increase in System Service spending over the upcoming test period relative to historical as shown in reference 2.

RESPONSE (A):

Yes. While there is no single "value […] per dollars spent" metric, Toronto Hydro undertakes business case evaluations and expected benefits analyses for modernization projects at the appropriate stage prior to release of funding.[1] The exact form of these analyses will vary depending on the type of

[1] Note that for its full-scale programmatic system investments, including segments within the System Enhancements program, Toronto Hydro is in the process of developing a value framework that will eventually support project-based comparison of quantified value. For more information, see Exhibit 2B, Section D1.

investment and the nature of the benefits (e.g., software vs. field technology; pilot vs. full implementation).

For grid modernization field technologies that have reached the level of full-scale implementation (e.g., overhead SCADA switches), investment decisions are handled in the same manner as any other system investment program, i.e., as part of the utility's Investment Planning & Portfolio Reporting ("IPPR") process and associated Scope & Project Development process (refer to Exhibit 2B, Section D1.2 for more information). Through the IPPR process, planners propose investment pacing options which are evaluated on a risk and outcomes basis (using relevant leading and/or lagging indicators). Management assesses trade-offs versus other programs that may achieve (i) similar outcomes in different ways, or (ii) different, but no less important, outcomes (e.g., reliability vs. compliance). This process results in an integrated capital expenditure (and maintenance) plan, designed to achieve an appropriate balance of outcomes within the given financial constraints, leveraging a combination of Growth, Sustainment, and Modernization investments. Throughout this process, Toronto Hydro's objectives for customer-focused outcomes remain tied to objectives established within the applicable five-year Distribution System Plan.

Note that the System Service investment category consists of both Modernization and Growth (Stations Expansion) investments. The largest driver of increases in this category is the accelerated pace of Contingency Enhancement (Exhibit 2B, Section E7.1) – specifically, the deployment of additional SCADA tie and sectionalize points and the introduction of reclosers as part of the broader strategy of enhancing System Controllability & Automation in the Horseshoe, and the longer-term goal of achieving self-healing grid operations in the Horseshoe beginning in 2030. For a full overview of the need for and expected benefits of Toronto Hydro's System Controllability & Automation investments (including various quantified benefits), please refer to Exhibit 2B, Section D5.2.1.2.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-171

Reference: Exhibit 2B, Section E1.2, Page 4

Preamble:

With respect to Table 2: Planned Capital Investment by OEB Investment Category ($ Millions)

QUESTIONS (A) AND (B):

a) Please compare the proposed increase in System Access spending to the historical and forecasts rates of energy and demand growth.

b) Please provide a chart showing actual and forecast trends in System Access spending, peak load demand and annual energy deliveries for each year from 2020 to 2029, expressed in terms of percentage change relative to the prior year.

RESPONSES (A) AND (B):

Please see the table below. Please note that the System Access category is made up of five programs, not all of which relate directly to load growth. In particular, three of the five programs (i.e. (i) the Metering program which also addresses a renewal need, (ii) the Externally Initiated Plant Relocations and Expansion program, which is driven by third-party initiated infrastructure development in the City of Toronto, and (iii) Generation Protection Control and Monitoring program, which is driven by DER connections) have a very limited relation to load. Excluding these three programs, Table 1 below provides the information requested.

With respect to the trends observed in Table 1 below, Toronto Hydro notes that this comparison is not meaningful for a number of reasons.

- First, the system access investments captured below (namely Customer Connections and Load Demand) reflect the targeted and localized system expansion and enhancement investments to ensure timely and efficient connections and service upgrades, and to alleviate capacity constraints to maintain service quality in high-growth areas (e.g., the downtown core and along the transit corridors). As observed in the table, the rate of change of expenditures in these programs can swing significantly from one year to another due to the myriad of factors as noted in the evidence at Exhibit 2B, Section E5.1.3.

- Second, the level of investment in system access is affected by customer contribution rates, which can vary significantly year-over-year based on: (i) the size and location of the connection; (ii) the degree of system expansion required to meet the obligation to serve, (iii) economic evaluations of the customers' load and revenue projections vis-à-vis the cost of expansion, and (iv) the impact of different cost allocation rules under the Distribution System Code amendments.
- Lastly, consistent with the customer connection horizon outlined in the DSC, there is an approximate five-year lag between Customer Connection related investments and energy/demand materialization on the system.

	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access: Customer Connections & Load Demand Expenditures	105%	-12%	-8%	-9%	43%	7%	-2%	7%	6%
System Peak Demand Forecast	-0.1%	-3.2%	3%	3.6%	2.9%	2.9%	1.7%	3.4%	3.1%
Electricity Consumption (Revenue Forecast)	-0.4%	1.8%	-1.3%	0.0%	-0.9%	-0.2%	-0.1%	0.5%	-0.2%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-172

References: Exhibit 2B, Section E1.3, Page 5
Exhibit 1B, Tab 5, Schedule 1, Appendix A, Page 5

<u>Preamble:</u>

Toronto Hydro states that: "Toronto Hydro strives to maintain and improve reliability at local, feeder-wide, and system-wide levels by continuously optimizing its system and deploying cost-effective technologies and solutions."

Question (A):

a) Does Toronto Hydro quantitatively evaluate its reliability investments to determine if they are cost neutral or cost reducing?
   i. If yes, please provide some representative benefit-cost analyses.
   ii. If no, please explain how Toronto Hydro determines that its proposed reliability improvement investments are benefit-cost effective.

RESPONSE (A):

Toronto Hydro is unclear as to what is meant by "cost neutral or cost reducing" in the context of "reliability investments." Investments to maintain or improve reliability are typically evaluated through a "least cost" lens. This involves identifying the most cost-effective solutions to achieve desired reliability levels. It prioritizes investments that provide the greatest reliability improvements for the lowest cost. Toronto Hydro achieves this through its outcomes-oriented, programmatic approach to investment planning, which is driven by customer needs and preferences. The utility has a diverse portfolio of established investments across its System Renewal and Service programs which contribute to reliability performance. Through the Investment Planning & Portfolio Reporting process, the utility assesses trade-offs across investment programs and develops an overall expenditure plan that is calibrated within given financial constraints to deliver the best achievable reliability outcomes across relevant time horizons. Note that cost, (including cost-savings from new technology) is a factor in this "least cost" investment planning approach. However, cost is treated as its own variable to be optimized through the planning process. This is achieved by (i) constraining the investment plan within budget parameters, and (ii) updating bottom-up capital and operational cost assumptions to ensure savings from past and future technology deployments are embedded in expenditure plans each year. An example of this would be the operational savings from deploying Network Condition Monitoring & Control technology, which have been embedded in future expenditure plan assumptions for the relevant maintenance program. (See Exhibit 2B, Section E7.3, page 12 for more information.)

As discussed in Section D1.2.1.1, as part of its ongoing multi-year effort to implement an industry leading Engineering Asset Investment Planning ("EAIP") platform, Toronto Hydro is developing a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes (including System Reliability). This will further deepen the utility's "least cost" optimization approach by increasing the consistency and objectivity of these evaluations at the project level.

Outside of this programmatic approach to investment planning, the utility also endeavors to offer customers value-for-money by exploring new technologies adopted by the industry, which may be more cost-effective than the current status quo. Toronto Hydro's Product Change Committee reviews and conducts pilot projects to assess the feasibility of new technologies and products. Typically, after a detailed pilot phase, the technology or product is evaluated for its cost-effectiveness in contributing to the utility's objectives, including the improvement of system reliability. For example, following a successful evaluation of mid-line reclosers through multiple pilot projects, the utility is now proceeding to deploy this innovative and cost-effective technology system-wide (Exhibit 2B, Section E7.1). The additional reliability benefits, such as reducing interruption frequency and duration for customers, supplement the remotely operated SCADA switches that Toronto Hydro has used for decades.

QUESTION (B):

b) Has Toronto Hydro identified unacceptable reliability trends relative to its historical performance or its peers? Please explain.

   i. If no, is Toronto Hydro only undertaking reliability improvement investments that are either cost neutral or cost reducing?

RESPONSE (B):

Toronto Hydro views its reliability performance as acceptable, both in comparison to historical data and in competitiveness among its peers. The utility continuously assesses reliability performance and trends relative to historical data, using measures reported on the EDS, as well as internally tracked measures. Toronto Hydro also completed a Reliability Benchmark study as part of developing this rate application, as detailed in Exhibit 1B, Tab 3, Schedule 3, Appendix A. In addition to tracking reliability measures, the utility investigates outages that significantly impact its customers on a weekly basis. In addition to interruptions originating from the distribution system, Toronto Hydro works in close partnership with Hydro One to ensure Loss of Supply events are investigated thoroughly and mitigated through appropriate action.

Toronto Hydro recognizes that on-going investments are required to maintain current levels of reliability performance and developed a plan that largely maintains system reliability over the next rate period while investing in modernization efforts capable of providing reliability benefits over the longer term to manage the impacts of electrification and other pressures and complexities. Please refer to the response to part (a) above, which describes the utility’s programmatic, outcomes-focused, least-cost approach to investment planning.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-173

Reference: Exhibit 2B, Section E1.3, Page 5

Preamble:

Toronto Hydro States: "Expected load changes can impact service consistency and demand requirements for the system. To address this, Toronto Hydro proactively adjusts and expands its infrastructure to optimize reliability and meet evolving customer needs."

QUESTION (A):

a) Please explain how Toronto Hydro evaluates non-wires solutions, for example, to ensure that the capacity of its existing wires assets is being optimally utilized prior to undertaking incremental system investments to expand capacity.
   i. Please provide several representative examples.

RESPONSE (A):

Please see Toronto Hydro's response to 2B-Staff-169 (b) and (c) for an explanation of how Toronto Hydro evaluated non-wires solutions. As described in the Load Demand program, a key tool for meeting capacity needs and ensuring system reliability and efficiency is bus level load transfers (i.e. load transfers between station buses to alleviate overloaded buses).[1] The Flexibility Services non-wires program directly supports Load Demand by identifying opportunities to defer or avoid these load transfers when and where it is appropriate. Station bus load forecasts are re-evaluated annually. Based on updated results, it may be necessary for Toronto Hydro to reprioritize load transfers. As part of this prioritization process, there is explicit consideration of the application of LDR.

[1] Exhibit 2B, Section E5.3.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-174

Reference: Exhibit 2B, Section E2, Page 14

Preamble:

Regarding the number of network transformers that materially deteriorated and will be undergoing replacement.

QUESTION (A):

a) Please reconcile the quantities of network transformers to be replaced, the numbers indicated that Toronto Hydro is replacing 225 units by the end of 2029, but only 192 units are currently and forecasted to be in HI4 and HI5 condition by 2029.

RESPONSE (A):

Toronto Hydro would like to clarify that it forecasted a total of 149 units in HI4 and HI5 condition by 2029 (which includes 43 already in HI4 and HI5 as of the end of 2022) and not 192 as stated in the question. While network transformer condition demographics is an important factor, Toronto Hydro also considered other drivers when developing its 2025-2029 plan for network unit replacement. As noted in Exhibit 2B, Section E2, these included:[1]

> *(1) the continuing prevalence of non-submersible network units, which are at a higher risk of catastrophic failure due to flooding regardless of their condition; and (2) an anticipated wave of network demographic issues beyond 2029, with over 50 percent of network units projected to be at or beyond end of useful life by 2034 without intervention.*

Toronto Hydro considered the above in developing the plan to replace 26 units per year over 2025-2029, a reduction of approximately 26 percent from the 2020-2024 pacing.

[1] Exhibit 2B, Section E2 at page 14, lines 4-7.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-175

References: Exhibit 2B, Section E2.1.1, Page 4

Preamble:

From Table 1: 2025-2029 Performance Objectives Toronto Hydro states: "Improve system reliability through enhanced fault management, leveraging automation and advanced metering through AMI 2.0"

QUESTION (A):

a) On its face, this objective conflicts with the "Maintain Reliability" objective cited in the Sustainment and Stewardship investment priority. Please explain how Toronto Hydro harmonizes these conflicting objectives when assembling its investment portfolio?

RESPONSE (A):

Toronto Hydro's objectives for the "Sustainment and Stewardship" and "Modernization" categories address different (overlapping) time horizons and are fundamentally compatible. For Sustainment and Stewardship, the reliability objective for the lagging indicators of SAIDI/SAIFI (and in particular, SAIFI due to Defective Equipment) is to maintain current levels of performance over the 2025-2029 period by moving forward with a paced investment strategy that manages the deterioration of assets and maintains (but does not improve) overall population health through the rate period. For Modernization, Toronto Hydro is looking beyond 2029 in preparation for increasing pressures from electrification, DERs, and climate change (as discussed in Exhibit 2B, Section E2, pages 18-20). It is over this longer time horizon that Toronto Hydro is aiming to improve system reliability (and resiliency) through modernization. While these investments have a long-term focus, Toronto Hydro recognizes that there will be benefits to reliability as these technologies are gradually deployed throughout this rate period. These benefits are reflected in the SAIDI and SAIFI projections shown in Exhibit 1B, Tab 3, Schedule 1, Figures 1 and 2.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-176

Reference: Exhibit 2B, Section E2.1.1, Page 4

Preamble:

From Table 1: 2025-2029 Performance Objectives Toronto Hydro states: “Connect customers efficiently and with consideration for an increase in connections volumes due to electrification”

“Expand stations capacity to alleviate future load constraints, with consideration for increased EV uptake, decarbonization drivers, and other growth factors (digitization and redevelopment)”

QUESTION (A):

a) What analysis does Toronto Hydro undertake to evaluate the risk of temporarily or permanently stranding capital investments should the anticipated connection volume trends fail to materialize over the planning period, to align with the principle of “least regrets” investments?

RESPONSE (A):

Toronto Hydro relies on its Capacity Planning process to adequately size capacity expansion efforts to deliver reliable service and timely connections to its customers, resulting in its “least regrets” planning approach. In order to identify and minimize the risk of temporarily or permanently stranding capital investments, Toronto Hydro relies on a robust System Peak Demand Forecast methodology, that is updated annually, that integrates a number of drivers of growth. Toronto Hydro enhanced this methodology to consider additional factors ahead of preparing the 10-year forecast that informed the 2025-2029 rate period. In addition, to support its decision-making Toronto Hydro leveraged a long-term, multi-scenario growth modelling tool known as the Future Energy Scenarios (“FES”) model to understand the range of possible scenarios under varying policy, technology, and consumer behaviour. Please refer to Exhibit 2B, Section D4 for more details on Toronto Hydro's capacity planning process.

Integral to the planning process enhancements has been the integration of the use of Local Demand Response in the assessment of alternatives to traditional wires investments. This provides Toronto Hydro with the ability to monitor the realization of needs before committing to longer term investments in growing system capacity.

These approaches, along with coordinated planning with key stakeholders such as Hydro One (the transmitter) and the Independent Electricity System Operator, allow Toronto Hydro to assess capacity needs for its system carefully and minimize the risk of stranding capital investments.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-177

Reference: Exhibit 2B / Section E2.1.1 / p. 5

Preamble:

Toronto Hydro states: "In addition to setting these performance objectives, Toronto Hydro adopted top-down financial constraints to ensure that the principle of balancing price and service quality outcomes remained top of mind throughout the planning process."

"Price Limit: Toronto Hydro set an upper limit of approximately 7 percent as a cap on the average annual increase to distribution rates and charges."

QUESTION:

Please create a chart comparing historical and forecast Toronto Hydro annual rate increases against the historical and forecast annual Ontario Consumer Price Index from 2020 to 2029.

i. Please explain any significant deviations between Toronto Hydro rates and inflation.

RESPONSE:

Please see the requested chart below comparing Toronto Hydro annual rate increases against the historical and forecast (2%) annual Ontario Consumer Price Index. Taking into consideration the rate decrease in 2020 resulting from rate riders, including gains on sale of properties that were returned to customers, Toronto Hydro's rates are overall consistent with Ontario inflation over the 2020 to 2029. Material deviations over the period are observed in 2022, primarily due to the OEB's inflation factor being higher than the capital-related inflation that was embedded in rates for that year, and in 2025-2029 as the utility's must invest in the grid, its operations and workforce to address the needs and challenges identified in the evidence and deliver outcomes that are important to customers. Toronto Hydro notes that rates under Price Cap IR would presumably track closer to

Ontario inflation than its proposed rate plan. In the responses to 1B-Staff-12 and 1B-Staff-15, the utility presents the revenue deficiency and financial impacts of managing within Price Cap IR rates.

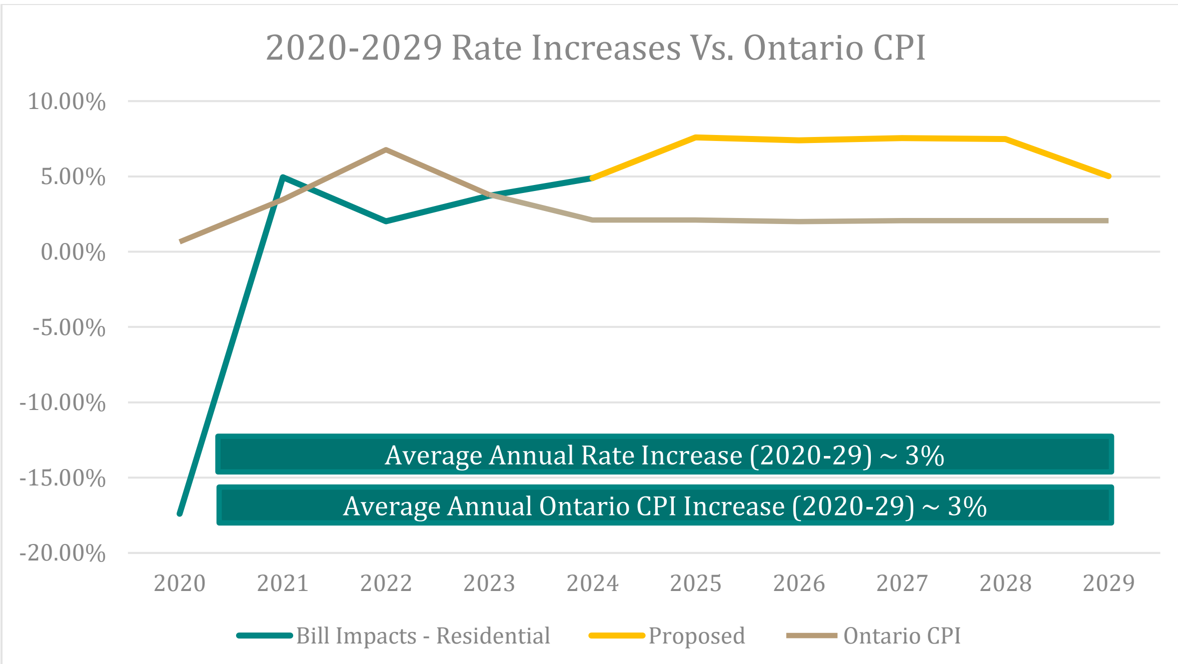


Figure 1 – 2025-2029 Rate Increases VS Ontario CPI

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-178

Reference: Exhibit 2B, Section E2, page. 7

Preamble:

Toronto Hydro states: "The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic objectives in the focus areas of Growth, Sustainment, Modernization and General Plant. From this starting point, an iterative process generated multiple versions of the capital expenditure plan, eventually producing a draft plan that formed the basis of Phase 2 of Customer Engagement. The differences between the initial version of the plan - which on an aggregate basis was higher than the $4,000 upper limit on capital expenditures."

QUESTION (A):

a) How was the upper limit capital expenditure envelope size of $4 billion determined?

RESPONSE (A):

Please refer to the response to interrogatory 2B-SEC-33.

QUESTION (B) :

b) Does the resulting capital expenditure plan satisfy Toronto Hydro's acceptable risk exposure assessment?
    i) If yes, does this indicate that the initial capital expenditure plan was larger than necessary?
    ii) If no, is Toronto Hydro's position that the proposed capital expenditure plan is imprudent?

RESPONSE (B):

Yes. Through an iterative and integrated planning process, the initial capital expenditure plan was adjusted/constrained to arrive at a balance between price and outcomes that Toronto Hydro's deemed to be acceptable. Achieving this balance necessarily meant taking on some additional risk and/or reducing the pace of progress in certain areas of the plan, as explained in the evidence at Exhibit 2B, Section E2 page 7. For example, the Downtown Contingency segment of System Enhancements was substantially reduced by focusing on creating station switchgear ties between Copeland Station and Esplanade Station to manage (rather than alleviate) contingency concerns within the downtown system.

QUESTION (C):

c) Given that the capital expenditure constraints that were imposed appear to have been generated top-down, rather than using Toronto Hydro's Asset Management processes, please explain how Toronto Hydro validated that the resulting solution is optimal as per Toronto Hydro's Asset Management or Risk Management processes.

RESPONSE (C):

The capital expenditure plan is the output of an iterative planning process that centered around Toronto Hydro's Asset Management system. Leveraging the analytical tools and risk-based decision-making frameworks contained with the Asset Management system and processes described in Exhibit 2B, Section D1, along with other relevant inputs and information, Toronto Hydro was able to adjust/constrain the initial plan to arrive at a balance between price and outcomes deemed to be acceptable from a risk perspective. For example, the Cable Chamber Renewal segment within the Underground Renewal - Downtown program was reduced by approximately $25 million by scaling back the number of poor condition assets to be addressed in the next rate period. The risk associated with this reduction was deemed to be acceptable by targeting asset locations that have the highest failure consequences.

QUESTION (D):

d) Please provide documentation demonstrating that capital expenditure levels lower than the $4 billion upper limit did not satisfy Toronto Hydro's Asset Management and Risk Management processes.

RESPONSE (D):

The System Renewal evidence in Exhibit 2B, Section E6 demonstrates that the capital expenditures proposed are aligned with Toronto Hydro's Asset Management and Risk Management processes. Please refer to the Appendix A1 at page 10 filed in response to 1A-CCC-01 for a high-level summary analysis of capital expenditure levels lower than the $4 billion upper limit.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-179

Reference: Exhibit 2B, Section E4.2.6, Page 20

<u>Preamble:</u>

Toronto Hydro states: "Toronto Hydro is expanding inspection and maintenance activities in key areas through the Preventative and Predictive maintenance programs, resulting in an 11 percent increase between 2024 and 2025, followed by a moderate 1 percent average annual increase from 2026-2029."

QUESTION (A):

a) Toronto Hydro is significantly increasing spending in at least three areas that directly affect system reliability, i) System Renewal spending by 35%, ii) System Service - System Enhancement program spending by 473%, and iii) Preventative and Predictive maintenance program spending by 11% followed by 1% compounding, in addition to significant amount of other program spending increases that will either directly or indirectly improve system reliability. Please reconcile these parallel spending increases with Toronto Hydro's strategy of maintaining reliability in response to indicated customer preferences.

RESPONSE (A):

Toronto Hydro is investing the minimum necessary to manage asset risk and achieve the goal of maintaining system reliability as measured by SAIFI Defective Equipment. The increase in System Renewal expenditures is driven by a number of factors, including inflation. Please see Toronto Hydro's response to 2B-Staff-169 for a discussion regarding the drivers of the increase in capital expenditures within the System Renewal category.

Please see Toronto Hydro's response to 2B-Staff-175 for more details on how investments in the "Modernization" category reconcile with Toronto Hydro's objective to maintain reliability over 2025-2029.

The increases in Toronto Hydro's Preventative and Predictive maintenance programs support the utility's objective to maintain reliability and are largely complementary to System Renewal investments, and meet outcomes in other areas such as safety and environment in addition to reliability outcomes. As such, the increase in the preventative and predictive maintenance programs are not solely driven by reliability considerations. Below is a list of other factors that drive these increases:

- As discussed in Exhibit 2B, Section D3.1.1, a large majority of preventative programs are cyclical in nature in alignment with regulatory requirements.
- Inspections serve as the primary input into Toronto Hydro's Asset Condition Assessment ("ACA") methodology, which is a key input for decision-making within System Renewal programs. For example, Toronto Hydro intends to increase the maintenance schedule for wood poles from 10 years to 8 years in order to improve the collection of condition information for this asset class.
- Increases in asset populations naturally drive increases in inspection and maintenance expenditures.
- The introduction of new technologies and increased penetration of DERs on the system also drive incremental inspection and maintenance requirements.
- Inflationary pressures are expected to drive costs, especially within the Stations maintenance programs.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-180

Reference: Exhibit 2B, Section E4.2.6, Page 21

Preamble: Toronto Hydro states: "The increase in the Corrective Maintenance Program is driven by the need to address a growing backlog of P3 deficiencies within the system."

QUESTION:

a) Is the planned 35% increase in Renewal spending expected to help address the backlog of P3 deficiencies within the system?
   i. If yes, does this mean that the Corrective Maintenance Program will be reduced in future test periods? Please explain.
   ii. If no, are P3 deficiencies not correlated with asset condition, or is the planned Renewal spending not being directed to assets with P3 deficiencies that require urgent attention? Please explain.

RESPONSE:

Toronto Hydro does not expect the planned 35 percent increase in Renewal spending to materially help address the backlog of P3 deficiencies for the following reasons:

- The Renewal spending increase is driven by a number of factors, which are discussed in Toronto Hydro's response to interrogatory 2B-Staff-169 (a), but as noted in Exhibit 2B, Section E2.1.1 at page 3, one of the key objectives is to manage asset risk by maintaining overall health demographics of the asset population.
- As discussed in Exhibit 2B, Section D3.1.1.3, even if the increased spending did lead to materially improved health demographics, this would not necessarily lead to a corresponding reduction in the volume of deficiencies requiring corrective maintenance as younger and healthier assets with defects may be more suited to being repaired than replaced.

- Planned renewal investments may support in addressing some of the backlog of P3 deficiencies where they happen to intersect with assets or areas targeted for capital intervention. However, based on recent historical data, on average there has been less than 1 percent of P3 work cancelled due to overlap with planned projects and therefore any impact is expected to be very limited.

ii. Toronto Hydro respectfully rejects the premise of the last part of the question. P3 deficiencies can be, but are not necessarily, related to asset condition. The P3 backlog includes deficiencies, such as tripping hazards[1] and nomenclature updates, which are unrelated to the condition of an asset. In addition, as noted above, renewal expenditures are targeted to maintaining, and not improving, overall asset health demographics and as such would not be expected to impact overall P3 deficiency volumes even if there was a close correlation.

With respect to the idea of the utility's planned renewal not being directed to P3 deficiencies that require urgent attention, Toronto Hydro agrees that planned renewal is not generally being directed to P3 deficiencies and notes that it should not be, but disagrees that P3 deficiencies require urgent attention. By definition, P3 deficiencies are the lowest priority, and therefore the least urgent deficiencies requiring attention.[2] Where asset replacement (i.e. capital work) is required to address the deficiencies, these are carried out through the Reactive capital segment (Exhibit 2B, Section E6.7); otherwise, deficiencies are addressed through the Corrective Maintenance program (Tab 2, Schedule 4). Therefore, Toronto Hydro notes that the P3 backlog referenced consists of the lowest priority deficiencies, specifically to be addressed through Corrective Maintenance. Corrective maintenance allows Toronto Hydro to address repairable issues in the short term in order to maximize performance of an asset, which in turn may defer the need to replace the asset.

[1] For example tripping hazards unrelated to underlying civil asset deterioration such as unlevel ground around Toronto Hydro assets.

[2] While less urgent than P1 or P2 deficiencies, Toronto Hydro still needs to P3 deficiencies before they worsen and lead to bigger issues, unlike P4 deficiencies, which are the lowest priority identified and which require monitoring only.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-181

Reference: Exhibit 2B / Section E5.1. / p. 20

Preamble:

Toronto Hydro states it proposes to increase the Basic Connection Fee allowance for Class 1 to 5 from $1,396 to $3,059.

QUESTION (A):

Please provide the actual amounts incurred by Toronto Hydro for the basic connection fee, per year, from 2020 to the end of 2023.

RESPONSE (A):

The following table provides the annual count of new connections and the corresponding basic connection fee totals with the fee of $1,396.

	2020	2021	2022	2023	2020-2023
New Connections (count)	2,713	2,404	2,408	2,611	10,136
Basic Connection Total ($)	3,787,348	3,355,984	3,361,568	3,644,956	14,149,856

QUESTION (B):

Please provide the forecast expense for Toronto Hydro, per year, for the basic connection fee, over 2025 through 2029, at the new rate.

RESPONSE (B):

Please see the response to interrogatory 2B-SEC-62 d).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-182

Reference: Exhibit 2B, Section E5.1.3.1, page. 3

Preamble:

Toronto Hydro states: “The energy transition is also an important driver of the Load Connections segment as customers look to the electricity grid to meet more of their energy needs.”

a) Please reconcile this statement with Toronto Hydro’s projected decrease in forecast energy sales and billable demand.

RESPONSE:

Please refer to Toronto Hydro’s response to interrogatory 1B-PP-18.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-183

References: Exhibit 2B, Section E5.1.3.1, page. 6

Preamble:

With respect to Figure 2 Historical and Forecast number of Toronto Hydro Customers.

QUESTION (A):

a) Please overlay on Figure 2 Toronto Hydro's historical and forecast annual capital spending on System Access connections.

RESPONSE (A):

The following figure overlays the historical and forecast annual net capital expenditures on customer connections, where 2012-2023 are actuals and 2024-2029 are forecasted:

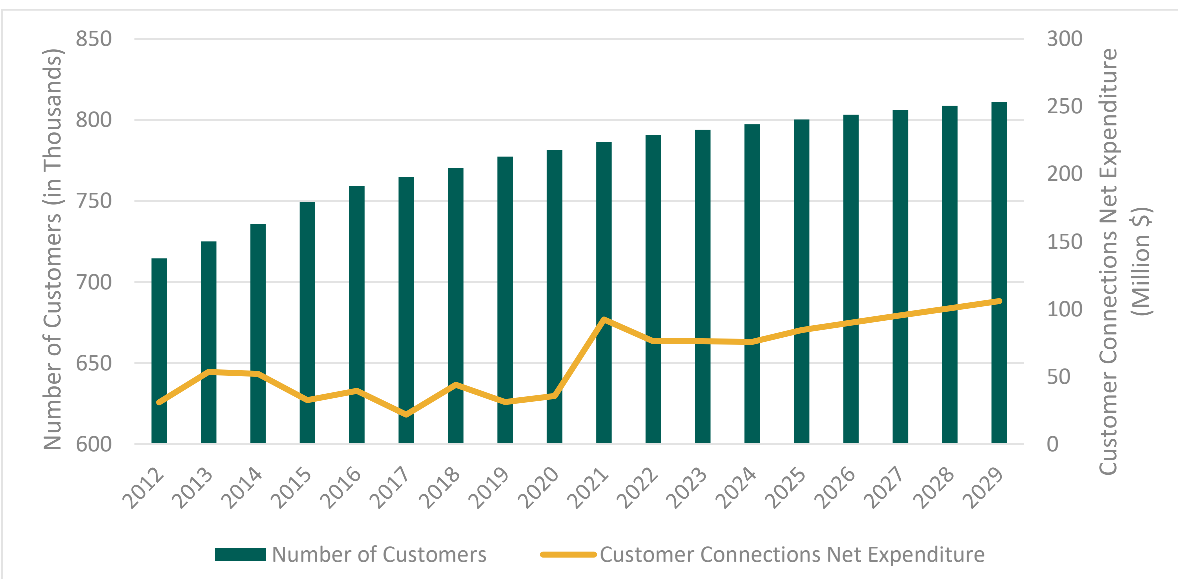


Figure 1: 2012-2029 Historical and Forecast Annual Net Customer Connections Expenditures

QUESTION (B):

b) Please provide the average growth rate for both customer count and connections spending for each of the following periods: 2012 - 2019, 2020 - 2024, 2025 - 2029.

RESPONSE (B):

The following table provides the average growth rates for Toronto Hydro's rate application periods for customer count and capital net expenditures.

Table 1: Average Growth Rates for Toronto Hydro's Rate Application Periods by Customer Count and Capital Net Expenditures

Rate Application Period	Average Customer Count Growth Rate for Period	Average Net Capital Expenditures for Customer Connections Growth Rate for Period
2012-2014	3.0%	68.1%
2015-2019	3.7%	-4.0%
2020-2024	2.0%	112.5%
2025-2029	1.4%	25.4%

QUESTION (C):

c) Please explain any discrepancies between the growth rates of connections spending and customer count.

RESPONSE (C):

Discrepancies between the observed growth rates between customer count and net capital expenditures is inherent to the data sets. It is difficult to make any meaningful comparative analysis between the two variables for reasons including:

- A single customer connection may represent a detached residence, a commercial or industrial facility, a hyperscale data centre, or a large multi-use development. Each of those will necessitate different types and levels investments to facilitate the connections. Please see Exhibit 2B, Section E5.1, page 5.

- The customer count may not fully reflect the number of customers served by Toronto Hydro. Toronto Hydro estimates that it serves approximately 340,000 end-use customers through bulk-metering and competitive sub-metering arrangements. As the sub-metering market has become more mature in Toronto over the last decade, a greater share of new multi-unit buildings opt for bulk-metering service connections. The practical effect of operating in this urban environment with a deregulated sub-metering market is a slower rate of formally reported customer growth from 2015 to 2029. Please see Exhibit 4, Tab 1, Schedule 1, pages 11-12.
- The geographical location of a customer can drive differences in required capital investments due to site location, available capacity, system constraints, design, system access configuration. Please see Exhibit 2B, Section E5.1, pages 7-10.
- Customers seeking upgraded connections would not be reflected in the customer count, despite those related costs being captured in the connection capital expenditures. Please see Exhibit 2B, Section E5.1, page 1.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-184

Reference: Exhibit 2B, Section E5.1.3.1, Page 8

<u>Preamble:</u>

With respect to Figure 3 High Voltage Connections 2020-2022

QUESTION (A):

a) Please update Figures 3, 4 and 6 to include the years 2023-2029. Please differentiate actual, estimated and forecast values.

RESPONSE (A):

The following are updates to Figures 3, 4 and 6 to include 2023 actuals. Toronto Hydro is unable to provide a forecast beyond 2023 for Figures 3, 4, and 6 as customer connections are typically based on size, required demand load, geographical location, and the available infrastructure.

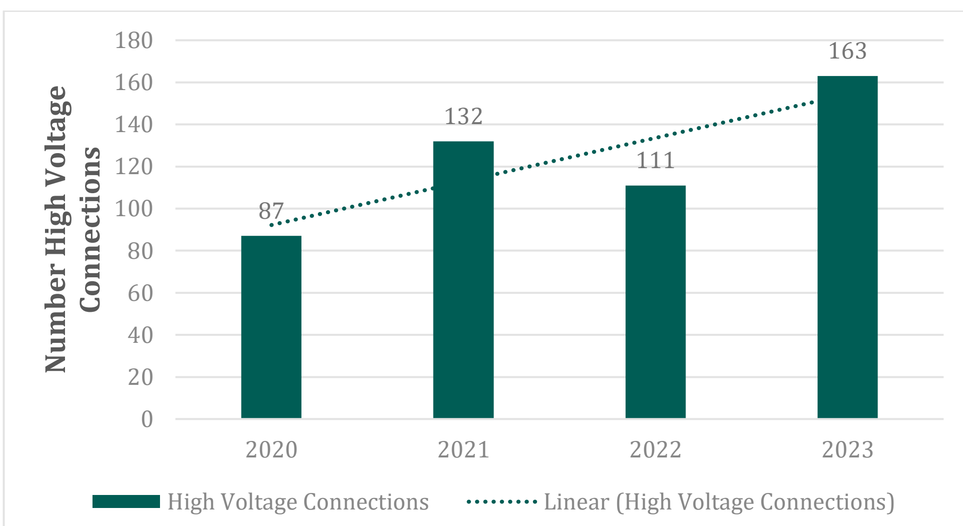


Figure 1: Updated Figure 3 - High Voltage Connections (2020-2023)

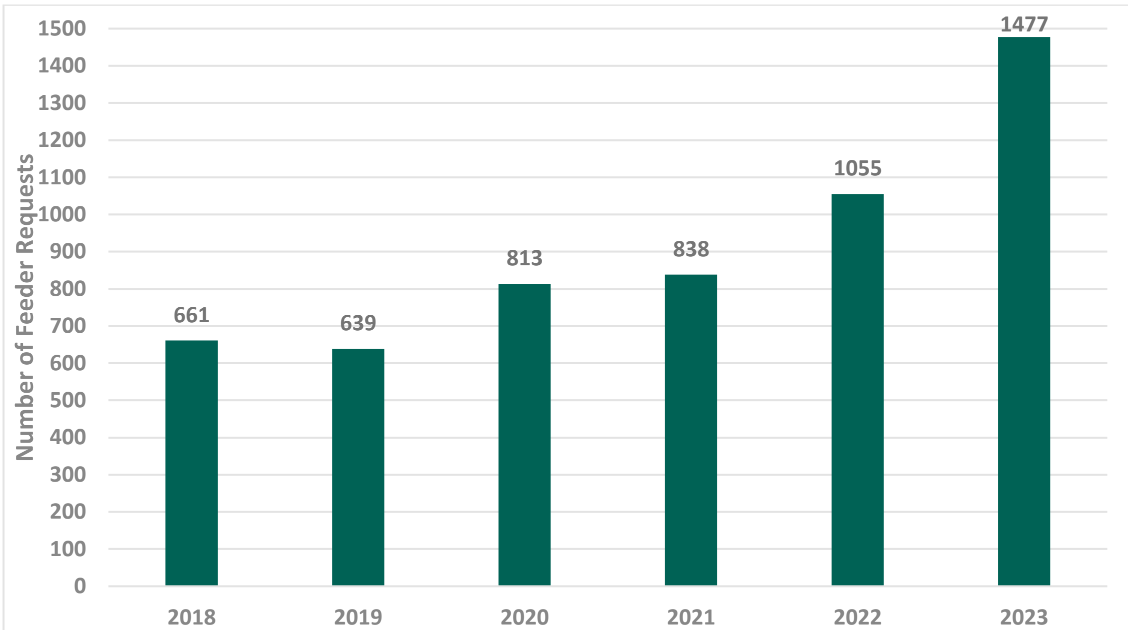


Figure 2: Updated Figure 4 - Feeder requests processed (2018-2023)

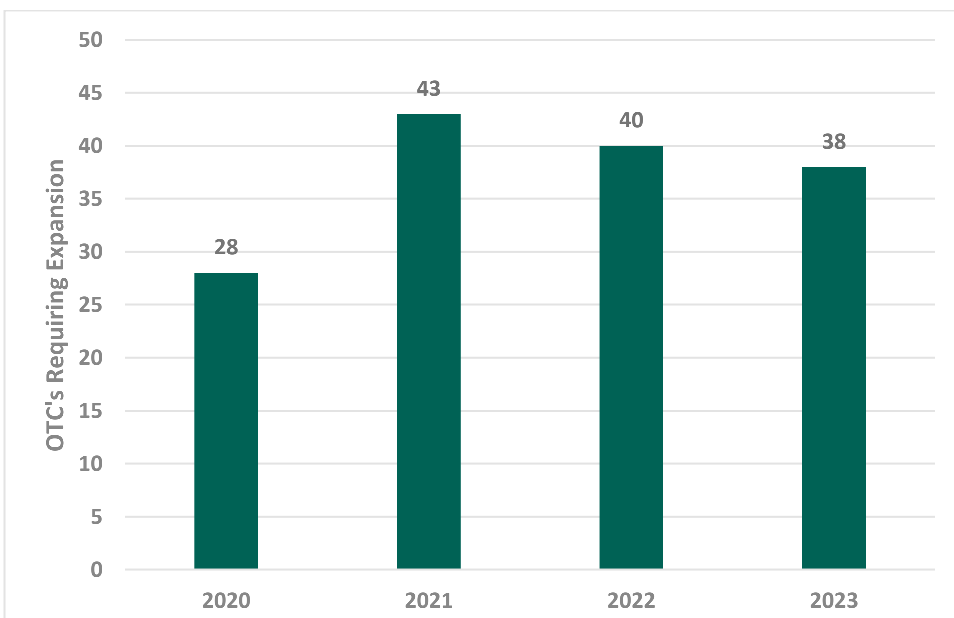


Figure 3: Updated Figure 6 - Offer to connect Requiring Expansion (2018-2023)

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-185

Reference: Exhibit 2B / Section E5.1.3.2 / p. 15

<u>Preamble:</u>

Toronto Hydro states: "Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system."

QUESTION(A):

a) Please explain how Toronto Hydro developed the additional renewable connections forecast and provide the confidence interval around the annual values given in Tables 6 and 7 (e.g.: +/- 5%, +10%/-25%, +/- 50%, etc.).

RESPONSE (A):

The renewable DER forecast is based on a model that uses historical data. It represents renewable DER intake in the years after the end of the Feed-In-Tariff (FIT) program. As renewable DERs and DER connections in general do not follow specific patterns and are primarily driven by customer demand, there is no confidence index associated with the analysis.

QUESTION (B):

b) The values shown in Tables 6 and 7 appear to be cumulative totals. Please provide tables showing the incremental annual additions for these same years.

RESPONSE (B):

Please see Table below.

Table 1: Annual Generation Connections (2023-2029)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	227	183	227	256	322	364	404
Energy Storage	16	3	6	5	8	7	9
Non-Renewable	16	2	2	2	2	2	2
TOTAL	**259**	**188**	**235**	**263**	**332**	**373**	**415**

QUESTION (C):

c) Please describe the representative generation technologies comprising the Renewable and Non-Renewable categories shown in these tables.

RESPONSE (C):

In terms of renewable generation, solar is the dominant generation type used on the data used for forecast. Other technologies used historically are biogas and wind. For non-renewable, CHP, diesel and natural gas generator technologies comprise the technologies used.

QUESTION (D):

d) What is the forecast Energy storage volume (in MWh) in each year?

RESPONSE (D):

Battery Energy Storage is forecasted on the basis of capacity, not energy storage volume.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-186

Reference: Exhibit 2B, Section E5.1.3.2, Page 15

Preamble:

Toronto Hydro states: "Toronto Hydro forecasts over 50 additional Energy Storage connections…to the distribution system. This would increase…the total installed Energy Storage capacity to 89.5MW."

QUESTION:

Does Toronto Hydro anticipate that the total volume of energy storage connected to its system by 2029 will materially assist in mitigating customer outage durations associated with events caused by freezing rain, windstorms or floods, i.e., similar to the events listed in the Extreme Weather and Major Event Day sections of this application (e.g. Exhibit 1B Section 2.3.4, Exhibit 2B Section C2.3)? Please explain.

RESPONSE:

No. The non-wires solutions proposed for the 2025-2029 period are outlined in detail in Exhibit 2B Section E7.2. Toronto Hydro intends to utilize DERs, including energy storage resources, as demand response in a manner that is practical and prudent given the current availability of DER capacity, and level of market maturity. At this time, Toronto Hydro is not utilizing customer-owned DERs to manage grid outages. The use of customer-owned DERs for this purpose would require specific connection arrangements and requires further study. Toronto Hydro will continue to explore such use cases and determine whether they are practical or prudent.

Toronto Hydro's ESS program targets the enablement of REG connections and does not contemplate additional use cases to support the distribution system. Please see Exhibit 2B Section 7.2.2 for more details.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-187

Reference: **Exhibit 2B, Section E5.1.4.2, Page 24**

Preamble:

Toronto Hydro states: “Toronto Hydro does not propose any net expenditure under this Program for the years 2025 to 2029. If during the course of the project, Toronto Hydro does not use all of the fees collected from the customer to facilitate the DER connection, Toronto Hydro will refund the difference back to the customer.”

QUESTIONS (A) AND (B):

a) Please identify all capital expenditures planned for 2025-2029 intended to enable the Toronto Hydro system to host new DERs connecting solely within the 2025-2029 test period.

b) Please identify all capital expenditures planned for 2025-2029 intended to enable the Toronto Hydro system to host new DERs connecting beyond the test period.

RESPONSES (A) AND (B):

Toronto Hydro intends to undertake investments in the following capital programs to enable the system to host DERs in the 2025-2029 period: (1) Generation Protection, Monitoring and Control (Exhibit 2B, Section E5.5); (2) Station Expansion – Sheppard TS (Section E7.4)[1]; and (3) Non-Wires Solutions (Section E7.2). Some of these expenditures may enable hosting capacity beyond the test period as well. In addition, Toronto Hydro is planning modernization and innovation investments to enhance the utility’s ability to monitor and forecast distributed resources and facilitate and leverage DER connections. These investments will have benefits in the 2025-2029 period and beyond. Please refer to the *Grid Readiness* section of Toronto Hydro’s Grid Modernization Strategy for more information (Exhibit 2B, Section D5.2.2).

[1] Updated January 29, 2024

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-188

Reference: Exhibit 2B, Section E5.2.4, Page 7

<u>Preamble:</u>

With respect to Table 1: Program Summary

QUESTION:

a) Toronto Hydro projects a $21.7M (40%) increase in net spending on this program, which appears to be largely driven by a $28.6M (9%) decrease in forecast Capital Contributions (i.e. a decreased in average contribution rate from 85% in the historic period to 79% in the forecast period). Please explain why Capital Contributions are expected to decrease and quantify the projects driving the bulk of the net spending increase.

RESPONSE:

The decrease in capital contributions is attributed to increased expansion work over the forecast period to meet anticipated future load growth. In particular, forecast expansion work associated with relocations under the *Building Transit Faster Act* contributes to approximately 70 percent of the proposed spending over the 2025-2029 period. Please refer to Exhibit 2B, Section E5.2.3.4, for more details on expansion work.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-189

Reference: Exhibit 2B / Section E5.3.2 / p. 2

Preamble:

With respect to the measures listed by Toronto Hydro for "Operational Effectiveness-Reliability" outcome.

QUESTION:

Although the preamble to the measures cell indicates that the Load Demand expenditures will contribute to Maintaining Toronto Hydro's System Capacity each of the four load demand measures indicate that the proposed investments are specifically intended to improve reliability. Please reconcile the apparent contradiction in corporate and program targets and quantify the proportion of spending in each element of this program that is intended to improve rather than maintain reliability.

RESPONSE:

Load Demand only invests in a small number of feeders relative to the overall feeder population, and while it improves reliability conditions on those few feeders, it is not enough on its own to overcome deterioration on other feeders over the period that cumulatively has a greater impact on overall system reliability.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-190

Reference: **Exhibit 2B / Section E5.3.3 / p. 3**

Preamble**:**

Toronto Hydro notes that "an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions.".

QUESTION(A):

a) Please explain which of these conditions typically rules and why.

RESPONSE (A):

Toronto Hydro stations are rated using N-1 operating conditions. While the limited time rating (LTR) capacity refers to an unusual configuration in N-1, it is not considered an emergency condition. Please refer to Toronto Hydro's response to interrogatory 2B-Staff-256 part (d).

QUESTION (B):

b) Since these are planning limitations, are they evaluated in N-1 conditions?
   i. If yes, please explain why utilizing 95 percent of firm capacity limitation while also imposing an N-1 contingency is not an overly conservative planning criterion?

RESPONSE (B):

The N-1 condition is employed for planning station capacity. Please refer to Toronto Hydro's response to interrogatory 2B-Staff-256 part (e) for details. Additionally, the 95 percent rule is intended to ensure that there is readily available capacity for connecting customers efficiently.

QUESTION (C):

c) Does Toronto Hydro evaluate bus constraints at non-coincident bus loading peak or coincident system peak for planning purposes?

RESPONSE (C):

Toronto Hydro evaluates bus constraint at non-coincident bus peak loads.

QUESTION (D):

d) Please quantify the average annual hours where a typical bus is loaded at 95% or greater of its peak loading.

RESPONSE (D):

As noted in its response to interrogatory 2B-Staff-256 part (c), Toronto Hydro is unable to provide a response as it does not have the requested information.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-191

Reference: **Exhibit 2B / Section E5.3.3.4 / p. 16**

Preamble:

Toronto Hydro states: "Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods. If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro's ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner."

QUESTION:

Toronto Hydro is projecting that it will change from a Summer Peaking to a Winter Peaking system. Please identify which of the proposed investments in become redundant after Toronto Hydro becomes a winter peaking utility or explain why if none of the investments will become redundant.

RESPONSE:

Based on the System Peak Demand Forecast in Exhibit 2B, Section D4, Toronto Hydro remains a summer peaking utility for this rate period, as explained in the response to 1B-Staff-153. In order to maintain service quality, Toronto Hydro must invest to manage restrictions during peak loads in both summer and winter months. Switching to a winter peak does not eliminate the summer peaks.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-192

Reference: Exhibit 2B, Section E5.3.3.4, Page 18

QUESTION (A):

a) Table 7: Summer Restrictions by year, indicates that by 2022, the number of summer feeder restrictions had dropped significantly from 2021. Table 2 indicates that Toronto Hydro plans to improve reliability by further reducing the number of feeder restrictions. Please reconcile this program target with the corporate goal of maintaining reliability.

RESPONSE (A):

The corporate goal of maintaining reliability is comprised of several components, which considers number of feeder restrictions as an input. Given that the program target only contributes to a portion of the corporate goal and due to the dynamic nature of Toronto Hydro's distribution system, the limit of the scale (i.e. level of spending) and geographic scope, a program-level goal of improving reliability is required to maintain overall system reliability.

The number of restricted feeders increases by 1 from 2021 to 2022, as indicated in Table 7 under Section E5.3.3.4. By reducing the overall number of restricted feeders and maintaining the total under 10, as specified in Section E5.3, reliability in the downtown area is expected to improve, which is one of the program measures listed in Table 2. Improving reliability at this granular level (i.e., at restricted feeders in the downtown area) will contribute to maintaining Toronto Hydro's overall reliability objectives given that there are contributing factors outside this program that also impact this objective.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-193

Reference: Exhibit 2B, Section E5.3.3.4, Page 19

Preamble:

Toronto Hydro states: "When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. Table summarizes the expected station upgrades within the 2025-2029 rate period that may require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure."

QUESTION:

Some of the spending in this program component appears to be intended to address existing deteriorated or obsolete civil structures, or else is driven by Renewal projects that will replace end of life substation equipment. Please explain why all such spending has not been categorized under System Renewal.

RESPONSE:

The spending in this program is not primarily to address deteriorated or obsolete civil structures, it is to alleviate emerging capacity constraints expected in Toronto Hydro's distribution system. While the civil enhancements planned as part of the program may rebuild deteriorated civil structures, it is not the primary driver behind the work. This work is driven by the capacity upgrades required in these areas. The switchgears identified in Table 8 in the Load Demand program (E5.3) are set to undergo an upgrade to increase their capacity. This means additional feeder positions and new feeders will be available and require sufficient civil infrastructure at the station egress to realize the additional capacity. Therefore, civil enhancements such as enhancing existing egress duct banks to increase the number of ducts, or building new duct structures is required to address the load growth needs of the system.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-194

References: Exhibit 2B, Section E5.4.5.1, Page 18

Preamble:

Toronto Hydro states that: "Toronto Hydro will not be able to capture the entire benefits of AMI 2.0 meters until the majority of the current meters are replaced."

Question (A):

a) In a table, please enumerate the benefits that the AMI 2.0 meters are providing and classify which of those benefits can or cannot be achieved until a majority of the current meters are replaced. In this table indicate the proportion of benefits achieved at 25%, 50%, 75% and 100% replacement penetrations.

RESPONSE (A):

Table 1: AMI 2.0 Benefits

AMI 2.0 Benefits	Can be Achieved Before Majority Replacement	AMI Replacement Penetration Level			
		~25%	~50%	~75%	~100%
		Proportion of Benefits Achieved			
Bi-Directional Metering	Yes	Medium	Medium	High	Full
Remote Connection/Disconnection	Yes	Medium	Medium	High	Full
Improved Bill Accuracy	No	None	None	Low	Full
Enhanced Outage Detection	No	None	None	Low	Full
Voltage Monitoring	No	None	None	Low	Full
System Planning and Load Forecasts	Partially	None	Low	Medium	Full
Improved Reliability and Power Quality	Partially	Low	Medium	High	Full
Data Analytics and Grid Modernization Enablement	No	None	None	Low	Full

AMI 2.0 Benefits	**Can be Achieved Before Majority Replacement**	**AMI Replacement Penetration Level**			
		~25%	**~50%**	**~75%**	**~100%**
		Proportion of Benefits Achieved			
Load Disaggregation and EV Detection	No	None	None	Low	Full
Customer Specific Technology Enablement	No	None	None	Low	Full

Proportion	**Explanation**
None	The benefit cannot be achieved at the specified penetration levels, due to a combination of lack of critical mass of penetration of meters or obsolete meters acting as a barrier.
Low	Minimal or very limited benefits achievable at the specified penetration levels, due to a combination of lack of critical mass of penetration of meters or obsolete meters acting as a barrier. Any benefits require a manual data extract and analysis and may have very limited benefits due to the amount of data flowing through.
Medium	Moderate benefits achievable at the specified penetration levels. Capabilities are limited by the penetration of meters and requires manual data extracts. This category represents a slightly improved benefit realization compared to low as some simple out of the box use cases can be operationalized.
High	Substantial benefits achievable at the specified penetration levels. Capabilities have increased as some geographical areas can utilize the full features of AMI 2.0 but processes remain manual as full penetration of AMI 2.0 meters is not realized.
Full	Benefit can be fully achieved at the specified penetration levels.

Notes: “Can be Achieved Before Majority Replacement" indicates whether a benefit can start being realized before the majority of meters are replaced.

