RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-1

References: **Exhibit 2B, Section A, Page 13**
Exhibit 2B, Section E6.2, Page 1
Exhibit 2B, Section A, Page 13

Preamble:

Ref 1: "The underground system is vulnerable to flooding from extreme rainfall, while the overhead system is susceptible to extreme winds, freezing rain, and wet snow, resulting in damage and outages."

Ref 2: "Outages caused by asset failure on the underground system take approximately 34 percent longer to restore than outages on the overhead system, resulting in lengthy interruptions that may last up to 24 hours or longer."

Ref 3: "Toronto Hydro now incorporates climate data projections into its equipment specifications and station load forecasting."

QUESTION (A):

a) What is THESL's overall strategy regarding asset investment/replacement as between overhead vs. underground?

RESPONSE (A):

Toronto Hydro manages its system based on the distinct needs of each asset class and system type across the grid, including both the overhead and underground system. Investment strategies depend on the specific characteristics of assets (or system configurations) and the risks they pose to the distribution system. Details regarding Toronto Hydro's asset lifecycle optimization policies and practices are discussed in Exhibit 2B, Section D3.1.

QUESTION (B):

b) What technologies are considered to deal with underground equipment failure such as cables, PVC ducts etc.

RESPONSE (B):

Toronto Hydro considers the following technologies:

- **Cables**: Cable testing procedures for underground circuits, including cables and accessories such as terminations and joints, are implemented to pre-emptively address cable failure. The primary goal of cable testing in underground circuits is to enhance reliability by identifying potential issues before they manifest as operational problems. This proactive approach allows for corrective measures to be taken, minimizing the risk of failures and ensuring the smooth operation of the electrical infrastructure.
- **Ducts:** Borescoping contractors may be engaged in order to locate PVC duct failures to flag for repair.
- **Transformers**: Network Condition Monitoring and Control ("NCMC") systems plays crucial role for SCADA monitoring and control, as well as environmental monitoring and functions within underground vaults. This provides real-time data on imminent equipment failures or scenarios that may cause equipment failures.
- **Switchgears**: Switchgears are capable of communicating functional outputs through SCADA capable radio frequency antenna in order to provide control room with real-time data.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-2

Reference: Exhibit 2B, Section A, Page. 20

Preamble:

"To ensure that price was kept top-of-mind, the utility also adopted top-down financial constraints for the development of the plan:

i. 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.

ii. Budget Limits: Toronto Hydro set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period."

a) How did THESL arrive at these price and budget upper limits - what is the basis or assumption or rationale for picking these limits? Please describe the approach or steps followed to arrive at these limits?

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-33.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-3

Reference: **Exhibit 2B Section E4 ORIGINAL, Page 8 of 23:**

"Expenditures [2020-2024] in the Underground System Renewal - Horseshoe, and Underground System Renewal - Downtown are forecasted to be approximately 24 percent lower than planned."

QUESTION (A):

a) Please identify and list Underground System Renewal program investments that were planned to be completed in the 2020-2024 rate period but deferred to the 2025-2029 rate period.

RESPONSE (A):

The following tables shows the amount of planned work for the referenced programs that was planned to be completed in the 2020-2024 period but was deferred to the 2025-2029 rate period.

Table 1: 2020-2024 Underground Asset Replacement Deferral Volumes

Asset Class	Planned Work Deferred	% of Planned Work Deferred
Total Cable (in circuit km)	12	6%
Transformers	0	0%
Switches	87	38%

Table 2: 2020-2024 Underground Renewal Downtown Asset Replacement Deferral Volumes

Asset Class	Planned Work Deferred	% of Planned Work Deferred
PILC (in circuit km)	0	0%
AILC (in circuit km)	47	89%
Cable chamber rebuilds	50	67%
Cable chamber roof rebuild	87	73%

Asset Class	Planned Work Deferred	% of Planned Work Deferred
URD Submersible Switches	5	38%
URD Transformers	0	0%
URD Vault Roof	9	50%

QUESTION (B):

b) In THESL's view, is the deferral of Underground System Renewal investments from the 2020-2024 rate period a major/material reason for the proposed increase in expenditure in the current application?

RESPONSE (B):

Deferral of work is one of several reasons Underground System Renewal - Horseshoe and Underground System Renewal – Downtown expenditures are increasing in 2025-2029. Toronto Hydro is proposing the minimum expenditures necessary to maintain reliability on the underground system. The various drivers of investment need are discussed and quantified in detail in Exhibit 2B, Section E6.2 and Section E6.3. Please see 2B-Staff-211 for additional details on the Horseshoe program.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-4

Reference: **Exhibit 2B, Section E4 ORIGINAL, Page 9 of 23:**
"Expenditures [2020-2024] in the Overhead System Renewal program are forecasted to be approximately 18 percent lower than planned."

QUESTION (A):

a) Please identify and list Overhead System Renewal program investments that were planned to be completed in the 2020-2024 rate period but deferred to the 2025-2029 rate period.

RESPONSE (A):

The following tables shows the amount of planned work for the referenced programs that was planned to be completed in the 2020-2024 period but was deferred to the 2025-2029 rate period.

Table 1: 2020-2024 Overhead Asset Replacement Deferral Volumes

Asset Class	Planned Work Deferred	% of Planned Work Deferred
Poles	3,727	32%
Pole Top Transformers	3,201	48%
Overhead Switches	0	0%
Primary Conductor (km)	27	8%

QUESTION (B):

b) In THESL's view, is the deferral of Overhead System Renewal program investments from the 2020-2024 rate period a major/material major reason for the increase in expenditure in this category in the current application?