For further detail on AMI 2.0 benefits as they pertain to modernizing the grid, please see Exhibit 2B, Section D5, subsection D5.3.1[1] and Section E5.4.[2]

[1] At p. 57-61.
[2] At p. 10-13.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-195

References: Exhibit 2B, Section E5.4.5.1, p. 19

Preamble:

Toronto Hydro states "Option 4 is selected based on the following criteria as summarized in Table 7."

QUESTION (A):

a) Has Toronto Hydro conducted a quantified risk assessment of each of the listed options?
   i. If yes, please provide documentation.
   ii. If no, please explain why not.

RESPONSE (A):

Toronto Hydro did not quantify the risks associated with the listed options since either the risk elements under consideration are not quantifiable, quantification would not materially improve the decision-making process, or the effort to quantify them would unreasonably delay benefits realization.

QUESTION (B):

b) What is the typical annual probability of failure of a meter that has reached age-derived EOL but whose seal has not yet expired?

RESPONSE (B):

For the annual probability of failure of a meter, please refer to page 5-177 of Concentric Advisors' 2022 Depreciation Study in Appendix D to Exhibit 2A, Tab 2, Schedule 1. The seal duration of the meter focuses on the accuracy of the metrology and is typically unrelated to other modes of meter failure or obsolescence.

QUESTION (C):

c) Does Measurement Canada allow re-sealing of meters that have a material likelihood of failing prior to the seal expiry? Please explain.

RESPONSE (C):

In Toronto Hydro's interpretation, Measurement Canada re-sealing requirements focus on meter accuracy, but do not include an evaluation of the likelihood of other meter failure modes, such as the failure of electronics, display, or communication components.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-196

REFERENCE: Exhibit 2B / Section E5.5.1 / p. 1

<u>Preamble:</u>

Toronto Hydro states "Installation of 315 monitoring and control systems ("MCS") for renewable DER facilities greater than 50 kW to provide situational awareness and control of DER facilities on the distribution system."

QUESTION:

Are DERs and Energy Storage projects responsible for the costs of providing adequate operational visibility to Toronto Hydro to enable safe operation of its system?

a. If not, please explain why not.

RESPONSE:

In accordance with section 3.3 of the Distribution System Code, non-renewable DERs and Energy Storage projects are responsible for the enhancements costs referenced. As a result, costs for these projects do not form part of the Generation Protection, Monitoring and Control (GPMC) program (Exhibit 2B Section E5.5).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-197

References: Exhibit 2B, Section E5.5.3.3, Page 10

<u>Preamble:</u>

Toronto Hydro states: "With the proliferation of DER in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of eleven distribution feeders have ratios ranging from 0.30 to 11.51 (refer to Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system."

QUESTION (A):

a) Does Toronto Hydro calculate the expected output of DERs at the time of minimum feeder loading, or does Toronto Hydro use nameplate DER rating in its feeder analysis?
    i. If yes, does this mean that solar DERs, which can be expected to have zero production at the time of minimum feeder loading (typically during nighttime light load hours), are being overcounted in Toronto Hydro's analysis? Please explain.

RESPONSE (A):

Toronto Hydro currently uses the nameplate DER system rating in its feeder analysis irrespective of time day intervals. The utility does not have control over when exactly the minimum feeder load condition will occur, and therefore to mitigate risk to the system, Toronto Hydro seeks to comply with the IEEE 1547 requirement for anti-islanding which states that aggregate DER capacity is to be less than one-third of the minimum load. This is further detailed in Exhibit 2B, Section E5.5, page 10. Modification of this approach will be considered as more tools are developed to interface with DER's in a dynamic operational environment.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-198

References: Exhibit 2B, Section DE6.1.1, Page 1, Table 1: Program Summary

QUESTION (A):

a) Rear Lot conversion spending is forecast to increase by $58.7M (95%) relative to historical. Considering that Toronto Hydro has been implementing this conversion program for some time, and presumably the most problematic segments have been addressed first, what has changed to drive this sudden doubling in planned program spending?

RESPONSE (A):

The Rear Lot segment for the 2025-2029 period has increased by 6 percent compared to what Toronto Hydro proposed in the 2020 CIR application for 2020-2024. This increase is driven by inflationary pressures and not pacing, which is consistent with the 2020-2024 proposal. The reduced pace relative to what was proposed for 2020-2024 (in accordance with the OEB's decision) has contributed to increased need for investment in rear lot areas, which continue to deteriorate with new areas starting to experience worsening reliability. Therefore, if anything, the proposed pace of investment over 2025-2029 is conservative and Toronto Hydro expects that, beyond 2029, it will need to maintain this pace or even increase it as these areas continue to age and deteriorate (see Figure 3 in Exhibit 2B, Section E6.1 at page 6).

QUESTION (B):

b) Do any of the feeders being improved via the Rear Lot program also appear on the worst performing feeder list?

    i. If yes, does Toronto Hydro intend to offset the proposed increase in Rear Lot spending by commensurately reducing spending on the Worst Performing Feeders program?

RESPONSE (B):

The Rear Lot program feeders don't overlap with feeders addressed by the Worst Performing Feeder program. While the Worst Performing Feeder target those with higher frequency of outages, the rear lot feeders are targeted based on the duration of the outages and the challenges they pose due to legacy equipment and safety concerns.

QUESTION (C):

c) Does Toronto Hydro anticipate that completion of the Rear Lot program will improve or maintain its overall reliability performance?

RESPONSE (C):

Rear Lot conversion is expected to eliminate tree contacts and reduce outage duration on those areas converted and therefore, improve reliability for customers in those areas, who tend to experience below-average reliability. The completion of the Rear Lot Conversion program will take decades and if viewed in the long-term (i.e., by comparing reliability in the 2020s versus 2050s post completion), may see some improvements that could be attributed to the conversions (and which may be offset by other factors). However, for 2025-2029, Toronto Hydro expects rear lot conversions to contribute to maintaining its overall reliability performance.

QUESTION (D):

d) Please provide the total contribution of Rear Lot outages to Toronto Hydro's SAIDI and SAIFI results for 2012-2022.

RESPONSE (D):

Rear Lot outages contributed to 4 percent to Toronto Hydro's SAIDI performance and 2 percent to SAIFI performance over 2012-2022.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-199

References: Exhibit 2B, Section E6.1.1, Page 10

Preamble:

Toronto Hydro states: “64 percent of the poles with available asset condition assessment information are showing moderate to material deterioration.”

QUESTION (A):

a) What is the expected annual failure probability for poles in HI3 and HI4 condition?

RESPONSE (A):

Toronto Hydro does not have probability of failure data specific to rear lot poles. Please see Toronto Hydro’s response to interrogatory 2B-Staff-151 part (c) for the general probability of failures for wood poles.

QUESTION (B):

b) What is the typical failure mode of Rear Lot Poles and what is the typical triggering event?

RESPONSE (B):

The failure modes for rear lot poles are largely identical to the general failure modes for wood poles, which are provided in Exhibit 2B, Section D2.2.1.2, Table 2. Rear lot poles are subject to the same typical condition-based failures, but due to the location of the poles, there is reduced risk from vehicle damage.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-200

References: Exhibit 2B, Section E6.1.3.1, Page 18

QUESTION (A):

a) What is the useful life of primary overhead conductors?

RESPONSE (A):

The useful life of primary overhead conductors is 60 years.

QUESTION (B):

b) What is the annual probability of failure per km of primary overhead conductor that is past its useful life?

RESPONSE (B):

Please see Figure 1 below.

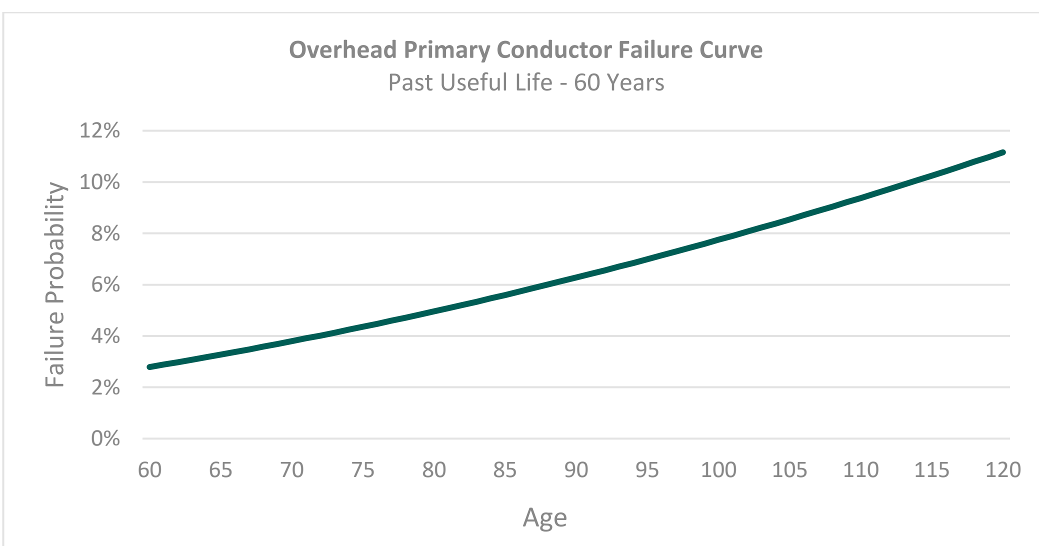


Figure 1: Overhead Primary Conductor Failure Curve (Past Useful Life)

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-201

Reference: Exhibit 2B, Section E6.1, Page 24

Preamble:

Toronto Hydro states that for the 2020-2024 period, "cost variance is driven by changes to the project schedule, including a number of projects that carried over from the 2015 - 2019 rate period."

QUESTION (A):

a) Does Toronto Hydro anticipate that any projects scheduled for completion in the 2020-2024 period will carry on to this test period. If yes, please provide a list of these projects, the expenditures that will occur in this test period, and the reason for the schedule change.

RESPONSE (A):

The Box Construction Conversion segment contains projects that involve work on a legacy system and the last projects to be completed in this segment are the most complex. There are a number of challenges that can impact the execution timelines of projects in this segment, including congestion and clearance issues for new asset installations, coordination issues with third parties (Ontario Line, Metrolinx, TTC, other developments, City of Toronto, Hydro One, etc.), coordination issues related to work zone, traffic, and pedestrian management. This can result in work being carried over from 2024 to the test period or work being advanced to take advantage of synergies with third parties. Please see Table 1 below for the list of projects along with the reasons and expenditures that are expected to be carried over from 2024 to the test period. Note that only the completion of "Danforth" has shifted from 2024 to the test period. The remaining projects listed in Table 1 only have a relatively small portion of total planned expenditures shifted into the test period from 2020-2024, and Toronto Hydro expects the overall projects will be completed in the 2025-2029 period as per the original plan.

Table 1: Box Construction Conversion Expenditure Carry-Over into 2025-2029 Period

Project	Expenditures Shifted into 2025-2029 ($M)	Reason for Schedule Change	Plan Construction Attainment
Danforth	2.54	Resource reprioritization	2025
Defoe-Strachan	0.34	Clearance, access and congestion issues	2026
Sherbourne	0.85	Clearance issues	2026
Highlevel	1.37	Supply chain and coordination issues	2029
University	3.04	Work zone coordination	2029

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-202

Reference: Exhibit 2B, Section E6.2.1, Pages 2, 15

Preamble:

Toronto Hydro states "As of 2022, there are 286 circuit-kilometers of direct-buried cable in dirt."

QUESTION (A):

a) What would be the expected impact on Toronto Hydro's SAIDI and SAIFI if the underground cable replacement program focused upon replacing the cables that are buried in dirt for the period 2025-29? In your answer, discuss Toronto Hydro's claim that XLPE cables installed in PVC ducts have expected service lives double those of XLPE cables directly buried in dirt.

RESPONSE (A):

In a hypothetical scenario where Toronto Hydro replaces only the remaining population of direct-buried cable in dirt (286 circuit-kilometers) during the 2025-2029 rate period, it anticipates that the cumulative impact on SAIFI and SAIDI for Defective Equipment interruptions would deteriorate by 6% and 5%, respectively, by the end of 2029, compared to Toronto Hydro's proposed 2025-2029 investment plan. This scenario does not replace any cables in PVC conduit or concrete-encased ducts. Due to the contiguous and integrated nature of Horseshoe distribution assets, this scenario is unrealistic. Toronto Hydro will inevitably need to replace some minimum amount of cable in PVC conduit and concrete-encased ducts as part of larger rebuild projects and in conjunction with other asset types. Furthermore, Toronto Hydro has included cables in PVC conduit and concrete-encased duct for replacement because these asset populations include aging cables at risk of failure, which should be addressed as part of a balanced underground renewal program.

Direct-buried cable in dirt has a useful life of 20 years, whereas cable in PVC conduit has a useful life of 50 years. The longer useful life for PVC Conduit is due to its enhanced protection against environmental conditions and mechanical stresses. For information on how Toronto Hydro determines its asset useful lives, please see response to 2B-Staff-131, part (a). Regardless of the different useful life values, failures can and do occur for cables in PVC conduit due to aging and a multitude of other factors, including insulation breakdown, moisture ingress, and overload.

QUESTION (B):

b) What is the annual expected failure rate per km for XLPE cables that are buried in dirt and for cables installed in PVC ducts?

RESPONSE (B):

Toronto Hydro estimates the historical failure rate (system interruptions per km) for direct-buried cable in dirt to be 0.11 and for cable in PVC conduit to be 0.12.

QUESTION (C):

c) What is causing the PVC ducts to become clogged with dirt?

RESPONSE (C):

PVC ducts can become clogged with dirt due to the following reasons:

- Some vintages of PVC ducts that have been installed in the past are of inferior quality and are prone to breakage
- Improper installation or ducts not being connected in a closed loop
- Unused ducts that are not properly sealed can experience dirt ingress; the dirt can be pushed further into the duct by ground water or local flooding events

QUESTION (D):

d) What mitigation alternatives are there to clear the dirt from these PVC ducts other than replacing the cables?

i. For the mitigation alternatives please provide comparative unit costing relative to cable replacement.

RESPONSE (D):

Toronto Hydro does not clear dirt from PVC ducts while the cable is in place. If the cable is functioning as required and there is a problem with the duct (clogged or damaged), Toronto Hydro will leave the cable until it needs to be replaced due to failure or a change in service, or until planned replacement can be carried out at the appropriate time. At the time a cable is being replaced, non-intrusive (plastic) mandrels are used to clear PVC ducts, provided there is space to fit a mandrel. Should the mandrel prove insufficient, alternative solutions, including installing new ducts or cleaning them out via power wash are considered.

Due to a drafting error, the explanation provided in Exhibit 2B, Section E6.2 incorrectly suggests that the issue of PVC ducts filling with dirt is a new or emerging issue driving incremental replacement. Toronto Hydro would like to clarify that this is not the case. The existing underground cable population in the Horseshoe consists of three predominant types, two of which (direct-buried cable in dirt and cable in PVC conduit) are legacy, obsolete standards. Cables in all three construction types (including concrete-encased ducts) experience failures and are addressed in different proportions by the planned investments in the Underground System Renewal – Horseshoe program. The utility expects that as the direct-buried cable population reduces through replacement, and cables in PVC conduit continue to age, cables in PVC conduit will become an increasing focus of the program.

QUESTION (E):

e) Please explain the scope of Toronto Hydro’s plans to “install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil or in PVC duct” throughout the horseshoe area. For example, is the concrete-encasement for road crossings only, or road crossings and industrial locations.

i. If the ducts are to be concrete encased in residential neighbourhoods, please provide the business case for the incremental costs and any examples of other jurisdictions that have similar construction standards.

RESPONSE (E):

Toronto Hydro's long-established policy for rebuilding underground areas is to install underground cable in concrete-encased duct up to the lot-line. The issue of concrete-encasement and alternatives was adjudicated by the Ontario Energy Board in Toronto Hydro's 2012-2014 Incremental Capital Module application (EB-2012-0064). As written in the Board's Partial Decision and Order (April 2, 2013):

> "While no party challenged THESL's assessment of the need to replace this cable, Energy Probe cross-examined THESL's witnesses extensively on possible alternatives to THESL's plan to replace this cable with concrete encased ducts. THESL's uncontradicted evidence was that the suggested alternatives were unsuitable in the situations encountered by THESL and that its approach was the most cost effective over the long term. Energy Probe argued that a reduction of $10 million should be made to reflect the fact that THESL's proposal for concrete encased duct banks is not justified from a reliability standpoint and that alternatives such as direct boring and flexible conduit or direct burying are acceptable alternatives and much more cost effective. THESL argued that Energy Probe's position should be rejected by the Board since initial installation cost is not the only cost and THESL's evidence had presented substantial information on the repair cost advantages for cable in concrete encased ducts which had been ignored by Energy Probe. THESL also stated that its evidence had clearly explained that concrete encased ducts offer the longest life and greatest reliability and facilitate future repair and replacement." (pg. 22-23)

> "The Board accepts THESL's evidence that the most effective way to replace the direct buried cable is with concrete encased ducts, and that the project is prudent and nondiscretionary. There was no credible evidence to support the alternatives or reductions

sought by the intervenors. Having found that the work is required and prudent, any reduction to the program is arbitrary and not supported by any evidence." (pg. 24)

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-203

Reference: Exhibit 2B, Section E6.2.1, Page 2

Preamble:

Toronto Hydro states "As of 2022, there are 286 circuit-kilometers of direct-buried cable in dirt."

QUESTION (A):

a) Please provide the historical actual and forecast all in per km costs for the periods 2020-2024, and 2025-2029 for the following activities:
   i. New XLPE underground cable in concrete duct.
   ii. Removal of existing XLPE underground cable in concrete duct with new XLPE.
   iii. New XLPE underground cable in PVC duct.
   iv. Removal of existing XLPE underground cable in PVC duct with new XLPE in concrete duct.
   v. New XLPE underground cable direct buried in dirt.
   vi. Removal of existing XLPE underground cable direct buried in direct with new XLPE in concrete duct.
   vii. Removal of existing PILC/AILC in duct and replacement with new XLPE.
   viii. Removal of existing PILC/AILC direct buried in dirt and replacement with new XLPE in concrete duct.

RESPONSE (A):

i. Table 1 shows actual historical unit costs for installing new primary cable in concrete encased ducts and concrete encased duct banks in the 2020-2023 period, and the forecast unit costs for new cable in concrete encased ducts.[1] Note that there are additional civil

[1] For primary cable installations in the Horseshoe region, Toronto Hydro uses TRXLPE cable.

costs not reflected in these units (e.g., cable chambers and splice boxes). Toronto Hydro does not develop long-term program forecasts for underground civil infrastructure on the basis of unit costs. This is because civil costs (and volumes) are highly dependent on the specific placement of ducts and associated restoration costs. Toronto Hydro estimates the civil portion of the underground program by applying a historical ratio of civil to electrical costs.

Table 1: Historical and Forecasted Costs for Primary Cable Installation

	Actual ($)				Forecast ($)					
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
New primary UG Cable in Concrete Encased PVC Duct (per m)	172	180	253	329	248	255	262	267	275	282
Install of duct bank (per m)	906	987	933	1,153	-	-	-	-	-	-

ii. Table 2 below shows the cost per m of removing existing primary cable in the Horseshoe from concrete encased ducts. The response in the first row ("New primary UG cable in concrete encased PVC duct (per m)" of part "a." provides costs of installing new cable in concrete encased duct.

Table 2: Cost per m to Remove Existing Primary Cable from Concrete Encased Ducts in Horseshoe

	Actual ($)				Forecast ($)					
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Removal of existing primary underground cable (excl. PILC) in concrete encased PVC duct (per m)	64	60	67	73	75	77	79	81	83	85

iii. Toronto Hydro does not install XLPE cable in direct buried PVC ducts (this is an obsolete legacy standard) and therefore does not have unit cost information. Please see response to 2B-Staff-202, part (e) for more information.

iv. Assuming the cable can be removed from the duct, removal costs are equivalent to those provided have been provided in (ii) and installation costs have been provided in (i) above. If the cable cannot be removed, it is retired in place.

v. Toronto Hydro does not install underground cable direct-buried in dirt.

vi. Toronto Hydro does not remove underground cable direct buried in dirt. Instead, the cable is retired in place. The cost for installing new cable has been provided in (i) above.

vii. Please see Table 3.

Table 3: Cost of Removal of Existing PILC and AILC in Duct

	Actual ($)				Forecast ($)					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Removal of existing PILC in duct and replacement with new TRXLPE[2] (per circuit m)	3880	1520	880	1030	1240	1500	1520	1540	1600	1630
Removal of existing AILC in duct and replacement with new XLPE (per circuit m)	N/A	520	220	300	250	570	590	610	650	670

[2] PILC and AILC are not part of the referenced Underground System Renewal – Horseshoe program. These unit costs include cable and all related civil infrastructure (ducts and cable chambers) and cannot be compared to the costs provided in response to parts (i) and (ii).

viii. The population of PILC/AILC direct-buried in dirt is exceeding small and Toronto Hydro has not performed this type of work in recent history. Therefore, the utility cannot provide any recorded unit cost.

QUESTION (B):

b) Please identify if there was no significant activity in any of the above categories.

RESPONSE (B):

The following categories of primary cable (and AILC) replacement/installation activities had no significant activity in 2020-2023:

i. New XLPE underground cable in PVC duct.

ii. New XLPE underground cable direct buried in dirt.

iii. Removal of existing PILC/AILC direct buried in dirt and replacement with new TRXLPE and XLPE in concrete duct.

QUESTION (C):

c) Please identify if there was significant activity in a category not listed above.

RESPONSE (C):

There are no additional categories of primary cable replacement/installation where significant activities were carried out.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-204

Reference: Exhibit 2B, Section E6.2.1, Page 2

Preamble:

Other distributors are undertaking extensive programs using cable injection remediation for earlier generation XLPE cables to mitigate water tree damage, as the per km costs are significantly lower than complete cable replacement.

QUESTION:

a) Has Toronto Hydro evaluated the costs and benefits of undertaking a cable injection program as an alternative to cable replacement?
   i) If yes, please provide benefit-cost analysis of the evaluation and explain why cable injection is not considered to be an economically viable solution to mitigate at least some of Toronto Hydro's underground XLPE cable deficiencies.
   ii. If no, please explain why not.

RESPONSE:

Toronto Hydro piloted cable injection in 2008 and found it to be unsuitable for use on its cable population. The 2008 pilot did not produce satisfactory results, with many cables failing within a year of injection. The utility reviewed updates to procedures for cable injection in 2015 and reconfirmed that cable injection was not compatible for Toronto Hydro's system. For cable injection to be effective, the conductors cannot be solid or strand-blocked (strand-filled), and connectors need to be "flow through" (not solid stop). This is generally not the case with Toronto Hydro's cable population.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-205

Reference: Exhibit 2B, Section E6.2.3, Page 8

QUESTION (A)

a) Please provide the ratio of Underground System Contribution to Overall System Customer Hours Interrupted for the 5-year period 2013-2017 vs. the 5-year period 2018-2022.

RESPONSE (A):

The normalized ratio is 31:30.[1]

QUESTION (B):

b) Please provide the ratio of Overall System Customer Hours Interrupted for the period 2013-2017 vs. the period 2018-2022.

RESPONSE (B):

The normalized ratio is 127:100.

QUESTION (C):

c) Please provide Toronto Hydro's total average customer count for the period 2013-2017 and the period 2018-2022

RESPONSE (C):

Toronto Hydro's total average customer count was 741,180 in the 2013-2017 period and 771,103 for the 2018-2022 period.

[1] Note that the statistics in all parts of this response are for the entire Toronto Hydro distribution system.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-206

Reference: **Exhibit 2B, Section E6.2.3.2, Page 18**

QUESTION (A):

a) Per Figure 14, 2022 appears to represent an outlier year versus the improving trend from 2017 to 2021. What occurred in 2022 to cause such a significant single year deterioration in performance?

   i. Did a large number of underground transformers suddenly deteriorate from acceptable to non-acceptable condition or were there other factors? Please explain.

RESPONSE (A):

Toronto Hydro disagrees with the characterization of 2022 as being a performance outlier. A review of the Figures 13-15, updated with 2023 results (see 2B-SEC-66), shows that this is not the case. In fact, a reasonable conclusion to draw from the 2013-2023 results is that 2021 performance was unusually good.

QUESTION (B):

b) Please plot the actual or estimated annual results for 2023 on Figure 14 and discuss the resulting trend implications.

RESPONSE (B):

Please see 2B-SEC-66 for an updated Figure 14 and 2B-Staff-207 for a discussion of the results.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-207

Reference: **Exhibit 2B, Section E6.2.3.2, Page 18**

QUESTION (A):

a) Per Figure 15, explain why despite there being more Customer Hours Interrupted in 2022 than in 2021, the 2022 results are significantly better than the results for the period 2013-2019.

RESPONSE (A):

2021 was an exceptionally good year for the number of outages caused by defective underground transformers and the impact of those outages on customers. Please see response to 2B-SEC-66, where the updated Figures 13-15 show a trend of performance deterioration between 2021 and 2023, with 2023 being the worst year for Customers Interrupted (CI) since the peak of 2017.

QUESTION (B):

b) Do the 2022 results indicate that Toronto Hydro maintained or improved the reliability performance of its Underground Transformer portfolio?

RESPONSE (B):

Due to the inherent volatility of annual reliability metrics, it is generally best to examine performance over longer time horizons and by leveraging rolling, multi-year averages. The following table compares the five-year averages for CIs and CHIs for underground transformers.

Table 1: 2013-2017 Avg. vs 2018-2022 Avg. CIs and CHIs for Underground Transformers

Measure	2013-2017 Avg.	2018-2022 Avg.
Customer Interruptions (‘000s)	23	24
Customer Hours Interrupted (‘000s)	22	13

The table shows that customer interruption performance has remained consistent, and customer hours interrupted have improved. This improvement may be partially due to Toronto Hydro's targeted and accelerated replacement of submersible transformers in poor condition during 2017-2018, aimed at addressing frequent oil leaks that had been observed in the population. However, identifying the exact factors behind this trend remains difficult due to the inherently unpredictable nature of reliability performance.

As discussed in part (a), 2023 results show a deteriorating trend in performance over the 2021-2023 period.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-208

Reference: Exhibit 2B, Section E6.2.3.2, Page 19

QUESTION (A):

a) Please provide the tabular data for Figure 16.

RESPONSE (A):

Please see Table 1 below.

Table 1: Number of Externally-Reported Oil Spills on Underground Transformers (padmount, submersible, and vault transformers)[1]

Year	Number of Spills*
2013	2
2014	24
2015	41
2016	65
2017	66
2018	135
2019	204
2020	133
2021	40
2022	26

QUESTION (B):

[1] Data from 2013 to 2017 may include +/- 1-2 spill(s) variance, annually

b) Please update Figure 16 to show data from 2013-2022 and include a trend line for externally reported oil spills from 2013-2022.

RESPONSE (B):

Please see Figure below. There was an error in the caption Figure 16 which has now been corrected to include number of spills on padmount, submersible and vault transformers across the entire system.

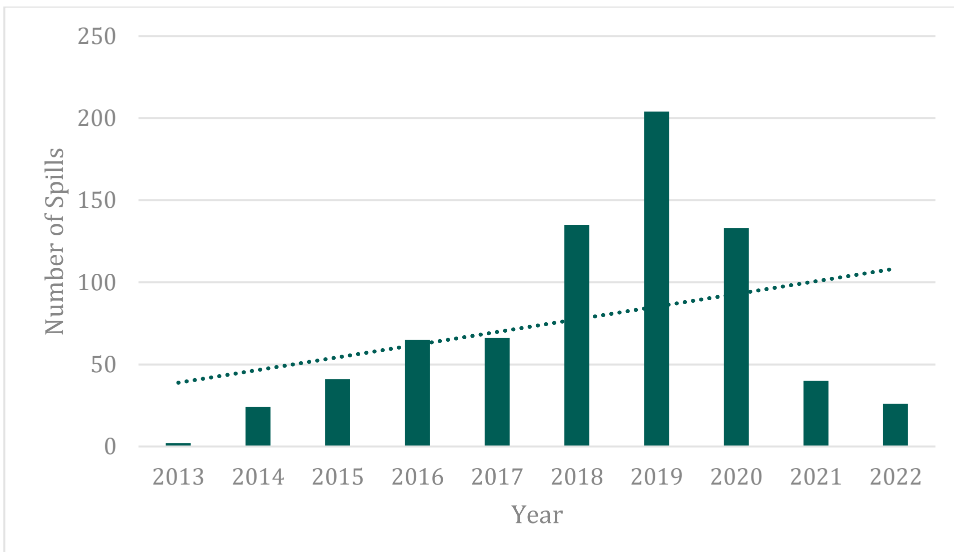


Figure 1: Number of Externally-Reported Oil Spills on Underground Transformers (padmount, submersible, and vault transformers) (Updated Figure 16)

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-209

References: Exhibit 2B, Section E6.2.3. 2, p. 21

Preamble:

Toronto Hydro states: "As of 2022, 26 percent of underground transformers in the Horseshoe area (i.e. 6,727 units) were at or beyond useful life (i.e. 30 years for padmount, submersible, and vault transformers)."

QUESTION (A):

a) Please explain how Toronto Hydro determined that the useful life for padmount, submersible and vault transformers should be set at 30 years, given that in 2022 6,727 of these transformers had been in service for more than 30 years, and in some cases significantly more than 30 years. In your response consider the information shown in Table 5 indicating that just 79 units out of the entire fleet of 25,209 units were assessed as being in HI5 - End of Serviceable Life condition in 2022, despite 6,727 of the units age-categorized as being beyond useful life.

RESPONSE (A):

The useful life of 30 years was adopted based on a review of the Depreciation Study completed by Concentric Inc., filed in Exhibit 2A, Tab 2, Schedule 1, Appendix D. Please see response to 2B-Staff-131, part (a), for a discussion regarding Toronto Hydro's useful lives and the extent to which they play a role in investment planning decisions. Please also see the response to 2B-SEC-44 for a comprehensive discussion regarding expected changes in asset demographics over the 2025-2029 period with investment.

Regarding Table 5 in Exhibit 2B, Section E6.2, the relatively small number of transformers in the worst condition band (HI5) as of 2022 is a positive indication as to the effectiveness of Toronto

Hydro's prioritization of the worst condition assets in investment planning. The fact that there were approximately 640 transformers in HI4 and HI5 condition in 2022 while over 6,500 units were operating beyond useful life underscores the benefits of having a robust condition model, which allows Toronto Hydro to focus more narrowly on replacing assets and rebuilding areas of the system that are most in need of investment.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-210

Reference: Exhibit 2B, Section E6.2.3.3, Pages 25-26

a) What occurred in 2021 to create the outlier results shown in Figures 22, 23 and 24?

RESPONSE:

Year-to-year variations in reliability for a given asset class are subject to a certain level of randomness, both in terms of frequency and impact of outages. There was a total of 23 outages that occurred in 2021 due to defective padmount switches. This is seven outages higher than the five-year average from 2016-2020 and three outages more than the worst year in that time period (i.e., 20 outages in 2016).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-211

Reference: Exhibit 2B, Section E6.2.4, Page 29

QUESTION (A):

a) Toronto Hydro plans to increase Horseshoe Underground System Renewal spending by $115.9M (32%) in 2025-2029 relative to 2020-2024. Please explain the spending increase in the context of Toronto Hydro's stated corporate goal of maintaining reliability performance and the improving reliability performance outcomes achieved for these assets at historical expenditure levels.

RESPONSE (A):

Exhibit 2B, Section E6.2 provides detailed analysis on the drivers and key assumptions behind the level of proposed expenditures in the Underground System Renewal – Horseshoe program. Toronto Hydro has proposed the minimum expenditures necessary to maintain reliability on this part of the system during the 2025-2029 period. The proposed investments are reflected in the SAIDI and SAIFI forecasts presented in Exhibit 1B, Tab 3, Schedule 1.

The reliability improvement trend that persisted between 2015-2019 was the result of significant capital investment in the replacement of direct-buried cable and associated assets beginning in the previous "ICM" period (circa. 2013), including an investment level of $115.5 million achieved in the year 2015. The pace of investment in this program dropped to around $70 million per year in 2018 and 2019. While the link between investments in one year and reliability performance in the next is clouded by the unpredictability of asset failure rates, Toronto Hydro notes that the previously positive reliability trend became a negative trend beginning in 2020. As further discussed in Section E6.2: "Through prioritized neighbourhood rebuild projects focused on replacement of high-risk direct-buried cross-linked polyethylene ("XLPE") cables, Toronto Hydro previously had success reducing the number of customer interruptions due to cable failure, from over 200,000 per year in

2013 to approximately 105,000 in 2019. However, more recently Toronto Hydro shifted focus away from rebuild projects addressing direct-buried cables in order to address the urgent environmental risk associated with PCBs. As a result, customer interruptions (and other reliability indicators) have started trending back up, reaching 199,000 in 2022."

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-212

Reference: **Exhibit 2B, Section E6.2, Page 30**

Preamble:

Table 8 provided by Toronto Hydro on Underground Circuit Renewal Horseshoe Program.

QUESTION (A):

a) In the last test period for the asset classes indicated in Table 8 what were the placeholder planning unit costs to determine program estimates and what were the actual unit costs incurred at program completion.

RESPONSE (A):

The following table shows the base unit costs that were assumed for estimating the 2020-2024 Distribution System Plan ("DSP"). Note that these unit costs do not include indirect engineering and administration costs, nor do they include the inflationary assumptions that were applied in the DSP. Both of these elements were layered on to the total estimated program cost as a final step.

Table 1: 2020-2024 Planning Assumptions

Asset Class	Planning Unit Cost				
	2020	2021	2022	2023	2024
UG Cable (per m)	$241	$241	$241	$241	$241
UG Transformers	$22,767	$22,767	$22,767	$22,767	$22,767
UG Switches	$87,333	$87,333	$87,333	$87,333	$87,333

The following table shows the actual unit costs. These unit costs are derived from in-service additions data and are therefore fully burdened.

Table 2: 2020-2023 Actual Costs

Asset Class	Actual Unit Cost			
	2020	**2021**	**2022**	**2023**
UG Cable (per m)	$172.4	$180.2	$253	$328.5
UG Transformers	$25,738	$40,002	$27,035	$37,806
UG Switches	$136,113	$147,194	$124,029	$144,211

The primary driver of cost increases across all asset classes during this period was price inflation. This is reflected in the commodity costs from the period, during which copper prices increased 88%, aluminum prices 142%, and steel 232%. Fluctuations in unit costs can also be attributed to annual variations in the mix of asset types being replaced (e.g., padmount vs. vault transformers; aluminum vs. copper conductors).

QUESTION (B) AND (C):

b) What percentage of the planned costs for this program for the period 2020-2022 were spent by the end of 2022?

c) What percentage of the planned costs for this program for the period 2020-2024 are forecast to be spent by the end of 2024?

RESPONSE (B) AND (C):

Toronto Hydro adjusts its plans on an annual basis as part of the Investment Planning & Portfolio Reporting process. For the Underground System Renewal – Horseshoe program, the 2020-2022 planning cycles resulted in an updated plan of $359.8 million for the 2020-2024 period (as show in Exhibit 2B, Section E6.2). As of the end of 2022, $188.8 million had been invested, equivalent to 52% of the updated plan. Toronto Hydro's latest reforecast, based on 2023 actuals (see response to 2B-Staff-104), is for a total of $363.1 million by the end of 2024, equivalent to 101% of the updated plan in Exhibit 2B, Section E6.2.

Compared to Toronto Hydro's original 2020-2024 DSP forecast of $460.3 million, the updated outlook of $363.1 million is a 21% reduction in spending. The reasons for constraining expenditures in the 2020-2024 period are summarized in Exhibit 2B, Section E4.1 and further discussed in Section E2.2.1.1 and Section E6.2.4.1.

QUESTION (D) AND (E):

d) What percentage of the program scope that was planned to be completed for the period 2020-2022 was completed?

  i. If less than 100%, what actions has Toronto Hydro taken to improve its execution effectiveness?

e) What percentage of the program scope that was planned to be completed for the period 2020-2024 is forecast to be completed by end of 2024?

RESPONSE (D) AND (E):

As discussed in response to part (b), Toronto Hydro adjusts its plans on an annual basis as part of the Investment Planning & Portfolio Reporting process. The following table corresponds to the expenditure figures provided in part (b). Specifically, column A corresponds to the $359.8 million forecast for 2020-2024 from Exhibit 2B, Section E6.2, while column D corresponds to the latest $363.1 million outlook for the program. (The figures in this table reflect corrections made 2B-SEC-66.)

	A	B	C	D	E
Asset Class	**2020-2024 Planned**	**2020-2022 Actual**	**2020-2022 % Completion**	**2020-2024 Forecast**	**2020-2024 % Completion**
Total Cable (in circuit km)	196	129	66%	184	94%
Transformers	1,941	792	41%	1,999	103%
Switches	231	127	55%	144	62%

Toronto Hydro has also provided a comparison of the latest 2020-2024 outlook for volumes of work to the original 2020-2024 DSP forecast volumes (corresponding to the original $460.3 million expenditure plan) in response to 2B-PWU-3, part (a). To the extent that volumes of work for certain asset classes have been reduced by an amount greater than the 21% reduction in expenditures, this can be attributed to a few major drivers: (1) volume and cost variances that occur as projects move from high-level estimates through detailed design and construction; (2) changes in the mix of assets addressed due to evolving program needs and constraints; and (3) significant inflationary pressures and supply-chain issues in the 2020-2023 period.

Toronto Hydro is committed to continuous improvement in its execution practices. Please refer to 2B-SEC-37 and 2B-AMPCO-29 for more information on Toronto Hydro's work program execution processes and the management of project variances.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-213

References: **Exhibit 2B, Section E6.3, Page 20**
Scorecard - Toronto Hydro-Electric System Limited, 2020
Scorecard - Toronto Hydro-Electric System Limited, 2021
Scorecard - Toronto Hydro-Electric System Limited, 2022

QUESTION (A) – (C):

a) Figure 15: Number of Lid Incidents in reference 1 shows that there were 9 lid incidents in 2020. Page 5 of the 2020 Scorecard MD&A states that of the 24 serious electrical incidents, "four involved lid ejections as a result of underground cable failures". Please reconcile the inconsistencies between these reports.

b) Figure 15: Number of Lid Incidents in reference 1 shows that there were 3 lid incidents in 2021. Page 5 of the 2021 Scorecard MD&A states that of the 22 serious electrical incidents, "four involved lid ejections due to underground cable failures". Please reconcile the inconsistencies between these reports.

c) Figure 15: Number of Lid Incidents in reference 1 shows that there were 5 lid incidents in 2022. Page 5 of the 2022 Scorecard MD&A states that of the 29 serious electrical incidents, "one (1) involved lid ejections due to underground cable failure". Please reconcile the inconsistencies between these reports.

RESPONSE (A) – (C):

Toronto Hydro notes that there is a one-year lag in reporting of serious electrical incidents ("SEI") in the scorecards, for example the 2022 Scorecard MD&A reports on incidents occurring in 2021 incidents not 2022.[1] Table 1 below compares the Scorecard MDMA lid ejection incidents with those reported in Figure 15 of Exhibit 2B, Section E6.3, considering this lag.

[1] The Scorecard relies on Electrical Safety Authority reporting for the SEI metric, which has on a one-year lag.

Table 1: Annual Comparison of Cable Chamber Lid Ejections

	Number of Lid Ejection Incidents	
	Scorecard MDMA	Figure 15
2019	4	4
2020	4	9
2021	1	3

The discrepancy noted in the table above is a result of the utilization of a predominantly manual process for reporting and recording data, which unfortunately led to unintentional omissions of certain incidents in the utility's reporting. During the data preparation phase for the application, Toronto Hydro took proactive measures to meticulously compile the numbers of lid ejections within the system, capturing some incidents which were inadvertently overlooked in ESA reporting.

In response to this oversight, Toronto Hydro has taken steps to enhance reporting procedures, provide comprehensive training to our staff, and bolster communication channels with the ESA. These measures have been implemented to mitigate the likelihood of similar discrepancies occurring in the future.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-214

References: **EB-2018-0165, Exhibit 2B, Section E6.3, Page 18**
Exhibit 2B, Section E6.3, Page 19

Preamble:

In reference 1, Toronto Hydro's 2020-2024 DSP, Toronto Hydro stated it planned to replace 252 cable chamber lids by the end of 2019 and 200 per year going forward.

In reference 2 Toronto Hydro states it has replaced 470 cable chamber lids since 2020, and plans to replace another 2,800 lids over 2025-2029, and that the increased pace is required to address the risk.

QUESTION (A):

a) Please confirm how many cable chamber lids Toronto Hydro replaced per year in the period 2020 through the end of 2023, and the cost per year.

RESPONSE (A):

Please see Table 1 below for cable chamber lid replacements and costs per year.[1]

Table 1: Cable Chamber Lid Replacements and Costs 2020-2023

	2020	2021	2022	2023
Lid Replacements	105	162	192	852
Cost ($M)	1.2	1.8	2.8	14.3

[1] Toronto Hydro notes that it incorrectly stated that it had replaced 470 lids on page 18 of Exhibit 2B, Section E6.3. The correct number is 459 as shown on pages 39 and 40 (Table 9) in Exhibit 2B, Section E6.3 and as shown in Table 1.

QUESTION (B):

b) How many chamber lids does Toronto Hydro forecast replacing in 2024?

RESPONSE (B):

Toronto Hydro forecasts replacing 180 cable chamber lids in 2024.

QUESTION (C):

c) If the total number of lids replaced from 2020 through 2024 is less than 1,000 (i.e. 5 x 200) please explain the reason for the reduction in scope to this program.

RESPONSE (C):

Toronto Hydro forecasts replacing more than 1,000 (1,491) cable chamber lids between 2020 and 2024. As shown in Exhibit 2B Section E6.3 Figure 15, in 2020, there was an increase in the number of lid ejections and, as a result, Toronto Hydro increased the pace of replacement of cable chamber lids between 2020 and 2024.

QUESTION (D):

d) After the 2024 program is complete, how many cable chamber lids remain that require replacement to mitigate the ejection risk?

RESPONSE (D):

The total number of chambers in the system is 10,500 and with the expected completion of 1,491 units by the end of 2024, Toronto Hydro forecasts that there will be 8,794 cable chamber lids remaining after 2024 and all of these require replacement to mitigate the lid ejection risk. Toronto Hydro has planned for an achievable pace of 2,800 cable chamber lids over the 2025-2029 period, prioritizing locations by relative risk.

QUESTION (E):

e) Have there been any injuries to workers or members of the public since 2020 due to the manhole lid ejection issue?

RESPONSE (E):

Toronto Hydro is not aware of any injuries to workers or members of the public since 2020 due to the manhole lid ejection incidents.

QUESTION (F):

f) Does the replacement of the cable chamber lids involve replacing the frame and cover, or replacing only the cover?

RESPONSE (F):

The replacement of cable chamber lids includes both the frame and the cover.

QUESTION (G):

g) Are the new cable chamber lids installed in new and rebuilt locations, or is another method used to mitigate the risk, such as arc proof tape?

RESPONSE (G):

Toronto Hydro installs new cable chamber lids on new and rebuilt cable chamber locations. Concurrently, Toronto Hydro has a cable testing program, which can help to identify potential issues with cables that may lead to cable chamber lid ejections.-Currently, no alternative methods are employed. While arc proof tapes are typically utilized to safeguard cables from heat and flames resulting from nearby failures, their practical application within Toronto Hydro’s system is limited due to the congestion in the cable chambers, where secondary distribution networks coexist with primary cables and other assets like communications equipment and street lighting.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-215

References: Exhibit 2B, Section E6.3.3.2, Page 16
Exhibit 2B, Section E6.4.3.2, Page 8

QUESTION:

a) For both of these programs (cable chamber renewal and network vault renewal) please confirm that all associated costs driven by replacement of the deteriorated civil works (e.g., electrical equipment replacements and/or cable replacements) are included in the civil works program spending.
   i. If not confirmed, please quantify the equipment and cable replacement costs primarily driven by civil remediations.
   ii. If not confirmed, please identify where the associated equipment and cable replacement costs are found in this application.

RESPONSE:

Confirmed. Toronto Hydro includes all associated costs driven by the planned replacement of the deteriorated civil works in the Cable Chamber Renewal and Network Vault Renewal segment spending.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-216

References: Exhibit 2B, Section E6.3.1, Page 2

Preamble:

Toronto Hydro states: "Replacement of legacy PILC and AILC cables will allow Toronto Hydro to maintain reliability performance by proactive replacement of high risk cables. This will also decrease the presence of designated substances (i.e. lead and asbestos) on the grid."

QUESTION (A):

a) Please describe and quantify the "designated substances" risks associated with leaving PILC and AILC cables in use vs. removing these cables.

RESPONSE (A):

PILC and AILC pose relatively low health risk to workers when left in the system undisturbed. However, any disturbance to the cable system due to cable faults, customer connection or planned renewal work would expose workers (e.g., via inhalation/ingestion) to the health hazards associated with designated substances such as lead or asbestos.

Proactive removal of these cables would decrease the overall frequency of exposure to these designated substances when working on or around them in the underground system. Eliminating the hazard (i.e., the designated substances) through removal of the cables is a more effective control to protect the health and safety of the workers as opposed to relying on less reliable administrative controls or personal protective equipment (e.g., respirators) to mitigate the exposure.

QUESTION (B):

b) How does Toronto hydro dispose of these cables following removal?

RESPONSE (B):

Toronto Hydro safely handles and disposes of asbestos and lead as prescribed in the *Ontario Occupational Health and Safety Act* (Reg. 8338), R.S.O. 1990 and the *Canadian Environmental Protection Act*, 1999.

Following the removal of lead or asbestos waste, smaller sections are wrapped up and sealed in plastic bags or sheeting and transported to designated bins. Cables removed on reels will have damaged or exposed ends of cables capped or tapped to prevent the release of the designated substance. Waste is removed from Toronto Hydro facilities by an appropriately licensed waste hauler vendor.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-217

Reference: Exhibit 2B, Section E6.3.3.3, Page 22

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

Toronto Hydro states "Defective equipment was the largest contributor to annual customer reliability representing about 70 percent and 80 percent of Customers Interrupted (CI) and Customers Hours Interrupted (CHI), respectively."

QUESTION (A):

a) The trend shown in Figure 18 indicates that defective equipment failures trended down significantly from 2018 to 2022, and failures from other causes trended up significantly. Please discuss the reasons for these apparent performance trends.

RESPONSE (A):

The Underground Residential Distribution system ("URD") serves a small portion of Toronto Hydro's distribution system, therefore the year over year reliability measures are substantially affected by individual outage incidents. URD equipment failures from 2018-2022 have generally dropped. Prior to 2020, Toronto Hydro managed these assets reactively and introduced as part of its 2020-2024 rate application a proactive renewal plan to address deteriorating URD assets.[1] Since 2020, these investments have resulted in improved reliability of the URD assets, and therefore, the apparent relative increase in interruptions is due to all other causes. The majority of these interruptions are generally beyond Toronto Hydro's control. As such, no concrete trends or conclusions related to the other causes of reliability performance should be inferred.

[1] EB-2018-0165, Exhibit 2B, Section E6.3.

QUESTION (B):

b) How many customers are supplied by this system?

RESPONSE (B):

Approximately 14,900 customers were supplied by the URD system as of February 2024.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-218

Reference: **Exhibit 2B, Section E6.3.3.3, Page 22**

Preamble:

Many Ontario distributors, as well as utilities in other Provinces, utilize a run-to-fail asset management strategy for pole-top transformers, to maximize the value extracted by customers from these assets, since they are relatively low-cost, quick to replace and economical warehoused in a range of standard sizes. Furthermore, because they have long service lives and can be replaced quickly upon failure, the net reliability impact of unit failure upon the customers connected to it is minimal over the longer term. Each unit failure interrupts customers for at most a few hours over a multiple decade reliable service life.

QUESTION (A):

a) Please provide a Benefit Cost Analysis supporting Toronto Hydro's decision to follow a proactive lifecycle management strategy for pole-top transformers.

RESPONSE (A):

Please see Table 2 on page 18 of Exhibit 2B, Section D3 which speaks to the approach for replacing pole top transformers.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-219

Reference: Exhibit 2B, Section E6.5.3.1. pages 7-8

<u>Preamble:</u>

Figure 1 indicates that less than a quarter of overhead system outages are caused by defective equipment, yet Toronto Hydro is accelerating its overhead system renewal expenditures by $139.5M (64%).

QUESTION (A):

a) Please explain why Toronto Hydro is increasing spending by 64% above historical levels to address a situation that is only responsible for 24% of historic overhead system outages.

RESPONSE (A):

The increase in this program does not represent an "acceleration" of investments.

The proposed Overhead System Renewal budget for the 2025-2029 period is higher than the 2020-2024 expenditures due primarily to the following reasons:

- the addition of the Overhead Infrastructure Resiliency segment ($85.9 million), which is a reintroduction and expansion of the work done through the Overhead Infrastructure Relocation program in Toronto Hydro's 2015-2019 Distribution System Plan;
- the deferral of work in the Overhead System Renewal segment from the 2020-2024 period into the 2025-2029 period, which was done to manage pressures across the broader capital expenditure plan; and
- inflationary increases.

Note that the proposed expenditure for the Overhead System Renewal segment (i.e. excluding the Overhead Infrastructure Resiliency segment) for the 2025-2029 period is $272.8 million. This is aligned with the original plan of $265.7 million in the 2020-2024 DSP (and would in fact represent a reduction in spending after accounting for inflation).

QUESTION (B):

b) Please discuss what Toronto Hydro is doing to address the other 75% of outages and relevant costs.

RESPONSE (B):

While the Overhead System Renewal program is aimed at reducing the failure risk of overhead equipment, these investments may contribute to other reliability improvements, such as:

- A reduction of tree-contact outages by replacing bare conductors with tree-proof conductors or relocating existing pole lines away from high vegetation areas,
- A reduction of foreign interference outages by relocating poles lines in high traffic areas,
- A reduction of unknown outages caused by tree contacts, animal contacts and incorrect fuse protection settings by replacing existing overhead assets with new assets that meet current standards.

Toronto Hydro also manages overhead reliability performance through the Area Conversions (Section E6.1), Reactive and Corrective Capital (Section E6.7), System Enhancements (Section E7.1), Preventative and Predictive Maintenance (Exhibit 4, Tab 2, Schedule 1) and Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4) programs.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-220

Reference: Exhibit 2B, Section E6.5.3.1, p. 10

Preamble:

Toronto Hydro states: "Through the Overhead System Renewal segment, Toronto Hydro replaces overhead transformers beyond useful life, which are at risk of failing and potentially posing an environmental risk due to oil leaks that may contain PCBs"

QUESTION (A):

a) What percentage of the transformers planned for replacement in 2025-2029 are suspected to contain PCBs.

RESPONSE (A):

With respect to the population of assets relevant to the referenced Overhead System Renewal program: Toronto Hydro expects to have an estimated remaining population of 618 overhead transformers at risk of containing PCBs as of the beginning of 2025. This number represents 13% of the overhead transformers planned for replacement in the 2025-2029 period. Note that this figure could increase or decrease slightly depending on 2024 work program execution and other updates (e.g., field inspections).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-221

References: Exhibit 2B, Section E6.5.3.1, pp. 11-12
Exhibit 2B, Section E6.5.1, p. 1

QUESTION (A):

a) Please reconcile the results shown in Figures 6, 7 and 8 with the statement made on lines 17-20 of Reference 2 that:

"Toronto Hydro has reduced the number of transformer related customers interrupted and customer hours interrupted from over 10,000 customers interrupted and 6,000 customer hours interrupted and per year on average to 4,133 customers and 4,360 customer-hours interrupted per year on average over the last five years (2018-2022)."

RESPONSE (A):

On average, Toronto Hydro saw over 10,000 customers interrupted and over 6,000 customer hours interrupted per year due to pole top transformers between 2013 and 2017. By contrast, on average, Toronto Hydro saw 4,133 customers interrupted and 4,360 customer-hours interrupted per year due to pole top transformers between 2018 and 2022.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-222

Reference: Exhibit 2B, Section E6.5.3.1, Page 12

QUESTION (A):

a) What drove the outlier results in 2022 shown in Figures 7: Customers Interrupted ("CI") for Pole-top Transformers and Figure 8: Customers Hours Interrupted ("CHI") for Pole-top Transformers?

RESPONSE (A):

There was one outage that contributed to an abnormal number of customers (CI) and a different outage that contributed to abnormal number of customer hours interrupted (CHI). Below are the details on each of those outages:

- F-2022-1213 on 34M2 (LEASIDE TS) with a CI of 3,177 (41.6% of 2022 CI)
- F-2022-978 on XJF2 (ELLESMERE MS) with a CHI of 3,340 (38.9% of 2022 CHI)

QUESTION (B):

b) Please update Figures 7 and 8 to show results from 2013-2022.

RESPONSE (B):

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-69.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-223

Reference: Exhibit 2B, Section E6.5.3.1, Page 14

a) Please explain why failures due to External Factors, Other and Unknown appear to significantly diminish for transformers older than 35 years relative to transformers that are younger than 35 years as indicated in Figure 11: Age and Cause Distribution for Failed Overhead Transformers 2018-2022.

RESPONSE:

Equipment failures result from a mix of cumulative (long-term) degradation factors and immediate degradation factors. Premature failures are typically linked to direct causes, while assets failing due to cumulative impacts over their lifespan are often considered end-of-life failures. For instance, a five-year-old transformer that starts leaking oil is attributed to a supplier quality paint issue. On the other hand, similar issues with a 40-year-old transformer would not likely be attributed to a supplier quality problem. Instead, such a failure would likely be categorized as an end-of-life failure, resulting from the cumulative impacts of environmental conditions or the natural degradation of the tank enclosure.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-224

Reference: Exhibit 2B, Section E6.5.3.1, Page 17

Preamble:

Toronto Hydro states: “Figure 15 illustrates that, despite ongoing renewal, approximately 287 poles on average had to be replaced reactively per year between 2019 and 2022.”