RESPONSE (B):

The deferral of Overhead System Renewal investments from the last filing period is one of several reasons for the increase in expenditure in this category. Please see response to 2B-Staff-219, part (a) for more information.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-5

References: **Exhibit 2B Section E4 ORIGINAL Page 3 of 23:**
"Connected approximately 10,000 customers through the Customer Connections program, with an increase of $147.5 million (71 percent) in capital expenditures over the forecast to maintain and exceed performance."

a) Was the $147.5 million increase in capital expenditure due to under-forecasting of customer connection or due to other factors?

RESPONSE:

The noted increase is due to a variety of factors which are discussed at pages 18-23 of the Customer Connections program evidence in Exhibit 2B, E5.1.4. Toronto Hydro also notes that the budget for this program was reduced by approximately $14.7 million by the OEB in Toronto Hydro's last rate application, due to concerns that the forecast was overstated.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-6

Reference: Exhibit 2B Section E4 ORIGINAL Pages 7-8 of 23

QUESTION (A):

a) The reference indicates that from 2020 to 2024, System Access expenditures are forecasted to be approximately 33 percent higher than planned due to higher than forecast expenditures in the Customer Connections program (55%), in the Load Demand program (38%), and Externally Initiated Plant Relocations and Expansions (18%).

Why were such significant variances in demand for resources for these programs not anticipated/foreseen in the plan?

RESPONSE (A):

Please refer to Toronto Hydro's response to Interrogatory 2B-SEC-58.

QUESTION (B):

b) It appears that the higher than planned expenditures in System Access are partially made possible by shifting resources away from investments in System Renewal, especially the overhead and underground system renewal programs. Did THESL consider other funding options such as ICM funding? If not, why?

RESPONSE (B):

No. Under a Custom IR rate framework, Toronto Hydro is not eligible for ICM funding.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-7

Reference: Exhibit 2B, Section E4, Page 9

Preamble:

"In Downtown program, Toronto Hydro was able to find some savings over the 2020-2024 rate period by engineering an alternative approach to cable renewal work which leverages existing available civil infrastructure to the extent possible."

a) Please describe and give example/s of such alternative approaches to cable renewal work.

RESPONSE:

As noted in Exhibit 2B, Section E6.3.4.1 at page 37, the alternative approach to limit civil work associated with cable renewal work was to use available civil infrastructure on the other side of a road or on another parallel road.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-8

References: Exhibit 2B, Section E4, Page 9

> - Expenditures in the Network System Renewal program are forecasted to be approximately 26 percent higher than planned.[23] The increase is driven in large part by design and execution complexities that emerged as the projects matured from conceptual to detailed design. This includes additional scope of work (e.g. civil construction and legacy cable removal), material cost increases driven by supply chain disruptions, and work execution challenges related to field conditions (e.g. urban congestion) and operational complexities (e.g. coordination challenges).
> - Expenditures in the Stations Renewal program are forecasted to be approximately 23 percent higher than planned due to project complexity, necessary scope increases, and inflationary cost escalations.[24]

a) The reference suggests that the forecasted increases in expenditure (for the 2020-2024 rate period) are due to changes in the scope, design, and complexity of projects as well as due to inflationary cost escalations. What lessons did THESL learn from this variance? Has THESL incorporated those lessons, if any, into the planning and design of projects proposed in the 2025-2029 system plan?

RESPONSE:

As described in Exhibit 2B Section D3 at pages 56-57, Toronto Hydro maintains a change management and governance process to track changes to project cost, schedule, or scope of work. This process provides visibility to all relevant stakeholders on major project changes, requiring approval so that the change is appropriately processed and documented for awareness regarding lessons learned for future projects. Toronto Hydro notes that in most cases, including the Network System Renewal program, it did not plan at the project level in developing its 2025-2029 proposals. Therefore, Toronto Hydro generally applies lessons learned, such as higher network unit renewal costs driven by legacy secondary cable replacements and installation of network automation components, by basing forecast 2025-2029 costs on recent historical actual unit costs that reflect these cost drivers. When the utility is planning and designing projects it will conduct field inspections prior to developing scopes to identify site-specific project requirements and better inform estimated costs.

In addition, for the Stations Renewal program, Toronto Hydro has provided specific details regarding lessons learned from 2020-2024 projects and how they are being applied to the planning of 2025-2029 projects and forecast costs in the Stations Renewal expenditure plan in Exhibit 2B, Section E6.6 (see pages 48 and 58-61). Examples of this include allocating additional resources to coordinate with switchgear suppliers to mitigate supply risks and conducting feasibility studies for specific Transformer Station switchgear replacements.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-9

Reference: Exhibit 2B, Section E4, Page 8, Lines 14-15

"From 2020 to 2024, System Renewal expenditures are forecasted to be approximately 5 percent lower than planned."

QUESTION (A):

a) Please confirm that the 5% lower than planned expenditure amounts to $76.6 million

RESPONSE (A):

The variance is $72.9 million (4.8 percent). Please see Table 1 for the calculation of the variance.

Table 1: System Renewal Capital Expenditure Summary from 2020-2024 ($ Millions)

Year	Plan	Act. / For.	Var.	Var. %
2020	290.5	261.7	(28.8)	(9.9%)
2021	307.2	247.3	(59.9)	(19.5%)
2022	304.7	276.6	(28.1)	(9.2%)
2023	319.4	314.0	(5.4)	(1.7%)
2024	309.5	358.8	49.4	(16.0%)
Total	**1,531.3**	**1,458.4**	**(72.9)**	**(4.8%)**

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-10

Reference: **Exhibit 2B, Section E4 ORIGINAL Page 20 of 23:**

"Starting in 2025 Toronto Hydro is adjusting inspection cycles for wood poles from ten years to eight years to manage failure risk driven by wood pole age and condition demographics. Toronto Hydro will also begin inspecting concrete and steel poles as part of its Pole inspection program on a ten-year cycle."

a) What study or other information did THESL use to apply an 8-year cycle and 10-year cycle for wood pole inspection, and concrete and steel poles, respectively? Did THESL consider the practices of other similar utilities including in other jurisdictions?

RESPONSE:

The decision to adjust the inspection cycles for wood poles from a 10-year to an 8-year cycle is to allow Toronto Hydro to (1) further refine the utility's asset condition assessment ("ACA") of wood poles to support transition to condition-based maintenance; (2) manage the increasing volume of wood poles past their useful life which represents over 24,000 poles; and (3) facilitate additional targeted inspections of wood poles in deteriorated conditions which represents over 9,400 poles (represented by HI4 & HI5). This number is projected to increase to over 32,000 poles by 2029 with no intervention.

In accordance with CSA C22.3 No. 11:22 – Maintenance of electric and communication utility equipment and systems standard, a dedicated inspection program for concrete and steel poles is required. There are approximately 33,300 of these poles across the system of which Toronto Hydro has little to no condition information for. A dedicated inspection program will allow the utility to collect detailed condition data for these assets so their health can be monitored over time. This will enable Toronto Hydro to make more informed decisions on planned overhead renewal investments for these assets and reduce the impact on reactive capital by replacing at risk poles before failure.

Please refer to Exhibit 4, Tab 2, Schedule 1, Section 5.1 at pages 15-16 for examples of steel and concrete poles in poor condition.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-11

Reference: **Exhibit 2B Section E4 ORIGINAL Page 20 of 23:**
"Toronto Hydro plans to reduce its Network Vault civil inspection program starting in 2027 as a result of the implementation of Network Condition Monitoring and Control resulting in reduced costs in that program."

QUESTION (A):

a) Please describe how the implementation of Network Condition Monitoring and Control has resulted in cost reductions in the Network Vault civil inspection program.

RESPONSE (A):

Please refer to Exhibit 2B, Section E7.3.3.2 for the description of how Network Condition Monitoring and Control (NCMC) is expected to impact the Maintenance program.

QUESTION (B):

b) What impact (positive or negative) on reliability and safety performance does THESL anticipate as a result of the plan to reduce the Network Vault civil inspection program?

RESPONSE (B):

NCMC is capable of providing real-time condition monitoring on developing hazardous conditions and allows for proactive actions to be taken to mitigate safety and reliability risks. Please refer to Section E7.3.3.1 of Exhibit 2B for further details on the benefits of NCMC.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-12

Reference: **Exhibit 2B, Section E5.1, Page 10 of 30:**

"Under Section 6.2 of the DSC, for all types of DERs, Toronto Hydro has an obligation to enable and connect the DER. Toronto Hydro must balance its obligations to prospective and existing DER connections with its responsibilities to maintain a safe and reliable distribution system for its load customers."

QUESTION (A) :

a) Please describe, with examples, the kind of safety and reliability risks that DER connections pose to existing load customers.

RESPONSE (A):

DERs could introduce unwanted system harmonics due to the electronics involved particularly with inverter based DERs. Toronto Hydro requires all DER applications to ensure that the harmonic level is within acceptable limits as prescribed by the CSA.

Outage back feed is another potential risk for DERs to customer load when islanding conditions are prohibited (some programs such as emergency back-up DERs are allowed to island based on required conditions). Unwanted back feed conditions are addressed by requiring anti-islanding provisions to be in place (generation prohibitive mode during outages). Unwanted islanding or excessive generation could also be mitigated through the remote disconnect means that the THESL SCADA monitoring and control equipment possess (refer to section Exhibit 2B Section E5.5).

QUESTION (B) :

b) Has THESL encountered safety issues such as islanding in connection with DER connections? Please describe safety risks, if any, suffered by THESL's employees or members of the public.

RESPONSE (B):

Toronto Hydro has not recorded any back-feed events related to DER within its distribution grid. To date, no adverse incidents have occurred related to DER islanding conditions. This speaks to the diligent commissioning steps and requirements in place to safe guard customers and the public in general.

QUESTION (C) :

c) How does THESL ensure that DER connections do not detract from the reliability of the distribution system?

RESPONSE (C):

Toronto Hydro has put into place processes that requires DER connections to go through in-depth testing to meet all industry related standards, such as IEEE-1547, CSA-C22.3 No. 9, etc. This is to determine facility compliance to all related electrical limit parameters and/or the existence of protection and reliability components that would deter any unwanted grid conditions.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-13

Reference: Exhibit 2B, Section E6.1, Pages 27-28

Preamble:

The reference describes the three options proposed for Rear-Lot Conversion

a) Please complete the table, making any corrections to the numbers that have already been provided.

OPTION	Estimated Cost
Option 1 - at Current (2020-2024) Pace	
Option 2 - Moderately Increased Pace **(selected)**	$ 236.7M
Option 3 - at Accelerated Pace	

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59. Toronto Hydro notes that the selected option cost (i.e. proposed Rear Lot segment costs for 2025-2029) is $120.6 million not $236.7 million.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-14

Reference: Exhibit 2B, Section E6.2 ORIGINAL, Page 13

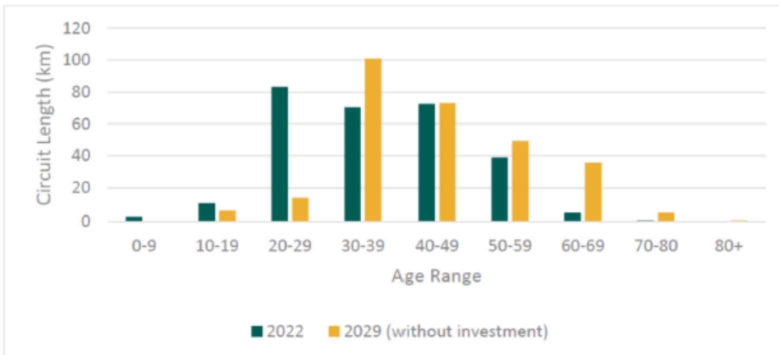

Figure 9: Age Demographics of Direct-Buried ("DB") Cable XLPE in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

QUESTION (A) :

a) Please provide the tabular data behind the chart, adding a column showing age demographics in 2029 with investment, i.e., assuming the proposed investment plan is approved by the Board.