QUESTION (A):

a) What are the primary failure modes of wood poles that require reactive replacement, and what are the most common triggering events?

RESPONSE (A):

Primary failure modes of wood poles are explained in Exhibit 4, Tab 2, Schedule 1 at pages 13-14 and Exhibit 2B, Section D2.2.1.2: Overhead Assets Failure Characteristics.

In summary, rot and decay are the most common and primary reasons for condemning a pole for replacement as they can weaken the mechanical strength and structure of the pole, which is the primary indicator of its health and remaining life. Ground rot at the base of the pole in particular is the worst location for rot to be in as the base is the most vulnerable to environmental degradation. Signs of mechanical damage such as holes or cracks and insect infestation, which can compromise the structure are another trigger for replacement.

QUESTION (B):

b) On average, how many poles per year does Toronto Hydro replace (or retire) under all of its capital and operating programs and projects; for example, road moves and widenings, reactive capital (storms, vehicle accidents, treefalls), Back Lot program, Box Frame program, voltage upgrades, underground conversions, and overhead system renewal?

RESPONSE (B):

On average, Toronto Hydro replaces approximately 4,100 poles per year under of all its programs.

QUESTION (C):

c) What is the ratio of poles replaced under the overhead renewal program to the poles replaced or retired under all other programs and projects?

RESPONSE (C):

The average ratio of poles replaced under the overhead renewal program to the poles replaced or retired under all other programs is approximately 35 percent. This number increases to 45 percent if the poles replaced under the externally driven programs are excluded, which is another significant contributor of pole replacements but is not driven by failure risk.

QUESTION (D):

d) Does Toronto Hydro consider all the pole replacements or retirements it is doing under these other programs or projects when evaluating the need to replace poles under the overhead system renewal program?

RESPONSE (D):

Yes, Toronto Hydro considers pole replacements under other programs when evaluating need under the Overhead System Renewal program. Please refer to 2B-SEC-44 for a discussion regarding expectations for wood pole replacements and demographic changes in the 2025-2029 period.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-225

Reference: Exhibit 2B, Section E6.5.4.1, page. 35

a) Does Toronto Hydro typically replace overhead conductors due to the condition of the conductors, or only when it is replacing a line segment for other reasons?

RESPONSE:

As a result of overhead line patrols, which are conducted every three years, and infrared scans of overhead primary lines, which are conducted annually, Toronto Hydro may determine that it is necessary to reactively replace defective or failed overhead conductors exhibiting deficiencies such as fraying or bird caging, excessive sag or low clearances, or the presence of thermal anomalies. In addition, Toronto Hydro will replace conductors as part of rebuilds and voltage conversion projects. Please refer to Section D3.1.2 of Exhibit 2B for more information regarding asset replacement practices.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-226

References: **Exhibit 2B, Section E6.5, Page 35**
Exhibit 2B, Section D3, Appendix A, Pages 4 and 6
Exhibit 2B, Section D3, Appendix B, Page 8

Preamble:

Over the planning period Toronto Hydro plans to replace 8,337 poles over 4 years which yields an average annual replacement rate of 2,084 poles per year. The condition assessment tables indicate that the number of wood poles in Hi4 and Hi5 will increase by 9,459 in 2022 and 32,158 in 2029. If Toronto Hydro was to maintain Hi4 and Hi5 at 2022 levels 22,699 poles would need to replaced between 2022 and 2029, yielding an annual replace rate of 3,242 poles per year.

QUESTION (A):

a) Toronto Hydro owns approximately 183,620 poles and approximately 107,000 wood poles were evaluated for asset condition between 2018-2022. Please explain why approximately 76,620 poles were not evaluated for condition assessment.

RESPONSE (A):

The total count of 183,620 poles mentioned in Exhibit 2B – Section A encompasses both streetlighting and distribution poles within the system. Among these, distribution poles consist of approximately 107,000 wood poles, 30,000 concrete poles, and 3,600 steel poles. Toronto Hydro's Asset Condition Assessment methodology specifically focuses on distribution wood poles as they are subject to a dedicated pole inspection program enabling the calculation of condition-based Health Scores. The condition of the remaining poles (concrete and steel) has not been assessed due to the lack of both a regular inspection program and an ACA methodology. Once inspections of these poles commence, ACA methodology and condition-based Health Scores will be established.

Please refer to Exhibit 4, Tab 2, Schedule 1, Segment 5 for details regarding overhead line patrols and pole inspections.

QUESTION (B):

b) Comparing the planned annual average replacement for wood poles of 2,084 per year to a condition replacement rate of 3,242, a shortfall of 1,158 assets appears to exist. Please explain how Toronto Hydro is achieving asset demographics, for example are there Hi4 and Hi5 pole replacements occurring in other spending categories that close the observed shortfall.

    i. Do the wood pole health indices for 2029 overstate the projected decay in wood pole asset condition, given that Toronto Hydro's consultant has indicated a potential miscalculation of wood pole useful life.

RESPONSE (B):

To clarify, the Overhead System Renewal program plans to replace 8,337 poles over five years, which is an annual replacement of 1,667 poles per year from 2025-2029. If no investment or pole replacement were done from 2022 till 2029, 32,158 poles are expected to reach HI4 and HI5 condition in 2029. Please see response to 2B-SEC-44 for a comprehensive overview of expected changes in asset demographics over the 2025-2029 period with investment, including a discussion regarding the utility's decision to restrain the pace of pole replacements.

i. In Toronto Hydro's experience, wood poles have proven to be a uniquely challenging asset to track and model from an ACA perspective. This is due primarily to the fact that inspections occur only once every 10 years, meaning that the model is in many cases relying on data that is upwards of nine years old. This, in Toronto Hydro's view, is the most significant factor in the comparatively high rate of deterioration seen in the Future Health Score model outputs (since the model is having to age the assets over a longer period of time, amplifying its effects). As discussed in Ex.2B, Section D3, App A, Toronto Hydro's assessment of the wood pole ACA model since its implementation in 2017 has led to reasonable adjustments that better align model outputs with observed reality. Toronto Hydro aims to further mitigate this issue through its proposed reduction of inspection to an 8-year cycle and by introducing targeted wood pole inspections based on the asset condition assessment (see 2B-PWU-10).

Regarding the Normal Expected Life for assets, please refer to 2B-Staff-146.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-227

References: **Exhibit 2B, Section E6.5, Page 35**
Exhibit 2B, Section D3, Appendix A, Pages 4, 6

QUESTION (A):

a) Please update the following 3 tables to show pole top transformers.
   i. Table 3: Summary of Health Index Distribution as of year end 2017
   ii. Table 4: Summary of Health Index Distribution as of year end 2022
   iii. Table 5: Summary of Health Index Distribution as of year end 2029

RESPONSE (A):

Due to the lack of a feasible and cost-effective method for collecting sufficiently detailed condition information in the field, there is no health score calculation methodology for pole top transformers.

QUESTION (B):

b) Provide an estimation of the pole top transformer asset condition assessment that are solely or primarily based on age.

RESPONSE (B):

Please see response to part (a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-228

Reference: Exhibit 2B, Section E6.6, Pages 1-3

Preamble:

Toronto Hydro states that: "Toronto Hydro plans to invest $282.7 million in the Stations Renewal Program in 2025-2029, which is a $107.3 million or 61 percent increase over the projected 2020-2024 spending in the Program." From the previous application the projected station renewal program was $141.6M rather than $175.4M that is forecast above in the current application.

Source: EB-2018-01652B -DSP Section E6.6 Stations Renewal pp. 1-2	**Source: EB-2023-0195 2B-E6.6 Section E6.6 Stations Renewal pp. 1-2**
Transformer Stations 5 TS Switchgear 9 TS Outdoor Breakers 61 TS Outdoor switches **$74.5M**	**Transformer Stations** 3 TS Switchgear Complete four TS from the 2020-2024 period. 12 TS Outdoor Breakers 63 TS Outdoor Switches Refurbish one station building in preparation for switchgear replacements required over the 2030-2034 period. **$134M**
Municipal Stations 12 MS Switchgear 10 Power Transformers 10 Primary Disconnect Switches 1 MS Primary Breaker **$37.7M**	**Municipal Stations** 12 MS Switchgear 15 Power Transformers 1 MS Primary Supply **$70.3M**
Control and Monitoring 6 new RTU Renew 39 RTUs Upgrade Protections a 5 Pilot-Wire Locations Replace 45km Cu Control Cable **$22.1M**	**Control and Monitoring** 33 RTU Renew 251 Obsolete Relays **$64.7M**
Battery and Ancillary Systems 3 Sump Pumps 67 Battery and Charger Systems 6 Station Service Transformers 2 Air Compressors **$7.3M**	**Battery and Ancillary Systems** 55 Batteries 8 Charger Systems 3 Station Service Tx 5 Station AC Service Panels 3 Sump Pumps **$13.6M**
Plans to invest $141.6M	**Plans to invest $282.7M**

QUESTIONS (A) – (D):

a) Please reconcile the discrepancy between $141.6M detailed in the station renewals in the 2020-2024 period from the previous application and the $175.4M detailed in the 2025-2029 application.

b) For each grouping in the table above for the period of 2020-2024 provide the planned scope of work, and what scope was completed. The scope descriptions should include a count of the items planned and completed.

c) For each grouping in the table above for the period of 2020-2024 provide the planned expenditures and actual expenditure.

d) Please explain the basis for the forecasts for the scope of work for 2025-2029.

   i. Please provide the detailed estimates.

RESPONSES (A) – (D):

Please refer to the expenditure plan in Exhibit 2B, Section E6.6.4 for a detailed variance analysis of 2020-2024 capital expenditures and the 2025-2029 forecast.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-229

Reference: Exhibit 2B, Section E6.6.3.1, Page 13

<u>Preamble:</u>

Toronto Hydro states: "The failure risk of KSO circuit breakers is high and the impact of failure is significant."

QUESTION (A):

a) Figure 9 indicates that all KSO breakers are in asset condition HI2 or HI3. What is the annual probability of failure of breakers in each of these categories?

RESPONSE (A):

KSO circuit breakers represent approximately 1 percent of all circuit breakers and are actively being removed from the system. Therefore, the sample size is too small to generate a representative probability of failure.

QUESTION (B):

b) Risk is the product of probability x consequence. Is the consequence of failure of these breakers so high that even with a low failure probability they represent an unacceptable risk to Toronto Hydro? Please quantify and discuss any associated risk analysis that has been undertaken.

RESPONSE (B):

As described in Exhibit 2B, Section E6.6.3.1.2, KSO breakers supply large amounts of load therefore when they fail they have the potential to disrupt thousands of customers. Replacing these assets requires long lead times and maintaining the system in contingency while these replacements are being completed can pose significant risks due to the added load on the surrounding parts of the system.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-230

References: Exhibit 2B, Section E6.6.3.2, Page 18

Preamble:

Toronto Hydro states: "Toronto Hydro's MS supply power to Toronto's suburban areas consist largely of residential and a few small general service customers (<1 MW). Major MS assets include switchgear, power transformers, and MS primary supplies composed of disconnect switches and power cable. A large portion of these assets are operating well beyond their useful life and are consequently at a heightened risk of failure."

QUESTION (A):

a) When Toronto Hydro states throughout this application that assets operating beyond their useful lives are at a heightened risk of failure, does Toronto Hydro actually mean that such assets exhibit a heightened probability of failure?

RESPONSE (A):

Toronto Hydro confirms that it expects assets operating beyond their useful life to have a higher probability of failure (on average, and before considering observed condition) than assets that are not as old. Toronto Hydro would like to further clarify that, in general, when it refers to assets operating beyond their useful lives as being a concern, this is meant to communicate the observation that there is a certain population of assets that are operating at an age where probability of failure is expected to increase at an accelerating rate, and that this population warrants consideration in asset management planning. Toronto Hydro <u>does not</u> replace assets simply because they have crossed the "useful life" threshold, and in fact runs many thousands of assets well beyond useful life.

QUESTION (B):

b) Where ACAs are not solely based on age, confirm that probability of failure should be determined based on the assessed ACA rather than asset age, since some older assets may be in good condition, and some relatively new assets may be in unsatisfactory condition.

   i. If not confirmed, why not?

RESPONSE (B):

Toronto Hydro confirms that for asset classes where condition information is available, the probability of failure should be assessed based on condition, where feasible (i.e., failure data exists).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-231

Reference: Exhibit 2B, Section E6.6.3.2, Page 21

Preamble:

Toronto Hydro states: "The useful life of a power transformer is 45 years."

QUESTION (A):

a) Would the same useful life apply to a transformer in a winter peaking system?

RESPONSE (A):

Toronto Hydro has not specifically assessed the impact of summer vs. winter peak on the useful life of transformers. Based on the System Peak Demand Forecast in Exhibit 2B, Section D4 (updated January 29, 2024), Toronto Hydro remains a summer peaking utility for this rate period.

QUESTION (B):

b) Toronto Hydro forecasts that it will become a winter peaking system. Should it be modifying the planning criteria it applies to make station asset investment decisions, since most station asset types will have higher capacity ratings in winter peak ambient temperature conditions than they will in summer peak ambient temperature conditions.

RESPONSE (B):

As noted in the response to part (a), Toronto Hydro remains a summer peaking utility for this rate period. The planning criteria used assesses the maximum ratio of load to transformer capacity, and considers all seasons. If and when Toronto Hydro's system evolves to a winter-peaking system, this criteria will not be affected.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-232

Reference: Exhibit 2B / Section E6.6.3.2 / p. 22

<u>Preamble:</u>

Toronto Hydro states: "Toronto Hydro has revised its target maximum age for its power transformers down from 70 to 65 years, in alignment with previous rate applications."

a) Please explain why this revised target maximum age remains appropriate since Toronto Hydro is becoming a winter peaking utility.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-Staff-231 part (a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-233

Reference: **Exhibit 2B / Section E6.6.3.2 / p. 23**

Preamble:

Regarding Table11: Power Transformers Proposed for Replacement

QUESTION (A):

a) Please confirm Dunsany MS Power Transformer 2408, Centennial MS Power Transformer 2412 are all scheduled for replacement solely due to age and not because of additional concerns.

    i. If not confirmed, please explain why not.

RESPONSE (A):

Power transformers replacements are not prioritized solely based on age. As described in Exhibit 2B, Section E6.6.4.2, Table 42 at page 56, Toronto Hydro considers the impact of failure, such as customer count, loading, degradation of oil, resiliency of operation, and voltage conversion plan in addition to age when prioritizing the replacement these assets. On average, the average Municipal Station ("MS") supplies approximately 500 customers. However, Centennial MS and Dunsany MS supply around 700 and 750 customers, respectively which represent 39 and 49 percent more than the average number of customers. As such, they are assigned a higher priority for replacement.

QUESTION (B):

b) Explain why Belfield MS Power Transformer 2504 is scheduled for replacement in 2029 at an age of 60 years despite exhibiting no concerns other than age, even though it will still be 5 years younger than Toronto Hydro's reduced maximum target age of 65 for Power Transformers in 2029.

RESPONSE (B):

Belfield Municipal Station consists of two Power Transformers (TR1 2503 and TR2 2504). As shown in Table 42 in Exhibit 2B, Section E6.6.4.2 at page 56, the need to replace Belfield MS Power Transformer 2504 is not solely based on age but due to the combination of age with the following:

- TR1 2503 will be 69 years old at the time of the project and has a high-power factor;
- A loading analysis of the area identified the need for only one power transformer, therefore resulting in the removal of TR2 2504 and replacement of TR1 2503;
- The primary supply to the MS also requires replacement due to the high risk of failure of direct buried ingress; and
- Belfield MS Switchgear is planned to be replaced in 2029. Coordination of the replacement in conjunction with the aforementioned work is a cost-effective alternative.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-234

Reference: Exhibit 2B, Section E6.6.3.3, Page 29

Preamble:

Toronto Hydro is planning to increase its Stations Control and Monitoring Renewal spending by $36.6M (130%).

QUESTION (A) AND (B):

a) What is the annual probability of failure of any of the existing electromechanical relays?
b) Are electromechanical relay failures trending up significantly?
   i. If yes, please provide documentation showing the increasing failure trends.

RESPONSE (A) AND (B):

Protection relay systems have built in redundancies that allow back-up systems to operate in the event of a single relay failure; and are inspected as part of a robust maintenance cycle. As such, Toronto Hydro does not track individual relay failures and is unable to provide their probability of failure or an indication whether electrotechnical relay failures are trending up

QUESTION (C):

c) Is adherence to Toronto Hydro's Grid Modernization Roadmap a major driver of the significantly increased planned spending on relay replacements relative to the historical period? Please discuss.

RESPONSE (C):

Confirmed. Toronto Hydro's planned investments in relays over the 2025-2029 period are driven by a combination of system observability, equipment obsolescence and improved fault location and protection equipment coordination. Modernizing old electromechanical relays to digital relays have other benefits for the system that reduces maintenance costs, improves reliability, and enhances grid observability. For more detail, please refer to Control and Monitoring drivers at Exhibit 2B, Section E6.6.3.3 and Grid Modernization Section D5.1.

QUESTION (D):

d) What percentage of the electromechanical relays targeted for replacement operate obsolete or poor condition breakers or switchgear?

RESPONSE (D):

As the monitoring and control work is carried out on a programmatic basis, Toronto Hydro cannot readily identify which relays are specifically linked to obsolete and poor condition breakers and switchgear outside of specific assets identified in project scopes and details.

To clarify, Toronto Hydro replaces electromechanical relays either through targeted renewal or as part of a switchgear/breaker replacement.[1] As described in response to part (c), the proposed investments are driven by station modernization to enhance system and station observability and improve fault location. The latter is done in conjunction with switchgear and breaker replacement. Toronto Hydro notes that the 2025-2029 relay investments proposed in the Monitoring and Control segment do not overlap with planned switchgear and breaker replacements.

[1] Please refer to Exhibit 2B, Section E6.6.4.3 Table 50 at page 68

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-235

Reference: Exhibit 2B, Section E6.6.3.3, Page 30

QUESTION:

a) Is the use of “(Without Investment)” in the header cells in Tables 14 and 15 a typo?
   i. If no, how is the number of obsolete/past useful life assets being reduced in all instances by 2029 without investment?

RESPONSE:

No. Tables 14 and 15 demonstrate the deterioration of the assets over the 2025-2029 period should Toronto Hydro not intervene. These assets are targeted through switchgear renewal investments and MS Conversions as proposed in Exhibit 2B, Section E6.6.3.3, Page 33, Line 8.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-236

References: **Exhibit 2B, Section E6.7, page. 13**

Exhibit 2B, Section E5.4, pages. 16-17

Preamble:

Toronto Hydro states that the Reactive Meter Replacement costs for 2025-2029 were "derived based on a four-year weighted average of historical costs. The average percentage of meters failing remains the same but the population is increasing yearly".

QUESTION:

Please explain why Toronto Hydro used historic performance of aged meters and did not consider the impact of replacing meters in the AMI 2.0 program when projecting meter failures in the 2024-2029 period.

RESPONSE:

Toronto Hydro used the historical failure rate of meters to forecast reactive meter replacement volumes and costs for the 2025-2029 rate period since the failure rates of newer meter models and communication infrastructure that the utility will install as part of the AMI 2.0 initiative are currently unknown.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-237

Reference: Exhibit 2B, Section E7.4, Pages 30-32

Preamble:

OEB Staff have created the following table which summarizes actual and forecast costs for 2020-2024 from the variance explanation in the reference 1.

Reactive Hydro One Contribution and True-Up Costs	2020-2024 $ million
Copeland TS Phase 1 True-Up	9.9
Switchyard Expansion Bermondsey and Richview TS	8.5
New Cable Carlaw TS to Gerrard TS	2.4
Additional Unforeseen	1.9
Reactive Total	**22.7**

QUESTION (A):

a) Table 18 in reference 1 shows a 2020-2024 Actual/Forecast Costs of $24.9M for Reactive Hydro One Contribution and True-Up Costs. Please reconcile the difference between this value and the value compiled in the table above.

RESPONSE (A):

Table 1 below expands upon the table provided in the preamble, and shows the complete costs adding to $24.9 million for Reactive Hydro One Contribution and True-Up Costs.

Table 1: Complete Actual and Forecast Costs Reactive Hydro One Contribution and True-Up Costs over 2020-2024 ($ Millions)

Reactive Hydro One Contribution and True-Up Costs	2020-2024
Copeland TS Phase 1 True-Up	9.9
Switchyard Expansion Bermondsey and Richview TS	8.5

Reactive Hydro One Contribution and True-Up Costs	2020-2024
New Cable Carlaw TS to Gerrard TS	2.4
Additional Unforeseen	1.9
Renewal and Customer Connection Projects (To be reversed)	1.2
Long-Lead Item Procurement	1.0
Reactive Total	**24.9**

The difference between the $22.7 million shown in the preamble, versus the $24.9 million reported in Exhibit 2B, Section E7.4 at page 27[1] is due to an additional: $1.0 million advanced payment incurred in 2022 for long-lead item procurement, and an additional $1.2 million for renewal and customer connection projects for which costs will be recovered from the customer.

QUESTION (B):

b) For each of the projects in Table 19: Hydro One Contributions 2020-2024 Variances, and the projects that make up the Reactive Contributions and True-Ups:

  i. Please categorize the costs as construction costs or load true-up.
  ii. Please provide the agreements between Toronto Hydro and Hydro One.
  iii. Please provide any invoices and calculations from Hydro One (i.e. output of the Hydro One DCF model).
  iv. For those costs not yet invoiced by Hydro One, please provide the cost estimate and calculations from Hydro One (i.e. output of the Hydro One DCF model). In the absence of documentation from Hydro One, please provide Toronto Hydro's detailed DCF calculations for the true-up payment.
  v. In cases where Toronto Hydro was, or may be, required to make a payment during 2020-2024 due to reduced or unrealized load, please explain why the load forecast at the time of the agreement with Hydro One was not realized. (For example, the $5.7M incurred on the Copeland TS Phase 1. Project).

[1] As of Toronto Hydro's Application update submitted on January 29

RESPONSE (B):

i.

Subsegment	Project	Cost Categorization
Horner Expansion	Horner Expansion	Construction Cost
Hydro One Transformer Upgrades	Bridgman TS T11/T12/T13/T14 Upgrade	Construction Cost
	Cecil TS T3/T4 Upgrade	Load True-Up
	Charles TS T3/T4 Upgrade	Construction Cost
	Dufferin TS T1/T3/T4 Upgrade	Construction Cost
	Main TS T3/T4 Upgrade	Construction Cost
	Strachan TS T12 Upgrade	Construction Cost
	Strachan TS T14 Upgrade (Partial Cost)	Construction Cost
Reactive Hydro One Contribution and True-Up Costs	Copeland TS Phase 1 True-Up	Load True-Up and Construction Cost
	Switchyard Expansion Bermondsey and Richview TS	Construction Cost
	New Cable Carlaw TS to Gerrard TS	Construction Cost
	Additional Unforeseen	Forecast – Expected: Construction Cost
	Incorrect Mapping of Renewal Work	Construction Cost
	Customer Connection Requiring HONI Contribution	Construction Cost
	Incorrect Mapping of Partial Cost of Strachan TS T12 Upgrade	Construction Cost

With regards to ii. and iii. please see the agreements and invoices attached as appendices.

iv. The only project without a CCRA and formal cost estimate is the Bermondsey TS switchyard expansion. Hydro One provided Toronto Hydro a planning estimate for this project which is reflected in the forecast.

v. There were two load true-up payments in the 2020-2024 period: the Copeland TS Phase 1 True-Up, and the Cecil TS T3/T4 Upgrade.

With respect to Copeland TS – Phase 1, the CCRA was based on Toronto Hydro's 2013 System Peak Demand (2012 actuals). In 2015, Toronto Hydro recalibrated its load forecasting methodology to reflect the latest growth trends observed in actuals and align with the 2016 Regional Infrastructure

Plan methodology.[2] These changes coupled with a drop in peak demand in the surrounding area resulted in the load true up. However, it is important to note that Copeland TS is needed both to enable switchgear renewal at Windsor TS, and to provide thermal capacity and feeder positions to its surrounding area. The value of switchgear renewal and additional feeder positions is not substantially diminished by partially unrealized load.

Similarly, Toronto Hydro made a load true-up payment for the historic project, Cecil TS T3/T4 Upgrade which was executed in 2005. The payment was the result of differences in Toronto Hydro's 2021 System Peak Demand Forecast relative to Toronto Hydro's 2015 System Peak Demand Forecast, submitted for each respective true-up evaluation. This difference is attributed to lack of load realization from customers relative to load requested over the 2013-2017 period, and the impact of COVID-19 in the Cecil area. Additionally, as the in-service date for Copeland Phase II had not been set at the time of the 2015 forecast, it did not reflect the impact of future load transfers from Cecil to Copeland TS (post-Phase 2). These transfers were reflected in the 2021 forecast which formed the basis of the true-up.

[2] Toronto Hydro notes that the 2016 Regional Infrastructure Plan was the first following the launch of the IRRP process (in May 2015).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-238

Ref 1: Exhibit 2B, Section E7.4, Page 27

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

Table 15: Historical & Forecast Program Costs by Segments includes costs for Hydro One Contributions segment for the 2025 to 2029 forecast period totalling $103M.

QUESTION (A):

a) For each year of the forecast period please provide a list of projects and forecast costs, as well as a categorization of the costs as construction costs or load true-up.

RESPONSE (A):

Table 1: Hydro One Contribution Project List and Annual Expenditures Forecasted Over 2025-2029

Project or Subsegment	Categorization	Forecast				
		2025	2026	2027	2028	2029
Downsview SS	Construction Costs		0.6	1.7	2.9	0.6
Sheppard TS Bus Expansion	Construction Costs		0.5	4.5	5.0	5.0
Manby TS DESN Reconfigurations	Construction Costs		0.5	3.5	4.0	4.0
Basin TS - T3/T5 Upgrade	Construction Costs	1.6				
Duplex TS - T1/T2 Upgrade	Construction Costs	1.6				
Leslie TS - T1 Upgrade	Construction Costs	0.3				
Strachan TS - T14 Upgrade	Construction Costs	0.8				
Scarborough TS - T23 Upgrade	Construction Costs		0.4			
Strachan TS - T13/T15 Upgrade	Construction Costs			1.6		
Duplex TS - T3/T4 Upgrade	Construction Costs				1.6	
Carlaw TS - T1/T2 Upgrade	Construction Costs					1.6
True-Up Costs	Construction and/or True-Up Costs	3.5	2.0	1.3	1.3	1.3
Total	**N/A**	**7.8**	**4.0**	**12.6**	**14.8**	**12.5**

QUESTION (B):

b) For each project please provide:

i. A copy of the agreement between Toronto Hydro and Hydro One.

ii. Load realized for each year of the agreement to date.

iii. Past invoices and calculations from Hydro One for true-payments.

iv. Where there is a load true-up payment due in the period, please provide estimates and calculations from Hydro One for the true-up payment. In the absence of estimates from Hydro One, please provide Toronto Hydro's detailed calculations of the true-up payment.

RESPONSE (B):

Parts (i), (ii), and (iii):

As shown in Table 2 below, all projects in the Hydro One Contributions segment for the 2025-2029 period are presently in the planning phase. In this phase, the project has been proposed by one or both of Toronto Hydro and/or Hydro One, but neither scope of work nor estimates have been developed by Hydro One. Similarly, no agreements or invoices have been provided by Hydro One at this time.

As mentioned in 2B-E7.4 at page 27 of Toronto Hydro's application,[1] the purpose of the Reactive Hydro One Contributions & True-Up Costs subsegment is "to support expansion projects or true-up costs unforeseen at the time of the application". As a result, there are no agreements or invoices in place at this time for this subsegment.

Table 2: Status of Hydro One Contribution Projects Proposed for the 2025-2029 Period

Project	Status
Downsview SS	In Planning Phase
Sheppard TS Bus Expansion	In Planning Phase

[1] Updated January 29, 2024

Project	Status
Manby TS DESN Reconfigurations	In Planning Phase
Basin TS - T3/T5 Upgrade	In Planning Phase
Duplex TS - T1/T2 Upgrade	In Planning Phase
Leslie TS - T1 Upgrade	In Planning Phase
Strachan TS - T14 Upgrade	In Planning Phase
Scarborough TS - T23 Upgrade	In Planning Phase
Strachan TS - T13/T15 Upgrade	In Planning Phase
Duplex TS - T3/T4 Upgrade	In Planning Phase
Carlaw TS - T1/T2 Upgrade	In Planning Phase
Reactive Hydro One Contribution & True-Up Costs	Forecasted

Hydro One has not provided cost estimates for potential future load true-up payments. However, Toronto Hydro has anticipated the potential for load true-up payments for the following projects: Copeland TS Phase 1, Horner TS Expansion, and Runnymede TS Expansion. In the absence of precise information regarding how the load is going to materialize in these areas, Toronto Hydro developed a forecast on a best effort basis using the historical Copeland TS and Cecil TS load true-up payments in the 2020-2024 period as described in its response to 2B-Staff-237. The utility used the average MW of load trued-up (48 MW), the average of $k per MW per year ($3.2k /MW-year), and a 20-year period to derive an estimate of $3.07 million per station, resulting in the $9.4 million forecast (including inflation). Toronto Hydro would like to emphasize that the actual true-ups are entirely contingent on the rate of customer load materialization, which is outside of the utility's control. Any variances between the forecasted true-ups noted above, and the actual true-ups that take place in the next rate period would be reconciled as part of the proposed Demand-Related Variance Account – Expenditures Sub-Account.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-239

References: Exhibit 2B, Section E6.7.1, Page 2

Preamble:

Under worst performing feeders Toronto Hydro states: "The objective of this segment is to identify feeders performing poorly over a rolling 12-month period and perform work in an effort to mitigate further interruptions."

QUESTION (A):

a) How does Toronto Hydro identify and rank feeders that are performing poorly?

RESPONSE (A):

Toronto Hydro defines and prioritizes poorly performing feeders as described in Exhibit 2B, Section E6.7 at pages 2, 16, and 24.

QUESTION (B):

b) What is the reliability threshold for being included in the Worst Performing list, or is the Worst Performing feeder list comprised of a fixed number of feeders?
   i. If a fixed number, what is that number?
   ii. If a threshold, what is that threshold?
   iii. If a feeder is scheduled to be addressed under either the Back Lot, Box Frame or other programs, will another feeder be added to the Worst Performing Feeder list to replace it?

RESPONSE (B):

There is no fixed number of "Worst Performing Feeders". Toronto Hydro considers any feeder that meets the threshold as outlined in the evidence referenced in the response to part (a) to be a "Worst Performing Feeder".

i. Not applicable

ii. Please see response to part (a).

iii. A feeder remains on the Worst Performing Feeder list as long as it meets the criteria regardless of whether it is being addressed via other programs. Prior to issuing work under the Worst Performing Feeder segment, Toronto Hydro checks existing projects to ensure that any proposed asset replacements are not being targeted under any other programs.

QUESTION (C):

c) Please provide the SAIDI and SAIFI for the worst performing feeders over the last 10 years, and the number of feeders that were on the Worst Performing Feeder list for each of the last 10 years.

RESPONSE (C):

Please see Table 1 and Figure 1 below.

Table 1: SAIDI and SAIFI for FESI-7 and FESI-6 Large Customer feeders 2014-2023

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total SAIFI	0.42	0.51	0.43	0.20	0.30	0.19	0.41	0.33	0.40	0.43
Total SAIDI	14.38	17.31	8.97	4.58	6.90	4.25	10.07	6.89	7.85	9.96

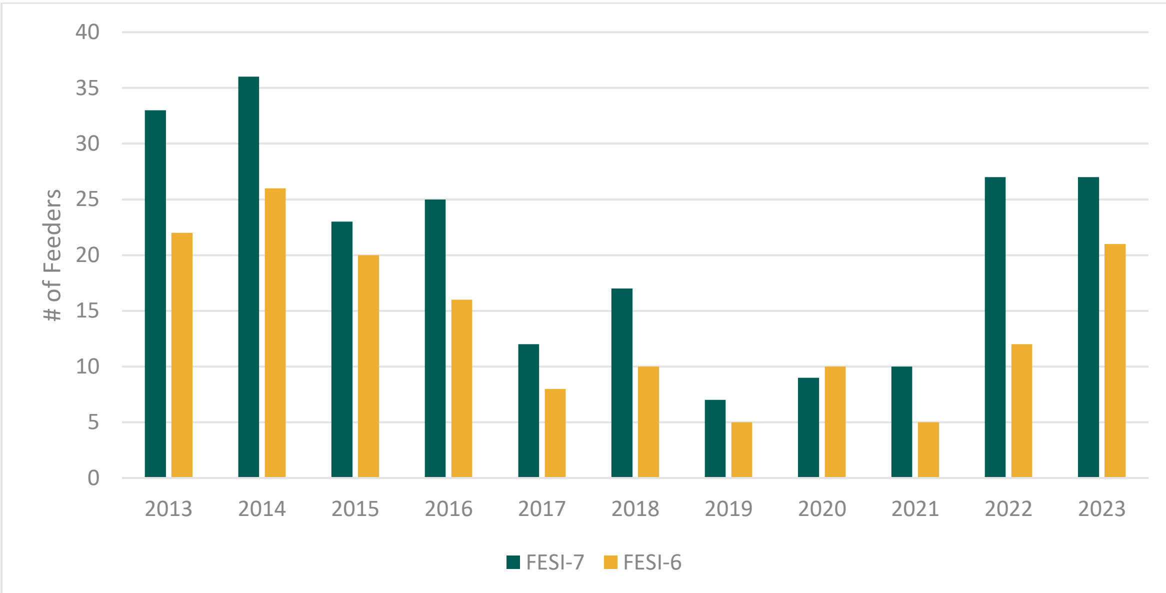


Figure 1: Number of FESI-7 and FESI-6 Large Customer Feeders 2013-2023[1]

QUESTION (D):

d) Please provide the average capital and OM&A spent to improve performance of the worst performing feeders, per year, for the last 10 years. Please discuss the effectiveness of these investments in terms of improved feeder performance.

RESPONSE (D):

Please see Table 2 below for the annual capital and OM&A spending on worst performing feeders.

Table 2: Annual Capital and OM&A Worst Performing Feeder Investments ($ Millions)

Year	Capital	OM&A
2014	3.08	0.63
2015	3.03	1.16
2016	4.09	1.86
2017	2.97	1.36

[1] In drafting this response, Toronto Hydro discovered that Figure 14 from Exhibit 2B, Section E6.7 at page 20 included some incorrect values. The correct values are included here.

Year	Capital	OM&A
2018	3.87	1.08
2019	3.72	1.09
2020	4.19	1.01
2021	3.67	1.10
2022	3.75	1.38
2023	5.71	1.84

On average over the last 10 years, Toronto Hydro has spent $3.8 million in capital and $1.3 million in OM&A investments per year on worst performing feeders. The performance of this program is measured largely by how many "Worst Performing Feeders" there are in a given calendar year. The annual number of FESI-7 and FESI-6 Large Customer feeders are a small subset of the more than 1,500 total feeders that make-up Toronto Hydro's distribution system and have been gradually trending down over the last 10 years as shown in Figure 1 in part (a). There was a noticeable increase in the number of FESI-7 and FESI-6 Large Customer feeders in 2022 and 2023. This is attributed to the increased sensitivity of the Outage Management System in recording interruptions, which is further explained in Exhibit 1B, Tab 2, Section 4 "Reliability Performance".

The Worst Performing Feeder program provides a near-term and cost-effective solution to address emerging issues on targeted feeders which are experiencing a disproportionate number of interruptions. Through this segment, Toronto Hydro replaces assets identified as having a risk of imminent failure before they would be scheduled for replacement under planned renewal programs, mitigating the risk of additional outages for customers already experiencing below-average reliability.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-240

Reference: Exhibit 2B, Section E6.7.1, Page 23

Preamble:

Figure 15: 2019-2029 Reactive Capital Work Requests Actuals and Forecast shows that the number of work requests decreased from 2019 to 2021 and increased slightly in 2022. Toronto Hydro predicts a steady level of work requests over the forecast period.

QUESTION (A):

a) Please explain the trend of work requests in this budget category.

RESPONSE (A):

As described in Exhibit 2B, Section E6.7, the work under the Reactive Capital segment is unplanned, unpredictable and non-discretionary. Hence, the data from year to year can vary significantly since the work is demand driven. The consistent decline in the number of work requests from 2019 to 2021 primarily stems from a reduction in the instances of oil leaks necessitating reactive transformer replacements. As Toronto Hydro continues to substitute non-submersible/non-stainless-steel transformers with stainless steel ones through its renewal programs, Toronto Hydro anticipates this decline in failures to persist and stabilize. Conversely, the incidence of deficiencies prompting reactive pole replacement requests has been increasing, attributed to the increasing number of poles surpassing their useful life and experiencing deteriorating asset condition.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-241

Reference: Exhibit 2B, Section E7.1, Page 1

QUESTION (A):

a) Confirm that the System Enhancements program will reduce the consequence of individual asset failures in many or most cases.
   i. If not confirmed, explain the purpose of the program, since it will not reduce the probability of asset failures.

RESPONSE (A):

Confirmed. Please refer to Exhibit 2B, Section E7.1, Page 5 for specific information on this topic.

Note that Toronto Hydro respectfully disagrees with the premise of part (i) of OEB Staff's question. The System Enhancements program contains a variety of field technology investments which will deliver benefits beyond reducing consequences of failure. The proposed System Observability segment of the program includes adding more sensors, relays and monitoring technology at specific nodes across the distribution grid. Gradually, these technologies will help the utility advance three core capabilities:

1. **Enhanced Fault Location:** Locating faults and other system disturbances faster and more efficiently in order to improve reliability and operate the grid more cost-effectively.
2. **Enhanced Decision-making and Grid Optimization:** Providing greater insight into real-time feeder and asset loading, condition, and other relevant operating characteristics. This assists the utility in managing short- and long-term uncertainty as well as driving optimal real-time operational decisions and longer-term investment planning decisions.
3. **Enhanced Asset Diagnostics:** Greater visibility into high-risk and previously hard-to-monitor assets will improve asset diagnostics, mitigating the risk of asset failure and impacts to personnel safety and environmental damage.

For more information on the multi-faceted benefits of Toronto Hydro's System Enhancements program, please refer to Exhibit 2B, Section E7, and the Intelligent Grid Section of Toronto Hydro's *Grid Modernization Strategy* (Exhibit 2B, Section D5.2.1).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-242

Reference: Exhibit 2B, Section E7.1, Page 1

<u>Preamble:</u>

The proposed Contingency Enhancement investment represents a $113M (568%) increase in segment spending.

QUESTION (A):

a) Please confirm that this increase is necessary to maintain rather than improve system reliability.
    i. If confirmed, please explain how Toronto Hydro has been able to significantly reduce its outage durations over the historical period despite a much slower pace of spending in this segment.
    ii. If not confirmed, please reconcile Toronto Hydro's strategic decision to increase spending in this segment by 568%, given its residential customers' preference to maintain reliability and control costs.

RESPONSE (A):

As mentioned in Exhibit 2B, Section E2, "Although Toronto Hydro's renewal and modernization efforts over the last decade have led to improvements in reliability performance that began in the mid-2000s, more recently this performance has plateaued." The investments in the Contingency Enhancement segment support Toronto Hydro's complimentary goals of maintaining reliability during the 2025-2029 period while improving reliability and resiliency for the longer-term. For more information, please refer to 2B-Staff-175.

QUESTION (B):

b) Toronto Hydro indicates elsewhere in the Application that Toronto Hydro has already implemented majority of its contingency enhancement plans. Has Toronto Hydro undertaken a benefit-cost analysis demonstrating that the proposed accelerated spending to rapidly complete this plan provides offsetting benefits of equal or greater value to customers?

   i. If yes, please provide the benefit-cost analysis documentation.
   ii. If no, please explain why not.

RESPONSE (B):

Toronto Hydro has not indicated that the majority of its contingency enhancement plans have been implemented. For a discussion regarding benefit-cost analysis related to modernization initiatives, including Contingency Enhancement, please refer to 2B-Staff-170. Pleaser also refer to 2B-Staff-162 for information on the expected long-term benefits of Fault Location Isolation and Service Restoration (‘FLISR’) implementation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-243

Reference: Exhibit 2B, Section E7.1.1, Page 2

Preamble:

Toronto Hydro states: "Under the Downtown Contingency, this segment provides for plans to add provisions in the downtown core for incremental Toronto Hydro-controlled back-up supply stations… The planned enhancements will provide N-2 (i.e., two station loss-of-supply issues at the same time) operational capability to address serious loss-of-supply scenarios."

QUESTION (A):

a) Please identify all N-2 loss of supply events that have caused significant Downtown customer outage over the past 5 years.

RESPONSE (A):

For the requested time period, the following are major Downtown loss of supply events in which the station-to-station switchgear ties would have reduced the impact on customers:

- A barge crane contact with HONI overhead transmission line on August 11, 2022. This event is described at pages 17-18 of the referenced section.
- A Charles Station loss of supply event on February 1, 2024. This event occurred subsequent to the filing, and is not included in Table 5 of E7.1.3.2.

QUESTION (B):

b) Please identify all Toronto Hydro service areas where Toronto Hydro is proposing to apply an N-2 planning standard going forward.

RESPONSE (B):

The Copeland-Esplanade project described in the referenced program is Toronto Hydro's only proposed interstation switchgear tie at this time. Please refer to part (c) below for more information on N-2 standards.

QUESTION (C):

c) Please identify any other North American utilities Toronto Hydro is aware of which apply a similar N-2 planning standard and explain the circumstances under which the N-2 standard is applied by these utilities.

RESPONSE (C):

N-2 operational capabilities are a common element of distribution system design across North America. N-2 capability is typically established at the distribution level when serving dense service areas and/or critical loads, such as financial centres, hospitals, and transportation infrastructure. Note, for example, that Toronto Hydro's own Horseshoe distribution system has *de facto* N-2 capabilities, as it is designed such that load can be transferred between stations at the feeder level. This configuration is common for urban and suburban distribution utilities. Another example is the secondary network system which Toronto Hydro operates in parts of its dense urban core. Many other utilities around the world operate similar secondary network systems, as well as other, even more robust network grid systems, which offer a very high degree of reliability for critical loads and dense service areas (e.g., Manhattan) and ComEd.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-244

Reference: Exhibit 2B, Section E7.1.2, Page 4

Preamble:

Toronto Hydro states: "Continues to maintain Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching."

QUESTION (A):

a) Please provide a list of switches that have a known safety issue that are subject to a manufacturer's recall/bulletin or ESA safety alert or product recall. Include the manufacturer, model, make, number in service and if available, link to the public announcement.

RESPONSE (A):

There are no known safety issues related to manufacturer recalls, bulletins or ESA safety alerts for manual switches currently in Toronto Hydro's distribution system.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-245

Reference: **Exhibit 2B, Section E7.1.3.1, Page 7**

Preamble:

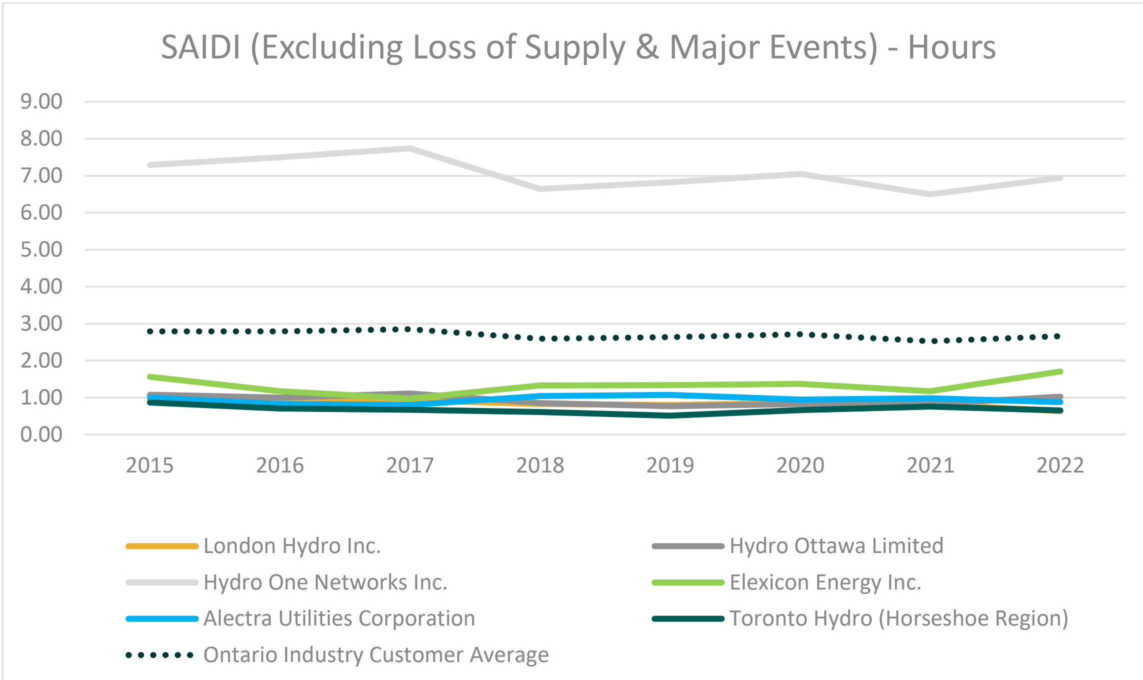
Toronto Hydro states: “This configuration ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level, effectively reducing the duration of an outage. During the 2018-2022 period, the average duration for outages on 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 SCACA tie-points was approximately 496 minutes.”

QUESTION (A):

a) How does Toronto Hydro’s SAIDI performance trend for the Horseshoe area compare with the SAIDI trends of its Ontario peers?

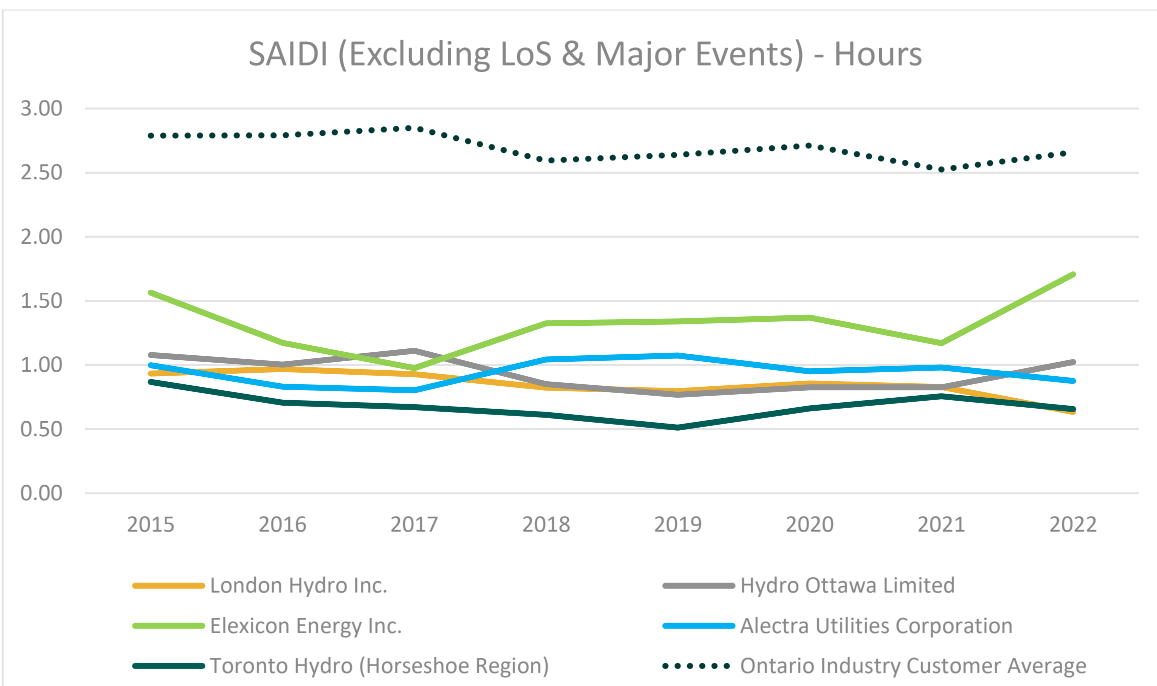
RESPONSE (A):

As seen in Figures 1 and 2 below, Toronto Hydro’s Horseshoe Region has shown strong performance in SAIDI (Excluding Loss of Supply and Major Events) in comparison to its peer distributors, and is generally within the range of SAIDI performance of other large distributors in Ontario. This reflects Toronto Hydro’s commitment over the years of delivering safe and reliable power to our customers, minimizing the duration of interruptions.



1 **Figure 1: SAIDI Industry Comparison Including HONI (Excluding Loss of Supply and Major Events)**

2



3 **Figure 2: SAIDI Industry Comparison Excluding HONI (Excluding Loss of Supply and Major Events)**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-246

Reference: Exhibit 2B / Section E7.1.3.1 / p. 8

Preamble:

Toronto Hydro states: "This work is expected to result in an average of approximately 12.6 percent reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in an average yearly total customer minute out (CMO) reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year."

QUESTION (A):

a) Please provide the cost in dollars per estimated "customer minute out" reduction for this project and all other projects that reduce customer outage minutes.

RESPONSE (A):

Based on the proposed 2025-2029 Contingency Enhancement Program ($133 million cumulative), Toronto Hydro estimates the CMO reduction over the rate period (2025-2029) to be approximately 2.6 million minutes, resulting in an effective cost of $50.95 per CMO reduced over 2025-2029. With an expected useful life of 30 years (Exhibit 2A, 2022 Depreciation Study, Pg. 48/383), considering average historical reliability performance and forecasted increases in number of customers (Exhibit 3, Tab 1, Schedule 1), the lifetime CMO reduction is estimated to be 37 million minutes, with an effective cost of $3.58 per CMO reduced over the lifetime of the assets (i.e., SCADA switches and reclosers).

Refer to Exhibit 1B, Tab 3, Schedule 1, Page 56-62 along with respective Table 22, 23, 24 and 25 for a benefit-cost analysis applying to all of Toronto Hydro's reliability-related investments in the 2025-2029 Distribution System Plan.

QUESTION (B):

b) Please explain how making incremental investments to materially reduce CMOs aligns with Toronto Hydro's stated strategy of making necessary expenditures to maintain rather than materially improve reliability.

RESPONSE (B):

Please refer to 2B-Staff-242 and 2B-Staff-175.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-247

Reference: Exhibit 2B, Section E7.2.1, Page 1

Preamble**:**

Toronto Hydro states: "The NWS strategy for the 2025-2029 period is focused on being flexible and adaptable to help system planners respond to load growth while navigating the underlying uncertainty that stems from changing demand patterns and increased reliance on electrification. This strategy builds on Toronto Hydro's experience utilizing DERs to reduce peak demand, helping to defer grid expansions or, in most cases, avoid grid expansions should demand not materialize as expected (e.g., lower than expected demand, fluctuating demand)."

QUESTION (A):

a) Please quantify by technology type the alignment of energy production by the DERs presently installed in Toronto Hydro's service area with the summer and winter peak demand hours on Toronto Hydro's distribution system.

RESPONSE (A):

As outlined in Exhibit 2B Section E7.2, Toronto Hydro plans for and procures third-party capacity in the form of dispatchable demand response to complement standard system planning approaches. The utility is unable to provide the requested data as Toronto Hydro does not procure energy (kWh) from DERs.

QUESTION (B):

b) Given the response to the prior question, please describe the effectiveness of Toronto Hydro's existing DER portfolio in mitigating capacity constraints encountered by Toronto Hydro during summer and winter peak demand periods.

RESPONSE (B):

Toronto Hydro does not control third-party owned, non-dispatchable DERs and thus cannot rely upon these assets to meet system needs (capacity needs or otherwise) on demand. Until a DER owner enters into a binding agreement with Toronto Hydro (via LDR procurement) to provide a specific service to the grid, Toronto Hydro will not consider this DER as a reliable system tool. As part of its Local Demand Response program, Toronto Hydro procured 8 MW of dispatchable demand response capacity between 2018-2020, 4 MW between 2022-2023, and 6 MW in 2024.

The non-wires solutions considered for the 2025-2029 rate period are described in Exhibit 2B Section E7.2. Toronto Hydro's use of NWSs 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.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-248

Reference: Exhibit 2B / Section E7.2.1 / p. 1

Preamble:

Toronto Hydro states: "NWSs are viewed as additive to conventional utility expansion strategies, enabling Toronto Hydro to expand its planning toolbox to include additional strategies for keeping up with load growth."

QUESTION:

Please provide examples of DERs or other Non-Wires Solutions presently existing on Toronto Hydro's system that enabled it to avoid more costly wires solutions to address system constraints.

i. Please quantify the cost savings for each of the examples.

RESPONSE:

The non-wires solutions considered for the 2025-2029 rate period have been outlined in detail in Exhibit 2B Section E7.2. Please refer to Toronto Hydro's responses to 1B-Staff-88 and 1B-Staff-89 for more information about the utility's non-wires strategy, investments and proposed incentives. Please also see Toronto Hydro's responses to other Staff interrogatories asking similar questions about the use of non-wires in planning: 2B-Staff-154, 2B-Staff-169, 2B-Staff-173, 2B-Staff-253, 2B-Staff-255.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-249

Reference: Exhibit 2B, Section E7.2.2.1, Page 19

Preamble:

Toronto Hydro states: "Toronto Hydro will build on its experience with BESS to move from individual pilot projects towards a standardized approach for design and deployment. The planned deployments will target areas with grid constraints to enable Renewable Energy Generation (REG) connections."