RESPONSE (A):

Toronto Hydro is unable to provide an accurate representation of the age demographics profile with investment as the specific list of projects and its corresponding assets have yet to be planned, designed, and issued for execution. Toronto Hydro typically produces detailed scopes of work 12-18 months in advance of construction. There are several other factors that impact asset renewal decisions which are discussed in detail in interrogatory response 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-15

Reference: **Exhibit 2B, Section E6.2 ORIGINAL, Page 14**

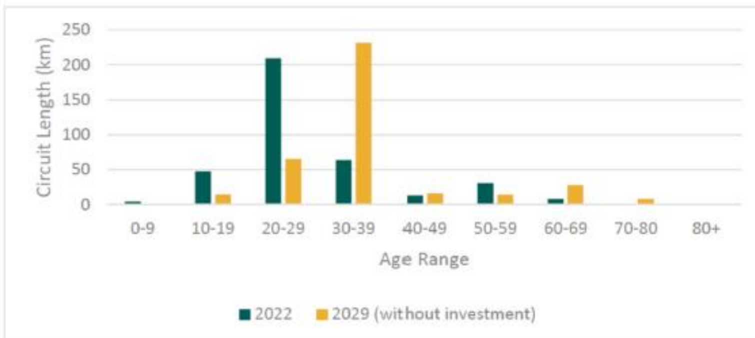

Figure 10: Age Demographics of Direct-Buried Cable in-Duct in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

QUESTION (A) :

a) Please provide the tabular data behind the chart, adding a column showing age demographics in 2029 with investment, i.e., assuming the proposed investment plan is approved by the Board.

RESPONSE:

Toronto Hydro is unable to provide an accurate representation of the age demographics profile with investment as the specific list of projects and its corresponding assets have yet to be planned, designed, and issued for execution. Toronto Hydro typically produces detailed scopes of work 12-18 months in advance of construction. There are several other factors that impact asset renewal decisions which are discussed in detail in interrogatory response 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-16

Reference: Exhibit 2B, Section E6.2 ORIGINAL, Page 14

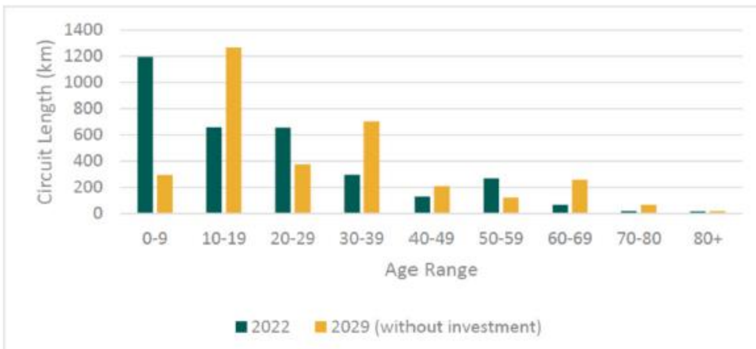

Figure 11: Age Demographic of Cable in in Concrete-Encased Ducts as of 2022 and by 2029 (without Investment)

QUESTION (A) :

a) Please provide the tabular data behind the chart, adding a column showing age demographics in 2029 with investment, i.e., assuming the proposed investment plan is approved by the Board.

RESPONSE (A):

Toronto Hydro is unable to provide an accurate representation of the age demographics profile with investment as the specific list of projects and its corresponding assets have yet to be planned, designed, and issued for execution. Toronto Hydro typically produces detailed scopes of work 12-18 months in advance of construction. There are several other factors that impact asset renewal decisions which are discussed in detail in interrogatory response 2B-SEC-44.

Figure 11 provided in the rate filing application had an error which has now been corrected below.

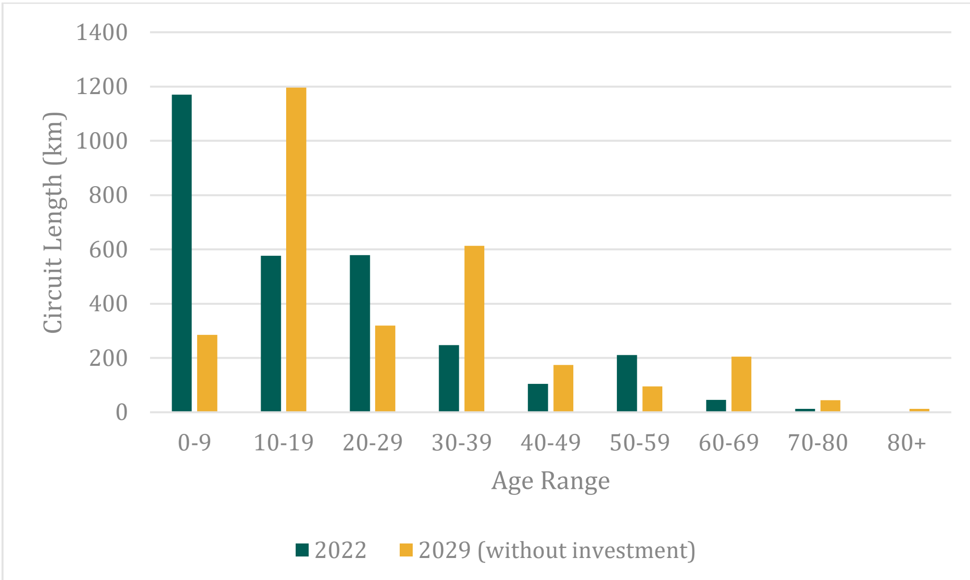

Figure 11: Updated: Age Demographic of Cable in in Concrete-Encased Ducts as of 2022 and by 2029 (without Investment)

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-17

Reference: Exhibit 2B, Section E6.2 ORIGINAL, Page 21

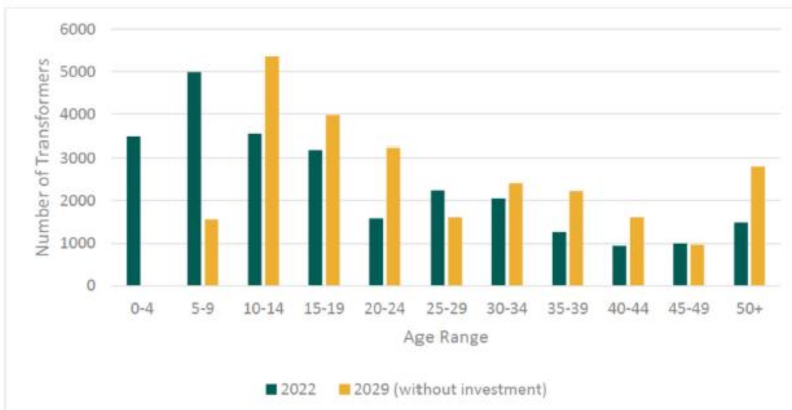

Figure 19: Age Distribution of All Transformers in Underground Horseshoe System as of 2022 and 2029 Without Investment

QUESTION (A) :

a) Please provide the tabular data behind the chart, adding a column showing age demographics in 2029 with investment, i.e., assuming THESL's proposed investment plan is approved by the Board.

RESPONSE (A):

Toronto Hydro is unable to provide an accurate representation of the age demographics profile with investment as the specific list of projects and its corresponding assets have yet to be planned, designed, and issued for execution. Toronto Hydro typically produces detailed scopes of work 12-18 months in advance of construction. There are several other factors that impact asset renewal decisions which are discussed in detail in interrogatory response 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-18

Reference: Exhibit 2B Section E6.2 ORIGINAL Page 22 of 36

Table 5: Asset Condition Assessment for Underground Transformers in Underground Horseshoe System in 2022 and 2029 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total	Total
	2022	**2029**	**2022**	**2029**	**2022**	**2029**	**2022**	**2029**
HI1 – New or Good Condition	4521	3920	7666	6939	6108	4625	18295	15484
HI2 – Minor Deterioration	1009	469	548	585	3618	1533	5175	2587
HI3 – Moderate Deterioration	476	804	130	534	494	3400	1100	4738
HI4 – Material Deterioration	215	561	120	178	225	506	560	1245
HI5 – End-of-Serviceable Life	22	489	46	274	11	392	79	1155
Grand Total	**6243**	**6243**	**8510**	**8510**	**10456**	**10456**	**25209**	**25209**

a) Please reproduce the table such that it includes figures for 2029 with investment, i.e., assuming THESL's proposed investment plan is approved by the Board.

RESPONSE:

For a comprehensive discussion of expected changes in asset demographics over the 2025-2029 period, please see Toronto Hydro's response to 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-19

Reference: Exhibit 2B, Section E6.2 ORIGINAL, Page 22 of 36

Table 5: Asset Condition Assessment for Underground Transformers in Underground Horseshoe System in 2022 and 2029 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total	Total
	2022	2029	2022	2029	2022	2029	2022	2029
HI1 – New or Good Condition	4521	3920	7666	6939	6108	4625	18295	15484
HI2 – Minor Deterioration	1009	469	548	585	3618	1533	5175	2587
HI3 – Moderate Deterioration	476	804	130	534	494	3400	1100	4738
HI4 – Material Deterioration	215	561	120	178	225	506	560	1245
HI5 – End-of-Serviceable Life	22	489	46	274	11	392	79	1155
Grand Total	**6243**	**6243**	**8510**	**8510**	**10456**	**10456**	**25209**	**25209**

a) Please reproduce the table such that it includes a column for figures for 2029 with investment, i.e., assuming THESL's proposed investment plan is approved by the Board.

RESPONSE:

For a comprehensive discussion of expected changes in asset demographics over the 2025-2029 period, please see Toronto Hydro's response to 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-20

Reference: Exhibit 2B, Section E6.3, Page. 17

Please provide the tabular data behind the chart, adding a column showing HI distribution in 2029 with investment, i.e., assuming THESL's proposed investment plan is approved by the Board.

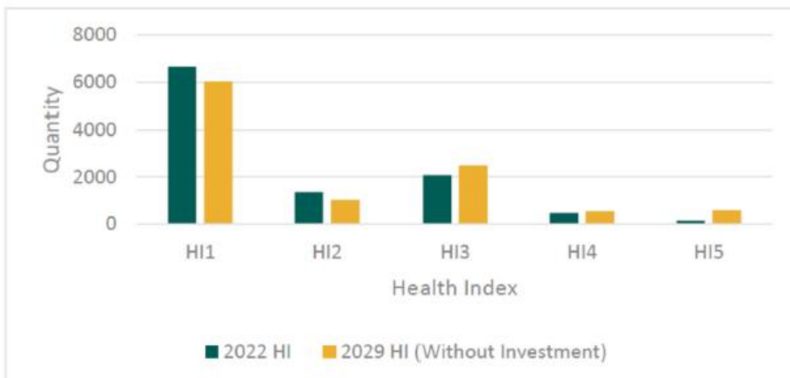

Figure 12: Cable Chamber HI Distribution (Actual and 2029 Forecast)

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-21

Reference: Exhibit 2B, Section E6.3, Page 32

Please provide the tabular data behind the chart, adding a column showing asset condition in 2029 with investment, i.e., assuming THESL's proposed investment plan is approved by the Board.