QUESTION:

Please quantify the capital and operating cost impacts of developing BESS using presently available commercial technology to address outage durations. Please express your answer in terms of average annual dollars per unit SAIDI improvement.

RESPONSE:

As outlined in Exhibit 2B Section E7.2.2, the use case for the proposed ESS deployments is to enable future renewable generation connections, not to address outage durations. As such, at this time, Toronto Hydro is unable to quantify the cost impacts of BESS to address outage duration. Toronto Hydro is currently undertaking preliminary engineering studies to assess the feasibility of utilizing BESS for the purpose of outage management and if appropriate, will evaluate the cost-effectiveness of this potential use case in the future.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-250

Reference: Exhibit 2B, Section E7.2.2, Pages 18-35

EB-2018-0165, OEB Decision and Order, Pages 114-115, 119

Preamble:

Toronto Hydro has proposed an expanded Energy Storage System as part of its Non-Wires Solutions for 2025-2029 to assist in providing distribution-level grid support. Toronto Hydro forecasts expenditures of $22.5 million over the 2025-2029 period to support the deployment of 9 projects with an aggregate capacity of 10.2 MW.

As part of the OEB's Decision in EB-2018-0165 it provided direction that it expected Toronto Hydro to respond to as part of any future application that seeks approval of Renewable Enabling Investments and Energy Storage Systems, including evidence of the benefits to power quality, reliability and capacity and an assessment of appropriate sharing of benefits for ESS projects as part of future requests for funding for provincial rate protection.

QUESTION (A):

a) Please discuss the pace of the BESS investment strategy. In particular, please provide more detail regarding the process Toronto Hydro will undertake in determining when to proceed with a BESS investment during the 2025-2029 term, including how Toronto Hydro plans to overcome the challenges faced in the recent past (siting, supply chain, integration into the existing system, low vendor interest).

RESPONSE (A):

As described in Exhibit 2B Section 7.2.2, Toronto Hydro intends to install front-of-the-meter, utility-owned and operated ESS to enable renewable DER connections. This plan is informed by a systematic analysis of feeders experiencing instability related to high-penetrations of renewable

DERs, which identified nine priority feeders to be targeted for ESS deployment. To ensure that ESS remains the appropriate solution, the analysis will be re-run to confirm the conditions of the feeder prior to project development. The methodology utilized is in compliance with the IEEE-1547-2022.

Of the challenges faced in 2020-2024, siting continues to be the most challenging. To manage this risk, Toronto Hydro is actively pursuing various pathways such as decommissioned Municipal Stations, private land opportunities, and public land opportunities in collaboration with the City of Toronto. For the remaining constraints, please refer to exhibit 2B Section 7.2.2.4 Page 28-30.

QUESTION (B):

b) Please discuss the status of the technical requirements currently in development to support the standardized process of ESS design and procurement, including what Toronto Hydro is using as the basis for the technical requirements.

RESPONSE (B):

As indicated in Exhibit 2B Section E7.2.2.4, Toronto Hydro has completed a technical specification review with respect to ESS technologies, which is continuously updated. The following list of engineering standards and codes have been used as a basis for Toronto Hydro's standardized technical specification document:

- Canadian Standards Association (CSA):
  - C22.2 No. 31 Switchgear Assemblies
  - C22.2 No. 94 Special Purpose Enclosures 2, 3, 4 and 5
  - C22/2 No. 193 High Voltage Full-load Interrupter Switches
  - CAN 3-C13 Instrument Transformers
  - C22.3 No 9 Interconnection of distributed resources and electricity supply systems
- Electrical and Electronic Manufacturers Association of Canada (EEMAC):
  - G8-3.2 Metal Clad and Station-type Switchgear
  - G10-1 Revenue Metering Equipment in Switchgear Assemblies
- Institute of Electrical and Electronic Engineers (IEEE):

  - Std 48 Test Procedures and Requirements for High Voltage AC Cable Terminations
  - C37.74 Standard Requirements for Subsurface, Vault, and Padmounted Load-Interrupter Switchgear and Fused Load-Interrupter Switchgear for Alternating Current Systems up to 38 kV
  - 386 Standard for Separable Insulated Connector Systems for Power Distribution Systems above 600 V
  - Std 80 Outdoor Grounding Requirements
  - C37.20.2 IEEE Standard for Metal-Clad Switchgear
  - C57.12.28 IEEE Standard for Pad-Mounted Equipment-Enclosure Integrity
  - 519 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
  - 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (if applicable)
  - 1584 Guide for Performing Arc Flash Hazard Calculations
- ANSI/CAN/UL:
  - UL9540 Energy Storage Systems and Equipment
  - UL1741 Standard for Inverters, converters, Controllers and Interconnection
  - System Equipment for Use with Distributed Energy Resources (if applicable)
  - UL1642 Lithium Batteries
  - UL1973 Batteries for Use in Stationary Application
  - ANSI C37 series of Standards
- International Standard (IEC):
  - IEC 62933-2-1 Electrical Energy Storage (EES) Systems

QUESTION (C):

c) Please discuss how maintenance costs have been incorporated into the overall cost proposal for the ESS plan.

RESPONSE (C):

Maintenance costs for Toronto Hydro-owned ESS associated with annual inspection, testing, and cleaning are included in the Preventative and Predictive Stations Maintenance program forecast (Exhibit 4, Tab, 2, Schedule 3).

QUESTION (D):

d) Please provide more information on how the annual forecast BESS expenditures were developed, including the increase in planned expenditures in 2027 relative to other years.

RESPONSE (D):

The plan for BESS deployment focuses on deploying small-scale projects in 2025 and 2026 where potential sites have already been identified. Larger capacity systems will be deployed later on in the rate period. Toronto Hydro expects to carry the lessons learned from the smaller into the 2027 projects.

QUESTION (E):

e) Please provide more information on the how the total proposed cost of $22.5 million is broken out between that which is allocated to Toronto Hydro's rate base (i.e. six percent or $1.6 million) and that the remaining funding component through the provincial renewable enabling improvement revenue stream.

RESPONSE (E):

Please see Tables 1 and 2 for the capital expenditures and in-service additions 94/6 percent split, respectively. The in-service addition amounts are reflected in the Socialized Renewable Energy Generation Investments line item in Appendix 2-BA, Exhibit 2A, Tab 1, Schedule 2.

Table 1: Capital Expenditure 94/6 Split ($ Millions)

	2025	2026	2027	2028	2029	Total
Capital Expenditures (Rate Base at 6%)	0.2	0.2	0.5	0.2	0.2	**1.4**
Capital Expenditures (Socialized Renewable Energy Generation Investments at 94%)	3.3	3.4	7.1	3.6	3.8	**21.2**
Total	**3.6**	**3.6**	**7.5**	**3.8**	**4.0**	**22.5**

Note: Variances due to rounding may exist

Table 2: In-Service Additions 94/6 Split ($ Millions)

	2025	2026	2027	2028	2029	Total
In-Service Additions (Rate Base at 6%)	-	-	0.9	-	0.5	**1.4**
In-Service Additions (Socialized Renewable Energy Generation Investments at 94%)	-	-	13.9	-	7.3	**21.2**
Total	**-**	**-**	**14.8**	**-**	**7.8**	**22.5**

Note: Variances due to rounding may exist

QUESTION (F):

f) Please provide an assessment of the appropriate sharing of benefits for the proposed BESS projects between Toronto Hydro's customers and broader electricity customers across Ontario for those amounts requested to be recovered under the provincial renewable enabling improvement funding component.

RESPONSE (F):

Please see Exhibit 2A, Tab, 5, Schedule 1, section 2.2 (Energy Storage) for the requested assessment.

QUESTION (G)

g) Please discuss the nature of the proposed BESS investments and indicate if any are proposed to be behind-the-meter. If so, please discuss the nature of these projects and the anticipated benefits.

RESPONSE (G):

All proposed energy storage investments are front-of-meter.

QUESTION (H):

h) Please discuss the analysis Toronto Hydro has undertaken to understand the pace of battery technology evolution. As part of your response, please address how Toronto Hydro will assess the long-term viability and performance of battery technologies installed. Please also discuss the risk mitigation efforts to avoid investing in technologies that become obsolete in a short period of time.

RESPONSE (H):

Toronto Hydro has conducted an Energy Storage System (ESS) Technology Evaluation as referenced in Exhibit 2B Section E7.2, page 31 which took a technology agnostic approach to analyzing the available market options with renewable enablement as the primary use-case. The approach focused on the assessment of storage technologies (not just electrochemical storage) with relation to physical footprint, modularity, technology maturity, market availability, environmental impact, performance and financial metrics among others. The evaluation referenced supplier engagements that Toronto Hydro conducted as well as similar studies by the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

Toronto Hydro periodically updates the evaluation to assess the long-term viability of available storage technologies and ensures review of the available technologies ahead of each procurement to mitigate the risk of investing in technologies that may become obsolete before the deployment end-of-life. Toronto Hydro maintains awareness of the rapidly changing landscapes in storage technology development through industry engagements with suppliers.

QUESTION (I):

i) The ESS strategy is being prioritized to reduce the minimum load to generation ratio for specific feeder stations. Please discuss the process Toronto Hydro proposes to undertake to assess the performance and reliability of planned BESS investments to ensure they meet or exceed performance requirements.

RESPONSE (I):

Toronto Hydro will use real-time feeder loading and generation data to perform measurement and verification to ensure the MLGR ratio is within compliance with the IEEE-1547-2022, utilizing standard IEEE methodologies.

QUESTION (J):

j) Please discuss the consideration of life cycle environmental impacts of the planned BESS investments, including the process to disposing of batteries after their useful life.

RESPONSE (J):

Toronto Hydro has conducted a storage technology evaluation of the different options and assessed the environmental impacts of each within business-specific applications. Toronto Hydro actively considers alternative storage technologies during its procurements that are more sustainable and easier to recycle whilst also balancing the performance requirements and market maturity to ensure service reliability.

QUESTION (K):

k) Please discuss how Toronto Hydro proposing to assess how potential BESS projects contribute to the resilience and security of Toronto Hydro’s system.

RESPONSE (K):

The primary use case of Toronto Hydro’s proposed BESS projects is renewable enablement. Enhancing Toronto Hydro’s grid resilience and security through BESS is currently being evaluated through on-going engineering studies and will be pursued as a secondary use case if appropriate.

QUESTION (L):

l) Please discuss how current and future ESS projects may contribute to the Local Demand Response program, if at all.

RESPONSE (L):

The non-wires solutions considered for the 2025-2029 rate period have been outlined in detail in Exhibit 2B Section E7.2. Toronto Hydro's use of NWSs 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.

Toronto Hydro would not utilize its own front-of-the-meter ESS assets to participate in a competitive, market-based program such as LDR. The ESS assets could provide targeted peak-shaving benefits to the connected feeder, however, this would occur outside of the LDR program.

QUESTION (M):

m) Please provide a project schedule and expected completion date for the Optimal Planning Program developed in partnership with Toronto Metropolitan University.

RESPONSE (M):

The Optimal Planning Program developed in partnership with the Toronto Metropolitan University's Centre for Urban Energy (in Exhibit 2B Section E7.2, page. 20) was concluded in June 2023. This project was successful in developing a technology agnostic tool to help evaluate the net benefits associated with various ESS configurations and ownership models.

The project also developed a software tool, which is utilized by Toronto Hydro to analyze the opportunity to layer use-cases for a given ESS deployment and helps determine the ESS sizing. The tool can also aid in quantifying potential wholesale market revenues (i.e. IESO services) should the decision be made to pursue such activities in the future.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-251

Reference: Exhibit 2B, Section E7.2.2.3, Pages 21-22

<u>Preamble:</u>

With regards to Toronto Hydro's commentary on "Renewable Enabling BESS"

QUESTION:

Must increased REG penetration in Toronto Hydro's service area be accompanied by associated ESS developments to avoid creating system capacity deficiencies? Please discuss.

i. If yes, quantify the revenue requirement impacts of the associated ESS needed to support the anticipated REG developments over the test period.

RESPONSE:

As described in Exhibit 2B, Section E7.2.2.3, Toronto Hydro's pre-application process enables the discovery of potential distribution system issues that must be addressed to accommodate a proposed DER. High penetration of renewable energy generation sources on one feeder can lead to grid instability if not managed appropriately. This does not mean that all feeders will experience these issues. As noted in Table 14 of Exhibit 2B, Section E7.2.2.3, Toronto Hydro has identified 23 feeders that are currently of concern, and an additional 24 that could experience issues by 2029. Based on this analysis, 9 priority feeders have been selected and the expenditure plans related to the ESS requirements have been provided in Exhibit 2B, Section E7.2.2.4. The associated costs have been captured in the current filed application documents (see Table 18, Exhibit 2B, Section E7.2.2.4). The associated revenue requirement can be found in Exhibit 2A, Tab 5, Schedule 2, Appendix "OEBAppendices 2-FA-FB - EnergyStorage_20231117.XLSM"

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-252

Reference: Exhibit 2B, Section E7.4, Appendix A, page. 6

Question (A):

a) Toronto Hydro is anticipating overall area load growth for the Downsview area of 40-70% due mainly to electrification of heating and transportation. Please provide a load forecast for the Downsview area (for each station) that breaks out the heating and transportation demand. Please also confirm what percentage of the transportation demand is due to EVs and the percentage due to electrification of public transit.

RESPONSE (A):

Please note that the referenced range is not forecast; it refers to growth modelled by the Future Energy Scenarios (FES), which was used to stress-test the need for Downsview TS in accordance with the least regrets planning approach outlined in the evidence at Exhibit 2B, Section D4. For more information about the Downsview area station bus load forecast please see the response to 2B-Staff-256.

Please note that Toronto Hydro's capital plan for Downsview TS was developed using the "25 Year Forecast" as provided in Exhibit 2B, Section E7.4, App A p. 7, as per Toronto Hydro's application evidence update submitted on January 29. As discussed, the 25 Year Forecast was produced by adding 70% of the demand forecast produced by a preliminary study from DPM Energy to Toronto Hydro's 10-year System Peak Demand Forecast. Please note additionally that Toronto Hydro's System Peak Demand Forecast does not model heat loads due to the decarbonization of heat. Finally, the DPM Energy study does not provide an estimate for heating demand separate from overall building demand. For these reasons, Toronto Hydro is not able to provide a forecast for the heating demand for the Downsview area.

The EV demand for each station is provided in Table 1. Regarding public transit, Toronto Hydro has also included the Finch West LRT in its load forecast (not shown in Table 1), contributing an additional 5.3 MVA to Bathurst TS.

Table 1 : EV Load by Station Forecasted for the Downsview Area (MVA)

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bathurst TS	0.0	0.0	0.0	0.1	0.1	0.3	1.5	2.8	4.1	5.5	6.8	8.2	9.6
Fairbank TS	0.2	0.4	0.8	1.2	1.8	2.7	4.2	5.7	7.2	9.0	10.8	12.9	15.1
Fairchild TS	0.2	0.3	0.6	0.9	1.6	2.6	3.6	4.6	5.7	7.0	8.4	10.4	12.4
Finch TS	0.4	1.1	2.1	3.2	4.7	6.6	9.2	12.0	14.6	17.7	21.1	24.6	28.6

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-253

Reference: Exhibit 2B / Section E7.4 / App A / pp. 18, 19

QUESTION (A):

a) Please confirm that the cost of option 6 - New TS incudes the cost of load transfers that will need to be implemented to manage local station capacity at 90% until Downsview TS comes into service. i. If not confirmed, please provide the total cost of Downsview TS that takes necessary load transfers into account.

RESPONSE (A):

The cost of option 6 – New TS does not include the cost of load transfers. Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

QUESTION (B):

b) Please update Table 4-Summary of Options to include the total costs of each of the options. If this is not feasible, please explain why not.

RESPONSE (B):

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

QUESTION (C):

c) Did Toronto Hydro consider the use of non-wires options in the area including flexibility options and energy storage solutions to defer the need for a new TS?

i. If yes, please provide the benefit cost analysis.

ii. If not, why not.

RESPONSE (C):

Toronto Hydro has considered the use for non-wires options in the Downsview Area. However as discussed in 2B-E7.4 App A pp. 11, non-wires options are not capable of addressing the magnitude of load growth forecasted for the Downsview Area. Ultimately, new station capacity is required to supply the loads and electrical energy needs of the Area, especially upon considering that flexibility options and energy storage solutions do not provide net electrical energy.

Instead, Toronto Hydro has chosen to combine the complementary strengths of wires and non-wires options to meet the needs of the Downsview Area. Toronto Hydro is proposing to construct Downsview TS to meet the long term needs of the Area, but is forecasting the station to be complete in approximately 10 years: Q4 2033. Until Downsview TS is ready, Toronto Hydro is proposing to manage station loading through its Load Demand (wires) and Non-Wires Solutions (non-wires) Programs. In particular, Toronto Hydro's Non-Wires Solutions Program is proposing to target the Finch TS service area with Flexibility Services (previously "Local Demand Response"). Please see 2B-E7.2.1.3 for more details.

Regarding the request for a benefit cost analysis, please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-254

References: Exhibit 2B, Section E7.4, App B, p. 6

QUESTION (A):

a) Toronto writes that it is anticipating Scarborough area load will grow by 75-105 % due mainly to electrification of heating and transportation. Please provide a 20-year demand and energy forecast for the area that breaks out heating, EV charging, and public transit for each station.

RESPONSE (A):

This project is no longer in scope in this proceeding, as Toronto Hydro retracted the request related to Scarborough TS (Exhibit 2B, Section E7.4 at Appendix B) through the evidence update which was submitted on January 29, 2024.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-255

REFERENCES: Exhibit 2B, Section E7.4, App B, Pages 18,19

QUESTION (A):

a) Please confirm that the cost of option 5 - New DESN incudes the cost of load transfers that will need to be implemented to manage local station capacity at 90% until the new DESN comes into service. If not confirmed, please provide the total cost accounting for load transfers.

QUESTION (B):

b) Please update Table 7-Summary of Options Outcomes to include the total cost of each option.

QUESTION (C):

c) What non-wires options were considered in this area to defer the need for the new DESN? ii. Please provide the benefit cost analysis.

RESPONSE (A), (B), AND (C):

This project is no longer in scope in this proceeding, as Toronto Hydro retracted the request related to Scarborough TS,[1] through the evidence update which was submitted on January 29, 2024.

[1] Exhibit 2B, Section E7.4, Appendix B

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-256

Reference: **Exhibit 2B, Section E7.4.1, Page 1**

Preamble:

Toronto Hydro states: "A demand study of the Downsview area has forecasted a load demand of 195 MW by 2035."

QUESTION (A):

a) Assuming the Downsview TS is not constructed, please provide the summer and winter planning capacity and forecast peak summer and winter demand for each year from 2030 - 2035 for Bathurst TS, Finch TS, Fairchild TS and Fairbank TS.

RESPONSE (A):

Tables 1 and 2 below respectively show the summer and winter peak forecasts for the Downsview Area, assuming Downsview TS is not constructed, over 2030-2035. Please note that building heating loads are not included in the forecasts shown in Tables 1 and 2, as noted in the evidence in Exhibit 2B, Section D4 and in the response to 2B-Staff-153.

Table 1: 2030-2035 Summer Forecast for the Downsview Area without Downsview TS

Station	Summer LTR (MW)	2030	2031	2032	2033	2034	2035
Bathurst TS	361	76%	77%	78%	80%	81%	83%
Fairbank TS	182	92%	96%	98%	99%	101%	102%
Fairchild TS	346	70%	71%	71%	71%	71%	71%
Finch TS	366	96%	99%	100%	101%	101%	102%
Area Non-Coincident %	**1255**	**83%**	**85%**	**85%**	**86%**	**87%**	**88%**

Table 2: 2030-2035 Winter Forecast for the Downsview Area without Downsview TS

Station	Winter LTR (MW)	2030	2031	2032	2033	2034	2035
Bathurst TS	389	66%	66%	68%	69%	70%	72%
Fairbank TS	202	72%	74%	76%	77%	78%	80%
Fairchild TS	389	59%	59%	59%	59%	59%	59%
Finch TS	394	80%	82%	82%	83%	84%	84%
Area Non-Coincident %	**1374**	**69%**	**70%**	**71%**	**71%**	**72%**	**73%**

QUESTION (B) :

b) When is Downsview area forecast to become winter peaking?

RESPONSE (B):

Toronto Hydro's 10-Year System Peak Demand Forecast does not forecast the Downsview areas to become winter peaking within the 10-Year Period. In a scenario where building heating loads are modelled, such as those being explored through long-term regional planning, the Downsview areas could become winter peaking by 2040.

QUESTION (C) :

c) What is the annual duration of the period in which demand is forecast to exceed the available Bathurst TS, Finch TS, Fairchild TS and Fairbank TS planning capacity in each year from 2030 to 2035?

RESPONSE (C):

The System Peak Demand Forecast, which is the basis for the capacity planning process both at the distribution level and for Regional Planning at the needs assessment stage, does not include a demand duration station forecast.

QUESTION (D) :

d) Please explain how the summer and winter planning capacity is determined for each of the above substations.

RESPONSE (D):

As stated in Hydro One's 2022 Needs Assessment Report at page 12: "Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station". Toronto Hydro uses the same capacity, the summer LTR, as the summer capacity for the transformer stations supplying its service territory. Similarly, Toronto Hydro uses the Hydro One winter LTR as the winter capacity for the transformer stations supplying its service territory.

QUESTION (E) :

e) Assuming all equipment is in service what is the operational capacity at each of these substations in each year from 2030 to 2035?

RESPONSE (E):

Please see the response to d) above. Consistent with Hydro One definitions, Toronto Hydro defines transformer station capacity as the LTR of a single transformer; or equivalently for a DESN where two transformers supply load in parallel, the LTR capacity under the loss of one transformer (N-1). Toronto Hydro's capacity planning process, consistent with the Regional Planning process, does not give consideration to capacity when all equipment is in service.

QUESTION (F)

f) What is the probability of a contingency exceeding the operational capacity at each of these substations in each year from 2030 to 2035?

RESPONSE (F):

Please see the response to part (c) above. Toronto Hydro has forecasted when peak demand is forecasted to exceed Summer LTR, as shown in Table 1.

QUESTION (G) :

g) Please provide any risk analysis that Toronto Hydro has undertaken to determine the risk of not being prepared to serve all loads in the Downsview Area post 2030.

RESPONSE (G):

Please see the Downsview TS Business Case in Exhibit 2B, Section E7.4 at Appendix A (updated January 29, 2024) for the risk analysis. Toronto Hydro has taken the Downsview Area Secondary Plan into consideration by producing the 25 Year Forecast (Table 2), and has considered the possible impacts of electrification by leveraging the Future Energy Scenarios (FES). These tools were used to assess when capacity constraints would (per the 25 Year Forecast) or could (per the FES) be encountered. Following that, Toronto Hydro assessed 6 options, described pages 9-19, to determine if and how it would be able to manage the risk of capacity constraints. Through this analysis, Toronto Hydro concluded that it would only be able to manage all loads in the Downsview Area in the long term by investing in its proposed Downsview TS.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-257

Reference: Exhibit 2B, Section E8.1, Pages 1, 4, 6

<u>Preamble:</u>

Toronto Hydro notes the following regarding EDC 1, "for example, EDC 1 will continue to require at least two to three shutdowns per year to allow for the execution of necessary and essential facilities operations and maintenance activities aiming to safeguard the integrity of the location."

QUESTION (A):

a) Please clarify the sentence above, what kinds of operations and maintenance activities need to be undertaken at EDC 1 owing to its particular site condition.

RESPONSE (A):

A number of construction and planned maintenance activities are required at the facility housing EDC 1, which necessitate power shutdowns. Examples of these activities include tying in the electric feed for new or replaced equipment (like electric vehicle chargers or electric-powered roof top units replacing a gas unit), and planned shutdowns for routine building maintenance. The shutdowns triggered by these activities affect the synchronising switchboard, which eliminates the backup generator redundancy and thus increases the risk of sudden failure of EDC 1 for the duration of the shutdown.

QUESTION (B):

b) Would these same activities and mitigations not need to be undertaken at EDC 2 or the newly proposed site?
    i. If yes, how does Toronto Hydro propose to manage these issues and what are the related costs?

RESPONSE (B):

No, the building power shutdowns due to operations and maintenance uniquely affect EDC 1 only because the facility housing EDC 1 has a shared generator that supports both the main building and the EDC. Any similar activities do not affect EDC 2 nor would they affect the proposed site. EDC 2 is currently aligned with Tier II requirements of the Uptime Institute's Tier Classification System and the proposed EDC will align with Tier III requirements, meaning both locations will feature independent generator backup dedicated to the data centre alone. This independence would fortify the redundancy of EDC 2 and the proposed EDC, eliminating the current risks and costs associated with EDC 1 being impacted by shutdowns in its current location.

QUESTION (C):

c) Please provide a table that shows EDC1, EDC2 and the new site's square footage and how each of the sites compare in capital cost/square footage.

RESPONSE (C):

Toronto Hydro is unable to provide the capital costs for EDC 1 and EDC 2 because the utility no longer has any records dating back to their construction. The proposed EDC's cost has been shown in the currency of the year of project completion.

Table 1: Proposed EDC Cost

Location	Square feet	Capital Cost ($ million)	$/sq. f.t
EDC 1	3,530	Unavailable	
EDC 2	8,700	Unavailable	
Proposed EDC	11,500	72.0	6,260

QUESTION (D):

d) Is the proposed cost of $72M for a new EDC site an all-in cost? In other words, does this cost include facilities and IT infrastructure and security?

i. If not, please provide the all in cost for the new EDC.

RESPONSE (D):

Yes, the proposed cost of $72 million is the all-in cost including inflation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-258

Reference: Exhibit 2B, Section E8.1, Page 7

Preamble:

Toronto Hydro notes that the assets at EDC 1 will be retired.

QUESTION (A):

a) Could the existing assets at EDC 1 be used to reduce the costs of assets needed at the new proposed location?
   i. If yes, what are the related cost savings and are they included in the proposed costs of the new EDC?
   ii. If no, why not?

RESPONSE (A):

Toronto Hydro does not expect that it can use existing assets at EDC 1 to reduce the costs of assets needed at the new proposed location for the following reasons:

1. While construction is ongoing at the proposed new EDC location, EDC 1 must remain in operation to maintain redundancy with EDC 2.
2. The assets constituting EDC 1 are at or beyond useful life and their reuse would not yield any material savings or benefits over their replacement.
3. Reusing the assets constituting EDC 1 at the proposed new EDC location would require investments in additional electrical equipment, which would materially add to project costs.

QUESTION (B):

b) How do the EDC 1 assets compare in age and useful life to assets at EDC 2? Please provide this information in a table and aggregate by asset type, as necessary.

RESPONSE (B):

Table 1: Useful Life Comparison- EDC 1 and EDC 2 Assets

Asset	EDC 1		EDC 2	
	Useful Life, Years	Years Remaining	Useful Life, Years	Years Remaining
Computer Room Air Conditioning Units	15	12	15	5
Fire Protection	20	-9	25	14
Controller	15	1	30	2
Fire Alarm Panel	15	9	15	4
Generator	25	11	25	15
Windows	45	11	N/A	N/A

Note: A negative number in years remaining indicates the number of years the asset has exceeded its useful life.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-259

References: **Exhibit 2B, Section E8.1, Page 8**
Exhibit 2B, Section E8.1, Page 11

<u>Preamble:</u>

Toronto Hydro notes the Tier Classification System of the Uptime Institute.

QUESTION (A):

a) Is Toronto Hydro required to abide by certain Tier Classification requirements?
   i. If yes, what are these requirements?
   ii. What standard, legislation and/or guidance governs the operations of Toronto Hydro's EDCs?

RESPONSE (A):

Although there is no governing body that mandates Toronto Hydro's compliance with the Uptime Institute's Tier Classification System, the utility recognizes significant value in designing and planning its EDC components in accordance with a body of internationally recognized data centre standards.

Toronto Hydro follows key design and operation standards with respect to its EDCs, including:

- **TIA-942**: Telecommunications Industry Association's standardizing the design and implementation of data centre infrastructure, and operations with guidelines on reliability, scalability, efficiency of cabling, network architecture, power distribution, cooling system and security measures.
- **Uptime Institute's Tier Standards**: These standards affect both design and operations through their guidelines specifying tier classification, redundancy, cooling efficiency, and

operational best practices to minimize downtime and ensure consistent availability of critical IT services.

- **ISO/IEC 27001**: This international standard specifies the requirements for establishing, implementing, maintaining, and continually improving an information security management system ("ISMS") within the context of the organization's overall business risks. Implementing this standard provides the EDC with robust security controls, risk management processes, and continual monitoring and improvement measures, enhancing the security posture of the EDC and protecting sensitive information from threats and vulnerabilities.
- **ANSI/BICSI 002**: This standard provides guidelines for data center design and implementation, covering aspects such as cabling, pathways, spaces, and grounding. The structured and standardized approach to infrastructure design leads to improved performance, scalability, and manageability of the EDC.
- **ASHRAE Guidelines**: The American Society of Heating, Refrigerating and Air-Conditioning Engineers provides guidelines for data center environmental conditions, including temperature, humidity, and airflow management. These conditions are crucial for maintaining optimal operating conditions and equipment reliability, ensuring energy efficiency equipment longevity and overall reliability of the EDC facility.

QUESTION (B):

b) What is the Tier Classification for EDC 2, and how does that compare to the classification proposed for the proposed EDC?
   i. If they will be different, will EDC2 need to be upgraded to a new classification?
   ii. If yes, when would this upgrade need to take place and at what cost?

RESPONSE (B):

EDC 2 is a Tier II classification and the proposed EDC will be aligned to a Tier III classification. The primary difference between Tier II and III is how the EDC and the electrical distribution interact with the backup generator. Both tiers feature two backup generators, but under the Tier II classification both generators are tied into a single distribution path, meaning a failure at that distribution path, such as a failure of the synchronization switchboard, input switchboard, or emergency switchboard would result in system failure. Under Tier III, each generator has its own distribution path to the EDC, providing greater redundancy between the two backup generators and better resiliency for the EDC.

Toronto Hydro currently does not estimate any material benefits to upgrading EDC 2 to a new classification, as the assets that constitute EDC 2 are relatively newer and remain within their useful lives.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-260

References: Exhibit 2B, Section E8.1, Page 18

<u>Preamble:</u>

With respect to EDC redundance and replacing EDC 1, Toronto Hydro states that, “A complete EDC failure would result in all of Toronto Hydro’s business applications becoming unresponsive and non-functional. In the event of a distribution system outage, this would have cascading and substantial financial and economic impacts on customers within the City of Toronto.”

QUESTION:

a) Please confirm that this comment refers to failure of both EDC sites and not just EDC 1, given that there are two locations to provide back up capability in the event of one site failing?

RESPONSE:

Confirmed. However, 1:1 redundancy will be lost in approximately 5 years time as described in 2B, E8.1, pg 16-17

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-261

Reference: Exhibit 2B, Section E8.1, Page 21

Preamble:

Toronto Hydro is requiring $72 million over the 2025-2029 rate period to relocate the existing EDC 1 to the new site and be operational by 2029.

QUESTION:

a) Please provide a table showcasing the progressive spending for the EDC relocation over the next 5 years

RESPONSE:

The following table outlines the estimated annual spend of the total EDC project.

Table 1: Estimated Annual Spend of the Total EDC Project

EDC: Forecast					
Year	**2025**	**2026**	**2027**	**2028**	**2029**
Forecasted Spend	$5.4M	$16.5M	$22.5M	$20.6M	$7.0M

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-262

Reference: Exhibit 2B, Section E8.1, Page 28

QUESTION:

a) Please provide the benefit-cost analysis that justified Toronto Hydro's selected option for the new EDC.

RESPONSE:

Please refer to section E8.1.4 "Options Analysis/Business Case Evaluation" of Exhibit 2B, Section E8.1.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-263

References: **Exhibit 2B, Section E8.1, Pages 23-24**
Exhibit 2B, Section D8
Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs[1]

Preamble:

On November 2, 2023, the OEB released a letter regarding a new Accounting Order to establish a deferral account to record cloud computing implementation costs. Amongst other things, the establishment of the generic deferral account allows utilities to perform optimized planning by allowing cloud computing implementation costs to be recovered outside of a rate rebasing year and potentially reduces rate impacts through a disposition period.

QUESTION (A):

a) Please provide the forecasted capital and OM&A spend on cloud computing solutions for the 2025-2029 period at the project level.

RESPONSE (A):

All currently forecasted spend on cloud computing solutions for the 2025-2029 rate period fall under OM&A. Toronto Hydro notes that while cloud computing is typically treated as an OM&A expense, the accounting treatment is unique to each contract and may also result in the costs being treated as capital. Please also refer to Toronto Hydro's response to interrogatory 2A-PP-24, subpart (c).

Table 1 below outlines the forecasted 2025- 2029 OM&A spend on cloud computing solutions, all included In the Information Technology OM&A program budget:[2]

Table 1: 2025-2029 IT forecasted OM&A spend on cloud computing solutions:

	$ Millions				
	2025 Forecast	**2026 Forecast**	**2027 Forecast**	**2028 Forecast**	**2029 Forecast**
Cloud Implementation	5	5.5	6	6.5	7
Cloud Subscription Fees	4.4	5.2	5.7	6.3	7
Total	**9.4**	**10.7**	**11.7**	**12.8**	**14**

Toronto Hydro is currently unable to break down this information at the project level because the development of specific cloud-based solutions for 2025–2029 rate period is still ongoing as part of the utility's IT investment planning process.[3] As part of that process, Toronto Hydro must assess and evaluate whether or not on-premise cloud technology is suitable to fulfill its business needs. The utility's above forecast is based on 2020-2024 expenditures on cloud-based solutions at an aggregate level.

QUESTION (B):

b) Please discuss whether Toronto Hydro has assessed the impact of having a generic account available for cloud computing implementation costs in their 2025-2029 plan. If not, why not.

    i. Please discuss any barriers to implementing cloud-based solutions as a result of the analysis.

RESPONSE (B):

[2] Exhibit 4, Tab 2, Schedule 17.
[3] The process is outlined in Exhibit 2B, Section D8, subsection D8.5 at p. 7-10.

Given that the proposed five-year OM&A funding through the Revenue Growth Factor[4] includes a forecast for incremental cloud implementation and subscription costs,[5] Toronto Hydro decided not to pursue a deferral account for 2025-2029 in this regard.

In the unfortunate event that parties oppose the custom funding request for OM&A and the OEB is inclined to entertain such a request, Toronto Hydro would seek alternative relief for a generic account to capture variances for cloud-related costs (implementation and subscription costs) to ensure that the utility is able to fund these prudent and necessary expenditures and reduce the financial barriers to adopting cloud-based solutions.

QUESTION (C):

c) In light of the new deferral account is Toronto Hydro reassessing its position on cloud computing as an alternative to the EDC project?

RESPONSE (C):

No, Toronto Hydro is not reassessing its position on cloud computing as an alternative to the EDC relocation project, as the new deferral account does not mitigate the reliability and operational risks that a cloud-based solution would introduce relative to an on-premises solution. As discussed in Toronto Hydro's options analysis for the EDC relocation project,[6] the introduction of a cloud-based solution would make the utility dependent upon its vendor(s) to manage the reliability and business continuity of the EDC, which is beyond Toronto Hydro's risk tolerance given the critical functions performed by the EDC. Operational Technology (OT) systems such as Supervisory Control and Data Acquisition ("SCADA") and the Network Management System ("NMS") are critical systems that ensure reliability of Toronto Hydro's daily operations. By having these systems on Toronto Hydro's premises as opposed to on the cloud, Toronto Hydro has full control and flexibility to manage the reliability of its critical operations as outlined in Exhibit 2B, Section E 8.1.4.3.2 pg 25-

[4] Exhibit 1B, Tab 2, Schedule 1.
[5] Exhibit 4, Tab 2, Schedule 17.
[6] Exhibit 2B, Section E8.1, subsection 8.1.4.3 at pages 25-26.

26. In addition, the introduction of a cloud-based solution to EDC 1 or the proposed EDC would render existing systems in EDC 2 incompatible with the new cloud-based components, triggering the need for further investments.

QUESTION (D):

d) In light of the new deferral account and the expanding number of cloud computing offerings, would Toronto Hydro consider reducing the size of the new EDC by implementing more cloud computing solutions? Please explain and include financial impacts to the new EDC project, as well as potential future savings for the existing EDC.

RESPONSE (D):

For the reasons discussed in the response to subpart (c) and the options analysis in Exhibit 2B, Section E8.1, Toronto Hydro does not consider full or partial implementation of cloud computing solutions to be a feasible alternative.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-264

Reference: Exhibit 2B, Section E8.2, Pages 8, 9, 11, 14, 17

Preamble:

With respect to Toronto Hydro's proposed Facilities Management and Security Investments and Figures 3, 4, 5, 8 and 16, and fire alarm systems.

QUESTION (A):

a) Please confirm whether the pictures included in the figures references above that depict architectural, structural and mechanical and plumbing deterioration are in fact outliers and not representative of the majority of facilities managed by Toronto Hydro?

RESPONSE (A):

The pictures used throughout Exhibit 2B, Section E8.2 are representative of the majority of stations facilities managed by Toronto Hydro and are not outliers.

QUESTION (B):

b) Please explain in detail how Toronto Hydro has been managing these facilities prudently given the state of the deterioration at some of these facilities as depicted in the figures.

RESPONSE (B):

As discussed in detail in Toronto Hydro's Facilities Asset Management Strategy,[1] the utility employs a comprehensive asset management approach that monitors and records the condition of facilities assets on an ongoing basis and at varying intervals as appropriate, in accordance with applicable legislative and technical standards. This approach provides Toronto Hydro central visibility into

[1] Exhibit 2B, Section D6.

conditions of its building assets at all times and supports the utility's decision-making by pinpointing the most critical needs by building system via a ranked, quantified evaluation of assets.

However, Toronto Hydro is also bound by fiscal prudence and the regulatory framework to prioritize its facilities investments in a manner that delivers that optimum value to ratepayers. As the OEB itself noted, "*it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates.*"[2] Given the vintage of the majority of Toronto Hydro's facilities,[3] the deterioration of a portion of facilities assets is unavoidable; the real challenge is to optimize costs and prioritize asset replacements in a prudent manner, which the utility accomplishes through the application of its Facilities Asset Management Strategy.

[2] OEB Handbook for Utility Applications (October 13, 2016), p. 13.
[3] Exhibit 2B, Section D6, p. 7, lines 11-13 and Section E8.3, p. 25, lines 9-12.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-265

Reference: Exhibit 2B, Section E8.2, Page 2, 26

Preamble:

In describing general plant investments related to work centres, Toronto Hydro states it plans to invest to decarbonize in line with its Net Zero 2040 Strategy.

QUESTION (A):

a) What are the annual capital expenditures in Facilities Management and Services related to Toronto Hydro's Net Zero 2040 Strategy?

RESPONSE (A):

Approximately $31.8 million of the Facilities Management and Services capital budget will be directed to work centre GHG emissions reduction initiatives by replacing end of life natural gas fired assets in accordance with Toronto Hydro's Facilities Asset Management Strategy.[1] Please refer to the below table for an estimated annual breakdown.

Table 1: Estimated Annual Breakdown

Program/Segment ($M)	2025	2026	2027	2028	2029	2025-29
Facilities Decarbonization Strategy	6.1	6.3	6.4	6.4	6.6	**31.8**

[1] Exhibit 2B, Section D6.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-266

References: **Exhibit 2B, Section E8.3, Pages 3-4**

EB-2018-0165, Decision and Order, December 19, 2019, Page 104

Preamble:

In reference 2 the OEB directed Toronto Hydro "to provide more detailed cost benefit analysis between EV, hybrid and combustion engines for its fleet program for future rebasing applications. In addition, the OEB directs Toronto Hydro to develop utilization measures beyond fleet use in standard hours." In response to the cost benefit analysis, Toronto Hydro's evidence stated that various phasing and cost options were analyzed for electrifying its fleet and the results of this analysis informed Toronto Hydro's procurement strategy for EVs and hybrid vehicles.

Question (A):

a) Please provide a copy of the analysis done to assess the costs and benefits between EVs, hybrids and combustion engine vehicles and the results of this analysis.

RESPONSE (A):

Toronto Hydro continues to work on obtaining disclosure consent from the third parties that authored the report on EV Phase-In. Once consent is obtained, Toronto Hydro will update this interrogatory response. Following the commissioning of this third-party report, Toronto Hydro further calibrated its business plan in support of the Fleet and Equipment Services capital program for 2025-2029, in view of material developments since the analysis was undertaken, such as the COVID-19 pandemic, EV pricing and availability, global supply chain challenges, and the Net Zero by 2040 mandate.

QUESTION (B):

b) Please explain Toronto Hydro's proposal for developing utilization measures beyond fleet use in standard hours.

RESPONSE (B):

For a discussion of the current metric, please refer to Exhibit 2B, Section E8.3, subsection 8.3.3.4 "Business Operations Efficiency" at pages 9-11. The previous utilization measure known as "standard utilization percentage" only considered vehicle usage during the standard field operations working hours of 7:30 am- 3:30 pm, which excluded vehicle utilization for units that operated outside of these hours such as shift workers, early starts, alternate shift schedules, overtime, etc. and as such, was not a true reflection of vehicle utilization. The old method of calculation was based on the number of hours the vehicle is utilized outside of its home zone between the hours of 7:30 am- 3:30 pm, divided by 8. By contrast, the current "days used" metric that Toronto Hydro adopted in the 2020-2024 rate period removes the limitations of a specific shift schedule and looks at daily usage throughout the month.

Toronto Hydro-Electric System Limited
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Appendix A
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FINAL REPORT
October 2021

Electric Vehicle Phase-in Plan

PREPARED FOR TORONTO HYDRO-ELECTRIC SYSTEM LTD.

AUTHORS: ROGER SMITH, MATTHEW PITTANA, JANA CERVINKA. CHIEF DATA ANALYST: HUGH ROBERTS

RICHMOND
Sustainability Initiatives

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Terms and Abbreviations

BAU – Business-as-usual
BEV – Battery-electric vehicle
BET – Battery-electric truck
CAC – Criteria air contaminants; a cause of ground level smog
CAFE – Corporate average fuel economy
Capex – Capital expense
CO_2 or CO_2e – Carbon dioxide or carbon dioxide equivalent
Downtime – Period when a vehicle is unavailable for use during prime business hours
EV – Electric vehicle
EVSE – Electric vehicle supply equipment
FAR™ – Fleet Analytics Review™ (Fleet Challenge Excel software tool)
GHG – Greenhouse gas (expressed in CO_2 equivalent tonnes)
HD or HDV – Heavy-duty vehicle (Classes 7-8)
HEV – Hybrid-electric vehicle
ICE – Internal combustion engine
KPI – Key performance indicator
LCA – Lifecycle analysis
LD or LDV – Light-duty vehicle
LMHD – Light-, medium-, and heavy-duty vehicle
LTCP – Long-term capital planning
MD or MDV – Medium-duty vehicle (Classes 3-6)
MHD or MHDV – Medium- and heavy-duty vehicle (Classes 3-8)
MHEV – Mild hybrid-electric vehicle
MT – Metric tonne
OEM – Original equipment manufacturer
Opex – Operating expense
PHEV – Plug-in hybrid electric vehicle
PM – Preventative maintenance
ROI – Return-on-investment
Solution – A technology, best management practice, or strategy to reduce fuel use and GHGs
TCO – Total cost of ownership
WACC – Weighted average cost of capital
ZEV – Zero-emission vehicle

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Foreword

This Electric Vehicle Phase-in Plan (also referred to as the Plan), has been prepared for Toronto Hydro-Electric System Limited (herein referred to as Toronto Hydro or the utility) by Richmond Sustainability Initiatives (RSI) of Toronto, Ontario and its project team Fleet Challenge (FC), collectively referred to as RSI-FC. We have included this foreword because we feel it is important for readers of this report to first have a full understanding of the situation and context.

The Plan is based on our team's detailed data analysis of one-year of historical data for **385 Toronto Hydro fleet vehicles** as submitted by the utility.

The RSI-FC team has made considerable effort to make the Electric Vehicle Phase-in Plan as meaningful and relevant as possible to Toronto Hydro. Our team analyzed and evaluated baseline fleet results and modelled an electric vehicle transition that makes economic sense and is reasonably attainable in the medium- to long-term. Results of scenario analysis are presented for the utility's consideration.

Our analysis for battery-electric vehicle (BEV) phase-in has been completed using a specialized software tool that was developed by RSI-FC, which is referred to as the Fleet Analytics Review™ (FAR). FAR has been designed to efficiently estimate the cost-benefit and GHG emissions-reduction potential of many best management practices and fuel-reduction solutions that have been proven to be beneficial to commercial and municipal fleets, including BEVs.

The Electric Vehicle Phase-in Plan provides a viable roadmap for consideration by Toronto Hydro's management, which can be implemented from 2022 through to 2037. Due to the limited availability of BEVs in the short-term, we have modelled BEV phase-in over a 15-year budget period following the year 2022 (i.e., from 2023-2037).

In addition to our electric vehicle phase-in analysis, we conducted a unit-by-unit analysis to determine electric vehicle supply equipment (EVSE), or charging infrastructure, requirements for Toronto Hydro's fleet, using an EVSE costing software tool.

We have made every effort to ensure that the business assumptions and estimates employed in our analysis are as accurate as possible – based on our years of experience working with commercial and municipal fleets, market research, and valuable input from Toronto Hydro Fleet Management.

Fossil fuel-use reduction translates directly to greenhouse gas reduction[1] (hereafter referred to as GHG reduction, carbon reduction, or CO_2 reduction); therefore, all references to fuel savings include the consequential GHG impacts (i.e., increase or decrease).

[1] The terms greenhouse gas, GHG, carbon, CO_2e, and CO_2 are synonymous for the purposes of this report.

Cautious Approach

Long-term capital planning (LTCP) for electric vehicles is dependent on the *speed and degree* of implementation. There are various uncertainties with electric vehicles that would modify capital expenses (Capex), operating expenses (Opex), and GHG reductions, including:

- Future BEV acquisition costs;
- Unexpected charging infrastructure costs (such as inadequate electrical capacity in facilities); and
- The timing of transitioning specific segments of the fleet based on market conditions (i.e., availability and supply).

For these reasons, our team, with input from Toronto Hydro Fleet Management, took a cautious approach with BEV acquisition costs by adding premiums ranging from 48% to 100% (lower ratios for light-duty units and higher ratio for medium- and heavy-duty units) for BEVs over internal combustion engine (ICE) counterparts. There is a strong likelihood that the acquisition cost of BEVs will decline with time as both supply increases and as battery technology continues to improve, and we have modelled this for the utility's consideration.

Challenges to Electric Vehicle Transition

The reality is that electric vehicle transition will require a degree of extra effort and cost to implement, as well as new operational challenges that must be resolved. The successful planning and execution of installing the correct charging infrastructure, including Level 2 electric vehicle charging stations and/or Level 3 direct current (DC) fast-charging stations, is of paramount importance for the smooth phase-in of electric vehicles into Toronto Hydro's fleet. Moreover, electric vehicles offer a different experience for operators in terms of both driving and re-fuelling (charging); therefore, change management is a critical piece of successful electric vehicle transition.

GHG Emissions Calculation Methods

Internationally, there are two standard reporting methods for vehicle GHG emissions modelling: (1) tailpipe combustion, and (2) fuel lifecycle (sometimes referred to as fuel cycle or well-to-wheel). Modelling of fuel lifecycle GHG emissions of motor fuels is used to assess the overall GHG impacts of the fuel, including each stage of its production and use, in addition to the fuel actually used to power a vehicle. Modelling of tailpipe emissions includes only the emissions produced by the vehicle itself through combustion. Lifecycle GHG emissions are, therefore, greater than tailpipe emissions.

While lifecycle emissions have been established for most fuel types, lifecycle emissions are often difficult to quantify for electric vehicles because of the different mixes of electricity sources in different jurisdictions and at different times of day (i.e., fossil-fuel based, nuclear, and renewables). Given that most electricity in the City of Toronto comes from nuclear power, as well as for simplicity of our analysis, we employed the tailpipe combustion method. Using this method, BEVs emit zero emissions. Although not providing a complete well-to-wheel picture of GHG emissions, the results of our modelling employing the tailpipe combustion method gives a clear indication as to the degree of GHG reduction potential through transitioning the fleet to BEVs.

Executive Summary

In September 2021, Toronto Hydro engaged Richmond Sustainability Initiatives – Fleet Challenge (RSI-FC) of Toronto, Ontario, to develop an Electric Vehicle Phase-in Plan for its fleet assets.

Through the development and implementation of an Electric Vehicle Phase-in Plan, RSI-FC aims to assist Toronto Hydro in realizing:

- A long-term capital budget plan for phasing in battery-electric vehicles (BEVs) and charging infrastructure;
- A fleet asset management strategy for selecting which internal combustion engine (ICE) vehicles are the best candidates to replace with BEVs based on a data-driven assessment and return-on-investment (ROI);
- Improved fuel efficiency and reduced fuel cost;
- Reduced GHG and air pollutant emissions; and
- Continued leadership in environmental sustainability.

About Richmond Sustainability Initiatives

Since 2005, RSI-FC has collaborated with fleet managers, technology providers, subject matter experts, and auto manufacturers to find viable solutions, technologies, and best management practices for reducing operating costs and vehicle emissions. From the beginning, we have remained a self-supporting and independently funded program without commercial biases or influences, providing fleet review and consulting services to dozens of leading private and public sector fleets in Canada and the United States.

About Fleet Analytics Review™

For the development of the Electric Vehicle Phase-in Plan, RSI-FC employed our innovative, leading-edge data-modelling techniques and our proprietary software, Fleet Analytics Review™ (FAR). FAR is a software tool designed and developed by our company specifically for complex fleet planning. FAR enables our team to develop short- to long-term green fleet plans and strategies by calculating GHG emissions reductions and return-on-investment (ROI) for various best practices and technologies – all driven by actual historical data. In turn, this allows us to evaluate the business case of each solution and provide meaningful recommendations for long-term capital planning (LTCP).

Vision, Goal, and Objectives

The vision for the Electric Vehicle Phase-in Plan is to assist Toronto Hydro in transitioning its fleet to battery-electric vehicles (BEVs) through a streamlined fleet asset management strategy and long-term capital budget plan. With this vision in mind, the goal is to provide an ambitious, yet feasible, roadmap for the utility to phase-in BEVs and achieve significant GHG emissions reductions in a fiscally responsible manner. To guide Toronto Hydro in achieving this goal, we have thoroughly analyzed the utility's in-scope fleet data and we have identified various paths for electrification with varying degrees of speed and implementation.

The objectives of the Electric Vehicle Phase-in Plan were to:

(1) Present findings of RSI-FC's Electric Vehicle Survey to gauge the current view and opinions of employees on battery-electric vehicles and charging requirements;

(2) Develop a fleet and GHG emissions baseline for current fleet assets;

(3) Data-model various fleet electrification pathways over a 15-year budget cycle and estimate their impacts (Operating expenses, Capital expenses, and GHG emission reductions) relative to the baseline;

(4) Data-model electric vehicle supply equipment (EVSE) requirements on a unit-by-unit basis and estimate charger costs over a 15-year budget cycle; and

(5) Create a fleet electrification plan, both in terms of BEV phase-in and charging infrastructure, that is achievable, based on ROI and in consideration of the utility's fleet budget constraints – with a degree of ambition.

Electric Vehicle Survey Results

Based on results and comments expressed in the electric vehicle survey, it is clear that Toronto Hydro Fleet's user-group stakeholders are, overall, very supportive of the transition to electric vehicles.

Although views are mostly similar, there are some differences in opinions between the management and driver/operator cohorts regarding views of electric vehicles. Generally, drivers/operators are more doubtful/unaware of the capabilities and benefits of modern-day electric vehicles.

Regarding charging requirements, both groups are generally undecided about the adequacy of Level 2 (slow) charging for the fleet, and feel more strongly about the use of Level 3 (fast) charging. RSI-FC's analysis of Toronto Hydro's charging requirements based on Level 2 charging (see *Section 7*) addresses this very concern.

In terms of change management approaches, survey results show that driver/operators are moderately supportive of BEV test drives but are highly in favour of BEV orientation, while managers are in strong support of both options. Efforts in familiarizing employees with driving and charging

BEVs would likely close knowledge gaps, hesitancies, and resistance towards this technology, allowing for a more seamless transition over the coming years.

Baseline Analysis

The Electric Vehicle Phase-in Plan is based on our team's detailed data analysis of one-year of historical data for **385 Toronto Hydro fleet vehicles** as submitted by the utility.

Key fleet-wide results from the one-year review period (August 2020 to July 2021) are shown below:

- There were 211 gasoline-powered units, 160 diesel-powered units, 1 plug-in hybrid-electric (PHEV) units, and 13 battery-electric vehicle (BEV) units.
- All units were owned.
- The original purchase price for the fleet was $48,630,000.
- The current-day estimated replacement cost (like-for-like replacements) was $67,549,000.
- The estimated market/trade-in value was $22,359,540.
- The total cost of preventive maintenance (PM) was $481,389.
- The total cost of reactive repairs was $1,663,860.
- The estimated total cost of fuel was $757,168.
- The total cost of repairs and maintenance, fuel, capital, and downtime was $4,399,845.
- Total kilometres-travelled was 1,796,605.
- Total fuel used was 633,851 litres.
- Total tailpipe GHG emissions were 1,624 metric tonnes CO_2e.
- The average unit annual mileage was 4,667 km.
- The average fuel consumption for the entire fleet was 56.6 l/100km.
- The average unit age was 6.7 years.