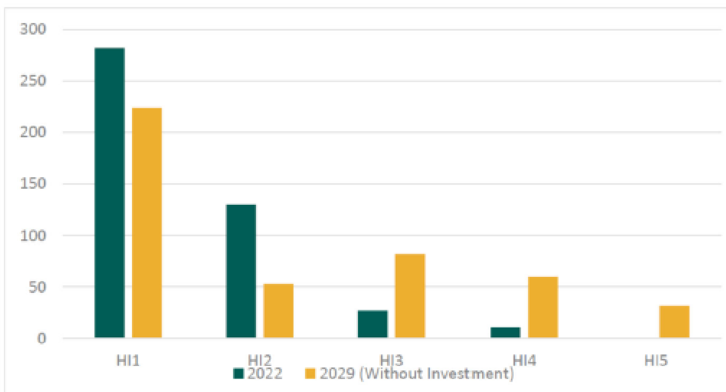

Figure 33: URD Transformer Asset Condition as of 2022 and 2029 (without investment)

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-67 part (b).

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-22

Reference: Exhibit 2B, Section E6.3, Page 34

Please provide the tabular data behind the chart, adding a column showing ACA distribution in 2029 with investment, i.e., assuming THESL's proposed investment plan is approved by the Board.

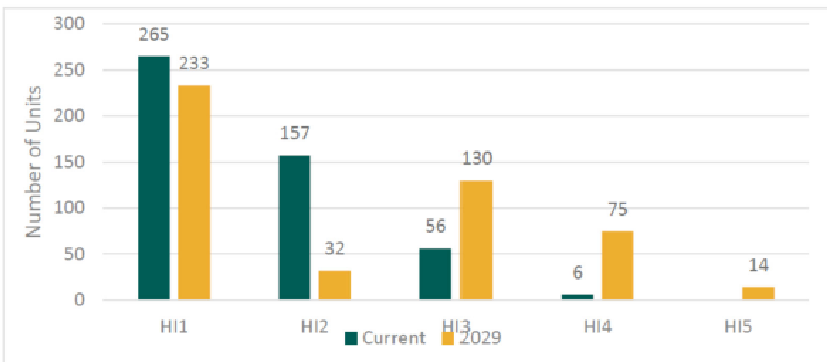

Figure 35: Underground Switchgear ACA distribution

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-67 part (b).

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-23

Reference: **Exhibit 2B, Section E6.4, Page 7**

Please provide the tabular data behind the chart, adding a column showing condition demographics in 2029 with Renewal, i.e., assuming THESL's proposed investment plan is approved by the Board.

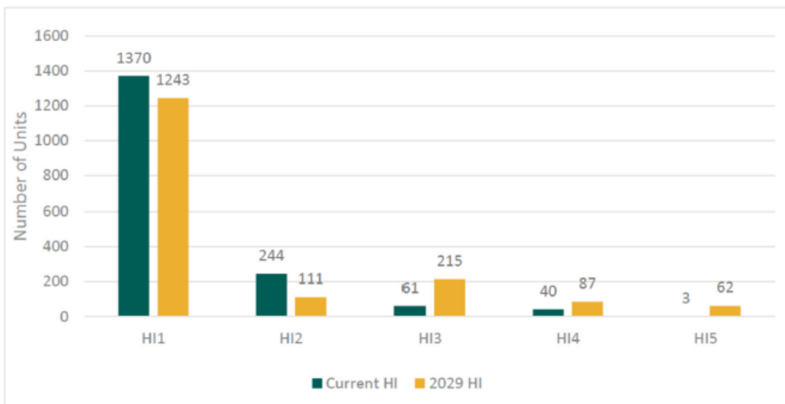

Figure 3: Network Transformers Condition Demographics – Current and Forecasted HI (without Renewal)

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-24

Reference: Exhibit 2B, Section E6.4, Pages. 24-28

Preamble:

The reference shows the three options considered for Network Unit Renewal and Network Vault Renewal

QUESTION (A):

a) Please complete the table, making any corrections to the numbers that have already been provided.

OPTION (Network Unit Renewal)	Estimated Cost
Option 1 – Reduced Pace	
Option 2 – Moderate Pace (selected)	$ 51.2 M
Option 3 - Accelerated Pace	

RESPONSE (A):

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

QUESTION (B):

b) Please complete the table, making any corrections to the numbers that have already been provided.

OPTION (Network Vault Renewal)	Estimated Cost
Option 1 – Reduced Pace	
Option 2 – Moderate Pace (selected)	$ 69.1M?
Option 3 - Accelerated Pace	

RESPONSE (B):

Toronto Hydro notes that the amount is $69.0 million. Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-25

References: **Exhibit 2B, Section E6.5 ORIGINAL, Page 3 of 43, lines 6-8:**

"Approximately 9 percent of wood poles are already showing signs of material deterioration (as of 2022) and, without intervention, this proportion is forecast to increase to 30 percent by 2029."

Exhibit 2B, Section E6.5 ORIGINAL, Page 9 of 43, Table 3

Table 3: Asset Demographics

	Population	Typical Useful Life (Years)	Assets Past Useful Life as of 2022 (%)	Assets Past Useful Life in 2029 without Investment (%)
Wood Poles	108,988	45	23	29
Concrete Poles	49,059	55	13	22
Overhead Transformers	27,690	35	8	17
Overhead Load Break Gang Operated Switches	3,015	30	18	26
Overhead Disconnect Switches	4,425	30	33	54

Exhibit 2B, Section E6.5 ORIGINAL Page 9 of 43, Table 4

Table 4: Condition Data for Wood Pole

Asset Condition Index	2022	2029 (Without Investment)
HI1 – New or Good Condition	68,193	60,253
HI2 – Minor Deterioration	7,536	8,310
HI3 – Moderate Deterioration	21,015	5,544
HI4 – Material Deterioration	8,918	24,404
HI5 – End-of-serviceable Life	504	7,655

QUESTION (A):

a) Given the total number of poles is 108,988 (Ref 2); 9% of wood poles with material deterioration (Ref 1) means 9,808 poles have shown material deterioration. However, that number is given as 8,918 in Ref 3. Please reconcile.

RESPONSE (A):

To clarify, Table 4 shows there are 9,422 wood poles with significant material deterioration (HI4 and HI5) out of a total of 106,166 that have had their condition assessed.

The 108,988 figure in Table 3 represents the total subject population of wood poles and includes a small number of poles that do not have condition information. The subset of poles with condition information totals 106,166. Nine percent of this subset is 9,422.

QUESTION (B):

b) Please reproduce Table 3 in Ref 2 adding a column showing Asset Past Useful Life in 2029 with investment, i.e., assuming the Board approves THESL's investment plans proposed in the current application)

RESPONSE (B):

Toronto Hydro is unable to provide an accurate representation of the age demographics profile with investment as the specific list of projects and its corresponding assets have yet to be planned, designed, and issued for execution. Toronto Hydro typically produces detailed scopes of work 12-18 months in advance of construction. There are several other factors that impact asset renewal decisions which are discussed in detail in interrogatory response 2B-SEC-44.

QUESTION (C):

c) Please reproduce Table 4 in Ref 3 adding a column showing condition data for wood pole in 2029 with investment, assuming the Board approves THESL's investment plans proposed in the current application)

RESPONSE (C):

For a comprehensive discussion of expected changes in asset demographics over the 2025-2029 period, please see Toronto Hydro's response to 2B-SEC-44.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-26

Reference: **Exhibit 2B, Section E6.5 ORIGINAL, Page 34 of 43:**

"The level of spending and overall unit volumes are both lower than forecast in the 2020-2024 DSP ($265.7 million and e.g. over 11,000 poles) as Toronto Hydro reduced the segment budget to support meeting overall capital funding limits and faced supply chain challenges and other pressures impacting pacing and costs."

Table 7: Historical & Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9

Table 8: 2020 – 2024 Overhead Asset Replacement Volumes

Asset Class	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Poles	1,418	1,263	1,137	790	2,674	7,282
Transformers	401	584	579	215	1,892	3,671
OH Switches	185	290	71	43	114	703
Conductors (km)*	53.0	60.0	76.0	4.8	45.1	238.8

*Primary cables only

Please clarify whether the $265.5 M spending and the over 11,000 poles mentioned above are 2020-2024 DSP plans or Board-approved amounts. If plans/forecasts, what were the corresponding Board-approved amounts?

RESPONSE:

These referenced figures are from the 2020-2024 DSP for Overhead System Renewal. The OEB did not order any reductions or modifications to this program.

RESPONSES TO POWER WORKERS UNION INTERROGATORIES

INTERROGATORY 2B-PWU-27

Reference: Exhibit 2B, Section E6.5 ORIGINAL Page 38-40 of 43

The reference lists and describes three options for Overhead System Renewal

a) Please complete the table, making any corrections to the numbers that have already been provided.

OPTION (Overhead system Renewal)	**Forecasted/Estimated Cost**
Option 1 – Limited rebuild/renewal	
Option 2 – Proactive rebuild/renewal (selected)	$272.4 M
Option 3 - Replace all assets in deteriorated condition (or beyond useful life)	Over $350 million

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-31

References: Exhibit 2B, Section A, Page 7

Please provide the data underlying Figure 2, by asset type.

RESPONSE:

Please see Table 1 below which breaks down the categories of Assets at End of Useful Life by 2023, Assets to Reach Useful Life by 2030, and Assets Not at End of Useful Life by asset type. The utility calculated the underlying data by following the methodology described in Toronto Hydro's response to interrogatory 2B-AMPCO-16.

Table 1: Break Down of Assets Past Useful Life - 2023

	Assets at End of Useful Life by 2023	Assets at End of Useful Life by 2030	Assets Not at End of Useful Life
OH Conductor	0.57%	0.80%	6.56%
OH Switches	0.10%	0.32%	0.47%
OH Transformers	0.85%	0.66%	4.52%
Poles	2.59%	0.59%	7.51%
UG Cables	7.38%	2.08%	25.47%
UG Switches	0.06%	0.05%	0.71%
UG Transformers	2.70%	2.12%	2.90%
Network Assets	0.42%	0.12%	1.35%
Switchgear	3.65%	1.53%	3.45%
DC Systems	0.06%	0.04%	0.02%
Power TX	1.02%	0.06%	0.91%
Circuit Breakers	0.59%	0.09%	0.92%
Civil Assets	4.24%	1.60%	8.79%
Meters	0.95%	0.64%	0.55%

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-32

Reference: Exhibit 2B, Section A, Page 17

Please provide a detailed chronology of when the various steps in the capital and business plan process took place that led to the filing of the application.