Business Case Optimization & Capex Benchmarking

In 2017, a lifecycle analysis (LCA) study was undertaken by RSI-FC for each vehicle category at Toronto Hydro to determine optimized economic lifecycles. After modelling the baseline with optimized economic lifecycles, it was apparent that some vehicles deliver better return-on-investment (ROI) than others. Lower ROI would result if a vehicle, still in good condition, was replaced prematurely; value will be lost.

The approach used by RSI-FC was to defer some vehicles to ensuing capital budget years to ensure full value is received from each unit. In our data-modeling, without knowledge of the physical condition of units due for replacement based on vehicle ages, our analysts selectively and strategically made deferrals for units showing low/no ROI over the budget cycle to maximize operating expense (Opex) benefits and balance year-over-year capital expenses (Capex). As a result, the annual capital budget over the 15-year cycle ranged from $5.3-7.9 million and averaged $6.2 million.

This step was intended to provide a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – and as a comparison for long-term capital planning for BEV phase-in.

BEV Phase-in Scenario Results

RSI-FC data-modelled several fleet electrification pathways, or scenarios, for Toronto Hydro – ranging from aggressive to conservative – and we calculated the potential impacts of each relative to the 2020-21 baseline. Details of our approaches and scenario results, as well our analysis for electric vehicle supply equipment (EVSE) requirements, are provided in *Sections 6 and 7*.

These "what-if" scenarios assessed the potential outcomes if each electrification pathway being modelled was in place for the same types of vehicles, the same number of vehicles, travelling the same number of kilometres as the baseline period.

Our modelling estimated annual capital costs as well as operating cost impacts and GHG emissions reductions relative to 2020-21 baseline. In *Table 1* (below), results are summarized and include average annual Capital expenses (Capex) over the budget cycle, average annual Operating expense (Opex) changes over the budget cycle relative to the baseline, and annual tailpipe GHG reduction by 2037 relative to the baseline. Due to the limited availability of BEVs in the short-term, we have modelled BEV phase-in over a 15-year budget period following the year 2022 (i.e., from 2023-2037).

On the positive side of the analysis, the most aggressive fleet electrification scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by **100% by 2034** – before the end of the modelling period. The more cautious and fiscally prudent scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by just over **70% by 2037** – with the potential to achieve even greater results should more internal combustion engine (ICE) units be replaced with BEVs towards the end of the modelling period, depending on pricing outcomes for BEVs compared to ICEs.

Firm acquisition costs for battery-electric medium- and heavy-duty trucks are unknown at this time, but initially expected to be significantly more than today's standard ICE trucks. This is reflected in our modelling based on discussion with Toronto Hydro Fleet Management. Moreover, BEV prices for all classes are expected to decrease over time and possibly reach parity with standard gas and diesel trucks; however, the timing for this is unknown. To model the possible implications of BEV price reductions over time, we applied a sliding scale to both the aggressive and fiscally prudent BEV phase-in scenarios (*Table 1*, below).

Due to the significantly higher acquisition costs *currently* anticipated for soon-to-emerge electric trucks, and owing to the fact that Toronto Hydro is, like all municipal utility fleets, a low-mileage operation, the fuel cost savings from a transition to electric vehicles will not offset the additional vehicle capital costs in many vehicle applications, resulting in a forecasted increase in operating expenses as shown in *Table 1*.

Note: The significantly higher operating expenses shown in Table 1 are due to the significantly increased cost of capital for acquiring new vehicles based on year-over-year book values of units.

Table 1: Summary of fleet-wide results of scenario analysis over the period 2022-2037 relative to the 2020-21 baseline.

FAR #	FAR Scenario Description	Implementation Timing[2]	Average Annual Vehicle Replacement Capex[3] [4]($ millions)	Average Annual Opex[5] [6] Impacts Over Baseline ($ millions)	Annual Tailpipe GHG Reduction[7] Over Baseline (tonnes CO_2e)	Annual Tailpipe GHG Reduction Percentage Over Baseline
1	Optimized lifecycles	2022 - 2037	6.7	+0.94	41	2.5%
2	Optimized lifecycles + ROI (benchmarking scenario)	2022 - 2037	6.2	+0.89	37	2.3%
3.1	BEV phase-in: aggressive and cautious pricing	2022 - 2037	*10.7	+3.23	1,623	100%
3.2	BEV phase-in: aggressive and optimistic pricing (sliding scale)	2022- 2037	*7.6	+2.29 (**est.)	1,623	100%
4.1	BEV phase-in: balanced, cautious pricing, more ICE replacements	2022-2037	8.3	+1.77	1,146	71%
4.2	BEV phase-in: balanced, optimistic pricing (sliding scale), more ICE replacements	2022-2037	7.0	+1.49 (**est.)	1,146	71%
5	BEV phase-in: balanced, cautious pricing, few ICE replacements due to greatly extended lifecycles	2022-2037	9.8	+2.31	1,503	93%

* Note that both of these scenarios involve significant Capex "spikes" in the short- to medium-term.

* Estimated based on applying a sliding scale in BEV pricing.

Electric Vehicle Supply Equipment Planning

Based on our analysis of Toronto Hydro's charging requirements, 381 out of 385 units would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. Therefore, our recommendation is to focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power (Level 3) charging for higher-mileage units.

[2] For data-modelling purposes, fleet-wide implementation is modelled over the period from 2022-2037 for the same types of vehicles, the same number of vehicles, travelling the same number of kilometres as the 2020-2021 baseline.
[3] Average annual Capital expenses (Capex) for the entire modelling period (2022-2037), including compounding inflation for each year at current rate of inflation.
[4] For BEV charging infrastructure, additional capital costs were estimated separately using an EVSE costing tool.
[5] Average annual Operating expenses (Opex) for the entire modelling period (2022-2037) , including compounding inflation for each year at current rate of inflation.
[6] For data-modelling purposes, Opex includes the annual cost of capital based on year-over-year book values of units.
[7] Annual GHG reduction by the end of the modelling period (2037) is relative to the 2020-2021 baseline.

Our charger costing outlook, based on a balanced BEV phase-in approach, shows that Toronto Hydro's fleet would be 100% BEV-ready by 2034 based on the current size of the fleet. Given our estimations, this translates to an average annual charger cost (excluding infrastructure) of about $74,000 per year for the next 13 years.

Preparing for a Battery-Electric Vehicle Future

Vehicle investments are long-term; units purchased today will remain in service for up to a decade or longer. ICE vehicles are quickly becoming outdated as BEVs rapidly take over. Globally, numerous jurisdictions have already legislated the end of the ICE – some as soon as 2030. On January 28, 2021, General Motors pledged to cease building gasoline and diesel cars, vans, and SUVs by 2035. Even more recently, on June 29, 2021, the Canadian government announced a mandatory target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100 percent sales by 2040[8]. ICE vehicles purchased today for a fleet with a current-day value in the millions of dollars may be nearly worthless when ICEs become obsolete.

BEVs have a fraction of the moving parts of an ICE vehicle, cost far less to maintain, offer better performance, and can have a much lower total cost of ownership (TCO) for higher-mileage applications. For these reasons, if the condition of currently-owned Toronto Hydro fleet ICE vehicles will allow, we suggest prolonging their lifecycles until BEV replacements are available.

Today, only light-duty (cars, SUVs), transit buses, and refuse trucks (the latter of which are not applicable to this study) are available in BEV models. However, by the mid 2020s the types of vehicles that comprise a major portion of the Toronto Hydro fleet, including pickups and vans, will likely be available as BEVs. Therefore, the time is now to **begin preparing for the transition to BEVs** by investing in electric vehicle supply equipment (EVSE) while awaiting suitable BEVs to become readily available.

[8] Source: https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html

Summary of Recommendations

In *Table 2* (below), we summarize our recommendations for Toronto Hydro's Electric Vehicle Phase-in Plan in terms of both (1) capital planning for transitioning the fleet to electric and (2) electric vehicle supply equipment (EVSE) requirements. Moreover, we have included recommendations on collaboration/partnerships and risk/change management for creating a culture of receptiveness to innovation and forward thinking.

Table 2: Summary of recommendations for Toronto Hydro's Electric Vehicle Phase-in Plan

Area/ Topic	Recommendations
Battery-Electric Vehicle Phase-In	(1) Through a lens of an aggressive BEV phase-in, allocate the majority of fleet capital spending on BEVs for appropriate vehicle categories as BEV models become available. (2) Through a lens of a balanced, selective BEV phase-in and fiscal prudence, prioritize replacement of ICE units with BEVs *that would maximize ROI* – typically ones that have relatively high annual mileage. (3) For units due for replacement that are still in good condition, conduct a temporary pause on purchasing new internal combustion engine (ICE) vehicles for the short term – 1-2 years for pickups, 2-3 years for medium- and heavy-duty vehicles (MHDVs) – while awaiting battery-electric vehicle (BEV) counterparts to become available and taking into consideration procurement timelines. Extend ICE lifecycle whenever possible. (4) Employ a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road. Consider applying the decision matrix used by our team to determine which units to replace with ICE units in the short-term. (5) Conduct pilot projects for several BEV types when they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

Area/ Topic	Recommendations
	(6) Assuming the pilot projects are successful, acquire BEVs in bulk to replace units that would provide the greatest ROI. (7) Closely monitor the acquisition costs for BEVs and re-evaluate the business case (cost-benefit) for individual units as prices change/ decline. (8) Consider purchasing plug-in hybrid vehicles (PHEVs) for lower-mileage units which would be able to fulfil daily duties on battery-power only and recharge overnight – essentially functioning like fully-electric vehicles.
Electric Vehicle Supply Equipment	(1) Over the next 10+ years, allocate capital towards chargers (and charging infrastructure, which is outside the scope of this study) required for the transition to BEVs for all vehicle categories. (2) Focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power charging (Level 3) for higher-mileage units. (3) Our general recommendation is for two Level 3 chargers be installed at each of the main Work Centers (Commissioners Work Center, Rexdale Work Center, and Milner Work Center) as a risk management strategy for time-dependent and/or urgent situations. However, without knowledge of the intricacies and specific use cases for each fleet vehicle, our secondary recommendation is to identify the most appropriate Work Centers for investment in higher-power (Level 3) charging, i.e., ones that consist of vehicles that may not always rely on overnight charging only. (4) Monitor upcoming funding opportunities from NRCan's Zero Emission Vehicle Infrastructure Program (ZEVIP), which may greatly offset the capital costs required to install charging infrastructure (outside the scope of this report). (5) Assess existing electrical capacity at facilities to determine whether substantial upgrades for charging multiple vehicles are required, as well as standby generator capacities

Area/ Topic	Recommendations
	(outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations. (6) Explore supplying power to each site/garage on two separate feeds from the grid to reduce the risk of local failure taking power away from the whole site. (7) To mitigate the risk of power grid failure or local failure at a site/garage, ensure backup generators have sufficient capacity to deal with short power outages, and assess the need for higher-capacity generators for longer outages. (8) Explore solar energy technology options to supply energy for EV charging to reduce GHG emissions that may be produced from the electricity supply used for charging. (9) Provide or expand on current high-voltage safety awareness and/or skills training to include operating and maintaining Toronto Hydro's electric vehicle charging stations, and closely monitor the launch of new electric vehicle fleet technician training programs.
Collaboration/Partnership Approaches	(1) Engage in internal partnerships within and across departments, such as multi-departmental funding applications for charging infrastructure, or sharing of BEV pilot program results to determine vehicles requirements and specifications (e.g., real-world range, real-world charging needs) ahead of large purchasing decisions involving many units. (2) Engage in external partnerships (e.g., other utilities in Ontario) for potential collaborations, such as joint specification writing and/or joint tenders and sharing of BEV pilot program results through working groups. (3) Leverage the knowledge gained on BEV transition (e.g., procurement of vehicles and charging infrastructure) through organizational memberships such as the Clean Air Partnership or the Canadian Utility Fleet Council (CUFC).
Risk/Change Management Approaches	(1) Develop BEV educational and outreach materials for employees and operators summarizing the reasons and benefits of transitioning to BEVs.

Area/ Topic	Recommendations
	(2) Invite frontline employees to take BEV test drives to familiarize them with fully-electric vehicles and charging, as well as to give them first-hand experience of improved performance (e.g., instant torque, little noise, regenerative braking). (3) Provide operators with a BEV orientation before releasing new models into the fleet to enable them to become familiar with the different driving experience (e.g., instant torque, little noise, regenerative braking), as well as to alleviate/eliminate any apprehension or uncertainties such as range anxiety. (4) As is recommended for the phasing in of BEVs, we recommend pilot projects for several BEV types as they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

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Section 1: Introduction and Background

Climate change is a critical and urgent global issue. The United Nations defines climate change as "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods[9]." The term includes major changes in temperature, precipitation, or wind patterns, among others, that occur over several decades or longer[10].

Greenhouse gases (GHGs) produced by human activity is the largest contributor to climate change. GHGs are gaseous compounds (such as carbon dioxide) that absorb infrared radiation, trap heat in the atmosphere, increasing global temperature and thus contributing to the greenhouse effect[11]. While there are several GHGs[12] to consider, when calculating emissions the most commonly used measure is carbon dioxide equivalent (CO_2e)[13]. This combines the effects of all the major GHGs into a single, comparable measure.

Over the past several decades, scientific evidence of climate change, also referred to as global warming due to the increasing temperatures of the global climate system, has been vast and unequivocal. Thus, the Paris Agreement (the Agreement, the Accord) was established with a goal of keeping global warming below two (2) degrees Celsius compared with preindustrial times. The Agreement entered into force on November 4th 2016. Canada is a signatory and, as so, has established aggressive carbon-reduction targets and plans.

In addition to climate change, emissions from engine exhausts also contribute to ground-level air pollution and human health risk. Criteria air contaminants (CACs) contribute to smog, poor air quality, and acidic rain. CACs include several gases, particulate matters and volatile organic compounds[14]. In scientific studies, CACs have been linked to increased risks of respiratory and cardiovascular diseases as well as certain cancers. The World Health Organization reports that in 2012 around seven million people died as a result of air pollution exposure; one in eight of total global deaths were linked to air pollution[15]. According to the American Medical Association, globally, an estimated 3.3

[9] Source: United Nations Framework Convention on Climate Change 1992: https://unfccc.int/files/essential_background/background_publications_htmlpdf/application/pdf/conveng.pdf
[10] Source: EPA. https://www3.epa.gov/climatechange/glossary.html
[11] Source: https://www.merriam-webster.com/dictionary/greenhouse%20gas
[12] GHGs include, but are not limited to carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6), nitrogen trifluoride (NF_3), perfluorocarbons (PFCs), and hydrofluorocarbons (HFCs).
[13] "Carbon dioxide equivalent is a measure used to compare the emissions from various greenhouse gases based upon their global warming potential. For example, the global warming potential for methane over 100 years is 21. This means that emissions of one million metric tonnes of methane is equivalent to emissions of 21 million metric tonnes of carbon dioxide." Source: https://stats.oecd.org/glossary/detail.asp?ID=285
[14] CACs include Total Particulate Matter (TPM), Particulate Matter with a diameter less than 10 microns (PM10), Particulate Matter with a diameter less than 2.5 microns (PM2.5), Carbon Monoxide (CO), Nitrogen Oxides (NOx), Sulphur Oxides (SOx), Volatile Organic Compounds (VOC), and Ammonia (NH3).
[15] Source: http://www.who.int/mediacentre/news/releases/2014/air-pollution/en/

million annual premature deaths (5.86% of global mortality) are attributable to outdoor air pollution[16], although ambient air pollution has been regulated under national laws in many countries.

Socially responsible institutional, commercial, and industrial fleets can play an important role in reducing GHG emissions and air pollution.

Fleet Sector Impact

Low-carbon transportation is essential to both short-term GHG and fuel-use reduction and long-term decarbonization of the economy. In 2020, the transportation sector accounted for about 25% of greenhouse gas (GHG) emissions in Canada, second only to the oil and gas sector[17]. Utilities can play a key role in cutting emissions by transitioning their fleets to low-carbon and/or electric vehicles, while saving fuel and maintenance costs.

The transition to battery-electric vehicles (BEVs) of all classes will be a game-changer as these vehicles take up more of the market in the next several years, both in terms of operational cost savings and the deep GHG emission reductions required to curb the most severe impacts of climate change. Significant and growing commitments to integrating BEVs into fleet operations will be a driving force in the transition to BEVs[18]. Moreover, continued improvements in range capability and charging infrastructure will accelerate the electrification of fleets.

About Richmond Sustainability Initiatives

Since 2005, Richmond Sustainability Initiatives – Fleet Challenge (RSI-FC) has collaborated with fleet managers, technology providers, subject matter experts, and auto manufacturers to find viable solutions, technologies, and best management practices for reducing operating costs and vehicle emissions. From the beginning, we have remained a self-supporting and independently funded program without commercial biases or influences, providing fleet review, strategies and management consulting services to dozens of leading private and public sector fleets in Canada and the United States.

Through the combination of our experience and the use of our Fleet Analytics Review™ (FAR) software tool, we are delivering an advanced Electric Vehicle Phase-in Plan for Toronto Hydro that is provides numerous electrification pathways based on the speed of BEV transition and BEV prices.

[16] Source: https://jamanetwork.com/journals/jama/article-abstract/2667043
[17] Source: https://climateactiontracker.org/countries/canada/
[18] Source: ChargePoint. Trends & Prediction in Fleet Electrification [pdf]. June 2020.

Background

Toronto Hydro owns and operates the electricity distribution system that provides electricity to approximately 785,000 customers in the City of Toronto, which has a population base of approximately 3.0 million people. The utility delivers about 17 per cent of the electricity consumed in the province of Ontario.[19]

The Electric Vehicle Phase-in Plan will help chart a path of environmental sustainability and the reduction of GHGs through an ambitious, yet feasible, roadmap – keeping in mind budget constraints, return-on-investment (ROI), availability of BEVs of various types, and procurement timelines.

Toronto Hydro has already deployed numerous BEVs into its fleet (Chevrolet Bolts). The Plan is the next logical step in these environmental initiatives; Fleet Management can utilize the scenario analysis provided in this report for fleet replacement strategies and long-term capital planning.

Vision, Goal, and Objectives

The vision for the Electric Vehicle Phase-in Plan is to assist Toronto Hydro in transitioning its fleet to battery-electric vehicles (BEVs) through a streamlined fleet asset management strategy and long-term capital budget plan. With this vision in mind, the goal is to provide an ambitious, yet feasible, roadmap for the utility to phase-in BEVs and achieve significant GHG emissions reductions in a fiscally responsible manner. To guide Toronto Hydro in achieving this goal, we have thoroughly analyzed the utility's in-scope fleet data and we have identified various paths for electrification with varying degrees of speed and implementation.

The objectives of the Electric Vehicle Phase-in Plan were to:

(1) Present findings of RSI-FC's Electric Vehicle Survey to gauge the current view and opinions of employees on battery-electric vehicles and charging requirements;

(2) Develop a fleet and GHG emissions baseline for current fleet assets;

(3) Data-model various fleet electrification pathways over a 15-year budget cycle and estimate their impacts (Operating expenses, Capital expenses, and GHG emission reductions) relative to the baseline;

(4) Data-model electric vehicle supply equipment (EVSE) requirements on a unit-by-unit basis and estimate charger costs over a 15-year budget cycle; and

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[19] Source: https://www.torontohydro.com/about-us/company-overview

(5) Create a fleet electrification plan, both in terms of BEV phase-in and charging infrastructure, that is achievable, in consideration of the utility's fleet budget constraints – with a degree of ambition.

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Section 2: Electric Vehicle Survey

Our organization recognizes the value of stakeholder engagement and user group participation in any go-forward plans under consideration by our clients. With that focus in mind, RSI-FC set out to gain staff perspectives and opinions from Toronto Hydro's Fleet user groups on electric vehicles and charging requirements.

RSI-FC understands the importance of hearing the opinions of *all* stakeholders, including both management and staff. It was clearly communicated to all survey recipients that their responses were confidential and anonymous; as so, they were encouraged to express their opinions freely.

We are aware that online surveys are not always the ideal method for collecting opinions and gathering information. It is known in the industry that people are often reluctant to provide their personal opinions in this manner; typically, survey response rates are known to only be in the 10 to 15% range. However, due to the Covid-19 pandemic, in-person meetings are not currently possible. Knowing that feedback from stakeholders is important for go-forward planning, as a workaround we opted to instead conduct a web-based online survey. During the last year and a half we have received some valuable feedback from online surveys, as it does give participants a sense of freedom to speak candidly and voice any concerns.

A unique survey was designed for management and drivers/operators to highlight differences in opinions and views, as well as to help inform our recommendations. In total, we received 66 responses (42 from management group and 24 from driver/operator group) out of 330 surveys sent to designated internal staff, which translates to an overall response rate of 20% – well above the typical industry range of 10-15%. We were pleased that responses were insightful and of high-quality, providing us with valuable feedback which we will outline and discuss in this section. Key figures of survey results can be found in *Appendix A*.

Breakdown of Participant Roles & Vehicles Driven

- For the management survey, about two thirds of respondents were either directors/managers or supervisors, with the remaining participants in various roles ranging from analysts to field operators. Over 40% of respondents drive either a cars or pickups, another 40% drive a van, and several respondents drive single bucket aerial trucks.

- For the driver/operator survey, there was a wide spectrum of respondents' roles ranging from certified crew leaders to technologists to mechanics. Over 40% of vehicles driven by respondents were pickups and passenger minivans, with the remaining covering a range of vehicle types from cars to cube vans to single/double bucket aerial trucks.

Views on Battery-Electric Vehicles

- There is strong agreement in both the management and driver/operator groups participants that BEVs can travel far enough to meet daily needs and are capable of performing job duties (mean scores ranging from 4.1/5 and 4.3/5).

- There is strong agreement in the management group that there is sufficient heating and cooling in BEVs (mean score of 4.0/5). However, the driver/operator group is generally undecided on this matter (mean score of 3.3/5).

- There is strong agreement in both groups that BEVs are safe to drive and charge, with some more hesitancy in driver/operator group (median scores of 5/5 and 4/5 in the management and driver/operator groups, respectively).

- Overall, both groups are undecided as to whether BEVs costs less to operate and will save money for Toronto Hydro (mean scores of 3.8/5 and 3.6/5 in the management and driver/operator groups, respectively).

- There is strong agreement in both groups that BEVs cause less pollution than standard gas and diesel vehicles, with slightly stronger agreement in the driver/operator group (mean scores of 4.1/5 and 4.3/5 in the management and driver/operator groups, respectively).

- In both groups, there is a lack of consensus and a wide range of opinions as to whether BEVs of the type Toronto Hydro requires are available now or will be available in the near future (mean scores of 3.7/5 and 3.6/5 in the management and driver/operator groups, respectively).

Views on Charging Requirements

- Overall, in both groups, there is a lack of agreement as to whether investing in Level 2 charging infrastructure would be sufficient for most of the BEV charging needs of Toronto Hydro (mean scores of 3.5/5 and 3.4/5 in the management and driver/operator groups, respectively).

- About 60% of respondents in both groups agree or strongly agree that investing in Level 3 charging infrastructure would be required to fulfil Toronto Hydro's BEV charging needs. Overall, there is slightly stronger agreement on this topic in the management group (mean score of 3.9/5 and 40% of respondents strongly agree) than in the driver/operator group (mean score of 3.8/5 and more than 40% of respondents undecided).

- In both groups, there is a lack of consensus and a wide range of opinions as to whether high-voltage safety awareness and/or training would be needed for operating and maintaining Toronto Hydro's electric vehicle charging stations (mean scores of 3.1/5 and 2.8/5 in the management and driver/operator groups, respectively).

Views on Change Management

- The majority of respondents in both groups agree that Toronto Hydro employees and operators would benefit from BEV educational and outreach materials (mean scores of 3.8/5 and 3.7/5 in the management and driver/operator groups, respectively), with stronger agreement in the management group (over 62% agree/ strongly agree vs. just under 55% in the driver/operator group).

- There is stronger agreement in the management group than the driver/operator group that Toronto Hydro operators would benefit from BEV test drives (mean scores of 4.2/5 and 3.8/5, respectively). Eighty (80) percent of management participants agree or strongly agree with this idea, versus under 60% in the driver/operator group.

- In both groups, there is strong agreement that operators would benefit from BEV orientation provided before releasing new models into the fleet (mean score of 4.0/5 for both groups). Seventy-five (75) percent of management participants and about 80% of driver/operator participants agree or strongly agree with this idea.

Comments & Concerns

At the end of the survey, participants were given the opportunity to provide their own comments in a "freestyle" section that allowed for additional thoughts and ideas on transitioning to electric vehicles.

There were several common thoughts and/or concerns from participants, including:

- Ensuring there is sufficient EV range in the winter for high-mileage vehicles.

- Ensuring there is a full charge to start the day, particularly for high-mileage vehicles in the winter when ranged is reduced.

- The benefit of Level 3 charging for particular applications, including vehicles taken home on standby as well as vehicles used in field operations.

- The benefit and successful application of electric light-duty vehicles (cars, pickups, and vans) in the fleet, but concern over the viability of larger electric trucks including bucket trucks and line trucks.

We have selected the following comments that were, overall, representative of participants' view on the matters of moving towards an electric fleet:

"As a utility, Toronto Hydro should be an early adopter of EV technology."

"I would love to see a shift in electric vehicles at Toronto hydro mainly, pickups, vans and small cars at the start and then move to a half and half system on our buckets and cranes"

"The only issue [with the Chevrolet Bolt] is with winter range which is approx 225k. If I take the vehicle home on Standby, I typically will have no range to do crew visits the following day and have enough range take it home again. There is also not enough time to charge it sufficiently. This is where I think a Level 3 charger might be of benefit."

"In general, I believe this is the right way to go. Only concern is that my team (metering) does a fair number of KMs per day. Need to ensure that even at -40, there is sufficient charge for the day and that overnight charging will consistently ensure the team starts with a full charge."

"YES electric vehicles and charging stations would be great, I think a job aid would be better than formal training"

"[EVs are] good to have but we will always need a good number of combustion engines. If there is an ice storm or other rolling blackouts, gas and diesel powered trucks will be invaluable"

Synopsis

Based on the results of this survey and participant comments, it is clear that Toronto Hydro Fleet's user-group stakeholders are, overall, very supportive of the transition to electric vehicles.

Although views are mostly similar, there are some differences in opinions between the management and driver/operator cohorts regarding views of electric vehicles. Generally, drivers/operators are more doubtful/unaware of the capabilities and benefits of modern-day electric vehicles.

Regarding charging requirements, both groups are generally undecided about the adequacy of Level 2 (slow) charging for the fleet, and feel more strongly about the use of Level 3 (fast) charging. RSI-FC's analysis of Toronto Hydro's charging requirements based on Level 2 charging (see *Section 7*) addresses this very concern.

In terms of change management approaches, survey results show that driver/operators are moderately supportive of BEV test drives but are highly in favour of BEV orientation, while managers are in strong support of both options. Efforts in familiarizing employees with driving and charging

BEVs would likely close knowledge gaps, hesitancies, and resistance towards this technology, allowing for a more seamless transition over the coming years.

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Section 3: General Approach and Methodology

RSI-FC maintains that fleet asset management plans must be sustainable – both environmentally and financially. For this reason, RSI-FC's approach to developing Toronto Hydro's Electric Vehicle Phase-in Plan is based on data-modelling of the current situation, data-modelling of optimized unit lifecycles considering return-on-investment (ROI), and assessing a number of electrification pathways to find a viable and financially prudent approach for the utility to transition its fleet to BEVs.

To achieve optimal efficiency in completing this type of analysis, our team developed Fleet Analytics Review™ (FAR), a software tool designed specifically for complex green fleet planning and evaluation of short- to long-term fuel-reduction strategies, including BEV transition, both in terms of cost savings and GHG reductions.

About Fleet Analytics Review™

Fleet Analytics Review™ (FAR) is a user-friendly, interactive decision support tool. FAR was designed to aid our team and fleet managers in developing short- to long-term green fleet plans by calculating the impacts of vehicle replacement and fuel-reduction solutions on operating costs, cost of capital, and GHG emissions. Moreover, it is used for long-term capital planning (LTCP) through an approach that works to balance, or smoothen, annual capital budgets and avoid cost spikes if possible. For a detailed FAR description, please see *Appendix B*.

Using optimized economic lifecycles, fuel-saving options, including switching to BEVs, are modelled for units due for replacement to determine if they can deliver operating cost savings over subsequent fiscal years and, if so, the potential GHG emissions reductions. In FAR, operating costs include fuel costs, repair and maintenance costs, and the cost of capital of acquiring units based on their year-over-year book values.

Transitioning to BEVs is the ultimate GHG reduction strategy for a fleet. In our analysis for Toronto Hydro, we modelled tailpipe emissions reduction; therefore, switching a unit to battery-electric reduces fuel consumption by 100% applying this method. However, in terms of life cycle GHG emissions, BEVs are "fuelled" by electricity needed to charge the battery, which can indirectly use fossil fuel depending on the source of electricity.

FAR will be licensed in perpetuity to Toronto Hydro for its internal use post-project. The FAR model is dynamic, and users can easily run future scenarios (such as assessing different vehicle types, fuels, or technologies) to see how such decisions impact operating expenses – ahead of their implementation, thereby heading off potentially costly errors.

Steps to Producing Electric Vehicle Phase-in Plan

RSI-FC employs a multi-step approach in low-carbon, green fleet planning. In Toronto Hydro's Electric Vehicle Phase-in Plan, the steps included:

1) **Baseline Analysis.** At the outset, it is crucial to confidently know the current fleet baseline in terms of several key performance metrics including acquisition and operating costs, fuel economy, and GHG emissions. For this step, we complete a FAR baseline analysis.

   For Toronto Hydro, we received baseline data of the in-scope fleet from Fleet Management. The dataset provided to our team included a list of units, makes/models/years, asset values and ages, asset descriptions, fuel types, fuel costs, repair costs, and maintenance costs for a one-year review period (2019). We loaded this input data into FAR and completed baseline analysis.

2) **Lifecycle Analysis.** With RSI-FC's proprietary lifecycle analysis (LCA) software tool, our team inputs a fleet's historical data to calculate the optimal economic lifecycles for each vehicle category in the fleet.

   For Toronto Hydro, we completed an LCA study for all vehicle categories in 2017 to determine optimized economic lifecycles. With support from Toronto Hydro Fleet Management, optimized economic lifecycles determined from this study were applied to the 2020-21 FAR baseline.

3) **Business Case Optimization.** Once optimized lifecycles have been modelled in FAR, it often becomes very apparent that some vehicles deliver better return-on-investment (ROI) than others. One reason is that some vehicles that are due for replacement may have had lighter usage than other similar age units. For vehicles in better condition, service life can be extended to optimize the total cost of ownership (TCO). Lower ROI would result if a vehicle, still in good condition, was replaced prematurely; value will be lost. Fleet managers everywhere must make tough vehicle replace-or-retain decisions like this each year to optimize and stretch the use of available capital. Using RSI-FC's ROI-based approach to deferrals, year-over-year long term capital budgets can be better balanced.

   For Toronto Hydro, the approach used by RSI-FC's data analysts was to *defer* replacement of some vehicles to the ensuing capital budget years to ensure full value is received from each unit. Ideally, this step should be completed by Fleet staff based on vehicle condition assessments and to balance go-forward annual capital budgets. Without any knowledge of vehicle condition, for this step our team deferred any units which, based on the data provided, were shown to have lower operating costs (including cost of capital) than if replaced.

This step was intended to provide a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – as a comparison for long-term capital planning for BEV phase-in.

4) **Battery-Electric Vehicle Phase-in Planning.** Although there are numerous advantages of BEVs, few, if any fleets would – or could – replace all their internal combustion engine (ICE) units immediately with BEVs given capital budgets constraints and the fact that BEV offerings are quite limited at this time. This means that BEVs must be phased in over many years. For this reason, we data-model the gradual impacts of fleet BEV adaptation on a 15-year phased-in basis.

   Phasing in of BEVs should occur based on optimized economic lifecycles and balanced long-term budgets through business case optimization (see Step 3). In other words, the first units to be replaced with BEVs should be those that have been assessed as the optimal candidate vehicles that will deliver the best ROI. These are typically units with higher utilization and fuel consumption.

   However, given the currently limited availability of BEVs as well as the long procurement timelines once models do become available for purchase, BEV phase-in planning becomes a balancing exercise between: (1) extending the life of ICE vehicles until BEV counterparts are expected to arrive (i.e., in-service years); and (2) immediately replacing due units that have high utilization and/or relatively high repair costs with ICE vehicles.

   For Toronto Hydro, our team used FAR to conduct a granular, unit-by-unit assessment of BEV replacement – both as a short-term financial risk-reduction strategy and a long-term capital planning strategy. Based on baseline data provided, we decided (for modelling purposes only) which units to replace with ICE vehicles and which to replace with BEVs through extension of their lifecycles, keeping in mind the fiscal years for which the type/categories of BEVs are expected to be in-service based on procurement timelines.

   Given the higher acquisition costs of BEVs compared to ICE vehicles, which were applied to our modelling in consultation with Toronto Hydro Fleet Management, lower-mileage units are unlikely to deliver ROI if replaced with a BEV. Fortunately, these would also generally be the units that have a relatively small impact on GHG emissions reductions. However, ROI is dependent on BEV pricing outcomes. There is a strong likelihood that the acquisition cost of BEVs will decline with time as both supply increases and as battery technology continues to improve, and we have modelled this scenario for the utility's consideration.

5) **Electric Vehicle Supply Equipment Planning.** Our team developed an EVSE planning tool for Toronto Hydro to inform long-term capital planning (LTCP) for the utility's charging

infrastructure needs, based on Level 2 charging and battery capacity estimations. We also estimated the costs of electric vehicle chargers (not complete infrastructure) over the modelling period from 2022-2037, based on the current size and mileage of Toronto Hydro's fleet and a balanced, fleet-wide BEV phase-in.

RSI-FC's position is that fleets should not be keeping up with the demand for electric vehicle supply equipment (EVSE) based on the number of new BEVs added; rather, EVSE installation should be *outpacing* demand to allow for a smooth and seamless transition. Therefore, we have estimated the number of Level 2 chargers required to outpace the influx of new BEVs into Toronto Hydro's fleet.

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Section 4: Baseline Analysis

A fleet baseline analysis provides a starting point for setting targets and measuring progress towards fuel- and GHG-emissions reduction. It is important that a baseline is as accurate as possible as it provides a snapshot of the current state of a fleet and is the foundation of a fleet management plan.

The Electric Vehicle Phase-in Plan is based on our team's detailed data analysis of one-year of historical data for **385 Toronto Hydro fleet vehicles** as submitted by the utility. RSI-FC collected baseline data of Toronto Hydro's fleet from Fleet Management. The dataset provided to our team included a list of units, makes/models/years, asset values and ages, asset descriptions, fuel types, repair costs, and maintenance costs for a one-year review period (2019). Our team then loaded input data into our proprietary software, Fleet Analytics Review™ (FAR), and completed a baseline analysis.

RSI-FC diligently collected and analyzed vehicle data provided by Toronto Hydro and made careful estimations and assumptions where needed. Key fleet-wide results from the one-year review period (August 2020 to July 2021) are shown below:

- There were 211 gasoline-powered units, 160 diesel-powered units, 1 plug-in hybrid-electric (PHEV) units, and 13 battery-electric vehicle (BEV) units.
- All units were owned.
- The original purchase price for the fleet was $48,630,000.
- The current-day estimated replacement cost (like-for-like replacements) was $67,549,000.
- The estimated market/trade-in value was $22,359,540.
- The total cost of preventive maintenance (PM) was $481,389.
- The total cost of reactive repairs was $1,663,860.
- The estimated total cost of fuel was $757,168.
- The total cost of repairs and maintenance, fuel, capital, and downtime was $4,399,845.
- Total kilometres-travelled was 1,796,605.
- Total fuel used was 633,851 litres.
- Total tailpipe GHG emissions were 1,624 metric tonnes CO_2e.
- The average unit annual mileage was 4,667 km.
- The average fuel consumption for the entire fleet was 56.6 l/100km.
- The average unit age was 6.7 years.

The baseline analysis sets the foundation for the next stages of the Electric Vehicle Phase-in Plan, starting with long-term capital planning (LTCP) for like-for-like replacements to determine a capital budgeting benchmark. The next stage involved modelling several electrification pathways for Toronto Hydro's fleet to provide an ambitious, yet feasible, roadmap for the utility to phase-in BEVs and achieve significant GHG emissions reductions in a fiscally responsible using a structured, methodical approach.

Section 5: Business Case Optimization and Capex Benchmarking

Providing capital to replace units each year with new vehicles is essential for any organization that relies on its fleet to provide its core services to customers. A guideline for fleet replacement is to invest capital at the rate of depreciation. For example, if vehicles are depreciated over ten years, then 10% of the total fleet replacement cost (current NPV) would be required each year to maintain the fleet's average age at the desirable level.

For Toronto Hydro, based on the current-day estimated replacement cost (like-for-like replacements) determined in the baseline analysis, about $6.8M would be required every year if vehicles are depreciated over 10 years. However, this guideline is only valid if performance indicators such as uptime and fuel-efficiency are satisfactory. If not, a one-time increase in spending would help bring the fleet's average age and performance up to an acceptable level.

Moreover, specific categories of vehicles have, on average, differing optimal lifecycles. Decisions to shorten or extend lifetimes of individual units are, of course, dependent on vehicle condition, mileage, and identification of "lemons" in a fleet. A lifecycle analysis (LCA) study conducted by RSI-FC in 2017 helped to provide Toronto Hydro with a data-driven method of optimizing lifecycles for vehicle categories.

To establish a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – as a comparison for long-term capital planning for BEV phase-in – our team conducted a Capex balancing exercise by deferring units shown to have low ROI if replaced prematurely.

2017 Lifecycle Analysis Summary

In 2017, a lifecycle analysis (LCA) study was undertaken by RSI-FC for each vehicle category at Toronto Hydro to determine optimized economic lifecycles. The LCA study took into consideration the cost of downtime (as caused by reduced reliability), the year-to-year "rollup" of weighted average cost of capital (WACC), inflation, worker cost/hour, salvage and market values, inflation, and average kilometres-driven data.

A discounted cash flow analysis was completed for each vehicle category to complete the LCA. Net present value (NPV) was calculated for outgoing cash flows (vehicle purchase cost, maintenance cost, the impact of downtime on driver productivity cost, improved fuel efficiency of a new vehicle compared to the old vehicle) and incoming cash flows (vehicle residual value) to calculate the total lifecycle cost for various vehicle retention periods.

With support from Toronto Hydro Fleet Management, optimized economic lifecycles determined from this study were applied to the 2020-21 baseline – serving as a starting point for the Electric Vehicle Phase-in Plan. The results from the 2017 study are summarized in *Table 3*.

Table 3: 2017 Lifecycle Analysis Results Applied to 2020-21 Baseline

Vehicle Category	Optimal Lifecycle Calculated through LCA (years)
Car	9
Cargo Minivan	7
Passenger Minivan	9
Full Size Van	10
Pickup	9
SUV	8
Cube Van	12
Single Bucket Aerial Device	12
Single Bucket Van Mount Aerial Device	11
Cable Truck	11
Crane Truck	10
Dump Truck	8
Line Truck	13
Double Bucket Aerial Device	14
Digger Derrick	13

Vehicle Condition Assessments

Replacement cycles should be considered a guideline only, as some vehicles in poor or unsafe condition may require replacement before the criteria are met. Conversely, some vehicles that exceed the criteria may be in good condition and may not warrant replacement. Fleet managers, of course, need to exercise judgment and fleet management principles in either advancing replacement or delaying replacement of individual vehicles case by case. A thorough ground-up and top-down physical assessment of each vehicle's condition, in conjunction with routine shop visits for preventive maintenance inspections, would serve to inform decisions around extending vehicle lifecycles during the waiting period for BEV models.

Recommendation

- In the context of BEV phase-in and determining which unit lifetimes to extend and which to not, our recommendation is to store vehicle condition information in Excel format or another database for easy access and tracking of summaries and/or analyses. A simple rating system such as a numerical 1 to 5 indexing where 1 = poor condition and 5 = good condition would greatly assist in determining the highest priority units for ICE replacement. If each vehicle's condition rating (1 to 5) was posted in each vehicle's profile in Excel or a software program, it could be easily accessed for capital budget planning.

Long-Term Capital Planning

After modelling the baseline with optimized economic lifecycles, the Fleet Analytics Review™ (FAR) software tool enables methodical, well-informed business decisions for long-term capital planning (LTCP) purposes.

Vehicle data provided by Toronto Hydro for the baseline year (2020-21) was input into FAR, and the tool calculated capital budgets for the ensuing fifteen years driven by vehicle lifecycles based on the optimized economic lifecycles that were calculated from the 2017 LCA study.

On a unit-by-unit basis, FAR calculates:

(1) Whether replacing units due for replacement would save Toronto Hydro operating expenses (Opex) or cost additional money; and
(2) The GHG-reduction impacts of vehicle replacements.

The tool also calculates and displayed the costs (operating and capital) and GHG impacts of those decisions for the fleet as a whole.

Typical of most fleets, year one of Toronto Hydro's LTCP showed a cost spike caused by previously deferred vehicles (see results in next sub-section). Replacement of some of these units can be again delayed because they are still in good serviceable condition, have low mileage, or perhaps have just received a costly refurbishment that will extend the unit's life. These decisions, which are typical for fleet managers everywhere that must adhere to a capital spending limit, can be aided by using FAR which displays to the user whether cost-savings are possible by replacing a unit.

In FAR, replacement of units shown not to provide return-on-investment (ROI) can be deferred to following years until replacement yields a net decrease in Opex or until replacement is deemed necessary from a financial risk reduction point-of-view – as units kept well beyond their optimal lifecycle have a greater chance of unexpected repair costs. Following this method, a fleet manager can balance go-forward annual capital expenses (Capex) and avoid year-over-year cost spikes. This approach can keep the average age of the fleet at an acceptable level, provide the lowest cost and highest uptime, and reduce emissions through strategically acquiring new (lower emission) vehicles.

While historical data in FAR demonstrates whether a business case exists for vehicle replacement, the final step, of course, in LTCP depends on fleet management personnel's expertise through vehicle condition assessments, as explained earlier. *No software tool can supplant this crucial human role in capital budget planning.*

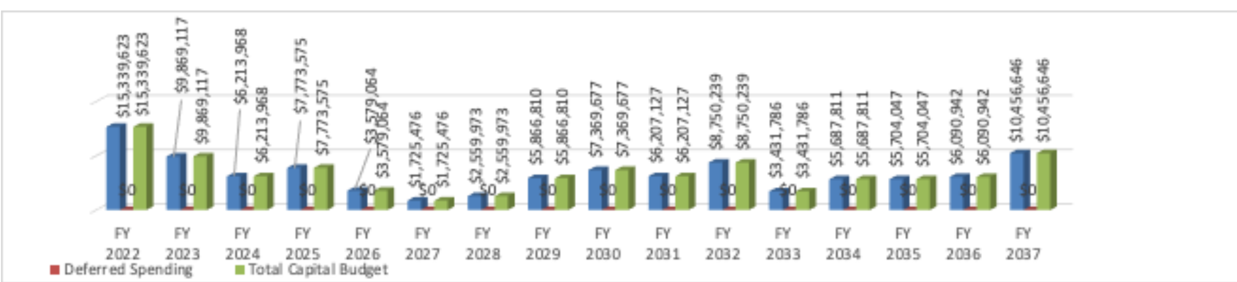
For modelling purposes only, our team conducted a Capex balancing exercise by deferring units shown to have low ROI if replaced prematurely. This established a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – as a comparison for long-term capital planning for BEV phase-in (covered in *Section 6*).

Optimized Economic Lifecycles – Results

FAR Scenario One modelled a 15-year budget cycle based on Toronto Hydro's optimized economic lifecycles determined in the 2017 LCA study.

As illustrated in *Figure 1* (below), it was estimated that, in 2022, $15.3 million would be required to replace all due or past-due units with new like-for-like vehicles (no BEVs at this stage). It should be noted that numerous vehicles in the Toronto Hydro fleet are *beyond the current planned age* for replacement – *significant "catch-up" is required to modernize the fleet.* In ensuing years, far fewer vehicles require replacement, bringing down capital spending to as little as $1.7 million in 2027. However, there is an uneven capital spend projected throughout the budget period.

Figure 1: Projected capital budget (blue), deferred spending (red), and total capital budget (green) for optimized economic lifecycles from 2022-2037



Balanced Capex – Results

Once optimized economic lifecycles were modelled, it became apparent that some vehicles deliver better ROI than others. Some vehicles in the fleet may have received lighter usage than other similar age units, which may have been worked harder. Vehicles in better condition and/or with lower mileage can have their service life extended to optimize their lifetime total cost of ownership (TCO).

Lower ROI would result if a vehicle, still in good condition, was replaced prematurely; value will be lost.

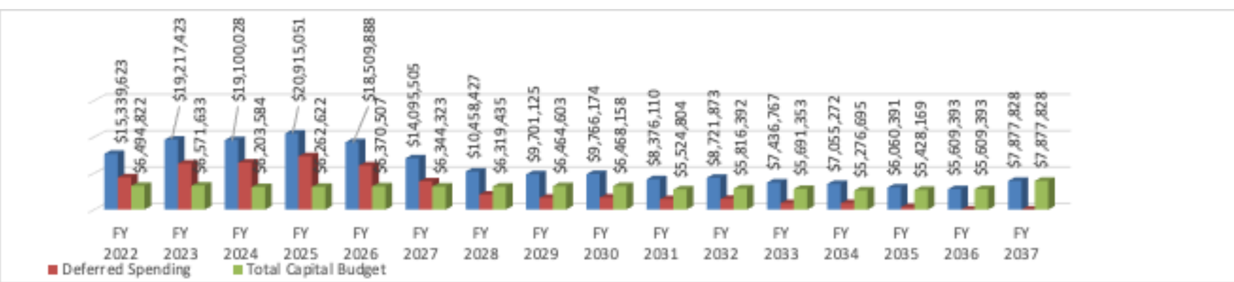
For FAR Scenario Two, the approach used by RSI-FC was to defer some vehicles to ensuing capital budget years to ensure full value is received from each unit. As third-party consultants without access to information to vehicle condition, and to reduce and apportion the required capital for vehicle replacement over a more extended period, we opted to defer using the following criteria:

(1) Units with low/no ROI
(2) Units that have most recently became due for replacement (to ensure past-due units get higher priority for replacement)
(3) Lower-accumulated mileage units (to ensure that higher-mileage units are replaced first)

Using this prioritization protocol, we selectively and strategically made deferrals over the budget cycle to maximize Opex benefits and balance Capex to the best of our ability. As a result, Capex is much more balanced over the budget cycle than FAR Scenario One.

As illustrated in *Figure 2* (below), the net result was an average annual capital budget of $6.2 million with annual amounts ranging from $5.3-7.9 million with clustering around $6-6.5 million, as compared to the much wider and more fluctuating range over the budget period for optimized economic lifecycles only as in FAR 1 (*Figure 1*, above).

Figure 2: Projected capital budget (blue), deferred spending (red), and total capital budget (green) for balanced Capex from 2022-2037



Recommendation

- Consider using RSI-FC's Fleet Analytics Review™ (FAR) software tool to extract maximum value from each vehicle by assessing whether cost-savings are possible by replacing a unit.

Section 6: Electric Vehicle Phase-in Planning

The primary objective of the Electric Vehicle Phase-in Plan was to analyze Toronto Hydro's in-scope fleet data and identify and assess electrification pathways with varying degrees of implementation and pricing outcomes.

RSI-FC first prepared the baseline from data provided by the utility for the review period (2019), including capital expenses (Capex) and operating expenses (Opex) for all units. From the baseline, we modelled a 15-year budget cycle (to 2037) for optimized economic lifecycles determined through lifecycle analysis (LCA), and then balanced Capex by deferring units shown to have low return-on-investment (ROI) if replaced prematurely. This established a data-driven benchmark for a balanced long-term capital budget if *like-for-like* replacements were to be made – as a comparison for long-term capital planning for BEV phase-in.

Starting from the baseline, we modelled a number of fleet electrification scenarios ranging from aggressive and over-budget to balanced and within budget – to demonstrate a spectrum of pathways. Although BEV phase-in is the most effective long-term GHG reduction strategy for a fleet, the reality is that there are currently higher upfront costs associated with the transition; therefore, it must be done in a fiscally responsible manner.

Based on our modelling, lower-annual mileage units at Toronto Hydro are unlikely to deliver ROI if replaced with a BEV at this time. To provide a viable BEV phase-in plan, our team strategically modelled the replacement of overdue lower-annual mileage units with internal combustion engine (ICE) vehicles in an effort to still achieve GHG emissions reductions while keeping within budget constraints. Moreover, we modelled replacement of overdue units that showed high usage and/or relatively high repair costs with ICEs as a financial risk-reduction strategy.

Overview of Battery-Electric Vehicles

Here, we provide an overview BEVs, including their benefits and expected market availability for different classes. More details on BEVs and charging can be found in *Appendix C*.

Why BEVs?

Air quality is a growing concern in many urban environments and has direct health impacts for residents. Tailpipe emissions from internal combustion engines are one of the major sources of harmful pollutants, such as nitrogen oxides and particulates. Diesel engines in particular have very high nitrogen oxide emissions and yet these make up the majority of the global fleet. As the world's urban population continues to grow, identifying sustainable, cost-effective transport options is becoming more critical. Battery-electric vehicles (BEVs) are one of the most promising ways of reducing harmful emissions and improving overall air quality in cities.

Globally, numerous jurisdictions have already legislated the end of the ICE – some as soon as 2030. On January 28, 2021, General Motors pledged to cease building gasoline and diesel cars, vans, and SUVs by 2035. Even more recently, on June 29, 2021, the Canadian government announced a mandatory target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100 percent sales by 2040[20]. ICE vehicles purchased today for a fleet with a current-day value in the millions of dollars may be nearly worthless when ICEs become obsolete.

Fleet managers who operate BEVs will see reduced maintenance and fuel costs. BEVs have considerably fewer parts than internal combustion engine (ICE) vehicles. A drivetrain in an ICE vehicle contains more than 2,000 moving parts, compared to about 20 parts in an BEV drivetrain. This 99% reduction in moving parts creates far fewer points of failure, which limits and, in some cases, eliminates traditional vehicle repairs and maintenance requirements, creating immense savings for fleet managers. BEVs do not require oil changes or tune-ups, do not require diesel exhaust fluid (DEF), and their brake lining life is greatly extended over standard vehicles due to regenerative braking.

In recent years, BEV range has been considerably extended, thereby providing much wider BEV applications and reducing range anxiety. Today, many light-duty BEV models have EPA-estimated ranges exceeding 400 km, which provide much greater reliability when travelling longer distances.

The time required to charge BEVs is dependent on charging speed and battery size. For a battery-electric car or SUV, a full charge using a Level 2 charger takes several hours, but charging from a nearly depleted battery to 70% at a fast (Level 3) charging station can take only 30 minutes[21]. However, heavy-duty trucks charged between 50 and 100 kW (equivalent to DC fast charging) would potentially take several hours to charge[22] due to their much larger battery size.

Although recharging a BEV can take significantly longer than refuelling a conventional vehicle, most charging in a low-mileage fleet like Toronto Hydro can be done overnight in off-peak hours via Level 2 charging. Please see *Section 7* for details on RSI-FC's analysis of Toronto Hydro's charging requirements.

Battery-Electric Light-Duty Vehicles

There are multiple light-duty cars and SUVs currently on the market; current examples include the Nissan Leaf, Chevrolet Bolt (13 units currently owned and operated by Toronto Hydro), Kia Soul, and the Tesla Model 3. All with sufficient range for fulfilling daily duties, these vehicles have demonstrated that electrification is not only possible, but also convenient and within an acceptable and affordable

[20] Source: https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html
[21] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[22] Source: https://www.plugincanada.ca/electric-bus-faq/

price range, particularly when considering fuel and maintenance cost savings over the vehicle's lifetime.

The "workhorses" of utility fleets like Toronto Hydro are light-duty pickup trucks and vans. For Toronto Hydro's fleet, pickups and Class 1 and 2 vans comprise about 42% of the vehicles based on the data provided (84 pickups and 78 light-duty vans out of a total of 385 vehicles). Therefore, BEV options in the light-duty pickup and van categories have the potential to make a significant impact on the utility's fleet operating cost savings and GHG emissions reduction. At this time, there are no BEV pickups or vans available for purchase. However, several manufacturers, including General Motors and Ford, are preparing for BEV pickups and vans to enter the market in 2022.

Battery-Electric Trucks

Medium- and heavy-duty battery-electric trucks (BETs) are quickly being developed by many manufacturers. Almost all truck manufacturers have announced plans to launch battery-electric trucks in these classes soon, which will likely become available for purchase by 2023. However, several manufacturers are taking orders now, including Lion Electric, Tesla, and Navistar.

Like all BEVs, BETs offer a multitude of benefits with some additional ones given their size and load, including:

- Less noise pollution
- Zero tailpipe GHG emissions
- Oil-free operation with very few moving parts
- Simple, low-maintenance electric powertrain with few components
- Longer lasting brakes due to regenerative braking system
- Potential to significantly extend range due to high regenerative braking from carrying heavy loads[23]. The heavier the truck load, the greater the energy produced from regenerative braking.
- Overnight recharging when the vehicle is not in operation and when demand for electricity is lower, which reduces energy costs
- Massive savings potential in total energy costs and service costs

[23] Source: https://www.firstpost.com/tech/science/worlds-largest-electric-vehicle-is-a-110-tonne-dump-truck-that-needs-no-charging-7190131.html

BEVs – Feasibility Considerations

- Caution must be exercised to ensure longer charging times do not create operational challenges. However, most charging in a low-mileage fleet like Toronto Hydro can be done overnight via Level 2 charging. Please see *Section 7* for details on RSI-FC's analysis of Toronto Hydro's charging requirements.

- Extreme cold temperatures can significantly reduce range in BEVs due to heating of the cabin and heating of the battery itself[24]. Therefore, it is important to account for this when purchasing BEVs to ensure sufficient range is provided to cover a day's worth of routes in the heart of winter. However, in a low-mileage fleet like Toronto Hydro this would likely not pose an operational issue for most units. Please see *Section 7* for details on RSI-FC's analysis of Toronto Hydro's charging requirements.

- Power grid failure or local failure at a site/garage could pose a significant risk to Toronto Hydro's operations. To mitigate this risk, backup generators can deal with short power outages. For longer outages, larger generators would be needed, but this would come at a very expensive cost.[25]

BEV Phase-in Approaches

RSI-FC data-modelled several fleet electrification scenarios ranging from aggressive and over-budget to balanced and within budget – to provide a spectrum of options that Toronto Hydro can use to inform their purchasing decisions.

For each scenario, FAR calculated annual GHG emissions, operating costs, and capital requirements from 2022 to 2037 – providing multiple long-term capital planning (LTCP) outlooks based on the speed and degree of implementation of BEVs into Toronto Hydro's fleet. These "what-if" scenarios assess the potential outcomes of BEV phase-in for the same vehicles, the same number of vehicles, travelling the same number of kilometres as the baseline period.

For balanced scenarios considering budget constraints, our team used Fleet Analytics Review™ (FAR) to conduct a granular, unit-by-unit assessment of BEV replacement – both as a short-term financial risk-reduction strategy and a long-term capital planning (LTCP) strategy. Based on baseline data provided, we decided (for modelling purposes only) which units to replace with ICE vehicles and which to replace with BEVs through extension of their lifecycles, keeping in mind the fiscal years for which the type/categories of BEVs are expected to be in-service based on procurement timelines provided by Toronto Hydro (*Table 4*).

[24] Source: https://www.geotab.com/blog/ev-range/
[25] Source: https://www.plugincanada.ca/electric-bus-faq/

Table 4: Toronto Hydro procurement timelines for different vehicle types

Vehicle Type	Timeline from RFP Submission to Final In-service Date
Light-duty	~1 year
Medium-duty	~2 years
Heavy-duty	~3 years

For both the aggressive and balanced BEV phase-in scenarios, units due for replacement showing low ROI in our FAR modelling were deferred to subsequent fiscal years in an effort to minimize operating expenses (Opex) and optimize capital expenses (Capex). Moreover, for modelling purposes we opted to extend the optimal lifecycles for all light-duty vans to 12 years and pickups to 11 years – as a strategy employing a temporary pause (when appropriate) on replacing ICE van and pickups, which comprise a very large portion of Toronto Hydro's fleet, until equivalent BEV models are expected to be in-service.

Aggressive, Fleet-wide BEV Phase-in

The aggressive approach to BEV phase-in involved fleet-wide replacement with BEVs and shortened procurement timelines. For demonstration and comparative purposes, this scenario shows what a higher-pace transition would look like from a capital budgeting perspective with lower-than-expected market availability and/or wait times for new vehicles.

Expected BEV in-service years in our modelling, based on shortened procurement timelines than the ones provided by Fleet Management, are as follows:

- SUVs: orders placed immediately and models in-service 2022 onward (less than 1-year wait time)
- LD vans and pickups: orders placed in 2022 and models in-service 2023 onward (1-year wait time)
- MDVs: orders placed in 2023 and models in-service 2024 onward (1-year wait time)
- HDVs: orders placed in 2023 and models in-service 2024 onward (1-year wait time)

Balanced, Selective BEV Phase-in

The balanced approach to BEV phase-in involved more ICE replacements (for appropriate units, mainly HDVs) as well as in-service based on procurement timelines provided by Toronto Hydro. The purpose of this exercise was to align with Toronto Hydro's procurement timelines and stay within capital budget constraints while *still* achieving significant GHG emissions reductions by the end of the modelling period (i.e., 2030s).

Taking this approach, the budget is much more balanced year-over-year than the aggressive BEV phase-in approach, and does not require significantly more capital spending as compared to the like-for-like replacement benchmark (see results and comparisons in the next sub-section). This approach employs a strategy that calls for increased capital spending upfront (i.e., in the next few years) to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements, which allows for balanced capital spending on BEVs down the road.

Expected BEV in-service years in our modelling, based on more cautious order dates for LD vehicles, as well as (longer) procurement timelines provided by Fleet Management, are as follows:

- SUVs: orders placed in 2022 and models in-service 2023 onward (1-year wait time)
- LD vans and pickups: orders placed in 2023 and models in-service 2024 onward (1-year wait time)
- MDVs: orders placed in 2023 and models in-service 2025 onward (2-year wait time)
- HDVs: orders placed in 2023 and models in-service 2026 onward (3-year wait time)

We made the presumption that fossil-fuelled vehicle replacements would be in-service over shorter timelines than BEVs at the beginning of the budget period – reasoning that some replacements have already been confirmed are thus "in queue." Otherwise, there would be a pent-up demand for overdue units in the short- to mid-term creating an unavoidable spike in Capex.

Although we have made every effort to ensure that the business assumptions and estimates employed in our analysis are as accurate as possible, we acknowledge that FAR is not intended to be accounting-accurate but rather provide Toronto Hydro a viable pathway for achieving electrification of its fleet in consideration of budget constraints and procurement timelines.

To select the units to replace with ICEs, we created a "decision matrix" containing key indicators from Toronto Hydro's fleet baseline data that helped to highlight which units were most suitable candidates for ICE replacement. These indicators include:

- Lifetime kms (flagged if greater than 120,000 km)

- Review period kms (flagged if less than 5,000 km; this would indicate low ROI with BEV replacement as well as low impact in terms of GHG reduction)

- Preventive Maintenance/reactive repair ratio (flagged if less than 0.25; this would give an indication of vehicle condition based on data only and flag potential cases where a unit should be replaced sooner)

- Lifecycle remaining (flagged if the unit is due for replacement before expected BEV in-service years)

- Lifecycle remaining plus 2-yr deferral (flagged if, with a 2-yr deferral, the unit is due *still* due before expected BEV in-service years)

The various "flags" allow for an informed, structured method of holistically deciding, for modelling purposes, which vehicles should be replaced with ICE units due to high usage and/or relatively high repair costs, and which vehicles should be replaced with ICE units simply because they have such low-kms and, therefore, have much less ROI and contribute relatively little GHG emissions. Of course, as described in *Section 5*, a physical assessment of each vehicle's condition would be required to inform decisions around which units to replace with ICE units and which to extend lifecycles during the waiting period for BEV models.

The overall purpose of completing and applying this exercise to the FAR modelling was to obtain results that stay within Toronto Hydro's budget while still achieving high GHG emissions reduction. It would be very possible to fully convert the fleet to electric by 2040 – or perhaps sooner – depending on BEV pricing outcomes, as will be outlined next.

BEV Pricing – Cautious

In discussion with Toronto Hydro Fleet Management and based on current MSRP ratios when comparing BEVs to conventional ICE vehicles, we have applied the following BEV/ICE acquisition cost ratios to our modelling:

- SUVs: 1.48
- Pickups: 1.74
- Full size vans: 1.66
- Medium-duty units: 1.75
- Minivans: 1.57 (since there is no EV option currently in the market, the ratio was estimated to be between SUVs and full size vans)
- Heavy-duty units: 2 (this is a cautious estimation that includes the cab/chassis and body portions)

We have applied these ratios to the entire modelled budget period for both the aggressive and balanced BEV phase-in scenarios as a cautious pricing approach that does not assume any future BEV price reduction.

Based on these BEV/ICE acquisition cost ratios, the current-day estimated BEV replacement cost for Toronto Hydro's fleet is $127.7M as compared to the current-day estimated like-for-like (i.e., ICE) replacement cost of $67.5M – about an 89% increase.

BEV Pricing – Sliding Scale

For both the aggressive and balanced BEV phase-in scenarios, we then applied a “sliding scale” for BEV price reduction (starting from the initial ratios listed above) to model potential outcomes for more optimistic pricing.

We believe that providing both cautious and optimistic pricing outcomes will provide Toronto Hydro with better value through a range of possibilities – as the current reality is that we cannot firmly predict future outcomes regarding BEV pricing.

However, there is reason to expect BEV prices to steadily decline in coming years as supply increases and battery technology improves. This is provided in a 2018 Bloomberg New Energy Finance report that modelled a costing outlook for electric buses vs diesel buses, and demonstrated cost parity by 2030 mainly due to future cost reductions of the battery pack[26]. With this information, it is conceivable that BEVs of all classes would follow suit.

In consideration of modelling constraints as well as gradual price reduction to better reflect what would be expected should BEVs steadily decline, the logic of the sliding scale is as follows:

- In 2022, status quo BEV/ICE pricing ratios (ratios listed above) as discussed and agreed upon with Toronto Hydro, have been applied to our modelling.

- BEV/ICE price parity is expected, for modelling purposes, to occur in one decade (10 years) starting from 2023 for all units; therefore, price parity would be reached by 2032 (2023+9yrs).

- For modelling purposes, BEV/ICE ratios are reduced at a fixed rate for each year of the 10-year period until price parity is achieved. For example, heavy-duty units (with an BEV/ICE cost ratio of 2) would have a ratio reduction of 0.1 per year until the BEV/ICE cost ratio is approximately 1 (i.e., BEV and ICE prices are approximately equal).

- Taking into consideration procurement timelines:
    - HDVs show approximate price parity in our modelling by 2032+3yrs=2035
    - MDVs show approximate price parity in our modelling by 2032+2yrs=2034
    - LDVs show approximate price parity in our modelling by 2032+1yrs=2033

- Taking into consideration procurement timelines:
    - HDV price reduction starts in 2023+3yrs=2026 (year that earliest models would be in-service) and ends in 2035. Approximate price parity is continued for the duration of the modelling.

[26] Source: Bloomberg New Energy Finance. Electric Buses in Cities: Driving Towards Cleaner Air and Lower CO_2 [pdf]. March 29, 2018.

  - MDV price reduction starts in 2023+2yrs=2025 (year that earliest vehicles would be in-service) and ends in 2034. Approximate price parity is continued for the duration of the modelling)
  - LDV price reduction starts in 2023+1yrs=2024 (year that earliest vehicles with price reduction would be in-service) and ends in 2033. Approximate price parity is continued for the duration of the modelling.

Given the complexity of the FAR, the method employed to practically apply a sliding scale to our modelling, provided that *initial* acquisition costs are raised by inflation each fiscal year, was to:

(1) Divide the replacement costs in a given year by the agreed-upon *initial* ratios; and

(2) Multiply the replacement costs by a reduced ratio that scales over time (as explained earlier) to yield a reduced cost every year until approximate price parity with ICE counterparts is reached after 10 years.

Multiplication factors for LD, MD, and HD units have been included for each fiscal year in FAR and applied to all respective annual replacement costs. The factors remain constant once approximate price parity is achieved (as noted above).

Applying the sliding scale to the balanced BEV phase-in scenario provides a more complete and reasonable picture of what a balanced phase-in may look like if prices come down (see results in next sub-section). With cautious pricing and a sliding scale applied to both the aggressive and balanced BEV phase-in approaches, we have provided a spectrum of BEV phase-in scenarios that can be used to better inform future vehicle purchasing decisions, including:

- FAR 3.1 – aggressive, fleet-wide BEV phase-in with cautious pricing
- FAR 3.2 – aggressive, fleet-wide BEV phase-in with sliding scale
- FAR 4.1 – balanced, selective BEV phase-in with cautious pricing
- FAR 4.2 – balanced, selective BEV phase-in with sliding scale

Balanced, Fleet-wide BEV Phase-in

For demonstration purposes only, we have included one additional FAR scenario (FAR 5) which is a balanced, nearly complete transition to BEVs with far fewer ICE replacements than FAR 4.1 and 4.2. Phasing in BEVs using this approach require lifecycles to be extended far longer than planned (for modelling purposes) in an effort to pause the purchase of ICE vehicles until BEV replacements are available. Although we have modelled this to demonstrate what a *balanced and near 100%* BEV phase-in may look like for Toronto Hydro's fleet, we do not recommend extending lifecycles to such degree from a financial risk-reduction perspective.

BEV Phase-in Scenario Results

Our modelling estimated annual capital costs as well as operating cost impacts and GHG emissions reductions relative to 2020-21 baseline. In *Table 5* (below), results are summarized and include average annual Capital expenses (Capex) over the budget cycle, average annual Operating expense (Opex) changes over the budget cycle relative to the baseline, and annual tailpipe GHG reduction by 2037 relative to the baseline. Due to the limited availability of BEVs in the short-term, we have modelled BEV phase-in over a 15-year budget period following the year 2022 (i.e., from 2023-2037).

Note: The significantly higher operating expenses shown in Table 5 are due to the significantly increased cost of capital for acquiring new vehicles based on year-over-year book values of units.

Table 5: Summary of fleet-wide results of scenario analysis over the period 2022-2037 relative to the 2020-21 baseline.

FAR #	FAR Scenario Description	Implementation Timing[27]	Average Annual Vehicle Replacement Capex[28 29]($ millions)	Average Annual Opex[30 31] Impacts Over Baseline ($ millions)	Annual Tailpipe GHG Reduction[32] Over Baseline (tonnes CO_2e)	Annual Tailpipe GHG Reduction Percentage Over Baseline
1	Optimized lifecycles	2022 - 2037	6.7	+0.94	41	2.5%
2	Optimized lifecycles + ROI (benchmarking scenario)	2022 - 2037	6.2	+0.89	37	2.3%
3.1	BEV phase-in: aggressive and cautious pricing	2022 - 2037	*10.7	+3.23	1,623	100%
3.2	BEV phase-in: aggressive and optimistic pricing (sliding scale)	2022- 2037	*7.6	+2.29 (**est.)	1,623	100%
4.1	BEV phase-in: balanced, cautious pricing, more ICE replacements	2022-2037	8.3	+1.77	1,146	71%
4.2	BEV phase-in: balanced, optimistic pricing (sliding scale), more ICE replacements	2022-2037	7.0	+1.49 (**est.)	1,146	71%
5	BEV phase-in: balanced, cautious pricing, few ICE replacements due to greatly extended lifecycles	2022-2037	9.8	+2.31	1,503	93%

* Note that both of these scenarios involve significant Capex "spikes" in the short- to medium-term.

* Estimated based on applying a sliding scale in BEV pricing.

The most aggressive fleet electrification scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by **100% by 2034** – before the end of the modelling period. The more cautious and fiscally prudent scenarios have the potential to reduce Toronto Hydro's fleet tailpipe

[27] For data-modelling purposes, fleet-wide implementation is modelled over the period from 2022-2037 for the same types of vehicles, the same number of vehicles, travelling the same number of kilometres as the 2020-2021 baseline.
[28] Average annual Capital expenses (Capex) for the entire modelling period (2022-2037), including compounding inflation for each year at current rate of inflation.
[29] For BEV charging infrastructure, additional capital costs were estimated separately using an EVSE costing tool.
[30] Average annual Operating expenses (Opex) for the entire modelling period (2022-2037) , including compounding inflation for each year at current rate of inflation.
[31] For data-modelling purposes, Opex includes the annual cost of capital based on year-over-year book values of units.
[32] Annual GHG reduction by the end of the modelling period (2037) is relative to the 2020-2021 baseline.

GHG emissions by just over **70% by 2037** – with the potential to achieve even greater results should more ICE units be replaced with BEVs towards the end of the modelling period, depending on pricing outcomes for BEVs compared to ICEs.

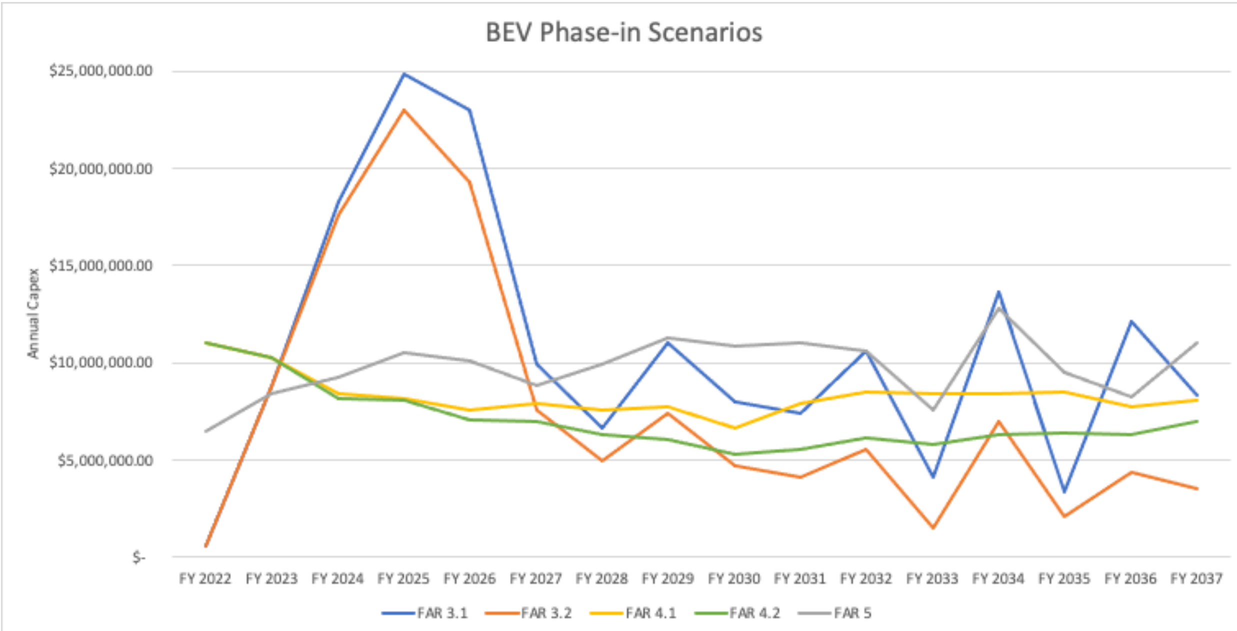
For the aggressive, fleet-wide BEV phase-in scenarios, average annual Capex is projected to be **$10.7M/yr** with cautious pricing (i.e., constant BEV/ICE ratios) and decrease to **$7.6M/yr** with the sliding scale in pricing. However, for both scenarios Capex is still very imbalanced and front-loaded (i.e., higher values in the short- to mid-term).

The balanced, selective BEV phase-in scenarios avoid annual Capex "spikes" and keep within annual budget constraints. Even with this approach, it will take significantly more capital to transition to BEVs based on current prices discussed with Toronto Hydro Fleet Management, with a modelled average annual Capex of **$8.3M/yr**. If price parity is gradually reached by the 2030s, average annual Capex is projected to decrease to **$7.0M/yr**. This value is approaching the projected annual Capex for like-for-like replacements of **$6.2M/yr**, although is based on a 70% GHG reduction achievement by 2037.

Note: Lower BEV prices over time mean that there is potential to achieve greater emissions reductions than what is modelled if ICE units, initially replaced with ICE units, are replaced with BEVs in their next replacement cycle.

In *Figure 3* (below), a breakdown of projected annual Capex based on the aggressive and balanced BEV phase-in approaches are shown as a time series from 2022-2037. Depicting the results graphically demonstrates year-over-year changes as well as differences in Capex variability between the scenarios.

Figure 3: BEV phase-in scenario results from 2022-2037



There are several features of the scenarios that become apparent when viewing *Figure 3*, as described below:

- The sliding scale in BEV pricing applied to FAR Scenarios 3.2 and 4.2 is demonstrated visually through lower annual Capex, starting in the year 2024, compared to FAR 3.1 and 4.1.

- The aggressive BEV phase-in scenarios (FAR 3.1 & 3.2) employ a strategy of deferring more units in the short-term, resulting in a pent-up demand for overdue units which are modelled to be replaced with BEVs. Consequently, there are significant Capex spikes modelled from years 2024-2027.

- The balanced BEV phase-in scenarios (FAR 4.1 & 4.2) employ a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road.

- FAR 5, the balanced *and* fleet-wide BEV phase-in scenario, employed a strategy of extending lifecycles far longer than planned in an effort to pause the purchase of ICE vehicles until BEV replacements are available. In addition to introducing financial risk through unexpected repair costs and increased likelihood of serious failure, this approach results in at or over-budget spending in many years of the modelling period.

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Section 7: Electric Vehicle Supply Equipment Planning

RSI-FC maintains the position that electric vehicle supply equipment (EVSE) should not be treated as a direct corporate vehicle capital expense, but rather as a facilities/properties capital expense. As per the feedback provided by Toronto Hydro Fleet Management, EV chargers are a Fleet expense and charging infrastructure development is the responsibility of Facilities.

With this in mind, we have developed an EVSE planning tool for Toronto Hydro, separate from Fleet Analytics Review™ (FAR), to inform long-term capital planning (LTCP) for the utility's charging infrastructure needs, based on Level 2 charging and battery capacity estimations described in this section. Our team has estimated the costs of electric vehicle chargers (not complete infrastructure) over the modelling period from 2022-2037, based on the current size and mileage of Toronto Hydro's fleet and a balanced, fleet-wide BEV phase-in.

EVSE & Asset Management

RSI-FC maintains that EVSE should be a capital asset paid for, owned, and managed from the budget of the corporate facilities/properties department. Therefore, the capital cost of charging equipment should not be directly posted to the fleet department; this aligns with Toronto Hydro's approach as per discussion with Fleet Management.

EVSE is an asset (an attribute/enhancement) that increases the market value of the facility/property where fleet vehicles are parked. Moreover, EVSE costs should be a capital expense for the facility's corporate "owner" (usually this is a facilities/properties department), not the vehicle's corporate "owner" (which is usually a fleet department). This is different than in the non-corporate world where the battery-electric vehicle (BEV) owner is often the same owner as the property owner, such as is the case for personal cars and homes. The benefit of this concept is that, unlike vehicles that depreciate quickly, facilities assets are generally depreciated over far longer periods – sometimes up to 20, 30 or more years. Long depreciation periods translate to lower annual costs, thereby making a better business case for electric vehicles.

Today, there is a lot of focus on asset management best practices for corporations, including the public sector. It is a contemporary asset management best practice that property-related costs, including capital and operating expenses, should be expense items managed by the responsibility centre that manages the asset, in this case the corporate facilities/properties department. The facilities/properties department can then apportion and transfer these costs to their internal users of each property, such as a fleet department.

In a “full cost recovery” business model as we espouse, the facilities/properties department must recover sufficient revenue to fully offset the costs of owning and managing the property, including the installation, use, and maintenance of EVSE.

Regarding the electricity needed to charge BEVs, we have included the cost of electricity as a “fuel” cost under operating expenses in FAR. However, the same asset management principles can be applied. In an ideal full cost recovery business model, the facilities/properties department would transfer electricity costs to its user departments for the amount used in each period. The EVSE would meter the amount of electricity used by each BEV – just like the amount of gas or diesel used by each internal combustion engine (ICE) vehicles is tracked with fuel pump meters.

EVSE Planning Tool

Capabilities

RSI-FC’s EVSE planning tool is user-friendly, including programmable and automated formulas for determining charging requirements on a unit-by-unit basis. The planning tool:

- Lists units based on their stored locations.
- Is based on estimated daily kms-travelled by each unit, derived from kms-travelled during the review period divided by the number of working days in year.
- Is based on each unit having access to one charger every night during off-peak hours (7pm-7am).
- Allows programmable upper and lower estimates of range that can be adjusted up or down for data-modelling purposes, in consideration of heating/cooling in cold- or hot-weather conditions as well as on-board accessory electrical DC loads such as lights, laptops, etc., that may diminish available driving range.
- Calculates the daily charging time required to return to near-full charge for vehicles of all classes by allowing for programmable estimates of BEV battery capacity, charger current, and charger voltage.
- Calculates the nightly electrical demand in kWh and cost, assuming all units will charge each night during off-peak hours.
- Allows programmable acquisition costs for chargers (or chargers plus infrastructure if desired) for each unit.

The tool simplifies charging rate (kms of range added per hour) by estimating it to be constant for all battery charge levels. This is, strictly speaking, not entirely reflective of reality; charging rate slowly diminishes as battery levels approach 100%. However, applying a constant charging rate does provide a very reasonable approximation, especially considering that we have modelled daily charging requirements based on 90% maximum battery charge levels – as a best practice for optimizing battery life.

Charging rate is dependent on the battery capacity of a vehicle and varies significantly with different vehicle types and battery sizes. The tool allows the user to change the battery size on a unit-by-unit basis if needed (i.e., by comparing a make/model of BEV that is equipped with larger/smaller battery size than another make/model), which makes the calculator even more accurate.

Estimations

The inputs chosen in the EVSE tool are based on a number of estimations in terms of charging level and battery capacity for different unit types. These can be easily modified by the user according to the specific charging infrastructure installed as well as actual specifications for BEV replacement units. We have included the following estimations in our EVSE modelling:

- Battery size/capacity estimates were based on class/ vehicle type, including:
    - 60 kWh for cars
    - 80 kWh for SUVS, pickups, passenger minivans, Class 1/2a cargo minivans
    - 100 kWh for Class 2b vans
    - 150 kWh for MDVs (Class 3-6 units)
    - 300 kWh for HDVs (Class 7-8 units)

- Upper range estimates (i.e., *actual* driving distance, not advertised range) were based on class/ vehicle type, including:
    - 320 km for cars
    - 300 km for SUVs, pickups, passenger minivans, Class 1/2a cargo minivans
    - 280 km for Class 2b vans
    - 250 km for MDVs (Class 3-6 units)
    - 250 km for HDVs (Class 7-8 units)

- Lower range estimates were based on a 50% reduction of upper range estimates for all units.

- Charger current and voltage estimates were based on a lower-power Level 2 charger, as well as the amps of current allowed by most BEVs[33]) including:

[33] Source: (https://www.chargepoint.com/en-ca/resources/how-choose-home-ev-charger/#:~:text=Most%20EVs%20can%20take%20in,of%20range%20in%20an%20hour.)

  - Current: 32 amps
  - Voltage: 240 volts

- The charging rate (kms range added per hour) was estimated by dividing driving range by the time for full charge. The time for full charge (i.e., 0 to 100%) was estimated by dividing battery capacity by charging power (calculated from current and voltage) and adding a 10% inefficiency[34] [35].

- Return-to-base battery levels are based on a starting charge of 90%, as a best practice for optimizing battery life.

- The time available for overnight charging was estimated as 12 hours during off-peak hours (7pm-7am).

Flagged Units

Overall, based on our pragmatic analysis, the majority of units (381 out of 385 units) in Toronto Hydro's fleet would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. In fact, most units would be able to recharge is much less time than units are parked; the average time to recharge to 90% battery level for all 385 units is an estimated 2.7 hours.

Our team flagged any units that, based on low capacity Level 2 charging, would either: (1) risk too low of a return-to-base charge; or (2) require too much time to recharge during off-peak hours. These include:

- One pickup unit (0408V) estimated to finish the work day at less than 20% battery charge (starting from 90%). A potential solution is to purchase battery-electric pickups with larger batteries, and thus higher range capabilities, for relatively higher-mileage pickups like this unit.

- Four Class 8 single bucket units (0757V, 0387V, 0952V, & 0950V) estimated to require more than 12 hours to recharge to 90% battery level. A potential solution is to install higher-power chargers for relatively higher-mileage Class 8 units to increase the charging rate per hour.

Level 3 Charging

Level 3, direct-current (DC) fast chargers, which charge at much higher amperage and voltage than Level 2 chargers, are recommended in the case of time-dependent duties/responsibilities when

[34] Source: https://www.caranddriver.com/shopping-advice/a32600212/ev-charging-time/
[35] Source: https://www.inchcalculator.com/widgets/?calculator=electric_car_charging_time

overnight charging is not an option, as well as for emergency situations such as extreme weather events. Additionally, if a vehicle operator forgets to plug in their vehicle overnight, a Level 3 charger would be required to avoid and/or minimize the loss of productivity during work hours. It is important to note that DC fast charging installation requires a commercial electrician[36] and costs an estimated $50,000 - $200,000 for equipment and installation[37]; therefore, the need for Level 3 charging should be carefully assessed.

Given the fact that 86% of Toronto Hydro fleet vehicles are parked at three Work Centers – Commissioners Work Center, Rexdale Work Center, and Milner Work Center – our general recommendation is for two Level 3 chargers be installed at each of these main locations to as a risk management strategy for time-dependent and/or urgent situations as described above. However, without knowledge of the intricacies and specific use cases for each fleet vehicle, our secondary recommendation is to identify the most appropriate Work Centers for investment in higher-power charging, i.e., ones that consist of vehicles that may not always rely on overnight charging only.

EVSE Charger Costing Outlook

Our team estimated the costs of electric vehicle chargers (not infrastructure) over the modelling period from 2022-2037, based on a balanced, fleet-wide BEV phase-in taking FAR Scenarios 4.1 and 4.2 as the minimum speed of transition. Please see *Table 6* (overleaf) for details and a description of our approach/method and estimations below for Toronto Hydro's fleet.

To determine the number of Level 2 (L2) chargers required to be installed annually over the modelling period for a smooth transition of the entire Toronto Hydro fleet to BEVs, our approach/method and estimations were as follows:

- A fleet should not be keeping up with the demand for EVSE based on the number of new BEVs added; rather, EVSE installation should be *outpacing* demand to allow for a smooth and seamless transition. Therefore, we have estimated the number of L2 chargers required to outpace the influx of new BEVs into the fleet.

- The purchase of chargers ahead of the addition of BEVs also makes use of the delay in purchasing BEV pickups, vans, and medium- and heavy-duty (MHD) vehicles based on availability and procurement timelines – to optimize the use of capital investment in EVSE to ensure ample capacity for charging down the road.

- EVSE is based on the current size of Toronto Hydro's fleet.

[36] Source: https://calevip.org/electric-vehicle-charging-101
[37] Source: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf

- FAR Scenarios 4.1 and 4.2 (balanced, selective phase-in approach) were considered to establish the minimum speed of transition to BEVs; the number of chargers required to be installed for each fiscal year outpace the number of BEVs integrated into Toronto Hydro's fleet according to these scenarios.

- In addition to the previous bullet point, we have considered the number of chargers for a complete, fleet-wide transition to BEVs.

  FAR Scenarios 4.1 and 4.2 model a transition of about 73% of Toronto Hydro's fleet to battery-electric by the year 2033 – 282 battery-electric units, including the 13 Chevrolet Bolts currently in the fleet, out of a total of 385 units. After 2033, the number of BEVs added to the fleet reflects *second replacement cycles for existing BEVs*.

  However, for the purpose of modelling the phase-in of chargers for a fleet-wide adoption of BEVs, we have taken the number of BEVs added to the fleet after 2033 to demonstrate *new BEVs replacing ICE vehicles* – in anticipation of the complete electrification of Toronto Hydro's fleet by the mid- to late-2030s (see tan-coloured rows in *Table 6*).

- We have cautiously estimated the cost of chargers only to be $2500/charger. This cost does not include infrastructure which would vary according to the charger level.

Importantly, existing electrical capacity at sites may require substantial upgrades for charging multiple vehicles, and/or new or upgraded standby generators to provide for emergencies, both of which may significantly add to infrastructure costs (outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations.

Based on our EVSE analysis and taking the balanced BEV phase-in approach as a realistic and fiscally responsible strategy, Toronto Hydro's fleet would be 100% BEV-ready by 2034 – based on the current size of the fleet (385 vehicles, see *Table 6*). Given our estimations, this translates to an average annual charger cost (excluding infrastructure) of about $74,000 per year for the next 13 years.

Table 6: Fleet-wide EVSE long-term charger costing outlook

Year # of BEV Phase-in Plan	Year of BEV Phase-in	Location	Number of BEVs added to Fleet (per balanced phase-in plan)	Cumulative Number of BEVs added to Fleet (per balanced phase-in plan)	Number of BEVs Serviced by each Charger	Estimated Number of Chargers Required for Purchase (to outpace BEVs added)	Cumulative Number of Chargers Purchased	Estimated Cost per Charger	Total Annual Cost of Chargers	Cumulative Cost of Chargers
1	2022	All Fleet Parking Sites	1	1	1	30	30	$2,500	$75,000	$75,000
2	2023	All Fleet Parking Sites	9	10	1	30	60	$2,500	$75,000	$150,000
3	2024	All Fleet Parking Sites	41	51	1	30	90	$2,500	$75,000	$225,000
4	2025	All Fleet Parking Sites	12	63	1	30	120	$2,500	$75,000	$300,000
5	2026	All Fleet Parking Sites	20	83	1	30	150	$2,500	$75,000	$375,000
6	2027	All Fleet Parking Sites	22	105	1	30	180	$2,500	$75,000	$450,000
7	2028	All Fleet Parking Sites	48	153	1	30	210	$2,500	$75,000	$525,000
8	2029	All Fleet Parking Sites	38	191	1	30	240	$2,500	$75,000	$600,000
9	2030	All Fleet Parking Sites	16	207	1	30	270	$2,500	$75,000	$675,000
10	2031	All Fleet Parking Sites	37	244	1	30	300	$2,500	$75,000	$750,000
11	2032	All Fleet Parking Sites	27	271	1	30	330	$2,500	$75,000	$825,000
12	2033	All Fleet Parking Sites	8	279	1	30	360	$2,500	$75,000	$900,000
13	2034	All Fleet Parking Sites	13	292	1	25	385	$2,500	$62,500	$962,500
14	2035	All Fleet Parking Sites	17	309	1		385	$2,500	$0	$962,500
15	2036	All Fleet Parking Sites	15	324	1		385	$2,500	$0	$962,500
16	2037	All Fleet Parking Sites	34	358	1		385	$2,500	$0	$962,500

Fleet Challenge
Driving Change

NRCan's Zero Emission Vehicle Infrastructure Program

The Government of Canada is committed to helping accelerate the decarbonization and electrification of our transportation sector, and charging infrastructure is a key component to achieving this. Natural Resources Canada (NRCan) has pledged to invest $130 million from 2019-2024 to further expand the country's charging network, particularly level 2 and higher stations, through its Zero Emission Vehicle Infrastructure Program (ZEVIP).

The funding is being delivered through cost-sharing contribution agreements for eligible projects, including:

- BEV charging infrastructure in parking areas intended for public use (e.g., service stations, restaurants, libraries, etc.);
- On-street charging infrastructure;
- Workplace charging infrastructure;
- On-road light-duty vehicle fleets;
- On-road medium- or heavy-duty vehicle fleets;
- Charging infrastructure for multi-unit residential buildings (MURBs); and
- Public transit charging infrastructure.

RFPs for ZEVIP are currently closed as per the program website[38]; however, we recommend that Toronto Hydro regularly checks for updates and openings to new funding application periods.

NRCan's contribution through this program will be limited to 50% of total project costs up to a maximum of $5M per project. The maximum funding and approximate costs for each type of charging infrastructure is shown in *Table 7* (directly taken from NRCan's website with costs and charging rates from the City of Toronto's Electric Vehicle Strategy Report[39]):

[38] Source: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/zero-emission-vehicle-infrastructure-program/21876
[39] Source: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf

Table 7: Specifications for NRCan's Zero Emission Vehicle Infrastructure Program, plus approximate total costs and charging rates

Type of Infrastructure	Output	Maximum NRCan Funding	Total Costs (Equipment + Installation)	Approximate Charge Rate Per Hour (LD vehicles)
AC Level 2 (208/240V) Connectors	3.3 kW - 19.2kW	Up to 50% of total project cost, to a maximum of $5,000 per connector*	$5,000 - $10,000	40 km
DC Fast Charger	20 kW - 49 kW	Up to 50% of total project cost, to a maximum of $15,000 per fast charger	-	-
DC Fast Charger	50 kW and above	Up to 50% of total project cost, to a maximum of $50,000 per fast charger (50 kW-99 kW) and $75,000 per fast charger (100 kW and above)	$50,000 - $200,000	300+km

* To calculate the funding for level 2 chargers, each connector can count as a unit towards the minimum of 20 chargers if each connector can charge a vehicle at the same time.

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Section 8: Recommendations & Additional Considerations

In this section, we provide our recommendations for the Electric Vehicle Phase-in Plan, in terms of both (1) capital planning for transitioning the fleet to electric and (2) electric vehicle supply equipment (EVSE) requirements. Moreover, we have included recommendations on collaboration/partnerships and risk/change management for creating a culture of receptiveness to innovation and forward thinking. We have also included considerations on batteries as well as additional fuel-reduction solutions.

Battery-Electric Vehicle Phase-In

(1) Through a lens of an aggressive BEV phase-in, allocate the majority of fleet capital spending on BEVs for appropriate vehicle categories as BEV models become available.

(2) Through a lens of a balanced, selective BEV phase-in and fiscal prudence, prioritize replacement of ICE units with BEVs *that would maximize ROI* – typically ones that have relatively high annual mileage.

(3) For units due for replacement that are still in good condition, conduct a temporary pause on purchasing new internal combustion engine (ICE) vehicles for the short term – 1-2 years for pickups, 2-3 years for medium- and heavy-duty vehicles (MHDVs) – while awaiting battery-electric vehicle (BEV) counterparts to become available and taking into consideration procurement timelines. Extend ICE lifecycle whenever possible.

(4) Employ a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road. Consider applying the decision matrix used by our team to determine which units to replace with ICE units in the short-term.

In the context of BEV transition planning, prioritizing units for immediate ICE replacement that have been kept (well) past their optimized economic lifecycle is a financial risk-reduction strategy. These units have the highest cost of continued ownership, are most likely to have unexpected repair costs, and are most likely to have a serious failure that requires more repair than the remaining values – potentially taking them out of service and dropping their salvage/resale value to (near) zero.

(5) Conduct pilot projects for several BEV types when they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

(6) Assuming the pilot projects are successful, acquire BEVs in bulk to replace units that would provide the greatest ROI.

(7) Closely monitor the acquisition costs for BEVs and re-evaluate the business case (cost-benefit) for individual units as prices change/ decline.

(8) Consider purchasing plug-in hybrid vehicles (PHEVs) for lower-mileage units which would be able to fulfil daily duties on battery-power only and recharge overnight – essentially functioning like fully-electric vehicles.

Electric Vehicle Supply Equipment

(1) Over the next 10+ years, allocate capital towards chargers (and charging infrastructure, which is outside the scope of this study) required for the transition to BEVs for all vehicle categories.

(2) Based on our analysis of Toronto Hydro's charging requirements, 381 out of 385 units would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. Therefore, our recommendation is to focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power charging (Level 3) for higher-mileage units.

(3) Our general recommendation is for two Level 3 chargers be installed at each of the main Work Centers (Commissioners Work Center, Rexdale Work Center, and Milner Work Center) to as a risk management strategy for time-dependent and/or urgent situations. However, without knowledge of the intricacies and specific use cases for each fleet vehicle, our secondary recommendation is to identify the most appropriate Work Centers for investment in higher-power (Level 3) charging, i.e., ones that consist of vehicles that may not always rely on overnight charging only.

(4) Monitor upcoming funding opportunities from NRCan's Zero Emission Vehicle Infrastructure Program (ZEVIP), which may greatly offset the capital costs required to install charging infrastructure (outside the scope of this report).

(5) Assess existing electrical capacity at facilities to determine whether substantial upgrades for charging multiple vehicles are required, as well as standby generator capacities (outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations.

(6) Explore supplying power to each site/garage on two separate feeds from the grid to reduce the risk of local failure taking power away from the whole site[40].

[40] Source: https://www.plugincanada.ca/electric-bus-faq/

(7) To mitigate the risk of power grid failure or local failure at a site/garage, ensure backup generators have sufficient capacity to deal with short power outages, and assess the need for higher-capacity generators for longer outages.

(8) Explore solar energy technology options to supply energy for EV charging to reduce GHG emissions that may be produced from the electricity supply used for charging. Our recommendation is to pursue rooftop (as opposed to canopy) solar energy systems, as this provides renewable energy for the entire building/facility as opposed to charging stations only – which more holistically achieves GHG emissions reductions and allows for additional benefits such as vehicle-to-grid (V2G) technology and battery energy storage (see more details in next sub-section).

(9) Provide or expand on current high-voltage safety awareness and/or skills training to include operating and maintaining Toronto Hydro's electric vehicle charging stations, and closely monitor the launch of new electric vehicle fleet technician training programs. A pilot for a new EV Maintenance Training Program for automotive technicians was successfully completed at BCIT and is available to the public[41]. There is also an Electric Vehicle Technology Certificate Program offered by SkillCommons, managed by the California State University and its MERLOT program, which offers free and open learning materials on electric vehicle development, maintenance, alternative/renewable energy, and energy storage[42].

Collaboration/Partnership Approaches

With the transition to BEVs in the early stages and expected to gain significant momentum in the short- to mid-term, we recommend that Toronto Hydro strengthen current partnerships and establish new partnerships – both internal and external – to leverage knowledge and resources and better prepare for the transition by undertaking the following actions:

(1) Engage in internal partnerships within and across departments, such as multi-departmental funding applications for charging infrastructure, or sharing of BEV pilot program results to determine vehicles requirements and specifications (e.g., real-world range, real-world charging needs) ahead of large purchasing decisions involving many units.

(2) Engage in external partnerships (e.g., other utilities in Southern Ontario) for potential collaborations, such as joint specification writing and/or joint tenders and sharing of BEV pilot program results through working groups.

[41] Source: https://commons.bcit.ca/news/2019/12/ev-maintenance-training/
[42] Source: http://support.skillscommons.org/showcases/open-courseware/energy/e-vehicle-tech-cert/

(3) Leverage the knowledge gained on BEV transition (e.g., procurement of vehicles and charging infrastructure) through organizational memberships such as the Clean Air Partnership or the Canadian Utility Fleet Council (CUFC).

Risk/Change Management Approaches

(1) Develop BEV educational and outreach materials for employees and operators summarizing the reasons and benefits of transitioning to BEVs, in terms of the environment (improved air quality and greatly reduced lifecycle GHG emissions), reduced fuel and maintenance expenses (the business case), improved performance (e.g., instant torque, little noise, regenerative breaking), greater reliability due to fewer moving parts than internal combustion engine (ICE) vehicles, and continuously expanding charging infrastructure. This should include dispelling myths about BEVs, such as potential negative and/or false perceptions on battery safety, battery life, battery end-of-life, and vehicle performance – facilitating a cultural shift from fossil-fuelled vehicles to clean, zero-tailpipe emission BEVs.

(2) Invite frontline employees to take BEV test drives to familiarize them with fully-electric vehicles and charging, as well as to give them first-hand experience of improved performance (e.g., instant torque, little noise, regenerative braking).

(3) Provide operators with a BEV orientation before releasing new models into the fleet to enable them to become familiar with the different driving experience (e.g., instant torque, little noise, regenerative braking), as well as to alleviate/eliminate any apprehension or uncertainties such as range anxiety.

(4) As is recommended for the phasing in of BEVs, we recommend pilot projects for several BEV types as they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

Additional Considerations

Battery Replacement, Energy Storage, and Battery Disposal

Global lithium-ion battery demand has risen dramatically over the last ten years, and this is expected to only be the "tip of the iceberg" as we are only at the beginning of the electric vehicle revolution.

Most, if not all, battery-electric vehicle (BEV) manufacturers have an eight-year or 100,000 mile (160,000 km) warranty on their batteries – whichever one (i.e., vehicle age or distance travelled) comes first[43]. However, the current prediction is that a BEV battery will last from 10-20 years,

[43] Source: https://www.myev.com/research/ev-101/how-long-should-an-electric-cars-battery-last

depending on usage, before it needs to be replaced[44]. Consumer Reports estimates that the average BEV battery pack's lifespan is around 200,000 miles (320,000 km), which is nearly 17 years of use if driven 12,000 miles (19,200 km) per year. As a comparison, the average annual mileage for all Toronto Hydro fleet vehicles is under 5,000 km. Therefore, in most cases, BEVs will reach their end-of-life before there is a need for battery replacement.

When battery capacity falls below 80%, drivers may start to see a decline in range[45] – which would most likely occur at or after the typical vehicle replacement age because battery degradation is a very gradual process[46]. Once the BEV battery capacity becomes undesirable for powering a vehicle, it can be used to power a building by contributing to a battery storage system, which stores energy from a battery that can be used at a later time[47]. For example, if a building is powered by renewable energy such as wind or solar, an "old" BEV battery can be used to store energy produced while the wind is blowing or the sun is shining, and then release the stored energy during low-wind periods or at night. This method of generating electricity has multiple benefits, including:

- An effective way of continuing the life of an old BEV battery;
- Reducing energy used from the grid, thereby reducing energy costs; and
- Increasing energy security when using renewables, which have variable energy outputs, by releasing stored energy during off-peak times.

When batteries reach the end of their working life, they can be recycled, which typically involves separating out valuable materials such as cobalt and lithium salts, stainless steel, copper, aluminium, and plastic. Currently, about half of the materials in a BEV battery pack are recycled, but with BEVs expected to undergo an explosion in popularity over the next decade or so, car manufacturers are looking to improve this[48]. Moreover, battery recycling companies have emerged with the growing need for electric vehicle battery recycling, as well as due to the shortage of domestic critical raw materials including lithium, cobalt, and nickel[49].

End-of-lifecycle lithium-ion batteries are first brought to facilities, known as "spokes," which physically separate materials (e.g., shredded metals, mixed plastics, etc.) – much like municipal material recycling facilities (MRFs). These separated materials are then brought to centralized locations, known as "hubs," where battery-grade end products, i.e., the original raw materials (metals) are produced. In May 2020, the lithium-ion battery recycling company Li-Cycle opened a

[44] Source: https://www.edfenergy.com/electric-cars/batteries
[45] Source: https://www.edfenergy.com/electric-cars/batteries
[46] Source: https://www.myev.com/research/ev-101/how-long-should-an-electric-cars-battery-last
[47] Source: https://www.edfenergy.com/electric-cars/batteries
[48] Source: https://www.edfenergy.com/electric-cars/batteries
[49] Source: Li-Cycle Corporate Presentation, July 21 [non-confidential]

"spoke" facility in Kingston, Ontario with a capacity to process 5,000 tonnes of lithium-ion batteries per year. [50]

Utilities like Toronto Hydro will have the option of packaging and coordinating the shipment of end-of-lifecycle electric vehicle batteries to battery recycling companies, with preliminary cost estimates of 1-2 CAD per kilogram – depending on the size of the battery pack and the cathode materials.

Hybrid-Electric Vehicles

As discussed with Toronto Hydro Fleet Management, there are plans for increasing the number of hybrid units into the fleet with hybrid SUVs, pickups, and vans. Purchasing hybrid vehicles is an effective interim solution considering there is (1) currently limited and/or no BEV availability in the market for these vehicle types and (2) expected long procurement timelines for upcoming BEV models.

Hybrid Electric Vehicles (HEVs) use two or more distinct types of power, such as an internal combustion engine (ICE) and a battery-powered electric motor as the modes of propulsion, albeit with very limited range when in electric mode. When an HEV accelerates using the ICE, a built-in generator creates power which is stored in the battery and used to run the electric motor at other times. This reduces the overall workload of the ICE, significantly reducing fuel consumption and extending range. Examples of HEVs include the Toyota Prius and Ford Fusion Hybrid. [51]

Plug-In Hybrid Electric Vehicles (PHEVs) use rechargeable batteries, or another energy storage device, that can be recharged by plugging into an external source of electric power. PHEVs can travel considerable distances in electric-only mode, typically more than 25 km and up to 80 km for some models, due to their much higher battery capacity than HEVs. When the battery power is low (usually ~80% depleted), the gasoline ICE turns on and the vehicle functions as a conventional hybrid. Such vehicles typically have the same range as their gasoline counterparts. Examples of PHEVs include the Chevrolet Volt and Toyota Prius Prime.[52]

Given that Toronto Hydro is a very low-mileage fleet, it is conceivable that many PHEVs would be able to fulfil daily duties on battery-power only and recharge overnight – essentially functioning like fully-electric vehicles.

Feasibility Considerations

- Given the combination of an internal combustion engine (ICE) and a battery-powered electric motor in HEVs, there is little or no preparation required ahead of acquiring these vehicles,

[50] Source: Li-Cycle Corporate Presentation, July 21 [non-confidential]
[51] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[52] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/

making these attractive purchasing options while BEV supply and charging infrastructure catch up to demand.

- PHEVs may be plugged into a level one or two charger (120 V outlet or 240 V outlet, respectively), with the later achieving a much faster charging speed. However, if a charger is not readily available, the ICE will allow the vehicles to act as regular hybrids, eliminating any range anxiety.

Best Management Practices

Toronto Hydro may want to implement and/or improve its best management practices (BMPs) while transitioning its fleet to battery-electric – as interim solutions to reducing fuel usage and costs as well as GHG emissions. Summaries of the BMPs we are recommending as additional considerations are summarized below. For a complete description of all BMPs researched by RSI-FC, please see *Appendix D*.

Light-Weighting

Lighter vehicles consume less fuel, produce less emissions, and can carry larger payload. However, light-weighting may overstress some vehicles, increasing maintenance demand and lifecycle cost; therefore, fleet must exercise caution before choosing which vehicles to proceed with a light-weighting enhancement.

Low-Rolling Resistance Tires

Rolling resistance is the energy lost from drag and friction of a tire rolling over a surface[53]. The phenomenon is complex, and nearly all operating conditions can affect the final outcome. For heavy trucks, an estimated 15-30% of fuel consumption is used to overcome rolling resistance.

A 5% reduction in rolling resistance would improve fuel economy by approximately 1.5% for light and heavy-duty vehicles. Installing low-rolling resistance (LRR) tires and/or auto-inflation systems can help fleets reduce fuel costs. It important to ensure proper tire inflation in conjunction with using LRR tires.

Tires and fuel economy represent a significant cost in a fleet’s portfolio. In Class 8 trucks, approximately one-third of fuel efficiency comes from the rolling resistance of the tire. The opportunity for fuel savings from LRR tires in these and other vehicle applications is substantial.

According to a North American Council for Freight Efficiency (NACFE) report, the use of LRR tires, in either a dual or a wide-base configuration, is a good investment for managing fuel economy.

[53] Source: https://afdc.energy.gov/conserve/fuel_economy_tires_light.html

Generally, the fuel savings pay for the additional cost of the LRR tires. In addition, advancements in tire tread life and traction will reduce the frequency of LRR tire replacement.

Anti-Idling Policy and Technologies

Idling in a utility fleet is unavoidable for reasons including cab climate control for workers as well as for vehicles equipped with power takeoff (PTO) driven ancillary equipment, such as aerial devices, digger-derricks and cranes. That said, *avoidable and unnecessary* idling is not acceptable.

An idling-reduction policy is a way to motivate fleet drivers to limit unnecessary idling. However, for an idling-reduction policy to be successful continuous enforcement such as spot-checks and fuel use tracking must be present. An idling-reduction policy could be used as an overarching commitment to idling reduction that is carried out though driver training and motivation sessions, rather than an initiative on its own.

There are several idling-reduction technologies available that can aid in idle reduction, including auxiliary power units (APU), stop/start devices, auxiliary cab heaters, battery backup systems, and block heaters/ engine preheaters. Their functionality, potential, and costs vary considerably and are described in *Appendix D* (FAR models a cost of $5,000 for all vehicle categories). To reap the most benefits of any idling-reduction technology, installation should always be accompanied by behavioural solutions of driver training and motivation.

Driver Eco-Training

Driver training to modify driver behaviours and ongoing motivation to continue good behaviours are crucial components of successful idling-reduction programs. While most drivers understand the vehicle idling issue, many continue their inefficient practice of excessive idling due to lack of knowledge and/or motivation.

Driver training can be used to optimize the use of idle reduction technologies. The technologies can reduce idling but the drivers have the ability to override the technologies. Proper training can aid in utilizing the technologies to their full potential.

Further, driver training can promote good practices while on the road including progressive shifting, anticipating traffic flow, and coasting where possible.

Route Planning/Optimization and Trip Reduction

In addition to enhanced vehicles specifications and improved driver behaviours, fuel consumption and exhaust emissions can be further reduced through route planning/optimization and trip reduction.

Route planning software can be used optimize multi-stop trips. It can also be used for idling reduction initiatives by integrating GPS tracking software to monitor driver activity in real-time. Moreover, reporting and analytics features within route planning software can help with identifying when a fleet vehicle requires maintenance to ensure optimal fuel efficiency and thus minimize cost and emissions.[54]

Google™ Maps recently announced their mapping/guidance systems will soon feature and advise drivers of the lowest GHG-emission routes to their destinations. By embracing this technology where possible/practical in Toronto Hydro's fleet, and perhaps combining its use with a corporate policy or directive for employees to minimize their trips where possible, emissions (and costs) could be minimized.

[54] Source: https://blog.route4me.com/2020/05/carbon-emissions-reduction-route-optimization-helps-cut-tons-carbon-emissions/

Section 9: Overview and Discussion

In Toronto Hydro's Electric Vehicle Phase-in Plan, we presented:

(1) Findings of RSI-FC's Electric Vehicle Survey to gauge the current view and opinions of employees on battery-electric vehicles and charging requirements;

(2) Key results of the 2020-21 fleet and GHG emissions baseline for current fleet assets;

(3) Modelling results for various fleet electrification pathways over a 15-year budget cycle including their impacts on Operating expenses, Capital expenses, and GHG emission reductions relative to the baseline;

(4) Modelling results for electric vehicle supply equipment (EVSE) requirements on a unit-by-unit basis and an estimation of charger costs over a 15-year budget cycle; and

(5) Recommendations for a balanced, structured BEV phase-in as well as charging infrastructure planning.

Capex Benchmarking

Based on optimized economic lifecycles, it was estimated that, in 2022, $15.3 million would be required to replace all due or past-due units with new like-for-like vehicles (no BEVs at this stage). It should be noted that numerous vehicles in the Toronto Hydro fleet are beyond the current planned age for replacement – *significant "catch-up" is required to modernize the fleet.*

Starting with optimized economic lifecycles and then selectively and strategically making deferrals over the 15-year budget cycle to maximize Opex benefits, or return-on-investment (ROI) resulted in a much more balanced Capex over the 15-years. The net result was an average annual capital budget of $6.2 million with annual amounts ranging from $5.3-7.9 million with clustering around $6-6.5 million, as compared to the much wider and more fluctuating range over the budget period for optimized economic lifecycles only.

This step was intended to provide a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – and as a comparison for long-term capital planning for BEV phase-in.

Synopsis of Electric Vehicle Phase-in Plan

Starting from the baseline, we modelled a number of fleet electrification scenarios ranging from aggressive and over-budget to balanced and within budget – to demonstrate a spectrum of pathways. Although BEV phase-in is the most effective long-term GHG reduction strategy for a fleet, the reality is that there are currently higher upfront costs associated with the transition; therefore, it must be done in a fiscally responsible manner.

Based on our modelling, lower-mileage units at Toronto Hydro are unlikely to deliver ROI if replaced with a BEV at this time. Fuel cost savings, for many units, are not great enough to offset the increased cost of capital due to relatively low mileage. Of course, the higher the kilometres travelled, the stronger the business case for BEVs becomes. There is a strong likelihood that the acquisition cost of BEVs will decline with time as both supply increases and battery technology continues to improve, and we have modelled this for Toronto Hydro's consideration.

BEV Phase-in Approaches and Scenario Results

The aggressive BEV phase-in approach employs a strategy of deferring more units in the short-term, resulting in a pent-up demand for overdue units which are modelled to be replaced with BEVs. Consequently, there are significant Capex spikes in the short- to medium-term.

To provide a balanced and viable BEV phase-in plan, our team strategically modelled the replacement of overdue lower-mileage units with internal combustion engine (ICE) vehicles in an effort to still achieve significant GHG emissions reductions while keeping within budget constraints. Moreover, we modelled replacement of overdue units that showed high usage and/or relatively high repair costs with ICEs as a financial risk-reduction strategy.

The balanced BEV phase-in approach employs a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road.

The aggressive fleet electrification scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by **100% by 2034** – before the end of the modelling period. The more cautious and fiscally prudent scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by just over **70% by 2037** – with the potential to achieve even greater results should more ICE units be replaced with BEVs towards the end of the modelling period, depending on pricing outcomes for BEVs compared to ICEs.

For the aggressive, fleet-wide BEV phase-in scenarios, average annual Capex is projected to be **$10.7M/yr** with cautious pricing (i.e., constant BEV/ICE ratios) and decrease to **$7.6M/yr** with the sliding scale in pricing. However, for both scenarios Capex is very imbalanced and front-loaded (i.e., higher values in the short- to mid-term).

The balanced, selective BEV phase-in scenarios avoid annual Capex "spikes" and keep within annual budget constraints. Even with this approach, it will take significantly more capital to transition to BEVs based on current prices discussed with Toronto Hydro Fleet Management, with a modelled average annual Capex of **$8.3M/yr**. If price parity is gradually reached by the 2030s, average annual Capex is projected to decrease to **$7.0M/yr**.

For units due for replacement that are still in good condition, we are recommending a temporary pause on purchasing new internal combustion engine (ICE) vehicles for the short term – 1-2 years for pickups, 2-3 years for medium- and heavy-duty vehicles (MHDVs) – while awaiting battery-electric vehicle (BEV) counterparts to become available and taking into consideration procurement timelines.

Our position is that fleets should re-consider buying new fossil-fuelled units, when possible, because ICE vehicles will quickly become an outdated and archaic technology, and there will soon be BEV replacement options. The purchase of new ICE vehicles now, whether gasoline or diesel, means that a fleet, like Toronto Hydro's fleet, will commit to using new fossil-fuelled vehicles for approximately the next decade when zero tailpipe emissions BEVs are just around the corner.

A phased-in approach is recommended for Toronto Hydro to transition to a BEV fleet for fiscal responsibility reasons, in addition to this being the only option for fleets over the next few years. Utility replacement cycles are long-term – up to 10 or 12 years – or more for some vehicles. Therefore, a BEV phase-in plan over the long term is needed for a balanced approach to capital spending.

EVSE Planning

Over the next 10+ years, we recommend allocating capital towards chargers (and charging infrastructure, which is outside the scope of this study) required for the transition to BEVs for all vehicle categories.

Based on our analysis of Toronto Hydro's charging requirements, 381 out of 385 units would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. Therefore, our recommendation is to focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power (Level 3) charging for higher-mileage units.

It is also critical to assess existing electrical capacity at facilities to determine whether substantial upgrades for charging multiple vehicles are required (outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations.

High-Impact BEV Options

The “workhorses” of utility fleets like Toronto Hydro are light-duty pickup trucks and vans. For Toronto Hydro’s fleet, pickups and Class 1 and 2 vans comprise about 42% of the vehicles based on the data provided (84 pickups and 78 light-duty vans out of a total of 385 vehicles). At this time, there are no BEV pickups or vans available for purchase. However, several manufacturers, including General Motors and Ford, are preparing for BEV pickups and vans to enter the market in 2022. Therefore, BEV options in the light-duty pickup and van categories have the potential to make a relatively early and significant impact on the utility’s fleet operating cost savings and GHG emissions reduction – ahead of the introduction of medium- and heavy-duty battery-electric trucks.

Appendix A: Electric Vehicle Survey Results

Views on Battery-Electric Vehicles

Figure 4: Views on range capabilities – management group

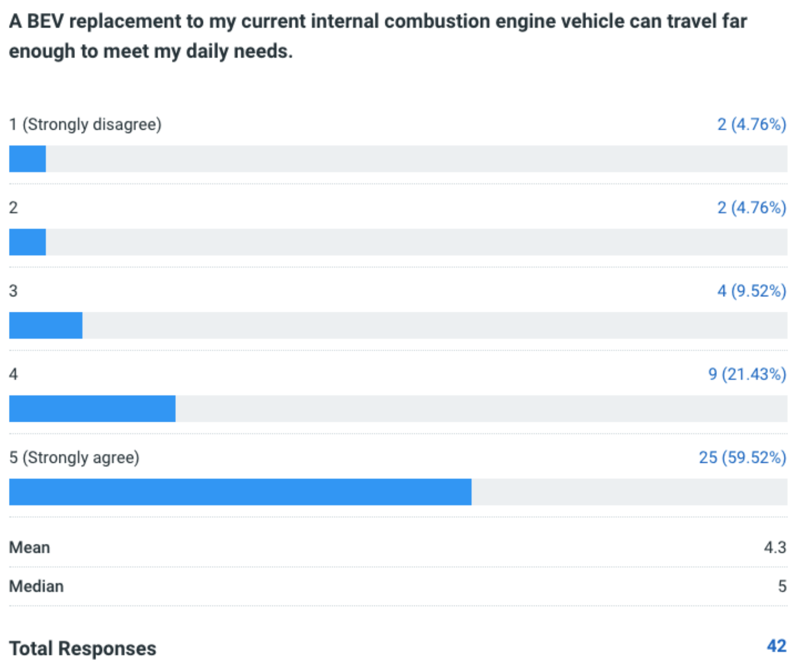


Figure 5: Views on range capabilities – driver/operator group

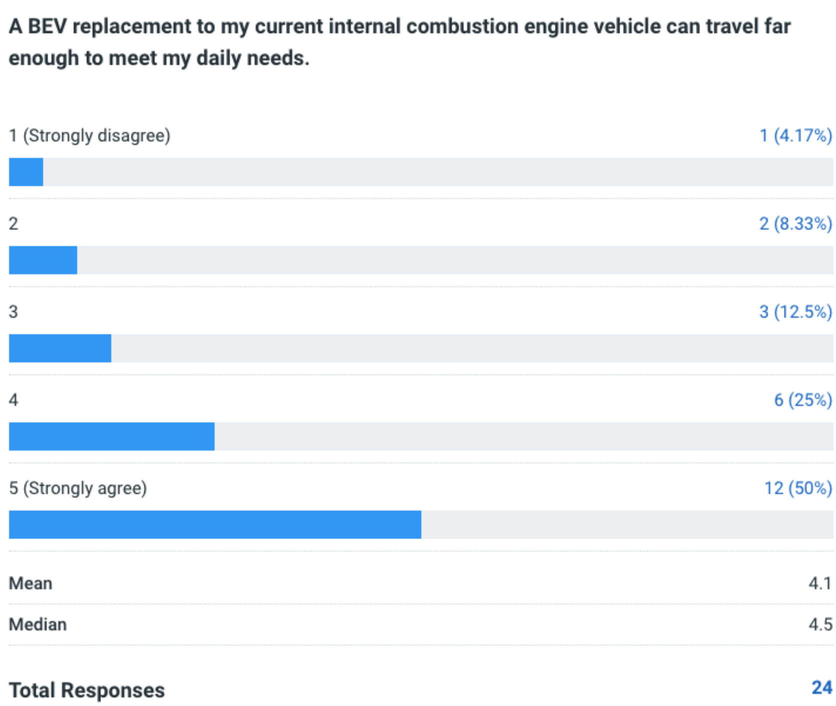


Figure 6: Views on air conditioning – management group

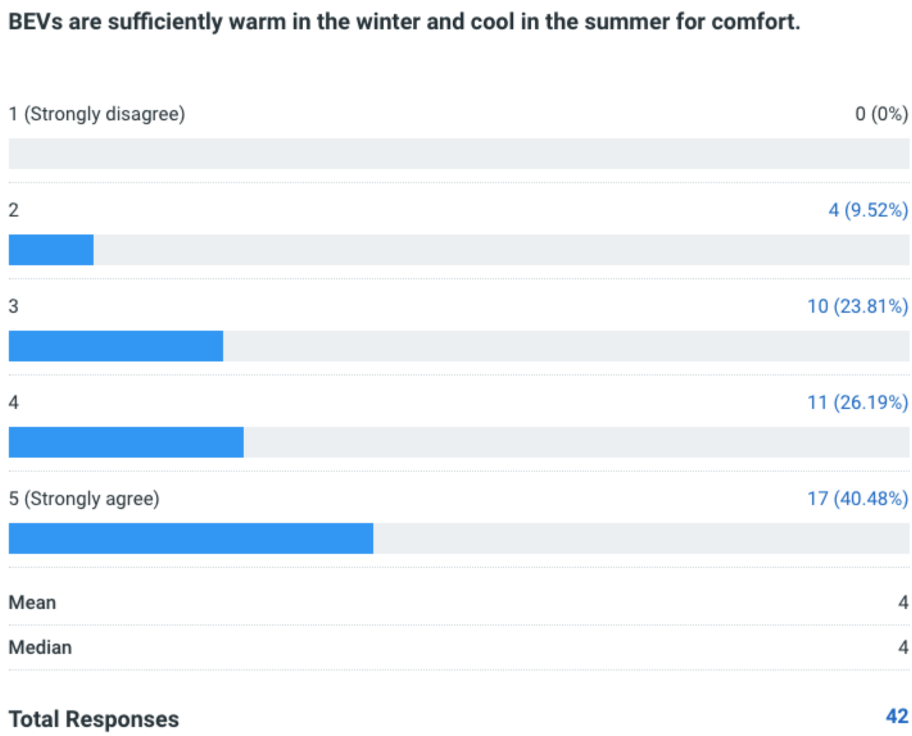


Figure 7: Views on air conditioning – driver/operator group

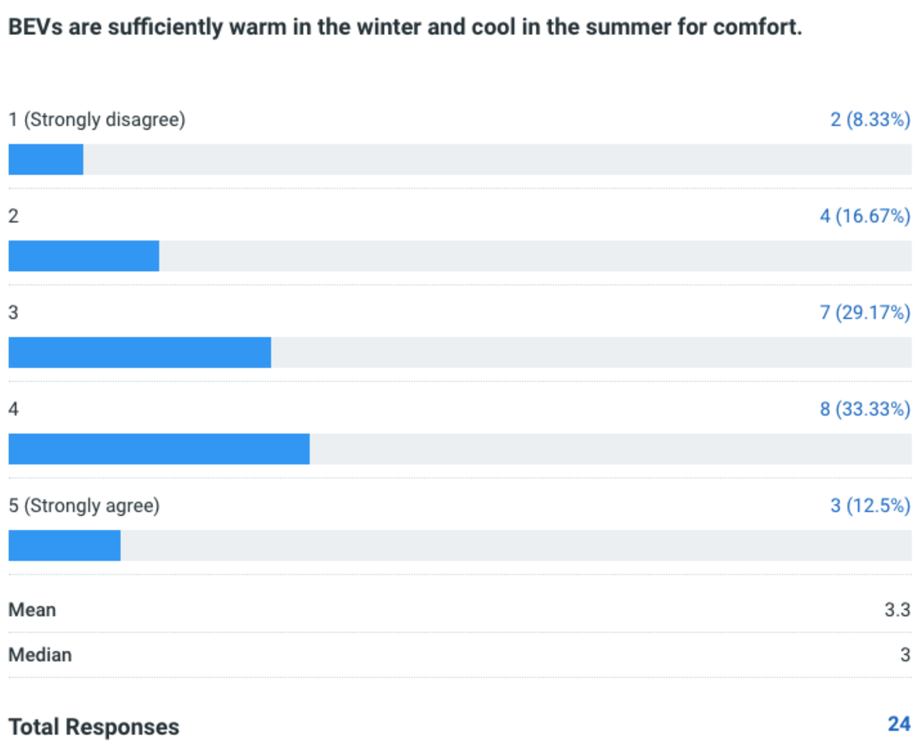


Figure 8: Views on safety – management group

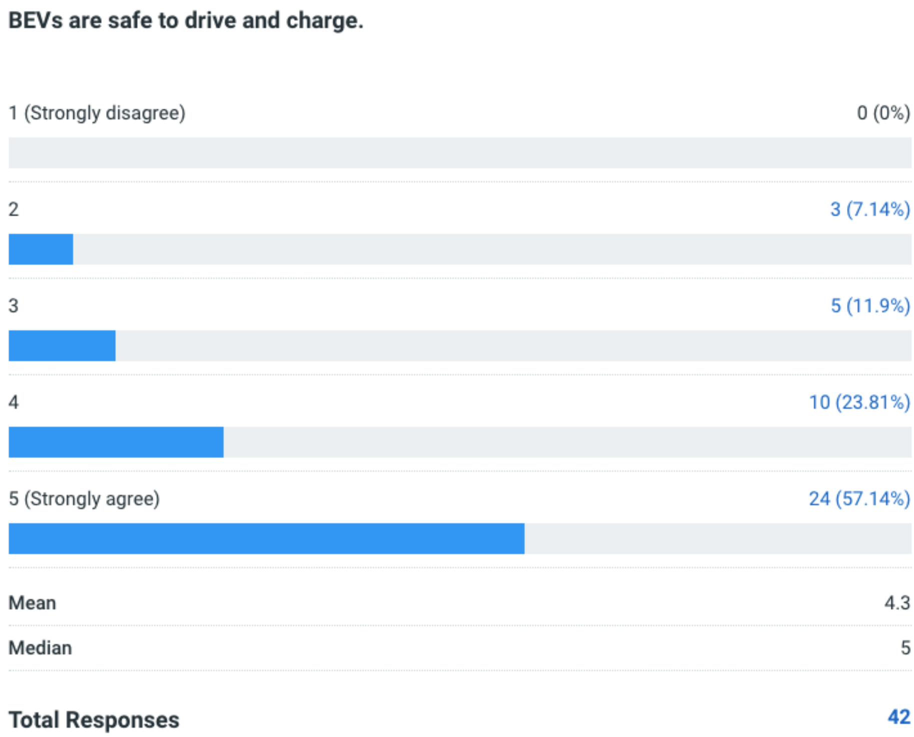


Figure 9: Views on safety – driver/operator group

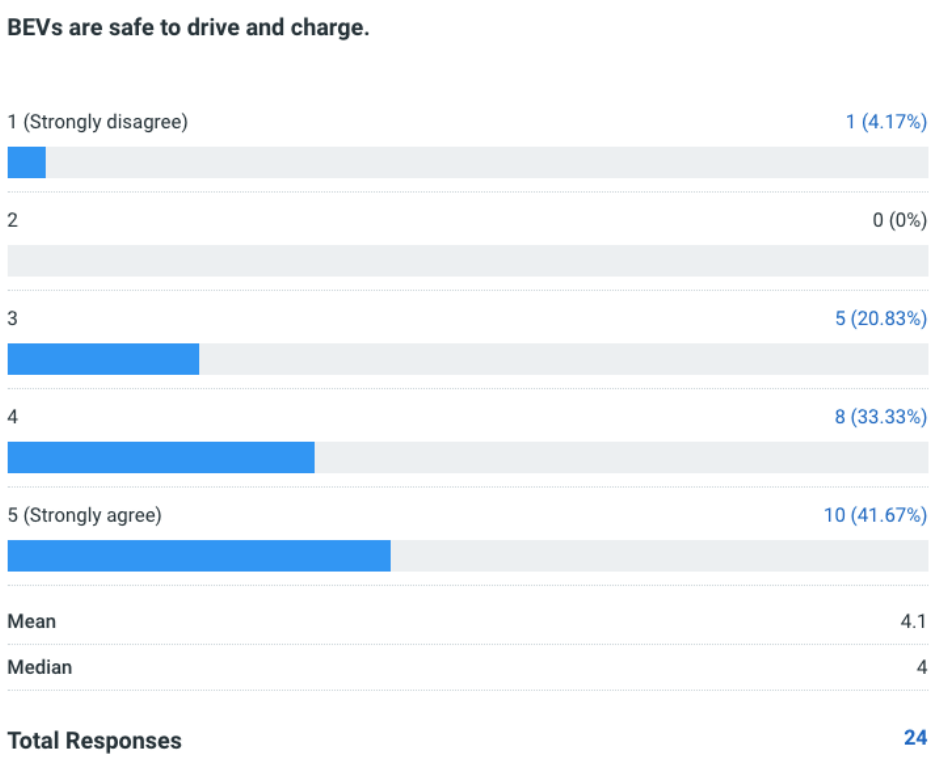


Figure 10: Views on costs – management group

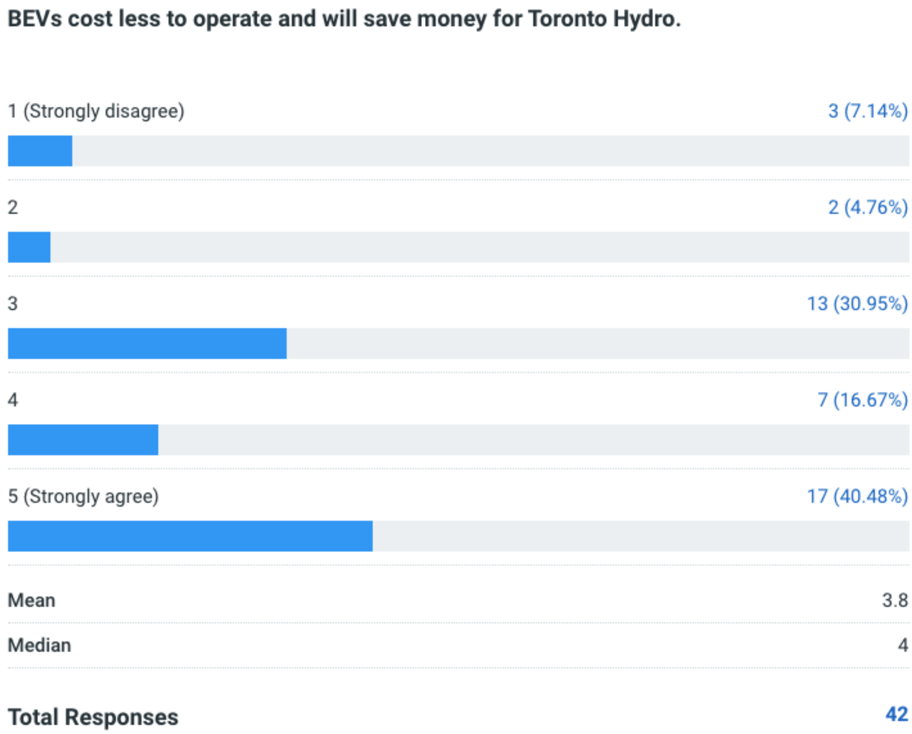
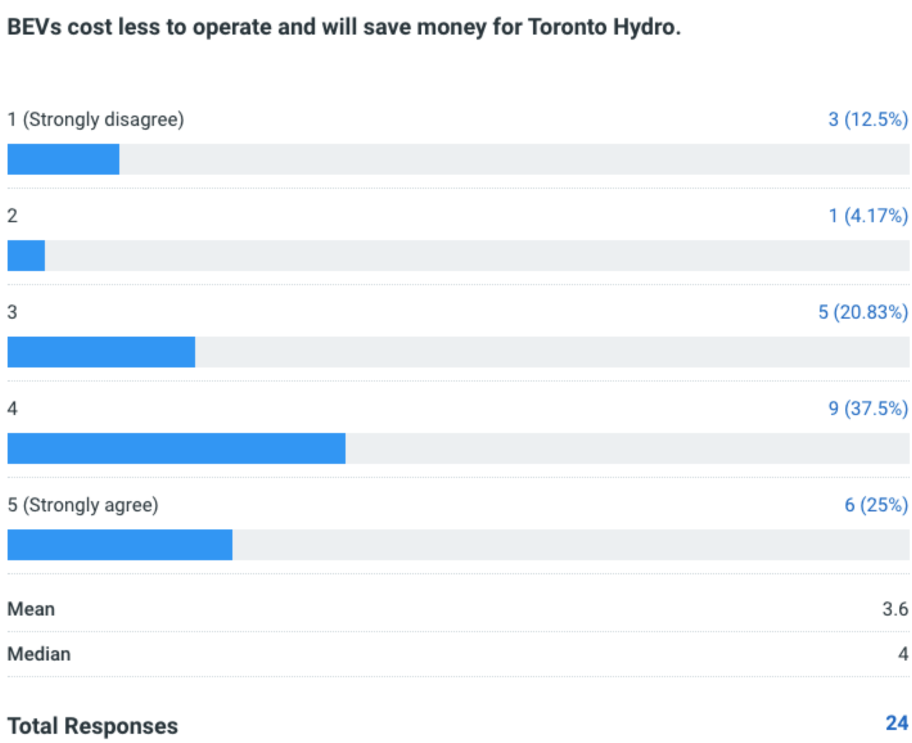


Figure 11: Views on costs – driver/operator group



Views on Charging Requirements

Figure 12: Views on Level 2 charging – management group

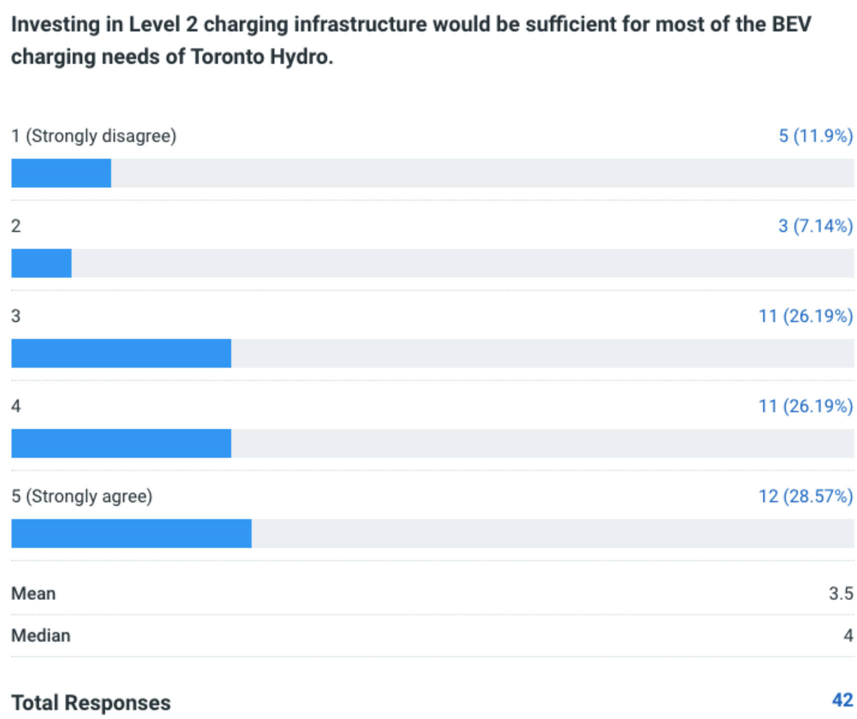


Figure 13: Views on Level 2 charging - driver/operator group

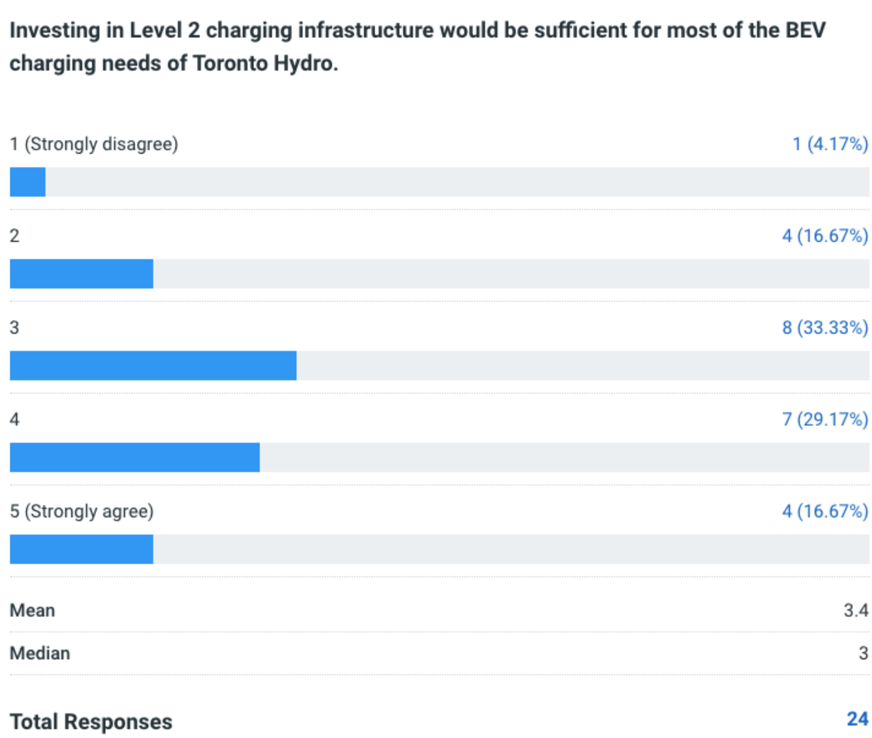


Figure 14: Views on Level 3 charging – management group

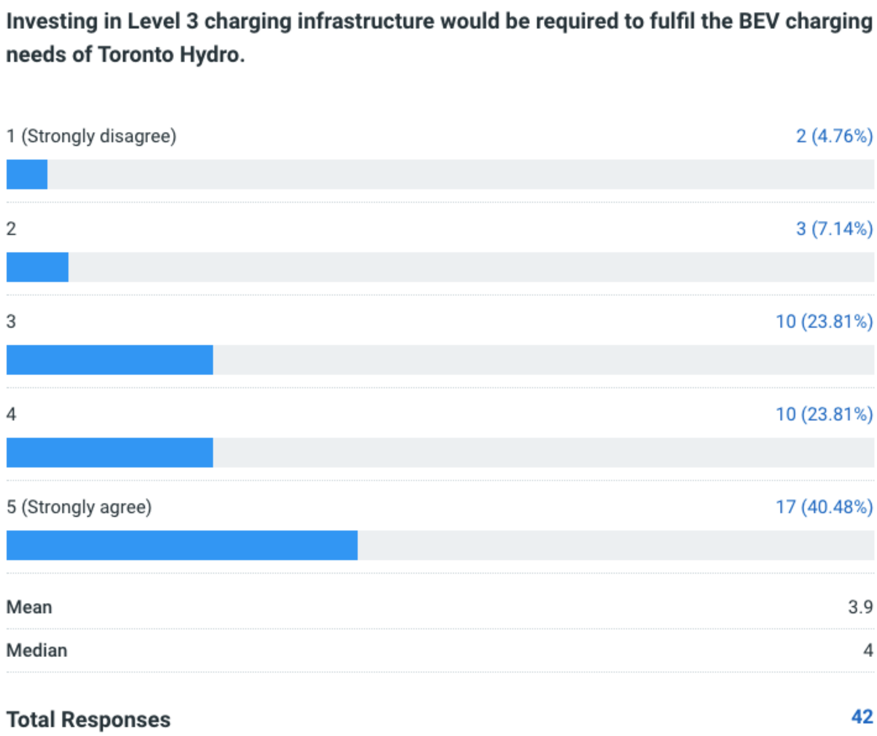
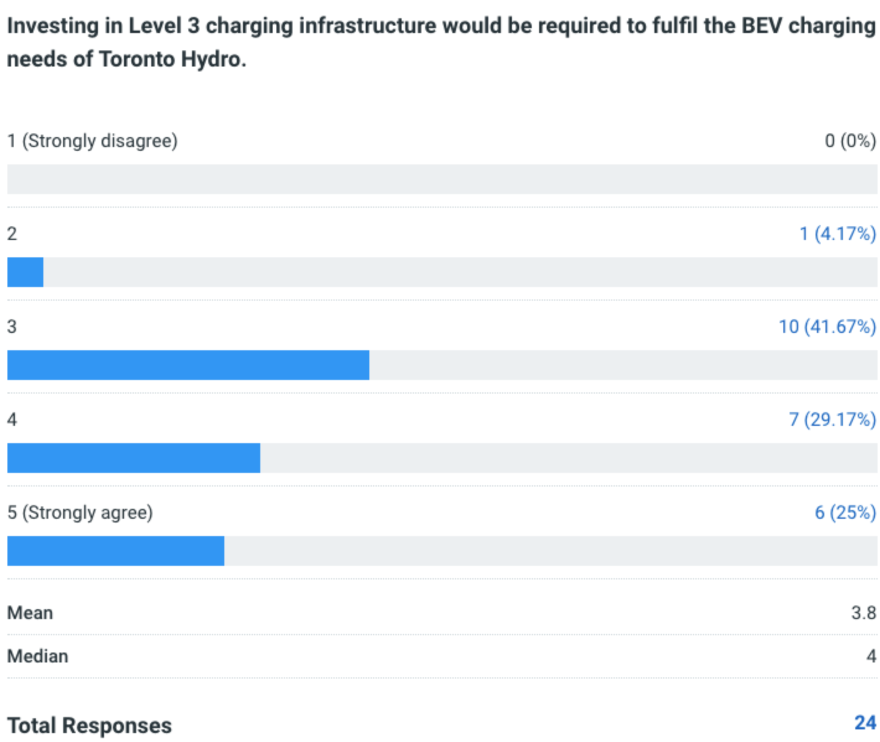


Figure 15: Views on Level 3 charging – driver/operator group



Views on Change Management

Figure 16: Views on test drives – management group

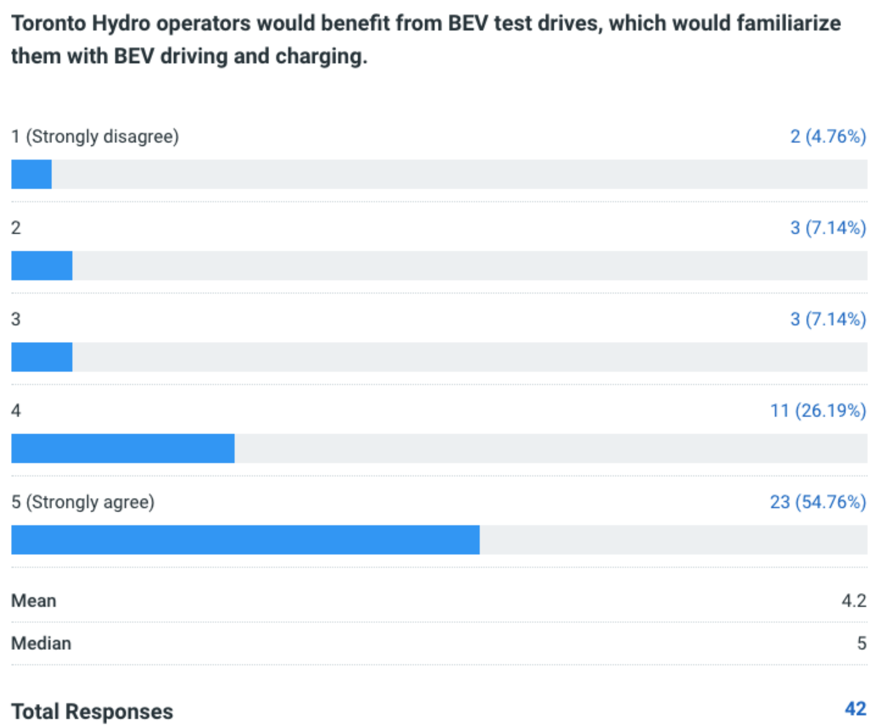


Figure 17: Views on test drives – driver/operator group

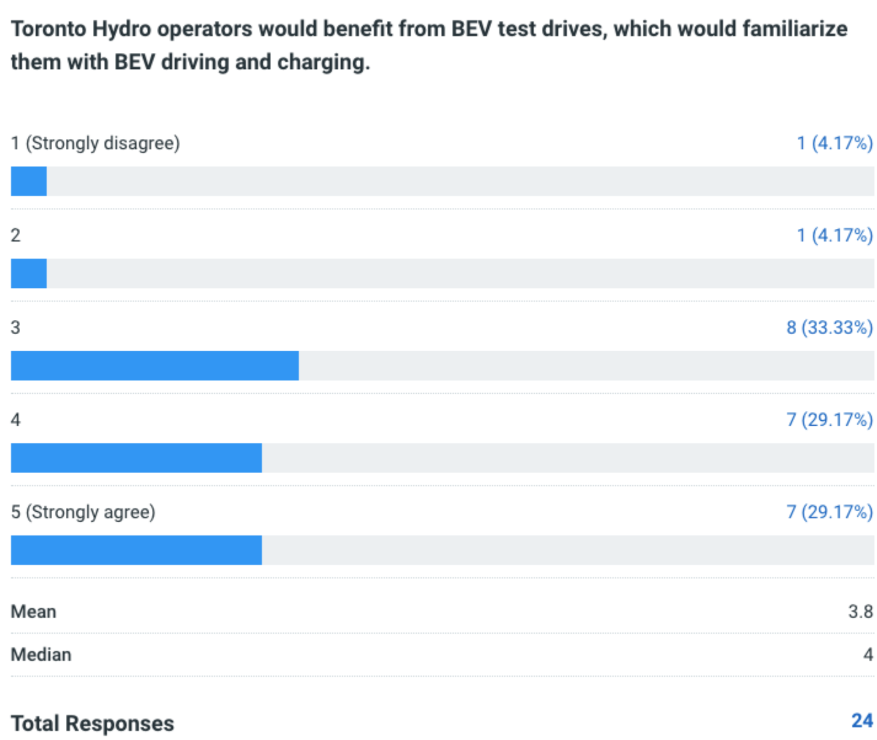


Figure 18: Views on orientation – management group

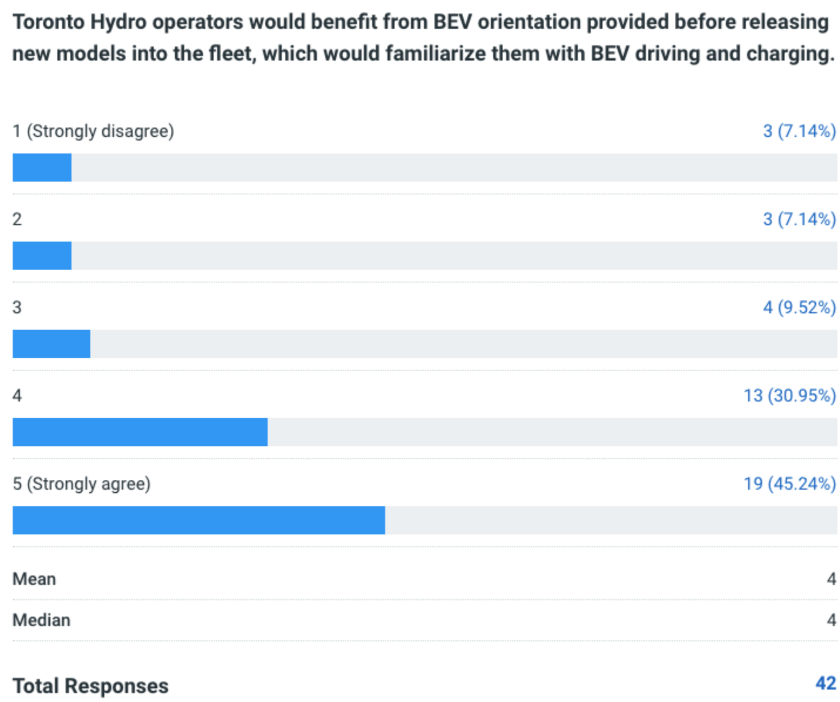
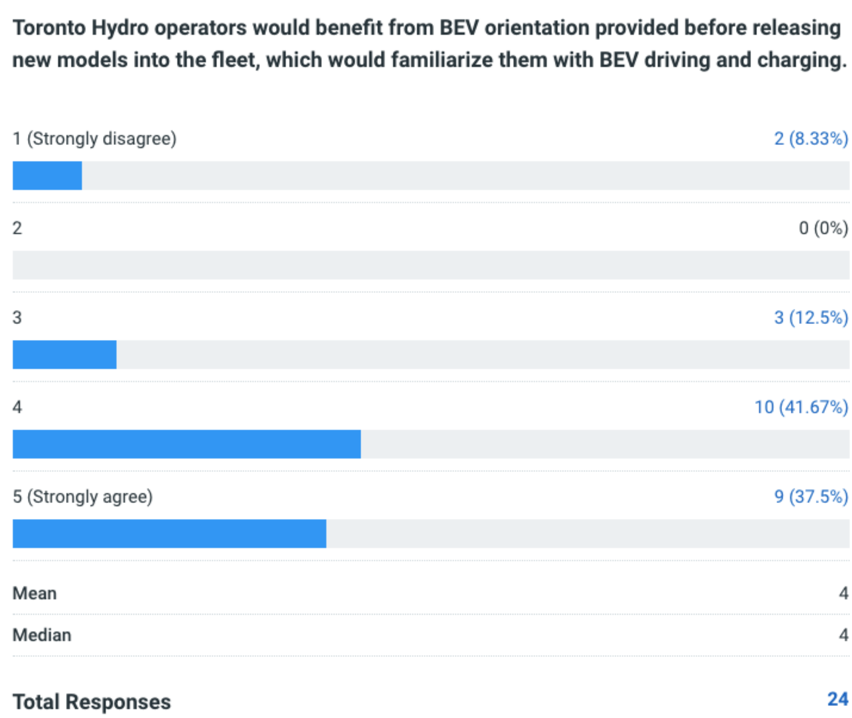


Figure 19: Views on orientation – driver/operator group



Appendix B: Fleet Analytics Review™

Fleet Analytics Review™ (FAR) is a user-friendly, interactive decision support tool designed to aid our team and fleet managers in developing short- to long-term green fleet plans by calculating the impacts of vehicle replacement and fuel-reduction solutions on operating costs, cost of capital, and GHG emissions. Moreover, it is used for long-term capital planning (LTCP) through an approach that works to balance, or smoothen, annual capital budgets and avoid cost spikes if possible.

FAR is a complex, sophisticated MS Excel software developed by the RSI-FC team in 2016. Since its inception, FAR has been used by our team as the foundational analysis platform for our work in helping fleets with green fleet planning and the transition to low-carbon fuels/technologies.

Clients to date for which reports were completed using FAR include:

- Municipality of Strathroy-Caradoc (2021)
- City of Brampton (2021)
- City of Hamilton (2021)
- City of Kawartha Lakes (2020)
- Durham Region (2020)
- Town of Gander (2020)
- Town of Whitby (2020)
- Town of Aurora (2019)
- NW Natural Gas Distribution, Portland, OR, USA (2018)
- The County of Middlesex Centre (2017)
- The Region of Peel (2017)
- The Town of Enfield, CT, USA (2017)
- Toronto Hydro-Electric System Limited (2017)
- Winnipeg Airport Authority (2017)
- Greater Toronto Airport Authority (2016)
- Oxford County (2016)
- The City of Vaughan (2016 - 2018)

Purpose

The core functionality of the FAR software is to calculate the financial and GHG reduction impacts of vehicle replacements, operational improvements, and low-carbon fuels/technologies for a fleet.

In the context of assessing fleet modernization, FAR is especially useful in calculating the operating expense (Opex) impacts of vehicles being retained in the fleet beyond their viable age and with diminishing salvage values. Aged, older-technology vehicles consume more fuel, produce more

GHGs, usually cost more to operate, are less reliable, and may also present a safety risk. FAR automatically calculates and quantifies these impacts in a defensible business case format.

For fuel-reduction solutions under consideration by fleet management as a means of saving fuel costs and avoiding GHGs, including best management practices (BMPs), alternate or renewable fuels (natural gas, propane, biodiesel, etc.), and EVs (battery-electric, plug-in hybrid, or hybrid), FAR calculates the cost-benefit of the investment in vehicle upgrades, vehicle conversion costs, fuelling infrastructure, or EV charging infrastructure, i.e., whether these solutions would yield a net operating cost reduction, unit-by-unit and fleet-wide.

Approach

The FAR software tool employs a holistic approach – all relevant factors and controllable expenses are considered in its analysis. The data points in our approach include energy equivalency factors of each alternative fuel type (compared to a fossil diesel fuel baseline), vehicle upgrade costs, alternately-fuelled vehicle acquisition (or vehicle retrofit) capital costs, vehicle maintenance considerations (higher or lower maintenance demand), fuel system/charging infrastructure capital costs, and any additional expenses for storage, handling & dispensing the fuel(s). All of these factors are modelled within the context of planned vehicle lifecycles – a total cost of ownership (TCO) approach.

The FAR process uses historical cost metrics and vehicle operating data (i.e., miles/km-driven, fuel usage, repair and maintenance costs, unit age, cost of capital, downtime, residual value, etc.) to establish not only the fleet's fuel usage and GHG emissions baseline, but also financial and service levels (i.e., utilization, availability/uptime) performance.

FAR highlights "exception" units, vehicles that are performing in a sub-standard way in terms of cost and performance, thus potentially enabling management to identify the reason(s) and take appropriate action(s).

Go-Forward Fuel-Reduction Solutions

With the FAR baseline established, the software is used to analyze go-forward fuel-reduction solutions. FAR takes into consideration the Opex implications and determines whether Opex reductions will offset any capital expenses (Capex) including vehicle upgrades, vehicle conversions, "up-charges" for premium vehicles (e.g., EVs), and investment in infrastructure.

The FAR analysis includes, but is not limited to:

- The fuel usage and cost differential (+ or -) for the fuel type selected vs the current type (if applicable)
- The energy-efficiency difference
- The unit cost of upgrade for the fuel-saving technology
- The unit cost of conversion to the selected fuel type
- The cost of fueling infrastructure for the selected fuel type apportioned evenly to the chosen vehicles for the fuel-switch
- The cost of charging infrastructure for EVs apportioned evenly to the chosen vehicles to be replaced
- The cost of capital for vehicle replacement for the selected fuel type

FAR then calculates whether a cost-savings or return-on-investment (ROI) would result within the remaining lifecycle for each of the vehicles selected for the vehicle upgrade or fuel switch.

Figure 20 shows a sample screen capture from FAR demonstrating the FAR fuel-switching capabilities. In this example, the user is switching several light-, medium-, and heavy-duty trucks from their current fuel source to renewable natural gas (RNG), and this is accomplished simply by selecting the vehicle(s) to be evaluated and then choosing (in this example) RNG from a drop-down list.

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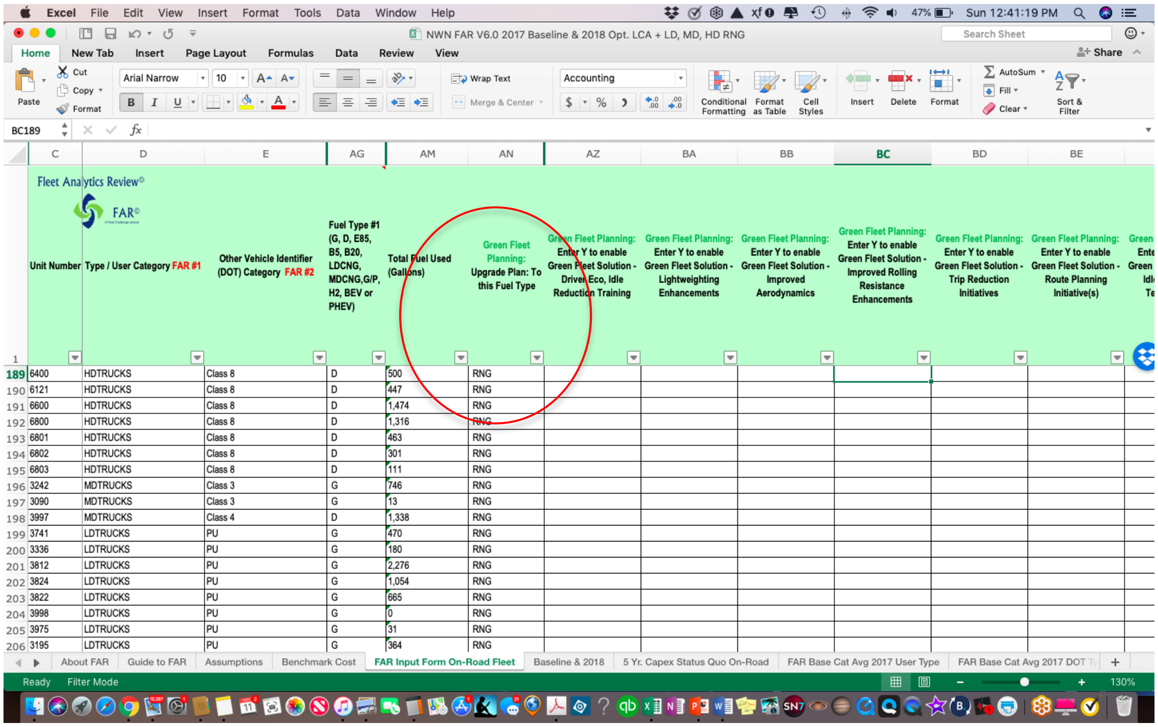
Figure 20: Sample Screen Capture of FAR Showing Fuel-Switching Options



FAR is user-friendly and intuitive; it is based on standard off-the-shelf MS Excel. It is dynamic, and users can run future scenarios (such as assessing different vehicle types, fuels, or engine/drivetrain combinations) to see how such decisions impact Opex ahead of their implementation, thereby mitigating risk and heading off potentially costly errors.

Recent Enhancements and Upgrades to FAR™

FAR V30.5 (beta) features upgrades and enhancements to the functionalities of the FAR tool. These include:

Fuel-Efficient Green Fleet Planning Tools – Fuel Switching. FAR now includes several powerful “Green Fleet Planning” tools. One of these tools is used to estimate the financial and GHG impacts of switching vehicle fuels from fossil-based (gas or diesel) to alternate or renewable fuels or BEVs.

In the Input Form, FAR analysts may make choices as to fuel-switching (for example, changing all gas or diesel-powered vehicles in specific categories to E85, B5-B100 biodiesel, hybrid, plug-in hybrid, battery-electric, CNG, or even hydrogen fuel cells). FAR calculates the net cost and GHG reduction of the fuel-switch being considered, taking into consideration not just the fuel/electricity costs, but the change in fuel efficiency, as well infrastructure costs such as installing a CNG fueling station, electric vehicle chargers, etc.

Enhanced Vehicle Replacement Cost-Benefit Analysis. Comparisons and analysis regarding either (a) aging a vehicle (or vehicles) that are now due for replacement for another year or (b) going ahead and replacing the vehicle(s) is now based on the actual average historical peer fleet cost data from our proprietary municipal fleet database.

In FAR, when a vehicle is due for replacement, it calculates the annual cost for a new replacement vehicle (including the capital, fuel, repairs, PM, and downtime) and then compares that amount to the actual average cost for a similar vehicle —that is one-year older (from our peer fleet database). FAR now displays the cost-benefit of replacing each unit that is due for replacement in the 5+ year Capex plan tab – in blue font each vehicle that will save Opex if it is replaced, and red font if it will incur more Opex. This marks a significant change in FAR and eliminates all guesswork or sketchy assumptions and supplants it with real peer fleet operating cost data by model year and vehicle categories we have collected since 2006.

Fuel-Usage and GHG Reduction for New Vehicles. For each vehicle that is due for replacement, FAR now shows the potential fuel-usage and GHG reduction.

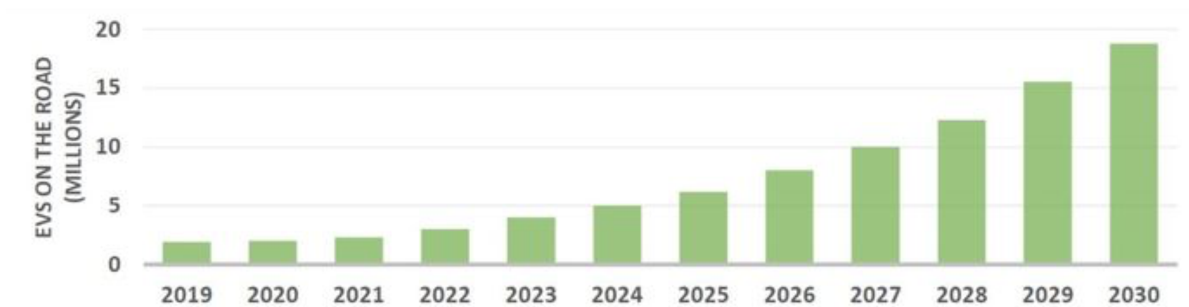
...

Appendix C: Details on Electric Vehicle Technologies

Over the past decade, electric transportation technologies including hybrid-electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs), and battery-electric vehicles (BEVs), have been rapidly developing and quickly gaining popularity in the market. Electric vehicle (EV) technologies offer significantly reduced or no tailpipe emissions and vastly improved energy efficiency.

Today, EVs have reached their tipping point and sales are booming while the public vehicle charging infrastructure rapidly grows. Demand for EVs accelerated during the 2010s and is expected to continue accelerating during the 2020s, as shown in *Figure 21* for the United States.

Figure 21: Forecasted EV Growth in US (Source: Edison Electric Institute)



For fleet managers looking to reduce their annual fuel budget and corporate emissions, battery-electric, hybrids, and plug-in hybrids are a good option. Savvy fleet managers will seek applications where the type of vehicle used will deliver sufficient fuel cost savings to offset their additional cost of capital and, after the vehicles are fully depreciated (usually ~5 years), deliver net cost savings until the end of their economic lifecycle (often ~10 years).

There are a number of light-duty electric vehicle technologies currently available in the market. They include:

- **Mild Hybrid Electric Vehicles (MHEVs)**, which are equipped with internal combustion engines (ICEs) and a motor-generator in a parallel combination allowing the engine to be turned off whenever the vehicle is coasting, braking, or stopped and which restart quickly. MHEVs use a smaller battery than full hybrid electric vehicles (HEVs, see below) and do not have an exclusively electric mode of propulsion; rather, the motor-generator has the ability to both create electricity and boost the gas engine's output, resulting in better performance and reduced fuel use. Examples of MHEVs are the Honda Insight and the 2019 Ram 1500. [55]

[55] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/

- **Hybrid Electric Vehicles (HEVs)**, which use two or more distinct types of power, such as an ICE and a battery-powered electric motor as the modes of propulsion, albeit with very limited range when in electric mode. When an HEV accelerates using the ICE, a built-in generator creates power which is stored in the battery and used to run the electric motor at other times. This reduces the overall workload of the ICE, significantly reducing fuel consumption and extending range. Examples of HEVs include the Toyota Prius and Ford Fusion Hybrid. [56]

- **Plug-In Hybrid Electric Vehicles (PHEVs)**, which use rechargeable batteries, or another energy storage device, that can be recharged by plugging into an external source of electric power. PHEVs can travel considerable distances in electric-only mode, typically more than 25 km and up to 80 km for some models, due to their much higher battery capacity than hybrids. When the battery power is low (usually ~80% depleted), the gasoline ICE turns on and the vehicle functions as a conventional hybrid. Such vehicles typically have the same range as their gasoline counterparts. Examples of PHEVs include the Chevrolet Volt and Toyota Prius Prime.[57]

- **Battery-Electric Vehicles (BEVs)**, or all-electric vehicles, which are propelled by one or more electric motors using electrical energy stored in rechargeable batteries. BEVs are quieter than ICE vehicles and have no tailpipe emissions. In recent years, BEV range has been considerably extended, thereby providing much wider BEV applications and reducing range anxiety. Today, many BEV models have EPA-estimated ranges exceeding 400 km, which provide much greater reliability when travelling longer distances. Recharging a BEV can take significantly longer than refuelling a conventional vehicle, with the difference depending on the charging speed. For a light-duty vehicle, a full battery charge using a Level 2 charger takes several hours, but charging from a nearly depleted battery to 70% at a fast (Level 3) charge station can take only 30 minutes[58]. Examples of light-duty BEVs include the Nissan Leaf, Chevrolet Bolt, Kia Soul, and Tesla Model 3.

While commercial battery-electric (BEV) pickups, trucks and vans are still limited/ have not yet arrived in the market, options are expected to become more plentiful in the next few years. Medium and heavy-duty battery-electric trucks are quickly being developed by many manufacturers. Demand for those offered by Tesla, Volvo, Freightliner, and others exceeds current supply and will soon be available for fleet purchase. Battery-electric buses and refuse trucks are currently available for purchase.

[56] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[57] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[58] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/

Plug-in hybrid electric vehicles would also be an excellent solution for a low-mileage, return-to-base fleet like Toronto Hydro. PHEVs have a much larger all-electric range as compared to conventional first-generation hybrid vehicles, and they eliminate any range anxiety that may be associated with all-electric vehicles because the combustion engine works as a backup when the batteries have become depleted. For fleet vehicles that return to base each night, PHEVs (as well as BEVs) are ideal for overnight, Level 2 charging. It is entirely conceivable that low-mileage PHEVs could be driven every day almost entirely on electric power, functioning like fully-electric vehicles.

Zero Emission Battery-Electric Vehicles

There is no question that BEVs are taking over traditional internal combustion engine (ICE) vehicles in a big way. Some jurisdictions have already legislated the end of ICEs. If they haven't done so already, fleet managers should start making plans for BEVs now.

While their upfront costs will be higher, BEVs have increasingly proven to be a viable solution to rising fuel costs and emissions. Since BEVs have few moving parts, tune-ups or oil changes are never required, and they seldom, if ever, require brake relining due to regenerative braking. And, best of all, they burn zero fuel.

Since the release of the first mass-produced BEV, the Nissan Leaf, which debuted in 2010 with an EPA range estimated at only 73 mi or 117 km[59], there has been a surge in lithium-ion battery production leading to a drastic decline in prices. Today, several more affordable BEV models have ranges exceeding 400 km, which provide much greater reliability when travelling longer distances. For example, the 2020 Tesla Model 3 Standard Plus has an EPA-estimated range of 402 km[60], while the 2020 Chevrolet Bolt has an EPA-estimated range of 417 km[61].

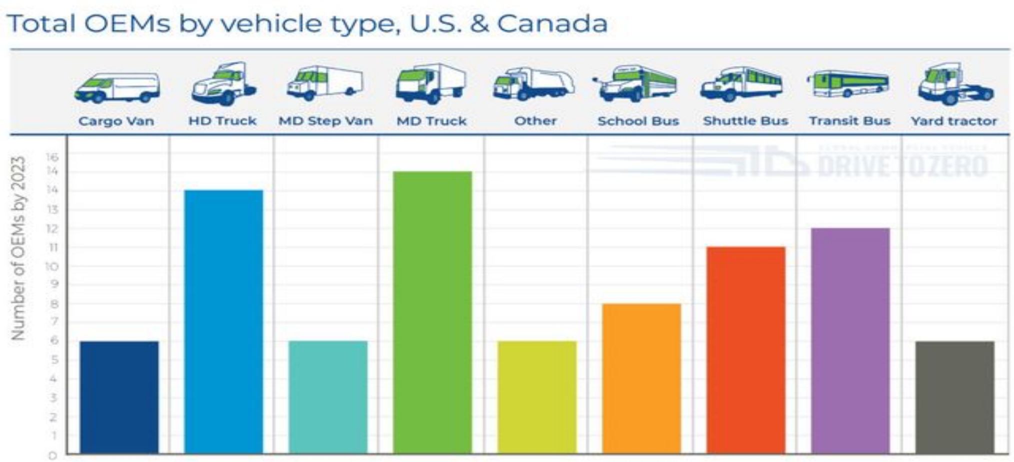
There has also been significant expansion in charging infrastructure through publicly available charging stations. As of early 2020, there were nearly 5,000 charging outlets across Canada, and Natural Resources Canada is investing $130 million from 2019-2024 to further expand the country's charging network, making range anxiety even less of a barrier to BEV ownership.

In addition to battery-electric pickups that are soon to emerge, battery-electric buses and emerging battery-electric medium- and heavy-duty trucks such as those planned by Tesla, Volvo, Freightliner, and other manufacturers are attracting considerable interest because of their the elimination of tailpipe GHG and CAC emissions, in addition to the potential for significant maintenance and fuel cost savings. In *Figure 22*, we see that the OEMs are quickly ramping up with other types of

[59] Source: https://www.mrmoneymustache.com/the-nissan-leaf-experiment/
[60] Source: https://www.tesla.com/en_ca/model3
[61] Source: https://www.chevrolet.com/electric/bolt-ev

commercial EV trucks (medium- and heavy-duty truck categories) that are suited for municipal work environments and utilities.

Figure 22: Total EV OEMs by 2023 (Source: Calstart)



Fleet managers who operate battery-electric trucks and buses can see massive savings in maintenance and fuel costs. BEVs have considerably fewer parts than internal combustion engine (ICE) vehicles. A drivetrain in an ICE vehicle contains more than 2,000 moving parts, compared to about 20 parts in an BEV drivetrain. This 99% reduction in moving parts creates far fewer points of failure, which limits and, in some cases, eliminates traditional vehicle repairs and maintenance requirements, creating immense savings for fleet managers. BEVs do not require oil changes or tune-ups, have no diesel exhaust fluid (DEF), and their brake lining life is greatly extended over standard vehicles due to regenerative braking. Though each fleet's electrification journey will be different, the transition to electric power can offer significant cost reductions over the long term.

A new study[62] quantified what commercial EV-makers have been saying for years: electric trucks and buses are a triple win. They save money for fleet operators, and reduce both local air pollution and GHG emissions. The study, which was commissioned by the National Resources Defense Council (NRDC) and the California Electric Transportation Coalition, and conducted by the international research firm ICF, looked at the value proposition for fleet operators of battery-electric trucks and buses (BETs).

Today, BETs have an upfront price premium compared to legacy diesel trucks and buses. However, the costs of battery packs and other components are rapidly falling, and the study found that, by

[62] Source: Posted January 2, 2020 by Charles Morris (https://chargedevs.com/author/charles-morris/) & filed under Newswire (https://chargedevs.com/category/newswire/), The Vehicles (https://chargedevs.com/category/newswire/the-vehicles/)

2030 or earlier, electric vehicles will offer a lower total cost of ownership (TCO) for nearly all truck and bus classes, even without incentives.

In *Table* 8, we provide a summary of the strengths and weaknesses of BEVs.

Table 8: Strengths and Weaknesses of BEVs

Strengths	Weaknesses
- Well-designed, no noise, few moving parts, long warranties - Little/no maintenance - Government grants and incentives may be available - Effectively eliminates need for idling-reduction initiatives - Very positive driver feedback - Very positive public opinions - Potential for significant lifecycle GHG emissions, depending on electricity source	- High capital cost particularly for battery-electric trucks/buses - Limited availability of new battery-electric trucks - Potentially significant capital costs required for charging infrastructure, particularly if 480V (DCFC) charging equipment is installed - Existing electrical capacity at facilities may require significant upgrades for charging multiple vehicles - Potential driver range anxiety that may require a change management approach - Although unlikely, potential for costly battery replacements in aged BEVs

Air Quality and Upstream Emissions

Air quality is a growing concern in many urban environments and has direct health impacts for residents. Tailpipe emissions from internal combustion engines are one of the major sources of harmful pollutants, such as nitrogen oxides and particulates. Diesel engines in particular have very high nitrogen oxide emissions and yet these make up the majority of the global bus fleet. As the world's urban population continues to grow, identifying sustainable, cost-effective transport options is becoming more critical.

Battery-electric vehicles (BEVs) require electricity to recharge the batteries; therefore, electricity is effectively a "fuel" in these types of vehicles. Battery-electric vehicles (BEVs) may be defined as zero emissions vehicles (ZEVs) since the California Air Resources Board (CARB) defines a ZEV as a vehicle that emits no exhaust gas from the onboard source of power[63]. However, CARB's definition accounts for pollutants emitted at the point of the vehicle operation and the clean air benefits are usually local. Depending on the source of the electricity used to recharge the batteries, air pollutant emissions are shifted to the location of the electricity generation plants. For example, if electricity used for charging vehicles comes primarily from "dirty" sources such as coal, lifecycle vehicle emissions will result.

[63] Source: California Air Resources Board (2009-03-09). "Glossary of Air Pollution Terms: ZEV"

From a broader perspective, to have almost none or zero well-to-wheel emissions, the electricity used to recharge the batteries must be generated from renewable or clean sources such as wind, solar, hydroelectric, or nuclear power. In other words, if BEVs are recharged from electricity generated by fossil fuel plants, they cannot truly be considered as ZEVs. Upstream emissions should be considered when evaluating the effectiveness of ZEVs in reducing emissions. Generally, when considering upstream emissions from electricity supply, BEVs still emit more than 50% less GHG emissions than their gasoline or diesel counterparts[64], and in some cases emit over 80% less in a grid composed of mostly renewable electricity[65]. This level of emissions reduction is what cities need in order to collectively achieve the "deep decarbonization" necessary to mitigate the most serious impacts of climate change.

Charging Technologies

The time it takes to charge a BEV is dependent on a multitude of factors, including:

- The type (level) of charger used (i.e., Level 1, 2, or 3);
- The vehicle's technology (i.e., the maximum amount of current allowed by the vehicle, in amps);
- Battery capacity (generally increases with vehicle size);
- Driving range (dependent on battery capacity and vehicle size)
- Starting charge level (charging rate slowly diminishes as battery levels approach 100%)

The charging rate is expressed in kilometers/miles of range per hour of charging. It is estimated by dividing driving range by the time for a full charge (i.e., 0 to 100%) and is dependent on the battery capacity of a vehicle, varying significantly with different vehicle types and battery sizes (see *Table 9*, below). The time for a full charge is estimated by dividing battery capacity, in kWh, by charging power (calculated from current and voltage) and adding a 10% inefficiency[66 67].

Characteristics of the varying levels of chargers ranging from Level 1-3 are shown for LD vehicles in *Table 9*[68]:

[64] Source: https://www.eei.org/issuesandpolicy/electrictransportation/Pages/default.aspx
[65] Source: https://blog.ucsusa.org/rachael-nealer/gasoline-vs-electric-global-warming-emissions-953
[66] Source: https://www.caranddriver.com/shopping-advice/a32600212/ev-charging-time/
[67] Source: https://www.inchcalculator.com/widgets/?calculator=electric_car_charging_time
[68] Source: https://calevip.org/electric-vehicle-charging-101

Table 9: Characteristics of BEV charging levels for different vehicle classes

BEV Charging Levels	Outlet Voltage	Amperage	Added Range Per Hour		
			LD	MD	HD
Level I	120V	12-16 amps	5-10 km	< 5 km	< 2 km
Level II	240V	16-40 amps	22-56 km	10-25 km	5-12 km
Level III	480+V	100+ amps	>200 km	> 70 km	> 35 km

Level 1 chargers can be plugged right into a standard outlet. They are the most economical option for private owners; however, at such a low charging rate it is usually not practical to use Level 1 chargers exclusively. For example, it would take about 40 hours to fully charge a light-duty BEV with a range of 400 km starting at 20% battery (80 km range remaining).

Level 2 chargers are common in private households as well as public spaces such as mall parking lots. They incur an installation cost but are similar to common 240V installations such as the outlets that power clothes dryers. For a light-duty BEV with a range of 400 km and at 20% battery (80 km range remaining), it would take about eight hours to fully charge. Level 2 charging is usually done overnight during the off-peak period. Installing Level 2, 240V chargers, including the wiring infrastructure involved, typically range in cost from around $1,500-10,000, depending on electrical system requirements. The vast majority of the time, BEV owners only need a Level 2 charger; the exception is when travelling longer distances and/or not returning-to-base at the end of the work day. Another possible exception is for heavy-duty vehicles that take longer to charge due to their battery size. For these applications, much faster charging rates are required through Level 3 charging.

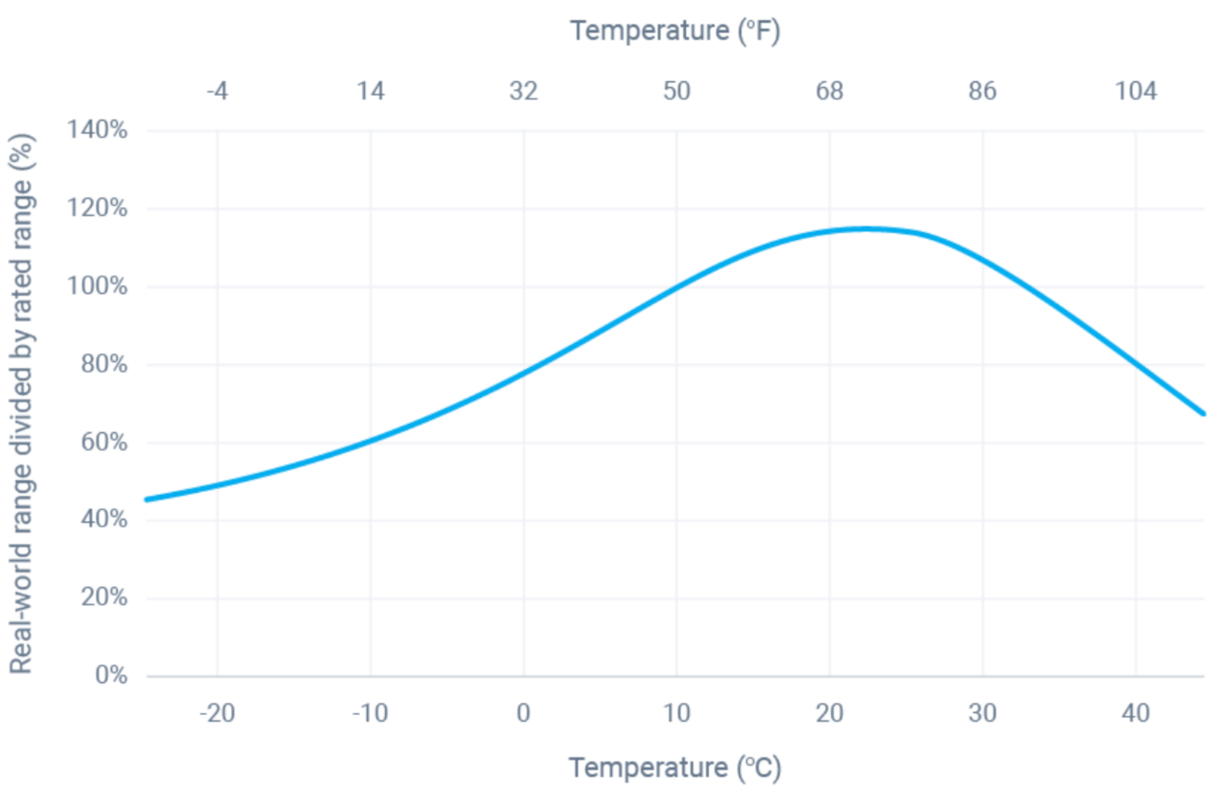
Level 3, or direct current fast chargers (DCFCs), requiring inputs of 480+ volts and 100+ amps (50+ kW)[69], are specialized systems designed to quickly charge vehicles and provide flexibility to owners travelling longer distances or in need of a partial quick charge. For a light-duty BEV with a range of 400 km and at 20% battery (80 km range remaining), it would typically take less than one hour to fully charge. Installations of DCFCs require a commercial electrician due to the electrical load and wiring requirements[70]. The costs for installing a Level 3 DCFC vary greatly. Costs for a fast-charging station are dependent on the electrical supply available at the chosen charging site, site preparation costs including trenching, cable runs, and many other installation considerations. Equipment and installation costs for DC fast charging stations can range from $50,000 to $200,000[71].

[69] Source: https://calevip.org/electric-vehicle-charging-101
[70] Source: https://calevip.org/electric-vehicle-charging-101
[71] Source: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf

Impact of Temperature on Battery Performance

Canadians enjoy the ebbs and flows of seasonality and extreme temperatures. BEV range is adversely affected by cold and hot temperatures because of auxiliary heating and cooling – that is, heating/cooling the vehicle cabin, and heating/cooling the battery itself to maintain optimal performance. Batteries are susceptible to temperature fluctuations which hinder, but in some cases helps, range. For example, on a typical winter day in central Canada with a temperature at -15°C, range can drop by over 50% of the EPA estimated range, meaning that a BEV with a range of 400 km will only be able to drive 200 km (*Figure 23*, below). Conversely, at temperatures in the low-twenties, range can significantly exceed the EPA-estimated range given that other conditions are optimal (e.g., starting temperature, terrain, and driver habits). With some preparation and knowledge, owners and operators of BEVs can mitigate the effects of temperature on performance by pre-conditioning their vehicle (i.e., warming up or cooling down before use) as well as keeping their vehicle plugged in when temperatures are extreme; this allows the system to maintain battery temperature controls and also prolongs battery life.[72]

Figure 23: The Effects of Temperature on BEV Range



[72] Source: https://www.geotab.com/blog/ev-range/

Training Options and Recommendations

While there is a paucity of BEV technician training in Canada, due to the rapid onset of electric mobility we suspect that reality will soon change. A pilot for a new EV Maintenance Training Program for automotive technicians was successfully completed at BCIT and is available to the public[73].

There is an Electric Vehicle Technology Certificate Program offered by SkillCommons, managed by the California State University and its MERLOT program, which offers free and open learning materials electric vehicle development, maintenance, alternative/renewable energy, and energy storage[74]. There is also a Hybrid and Electric Vehicles course offered at Centennial College in Toronto, which appears to focus more on hybrid systems than fully electric vehicles[75].

Before BEVs are deployed in a fleet to any great extent, we recommend high-voltage training for technicians. Published high-voltage guidelines specific to vehicle technicians servicing BEVs are not readily available through traditional sources. However, we suggest that anyone working with high voltage in any format, including BEVs, should be provided guidance on applying Occupational Health & Safety Management System fundamentals. This includes a "plan, do, check, and act" philosophy while working with energized electrical equipment[76]. Such training is available for non-electrical workers from Lineman's Testing Laboratories (LTL) of Weston, Ontario. LTL offers an awareness-level course for non-electrical workers which is claimed by the company to provide a basic-level understanding of workplace electrical safety.

Aside from awareness training, fleet technicians should also have access to, and be trained on the use of, electrical-specific personal protective equipment (PPE). Such PPE would include tested and certified non-conductive gloves as well as non-conductive tools and equipment as a last line of defence, ensuring all such gear is appropriately used and maintained. Protective gloves and other PPE, as well as non-conductive tools, must be re-tested periodically to ensure safety.

BEV Summary

For light-duty vehicles and buses, and soon for medium- to heavy-duty trucks, BEVs have excellent potential for a fleet due to the following:

- Significant lifecycle GHG emissions reductions

[73] Source: https://commons.bcit.ca/news/2019/12/ev-maintenance-training/
[74] Source: http://support.skillscommons.org/showcases/open-courseware/energy/e-vehicle-tech-cert/
[75] Source: https://db2.centennialcollege.ca/ce/coursedetail.php?CourseCode=CESD-945
[76] Source: https://training-ltl.ca/

- Significant reduction in operational costs due to elimination of fuel consumption, low costs for electricity, and minimal maintenance costs

- Relatively low charging infrastructure costs in comparison to infrastructure costs for other fuel-reduction / emission-reducing technologies such as compressed natural gas (CNG)

In planning for BEV phase-in, it would be prudent to consider installing at least one Level 3, direct current fast charger (DCFC) for high-mileage units and/or units that do not return-to-base on a regular basis. Moreover, such a fast charger would enable fleet management staff to relatively quickly charge their vehicles in situations where plugging in for overnight charging may not been possible or for emergency situations. For heavy-duty BEVs, it is important to consider that, depending on available amperage, a full charge may take several hours even with DCFCs.

Evaluation of the fleet to identify vehicles that have a potential for a replacement with a BEV should be completed. Furthermore, change management is recommended to be part of the transition process to help drivers accept and adapt to BEVs and overcome any lingering range anxiety.

Appendix D: Details on Best Management Practices

Here, we provide further details on many of the best management practices (BMPs) modelled in FAR, which have been researched by RSI-FC, and are effective interim solutions to reducing fuel usage and costs as well as GHG emissions.

Best management practices include: (1) enhanced vehicle specifications – vehicle choice and/or vehicle upgrades – which lower fuel consumption, lower GHG emissions, and improve overall performance; (2) proper maintenance procedures including tire inflation systems; and (3) fleet operational improvements including:

- Idling reduction initiatives
- Driver training to educate drivers on efficient driving practices
- Ongoing feedback and motivation to maintain good driving habits
- Route planning and optimization, including trip reduction, minimization, or elimination

Enhanced Vehicle Specifications at a Glance

There are a number of vehicle specifications that can aid in fuel-use and emissions reductions. *Table 10* lists sample vehicle specifications and their respective impacts.

Table 10: Strengths and Weaknesses of Enhanced Vehicle Specifications

Specification	Strengths	Weaknesses
Smaller Vehicles	Consume less fuel and thus have reduced emissions	Might not always be suitable for the job
Lighter Vehicles	Consume less fuel, produce less emissions, and can carry larger payload (e.g., if a truck is lighter by "x" pounds/kg, it can carry a commensurately increased payload), which increases efficiency	Light weighting may overstress some vehicles, increasing maintenance demand and lifecycle cost
Aerodynamically Designed Vehicles	Reduces fuel consumption and emissions	Minimal effectiveness in urban setting, high cost, increased maintenance demand for some solutions

Specification	Strengths	Weaknesses
Low Rolling Resistance (LRR) Tires and Wide-base Tires	Reduces fuel consumption and emissions, reduce frequency of tire replacement	Potential for on-road service issues, axle loading restrictions in some jurisdictions with wide-base tires
Electronically Controlled, Programmable Diesel Engines	Allow tailoring/minimizing power and torque needs, road speed, and idle time limits therefore reducing fuel consumption and emissions	Seldom give problems, however when they do, often require specialized and costly diagnostic skills (might need to be outsourced) with potentially protracted downtime
Idling-Reduction Devices	Reduces idle time and therefore lowers fuel use and emissions	Actual idling reduction benefits are dependent on the use of technologies by drivers, some who resent intervention by such devices; some may feel devices could cause a safety concern

Fleet Downsizing

Getting a fleet's "house in order" should include shedding any under-utilized vehicles, so that stranded capital tied up in low-usage units can be re-applied to fleet modernization and new electric vehicles (EVs). When exception data demonstrates that a vehicle's usage has been less than the organization's acceptable minimum threshold, the vehicle is incurring cost without serving a purpose. Hence, the vehicle is a liability, unless it has some redeeming value, i.e., a special-purpose or backup vehicle for emergencies, or a unit reserved for peak periods.

Low-usage units should be routinely and regularly reviewed to determine if there are more cost-effective ways of accomplishing the corporate end-goal. If a specific vehicle is used infrequently, management should be empowered to consider creative solutions for a less costly travel mode, e.g., an inter-departmental vehicle sharing arrangement, a 3rd party service-provider, video conferencing, use of employee's vehicles, etc.

A fleet's first step in cost reduction is to reduce the total number of low-utilization vehicles. Management should undertake a review to determine if some vehicles can be eliminated through early decommissioning.

Right-Sizing

In days past, some fleet managers subscribed to the adage "identify the size of truck you really need for the job — and then buy one bigger." Today, we know this is anachronistic thinking that led to fleets with oversized vehicles, poorer fuel economy, and higher operating costs and GHG emissions.

Instead, savvy fleet managers are leaving the old approach behind and employing the correct and most efficient approach, which is to right-size fleet vehicles – that is, correctly specify the size of vehicle for the job at hand, which leads to lower overall operating costs.

Job Suitability

The types of vehicles and the equipment staff members are fitted should be aligned with the vocational and load requirements. For example, a passenger sedan would be completely unsuitable for plowing snow or carrying loads of anything other than people. Rather, fleet vehicles types are matched specifically to the tasks at hand; in this case, a light-duty truck would be required for snow removal in, for example, parking lots.

Choose the Size Down When Appropriate

Downsizing is a recommended best management practice which results in a lower total cost of ownership (TCO). An example is acquiring light-duty (Class 2a) vans and pick-ups as opposed to heavier-duty units (Class 2b), which have higher acquisition and maintenance costs.

Another example is with heavy-duty units; selecting a single-axle plow-dump unit, which has inherently lower operating costs than a tandem-axle unit, is recommended when appropriate (i.e., when the specific task at hand, or job suitability, is fulfilled by either unit).

Accounting for Limited Space

Limited space for roads, as a result of urban development and densification, may lead to an increased number of traffic roundabouts. Roundabouts pose unique problems for snowplows as well as refuse and recycling trucks because of tight turning movements and lack of adequate space to maneuver. Single axle units are shorter in overall length and, therefore, turn in a smaller radius than tandem or tridem axle units. They also cost less to acquire and maintain. The disadvantages are that single axle trucks may have less traction/control in slippery conditions and have less load-carrying capacities, such as salt/sand or waste (less productivity). However, in urban, low-speed, traffic-congested environments with limited space, such as roundabouts, single axle plows or refuse/recycling trucks will have an advantage over multi-axle units. In this example, it is important to weigh the pros and cons for different sized vehicles; when space is tight, it is often recommended to go smaller when it is safe (i.e., at low speeds) and productivity is acceptable.

Right-Sizing Summary

In summary, it is important for a fleet to consider the following in regard to right-sizing:

- Ensure that fleet vehicles are matched specifically to the tasks at hand (i.e., are job suitable) in terms of both vocation and load requirements.
- When multiple sized units fulfil a task equally well, choose the size down.
- When space is limited, it is often best to choose smaller units, given that it is safe to do so and that the productivity level is acceptable.

Low-Rolling Resistance Tires

Rolling resistance is the energy lost from drag and friction of a tire rolling over a surface[77]. The phenomenon is complex, and nearly all operating conditions can affect the final outcome. With the exception of all-electric vehicles, it is estimated that 4%–11% of light-duty vehicle fuel consumption is used to overcome rolling resistance. All-electric passenger vehicles can use approximately 23% of their energy for this purpose. For heavy trucks, this can be as high as 15%–30%.

A 5% reduction in rolling resistance would improve fuel economy by approximately 1.5% for light and heavy-duty vehicles. Installing low-rolling resistance (LRR) tires can help fleets reduce fuel costs. It is also important to ensure proper tire inflation (see sections below).

Tires and fuel economy represent a significant cost in a fleet's portfolio. In Class 8 trucks, approximately one-third of fuel efficiency comes from the rolling resistance of the tire. The opportunity for fuel savings from LRR tires in these and other vehicle applications is substantial.

According to a North American Council for Freight Efficiency (NACFE) report, the use of LRR tires, in either a dual or a wide-base configuration, is a good investment for managing fuel economy. Generally, the fuel savings pay for the additional cost of the LRR tires. In addition, advancements in tire tread life and traction will reduce the frequency of LRR tire replacement.

[77] Source: https://afdc.energy.gov/conserve/fuel_economy_tires_light.html

Automatic Tire Inflation Systems

Proper tire inflation pressure is critical to the optimal operation of a commercial vehicle. Underinflated tires result in decreased fuel efficiency and increased tire wear[78]. A 0.5-1.0% increase in fuel consumption is seen in vehicles running with tires underinflated by 10 psi. Appropriate pressure reduces tire wear, increases fuel efficiency, and leads to fewer roadside breakdowns due to tire failures. An example of an automatic tire inflation system (ATIS) is shown in *Figure 24*.

Figure 24: Automatic Tire Inflation System (courtesy NACFE)

In the U.S., a large truckload carrier with 5,000 tractors and 15,000 trailers averaging 124,000 miles a year on tractors and 41,000 miles on trailers, conducted a fuel economy test with 60 trucks pulling trailers without tire inflation systems and 75 trucks matched with trailers with the systems installed. The results of the test showed a 1.5% improvement in fuel consumption for trucks with ATIS.

Tire Inflation with Nitrogen

Nitrogen is said to permeate tire walls up to four times slower than air. Tires will lose one to two psi over one month versus the six months it takes a nitrogen-filled tire to lose that same amount of pressure. As a result, the time spent adjusting the tire pressure is reduced.

Supporters of nitrogen for tire inflation claim better tire pressure retention. This is believed to result in:

- A smoother ride
- Improved steering and braking
- Reduced risk of blowouts by as much as 50 percent[79]
- Increased tires tread life by up to 30 percent, improving the tire's life and its grip to the road[80]
- Reduced fuel consumption by up to 6%[81]

[78] Source: https://nacfe.org
[79] Source: http://www.gonitrotire.com
[80] Source: http://www.gonitrotire.com
[81] The fuel consumption reduction estimates vary considerably. Enviro-fleets, A guide to helpful resources, June 2010, report an improvement of up to 10%, but the industry standard is between 3% and 6%.

It must be noted that it is not the nitrogen itself that improves the fuel efficiency, but rather the enhanced retention of inflation pressure over time[82]. Reduced tire pressure leads to increased fuel consumption. Therefore, if vehicle tire pressure is well monitored, there might not be a fuel consumption benefit of using nitrogen.

Idling Reduction

Idling reduction is an important concern for all leading fleets that are looking to optimize costs and reduce the environmental impact. Utility fleet vehicles left idling for no apparent reason are seen by the public as being wasteful and polluting. These negative messages are potentially damaging to the reputation of any utility.

Fuel consumption from idling of heavy-duty vehicles is significant. While we acknowledge there are times when idling is simply unavoidable, the U.S. Department of Energy estimates that unnecessarily idling heavy-duty vehicles wastes from half to one U.S. gallon (1.89 to 3.79 liters) or more per hour. Some fleets idle 30 to 50% or more of their operating time[83]. These are several main approaches to idling reduction, including:

- Idling-reduction policy
- Driver training and motivation
- Idling-reduction awareness and fact-based training
- Incentive programs
- Ongoing driver education
- The use of idling reduction devices, including:
    - Auxiliary power units (APU)
    - Stop/start devices
    - Auxiliary cab heaters
    - Battery backup systems
    - Block heaters / engine preheaters

Idling-Reduction Policy

An idling-reduction policy is a way to motivate fleet drivers to limit unnecessary idling. However, for an idling-reduction policy to be successful continuous enforcement such as spot-checks and fuel use tracking must be present. An idling-reduction policy could be used as an overarching commitment to idling reduction that is carried out though driver training and motivation sessions, rather than an initiative on its own.

[82] Source: NHTSA Report, 2009: https://one.nhtsa.gov/DOT/NHTSA/NRD/Multimedia/PDFs/.../2009/811094.pdf
[83] Source: FC Best Practices Manual 2008

When Engine Idling is Unavoidable

There are times when idling is unavoidable. These include:

- Cab heating/ventilation and air conditioning (HVAC)
- Power for critical equipment (such as the use of a PTO for ancillary equipment)
- Maintaining brake air pressure (MD and HD trucks)

It is important to differentiate between *unnecessary* idling and idling that is *unavoidable* due to operational requirements. The focus of all idling-reduction initiatives should be to reduce and, ideally, eliminate *unnecessary* idling and to explore alternatives of how to limit idling for operational purposes with solutions that do not impede with operations, but offer environmental and economic benefits.

Idling Reduction Devices

There are several idling-reduction technologies available that can aid in idle reduction. Their functionality, potential, and costs vary considerably and are described in *Table 11.* To reap the most benefits any idling-reduction technology, installation should always be accompanied by behavioural solutions of driver training and motivation.

Table 11: Idling Reduction Devices and Their Associated Costs

Technology	Description	Cost Estimates
Auxiliary Power Units (APU)	An APU consists of a small engine that provides power to heat and cool the cab, as well as to power accessories, heat the engine, and charge the start battery. DC-powered APU systems are also available.	APUs can cost anywhere from ~$8,500 to ~$10,000. Annual maintenance cost is estimated as high as $500.
Stop/Start Devices (Idle-Stop systems)	A stop/start system automatically shuts down and restarts the internal combustion engine to reduce the amount of time the engine spends idling. This technology is particularly useful for vehicles that spend significant amounts of time waiting at traffic lights or frequently come to a stop in traffic jams.	Stop/start devices typically are part of OEM hybrid vehicle systems, but more recently has also been introduced in regular combustion engine vehicles to reduce fuel consumption. Such devices can also be purchased separately (offered by companies like Bosch that also manufacturers OEM devices)

Technology	Description	Cost Estimates
		and their costs average at about $300-$350.
Auxiliary Cab Heaters	There are two types: (1) Gas- or diesel-fired auxiliary air heater: In most cases, it is fitted in the cab, drawing in cab air through a blower and heating it. (2) Gas- or diesel-fired auxiliary coolant heater: It is installed in a vehicle's engine compartment and enables the vehicle's own coolant circuit to work without the use of the entire engine. Such water-based auxiliary heaters use small amounts of fuel to heat up the liquid in the air-exchange system and provide warm air in the cabin. Compared to air-based auxiliary heaters, the advantage of water-based auxiliary heaters is that they also warm the engine in the process (similarly to block heaters), thus enhancing starting performance. Auxiliary coolant heaters are manufactured by companies like Webasto and Espar.	~$1,250 +
Battery Backup Systems	A battery backup system powers electric devices (emergency lights, etc.) without drawing power from the primary battery. The system consists of adding an isolator and an additional battery to a vehicle's electric system. When the vehicle is off, the isolator prevents power being drawn from the primary battery and instead uses the alternate battery to power any electronic systems. When the vehicle is running, both batteries are recharged; charging to the start battery is prioritized and it is charged first.	The system costs between $400-$600 plus the price of a battery which varies based on the required capacity.

Technology	Description	Cost Estimates
Block Heater / Engine Preheater	Engine block heaters use power from electrical outlets in corporate facilities, where vehicles are parked overnight to heat the engine block. The block heater on timer can be set to switch-on a few hours before the vehicle is used to warm up the engine block. This decreases required warm-up idling time. This is a very low-cost option, and a necessity in Canadian winters; however, it is limited to reducing warm-up idling only.	Block heaters cost between $70 and $150 and have a negligible annual maintenance cost.

Emissions Reduction Potential

Despite the wide selection of idling reduction solutions, when it comes to internal combustion engines, there is no technology that completely eliminates CO_2 and other emissions. Only battery-electric and hydrogen fuel cell vehicle technologies can eliminate tailpipe emissions. Idling-reduction initiatives can be helpful in reducing unnecessary idling in the short and medium term, and as a segue to gradual transition to electric trucks and, potentially, hydrogen fuel cells in the long-run.

Driver Training and Motivation

Idling-Reduction Training and Incentives

Driver training to modify driver behaviours and ongoing motivation to continue good behaviours are crucial components of successful idling-reduction programs. While most drivers understand the vehicle idling issue, many continue their inefficient practice of excessive idling due to lack of knowledge and/or motivation.

Driver training can be used to optimize the use of idle reduction technologies. The technologies can reduce idling but the drivers have the ability to override the technologies. Proper training can aid in utilizing the technologies to their full potential.

In addition to establishing corporate idling reduction policies, behaviour-based approaches for idling reduction include:

- Idling-reduction training for drivers; and
- Incentive programs to encourage drivers to limit idling.

For best results, these approaches should be used in conjunction. Regardless of the approach, the greatest impact pledges of idling-reduction should be made in a public forum. Moreover, idling-reduction targets should be customized as various fleet vehicles may have different operating requirements and will benefit from targets that accurately reflect their work environment. Beginning from a measured starting point, progress should be evaluated at regular intervals to modify and adapt the approach if progress is not occurring.

Driver Eco-Training

Driver eco-training should be fact-based and aimed at increased awareness and promotion of good practices. Typically, eco-training courses address the following areas:

- Progressive shifting (or use of automated transmissions)
- Starting out in a gear that doesn't require using the throttle when releasing the clutch
- Shifting up at very low RPM
- Block shifting where possible (e.g., shifting from third to fifth gear)
- Maintaining a steady speed while driving
- Using cruise control where appropriate
- Anticipating traffic flow
- Coasting where possible
- Braking and accelerating smoothly and gradually
- Avoiding unnecessary idling

Driver eco-training programs vary considerably. They can be organized as short (typically an hour long) information sessions/workshops or can be considerably longer and involve more hands-on activities. Extended training can vary in length from a half to a full day, or can also be scheduled into shorter sessions over a period of time.

Online Training

Online training courses are gaining popularity thanks to their flexibility. This trend has accelerated due to the Covid-19 pandemic and the need for social distancing measures. It is strongly recommended that discussion sessions among the drivers be organized to review training topics to deepen their understanding and provide a forum for questions and concerns. The individual responsible for the idling reduction incentives program could facilitate such sessions.

In-Person Training

In-person driver eco-training courses vary greatly in length, depth, and format. These courses offer a more personalized approach, facilitate immediate discussion, and typically allow for practical application. For best results, eco-training could be combined with professional driver improvement training.

NRCan SmartDriver Training Series

SmartDriver provides free, practical training to help Canada's commercial and institutional fleets lower their fuel consumption, operating costs, and harmful vehicle emissions. Fleet energy-management training that helps truckers, transit operators, school bus driver, and other professional drivers is claimed by NRCan to improve fuel efficiency by up to 35 percent. RSI-FC highly recommends NRCan's SmartDriver training: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/greening-freight-programs/smartdriver-training-series/21048

Continuous Motivation

Studies have demonstrated that driver training benefits, although significant, are likely to diminish over time. Ongoing feedback and motivation is recommended as a preventive measure. This can include:

(1) Tracking Idling to Provide Feedback to Drivers

- Monitoring the progress of any initiative is crucial not only to determine the impact, but to also provide feedback to the drivers to provide them the opportunity to modify their behaviour.

- Practices that track and report fuel consumption establish a valuable monitoring basis. Knowledge and comprehensive factual information can help build a stronger business case and "buy-in" for idling reduction.

- Telematics technologies help managers and drivers track idling and provide measurable data to manage goals. Such technologies, however, can be expensive as they typically use GPS systems and OBD monitoring devices.

(2) Implementing a Corporate Idling Reduction Policy

- It is our opinion that in most cases drivers want to "do the right things." By ramping up communications about excessive idling and instituting a clear idling policy, a reduction of unnecessary idling will likely result.

(3) Ongoing Information Campaigns and Reminders

- In general, information campaigns are low-cost, easy to manage, and lead to a more knowledgeable and receptive public. To raise awareness of the issues these can be initiated even before driver training commences. Numerous resources that address idling awareness issues are available free of charge and ready to implement.

(4) Non-Monetary Incentives Programs

- There are a few approaches that can aid in motivating drivers to continue to apply the skills gained during eco-training. Competition among departments/teams to reduce idling can be an effective approach. Periodic recognition of high-performers can be either public or private. An example of a non-monetary reward might be the donation to a charity in the amount of the lowest idling department's fuel cost savings.

Summary and Potential Impact

Driver training is an initiative that attempts to change an individual's behaviour and thus the results are hard to predict and the variance is large. A multitude of aspects, such as the current level of driver education and driving practices, the level of idling, corporate culture and policy, and individual receptiveness and willingness to change will influence results. It is estimated that driver training has a potential to reduce vehicle fuel consumption by anywhere from 3% to 35%, with the typical results between 5% and 10%.

Route Planning and Optimization

In addition to vehicle upgrades, proper maintenance, driver training, and continuous motivation to maintain good driving habits, a fleet can further minimize fuel consumption and exhaust emissions through route planning and optimization. Route planning software can be used optimize multi-stop trips. There are different software available for categories in both public and private fleets (e.g., service dispatch software, courier software, trucking software, etc.) [84].

Route planning software used for delivery services ensures the minimum driving time for multi-stop trips by using advanced algorithms to arrive at the optimal route that provides the highest collective reduction in total driving time and, consequently, fuel consumption. This can also mean fewer vehicles and less traffic on the road at one time.[85]

[84] Source: https://www.capterra.com/route-planning-software/
[85] Source: https://blog.route4me.com/2020/05/carbon-emissions-reduction-route-optimization-helps-cut-tons-carbon-emissions/

Route planning software can also be used for idling reduction initiatives by integrating GPS tracking software to monitor driver activity in real-time. Moreover, reporting and analytics features within route planning software can help with identifying when a fleet vehicle requires maintenance to ensure optimal fuel efficiency and thus minimize cost and emissions.

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RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-267

References: **Exhibit 2B, Section E8.3, Pages 3-4**
EB-2018-0165, Decision and Order, December 19, 2019, Page 104

Preamble:

In reference 2 the OEB directed Toronto Hydro "to provide more detailed cost benefit analysis between EV, hybrid and combustion engines for its fleet program for future rebasing applications. In addition, the OEB directs Toronto Hydro to develop utilization measures beyond fleet use in standard hours." In response to the cost benefit analysis, Toronto Hydro's evidence stated that various phasing and cost options were analyzed for electrifying its fleet and the results of this analysis informed Toronto Hydro's procurement strategy for Evs and hybrid vehicles.

QUESTION (A):

a) Please provide a copy of the analysis done to assess the costs and benefits between Evs, hybrids and combustion engine vehicles and the results of this analysis.

RESPONSE (A):

Please refer to Toronto Hydro's response to 2B-Staff-266(a).

QUESTION (B):

b) Please explain Toronto Hydro's proposal for developing utilization measures beyond fleet use in standard hours.

RESPONSE (B):

Please refer to Toronto Hydro's response to 2B-Staff-266(b).

QUESTION (C):

c) Please indicated the number of units and associated percentage of internal combustion engines vehicles to be replaced by Evs.

RESPONSE (C):

Toronto Hydro will replace 115 of 264 (approximately 44%) internal combustion engine ("ICE") units from 2025 to 2029 with electric/hybrid vehicles, depending on market availability and vehicle suitability.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-268

Reference: **Exhibit 2B, Section E8.3, Page 7**
Exhibit 2B, Section E8.3, Page 2

QUESTION (A):

a) Please provide Toronto Hydro's fleet asset management plan.

RESPONSE (A):

Toronto Hydro's Fleet Asset Management strategy is explained in subsection E8.3.1.1 of Exhibit 2B, Section E8.3.[1]

QUESTION (B):

b) Please provide several representative examples of life cycle analyses for short term (0-2 year) turnover assets, and long-term turnover (2-7years) assets.

RESPONSE (B):

Longer-term asset planning (2-7 years) relies primarily on the Life Cycle Analysis ("LCA") for forecasting purposes; this is also referred to as the "first step" in subsection E8.3.1.1 of Exhibit 2B, Section E8.3.[2] Short-term asset planning (0-2 years) happens as the vehicle gets closer to replacement period; this is referred to as the "second step" in subsection E8.3.1.1 of Exhibit 2B, Section E8.3.[3] This planning step takes into account the condition of the vehicle, end-user feedback, and utilization to determine if a replacement is required.

[1] At p. 2-3.
[2] At p. 2.
[3] *Ibid*.

For example, When the initial planning was completed in 2017/2018 for dump trucks, Toronto Hydro had six 2009 model units in its fleet planned for replacement in 2023 (3 units) and 2024 (3 units) according to the LCA. The LCA for this type of vehicle recommended replacement between 8-12 years.

Prior to initiating competitive bidding for these vehicles, Toronto Hydro determined that 2 of the vehicles were no longer required and would not be replaced, and that the condition of the remaining four vehicles was still rated as fairly good condition. As such, the utility determined to defer the replacements into 2025-2026 and review again at a later date. There was also consideration given for the specialized nature of these vehicles (used in very specific applications), feedback from end-users, and the relatively low mileage.

As another example, the LCA for 9 sports utility vehicles ("SUVs") units indicated a replacement after 8 years. Toronto Hydro had deferred their purchase with a batch of SUVs replaced in 2021; however, subsequent condition assessments for these units indicated that they would need to soon be replaced due to deteriorating conditions. These were ultimately replaced in 2022 (3 units) and 2023 (6 units).

QUESTION (C):

c) Are corrosion related impacts a major driver of fleet turnover?
    i. If yes, what actions does Toronto Hydro take to mitigate corrosion related impacts to its fleet?

RESPONSE (C):

As discussed on page 7 of Exhibit 2B, Section E8.3, corrosion can pose safety and reliability risks, lead to vehicles being decommissioned earlier than expected, and typically impacts vehicles that are near end of life. Vehicles receive rust proofing inhibitor prior to delivery from the vendor when they are purchased. Toronto Hydro is currently evaluating 3 methods of corrosion prevention for future implementation. A test group of 18 vehicles have been designated for evaluation. Six vehicles will receive one of the following rust proofing methods: electronic module, one-time rust proofing application, and yearly rust proofing application until end of life to determine the most effective method.

QUESTION (D):

d) What fleet vehicles does Toronto Hydro outsource?

   i. For outsourced fleet vehicles, do the forecast capital costs for the test period include outsourcing costs?

   ii. For outsourced fleet vehicles, please provide benefit-cost analysis.

RESPONSE (D):

Toronto Hydro does not outsource any vehicles.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-269

Reference: Exhibit 2B, Section E8.3, p. 4

Preamble:

Toronto Hydro writes that "In view of the size and dense urban nature of its service territory, Toronto Hydro estimates that all vehicle types (ICE, EV, and hybrid) would perform at the same level of reliability."

Question (A):

a) Please provide several representative examples of when the above statement would and would not be true in the Toronto Hydro service territory for heavy-duty vehicles.

RESPONSE (A):

As discussed in Exhibit 2B, Section E8.3,[1] Toronto Hydro is currently exploring the procurement of fully electric heavy-duty vehicles in small numbers and on a pilot basis. The market availability of these types of vehicles remains relatively low and further field experience is required to analyze the reliability and performance of these units under normal and emergency operating conditions. Nonetheless, given its relatively small service territory at approximately 631 kilometre squares[2] and low vehicle travel times, Toronto Hydro estimates that hybrid and electric vehicles will have sufficient range and battery capacity to perform at the same level as internal combustion engine vehicles. The utility will continue to monitor and evaluate the field performance of all hybrid and electric heavy-duty vehicles as needed.

Question (B):

[1] At page 5, lines 1-7.
[2] Exhibit 1B, Tab 1, Schedule 1, Table 1 at p. 8.

b) How will Toronto Hydro ensure that its EV fleet maintains its ability to be dispatched during prolonged power outages?

    i. What are the limitations of the selected strategy with regards to the geographic extent and duration of power outages?

RESPONSE (B):

Toronto Hydro plans to keep its battery hybrid and electric vehicles at full charge when not in use to ensure effective operation at the beginning of prolonged power outages. The utility already has a number of charging infrastructure in operation at its work centres and plans to continue investing in such infrastructure, including Level 3 chargers, as part of the capital expenditures outlined in Exhibit 2B, Section E8.2. Toronto Hydro has contingency plans in place to ensure that electric vehicle charging infrastructure at its facilities will continue to operate during prolonged power outages and will continue to explore alternative methods to ensure business continuity, such as external charging infrastructure, mobile charging technologies, and other power sources.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-270

Reference: Exhibit 2B, Section E8.3, Page 12

Question (A):

a) Please reconcile the apparent change in Heavy-Duty vehicle unit cost between 2025 and 2027 (year 2025, 13 vehicles to be replaced at a cost of $7M, and in 2027, 23 vehicles to be replaced at a cost of $7.7M)?

RESPONSE (A):

Unit costs within the heavy-duty category vary widely depending on the specific vehicles being replaced, as this category includes a very diverse range of vehicles such as crane trucks, derricks, single and double bucket trucks, cube trucks, etc. In addition, progress payments for heavy-duty vehicles that require significant equipment fitting and customization can cause variations in unit costs over multi year delivery cycles.

QUESTION (B):

b) Please provide total number of assets owned by Toronto Hydro under each of the categories of Heavy Duty, Light Duty and Equipment.

RESPONSE (B):

There are currently 149 heavy-duty vehicles, 210 light-duty vehicles, and 69 equipment units in Toronto Hydro's fleet.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-271

Reference: Exhibit 2B, Section E8.3, p. 18

QUESTION (A):

a) Please provide the benefit-cost analysis that shows that option 2 “sustainment” is the preferred solution of the three options considered.
   i. If a benefit-cost analysis was not performed please provide the quantitative analysis justifying the selection of the preferred solution.

RESPONSE (A):

The options analysis in Exhibit 2B, Section E8.3, subsection E8.3.5 “Options Analysis / Business Case Evaluation (“BCE”)” details the benefits and costs that informed Toronto Hydro’s selection, including estimated costs, average fleet age, and greenhouse gas emissions under each option.[1] Please also refer to Toronto Hydro’s response to 2B-SEC-59.

[1] Exhibit 2B, Section E8.3, Table 8 at p. 18.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-272

Reference: Exhibit 2B, Section E8.4, Pages 18, 19

<u>Preamble:</u>

With respect to hardware volumes that are proposed to be replaced.

QUESTION (A):

a) Please provide the percentage and number of units indicated in Table 5 that fall within the 4, 5, 6 and 7 year age buckets.

RESPONSE (A):

As of 2024, the units for the 2020-2024 rate period are aged as follows.

Table 1: Unit Ages for the 2020-2024 Rate Period

Asset Category	IT Hardware	4 years		5 years		6 years		7 years	
		Units	%	Units	%	Units	%	Units	%
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	168	33%	153	30%	36	7%	15	3%
	Linux x86 Virtual Servers	111	35%	105	33%	25	8%	6	2%
	Windows Virtual Servers	967	40%	870	36%	121	5%	121	5%
Endpoint Assets (Units)	*Personal Computing Devices*	577	25%	138	6%	46	2%	-	0%
	Printers & Plotters	36	20%	22	12%	9	5%	-	0%

QUESTION (B):

b) Please also indicate the percentage of hardware that is still operational, and vendor supported.

RESPONSE (B):

Table 2: Percentage of Hardware Operational and Vendor Supported

Asset Category	IT Hardware	Operational & vendor support available
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	92%
	Linux x86 Virtual Servers	95%
	Windows Virtual Servers	89%
Endpoint Assets (Units)	*Personal Computing Devices*	98%
	Printers & Plotters	100%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-273

Reference: Exhibit 2B, Section E8.4, Page 24

Preamble:

With regards to the $11.5M proposed in spending under Regulatory Compliance.

QUESTION (A):

a) Please provide the list of regulatory compliance initiatives that occurred during the 2020-2024 period, the total capital cost of each, and the capital cost of each that is potentially recovered through a revenue recovery mechanism other than existing rates (for example, a DVA).

RESPONSE (A):

Toronto Hydro provides a table below with the Regulatory Initiatives occurring during 2020-2024 below.

Regulatory Initiatives	Description	Project capital cost (2020-2024), $ Millions[1]	Funding Source
Customer Choice	Providing residential and small business customers the choice between Time-of-Use ("TOU") and Tiered prices (EB-2020-0152)	$0.8	DVA
Ultra Low Overnight TOU	Implementation of the Ultra Low Overnight ("ULO") pricing option for eligible customers on the Regulated Price Plan ("RPP") (O. Reg. 393/07)	$2.2	DVA

[1] Includes 2020-2023 actuals and 2024 bridge.

Centralize Billing Solution for Bi-directional Smart Metering Data	Collection, management and improved utilization of smart metering data for behind-the-meter distributed energy resources (ERO#: 019-6521)	$0.8	Rates
COVID-19 Energy Assistance Program ("CEAP")	COVID-19 relief for eligible residential and small business customers (EB-2020-0162/0185)	$0.6	Rates
Green Button	Implementation of the Green Button data standards and customer access platform (EB-2021-0183)	$2.4	DVA
OEB customer service rules	Implementation of requirements relating to Phase 1 of the OEB's Customer Service Rules Review (EB-2017-0183)	$1.1	Rates
Transition to Utility Work Protection Code	Implementation of changes required for Toronto Hydro's transition to the Utility Work Protection code	$2.8	Rates
TOTAL IT/OT Regulatory Compliance COST		**$10.7**	

QUESTION (B):

b) Please provide a list of incremental regulatory compliance initiatives that Toronto Hydro expects to comply with over the next five years, and their associated costs.

RESPONSE (B):

As regulatory compliance initiatives are triggered by third party requirements and can be announced at any time, Toronto Hydro cannot predict the specific incremental regulatory compliance initiatives that it will be required to comply with in the next 5 years. However, as outlined on page 24 of Exhibit 2B, Section E8.4, Toronto Hydro anticipates undertaking approximately six regulatory compliance initiatives in the 2025-2029 rate period with an estimated total cost of $11.5 million, based on the utility's historical experience and costs in the 2020-2024 rate period, as discussed in the response to subpart (a).

QUESTION (C):

c) Why are these incremental initiatives necessary beyond current regulatory program spending?

RESPONSE (C):

The incremental initiatives funding is required to meet new compliance-related initiatives, beyond current regulatory requirements. Please refer to lines 1-11 of page 14 of Exhibit 2B, Section E8.4 for a discussion of the non-discretionary nature of these expenditures given the legislative and regulatory requirements and public policy-driven changes mandated by the Government of Ontario, the OEB, and other authorities.