RESPONSE:

Toronto Hydro's integrated business planning process for this rate application unfolded as follows:

1. **In 2021,** through ongoing strategic planning discussions, Toronto Hydro began considering the incremental business requirements related to emerging drivers – such as technology availability, evolving customer needs and preferences, and decarbonization – that would require it to sustain, expand and modernize its grid and operations.
2. **In the last quarter of 2021**, Toronto Hydro undertook a first phase of customer engagement to collect feedback about customers' needs and priorities, which was used to inform and guide Toronto Hydro's investment priorities for 2025-2029. Please see Exhibit 1B, Tab 5, Schedule 1 for more details about customer engagement.
3. **In the first quarter of 2022**, after receiving the phase 1 customer engagement results, the utility-initiated capital and maintenance investment planning through a process which is described in Exhibit 2B, Section D1. Please see the response to interrogatory 2B-SEC-33 for more information about this stage of the process.
4. **In the second quarter of 2022**, in parallel with ongoing capital and maintenance planning activities being undertaken as part of step 3 above, Toronto Hydro began developing its workforce plan. Please see the response interrogatory 4-CCC-58 for more information about the workforce planning aspects of the process.
5. **In the third quarter of 2022**, the initial capital plan was refined through iterative engagements and deliberations among senior leaders involved in the planning process. Through these iterations and deliberations, the draft capital plan took shape in the summer

of 2022, following which the complimentary workforce and operational plans were considered, giving rise to a consolidated 2025-2029 draft investment plan.

6. **In the fourth quarter of 2022**, based on the draft investment plan, the budget and price limits were adopted to guide the further development, refinement and finalization of the 2025-2029 Investment Plan. For more information about the budget and price limits please see 2B-SEC-33.
7. **In the first quarter of 2023**, while detailed planning activities continued, Toronto Hydro prepared the Customer Engagement Phase 2 survey workbook based on the draft investment plan and lower/higher capital expenditure options that were considered through the planning process in 2022, as noted in the response to 2B-SEC-33. The survey was launched in March 2023. Please see Exhibit 1B, Tab 5, Schedule 1 for more information about Phase 2 Customer Engagement.
8. **In the second quarter of 2023**, the utility refined and finalized the 2025-2029 Investment Plan taking into account two sets of considerations: (i) updated planning considerations including the impact of 2022 actuals and refined workforce growth assumptions as noted in the response to 4-CCC-58, and (ii) customer feedback received from the Phase 2 engagement with respect to trade-offs between price and other outcomes of the plan.
9. **In the third quarter of 2023**, following the finalization of the 2025-2029 Investment Plan, Toronto Hydro worked cross-functionally to develop the 2025-2029 Custom Scorecard and targets to be achieved as part of the proposed Performance Incentive Mechanism (PIM), which is detailed in Exhibit 1B, Tab 3, Schedule 1.
10. **In the fourth quarter of 2023**, the rate application was filed on November 17.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-33

Reference: Exhibit 2B, Section A, Page 20

With respect to the top-down financial constraints used for the development of the plan:

QUESTIONS (A) – (E):

a) Please provide the specific basis for the 7% price limit Toronto Hydro chose.
b) Did Toronto Hydro consider other price limits, both in terms of level of price increase and how it was measured? If so, please discuss and provide a copy of any analysis that it undertook regarding the impact of different price increases.
c) Please provide the specific basis for the specific budget limit chosen ($4B for capital and $1.9B for OM&A).
d) Did Toronto Hydro consider other budget limits? If so, please discuss and provide a copy of any analysis that it undertook regarding the impact of budget limits.
e) Were any price limits for other classes considered? If so, please provide. If not, why not?

RESPONSE (A) – (E):

The referenced budget and price limits were set in the fall of 2022 based on the outputs of the first stage of the integrated planning process described in Exhibit 2B, Section E2 and in Exhibit 4, Tab 1, Schedule 1. In this stage of the planning process, which took place over the second and third quarter of 2022, Toronto Hydro determined the 2025-2029 draft investment plan, having regard to numerous considerations and factors, including customer needs and preferences identified in Phase 1 Customer Engagement (Exhibit 1B, Tab 5, Schedule 1).

As noted in the timeline provided in response to 2B-SEC-32, the integrated planning process commenced in the first quarter of 2022 with the roll-out of the Phase 1 of Customer Engagement results which were summarized in a placemat that was widely distributed to those involved in the capital planning process.[1] Planners developed investment options for the four investment priorities (i.e. sustainment, modernization, growth and general plan), based on asset needs, technical requirements and specific investment objectives which are summarized in Table 1 to Table 3 in Exhibit 2B, Section D1.2.1, Page 11-13.

The planners developed program budgets along a continuum of options which are summarized in the evidence at Exhibit 2B, Section E2 and outlined in detail in the response to interrogatory 2B-SEC-54. Through the planning process, Toronto Hydro arrived at the draft capital plan budgets that formed the basis of the $4B budget limit.

Similarly, the operational plan budget limit of $1.9B was based on the following assessments:

- Asset maintenance and operational requirements, which were developed alongside the capital plan for system-related and general plant investments. This included operational requirements for Preventative, Corrective and Emergency Maintenance, Public Safety and Damage Prevention, Customer Owned Equipment Services, Fleet and Equipment Services, Facilities Management, and Information Technology
- Workforce planning considerations as outlined in the response to 4-CCC-58(d).
- Operational requirements in customer-interfacing programs and corporate services
- Other costs such as training and insurance premiums and regulatory costs.

Toronto Hydro did not consider other budget and price limits, but in setting the referenced limits the utility considered other capital investment options (summarized in Exhibit 2B, Section E2, page 6) which had higher/lower budget and price implications.[2] These investment options were presented to customers in the Phase 2 Customer Engagement, with price impacts that cumulatively ranged from 5% to 9%. Over 33,000 customers participated in the Phase 2 engagement, and 84% of

[1] The Phase 1 Placement can be found at Exhibit 1B, Tab 5, Schedule 1, App A at Appendix 07.
[2] Please see Toronto Hydro's response to interrogatory 2B-SEC-53.

customers across all rate classes supported the total rate increase associated with Toronto Hydro's draft plan, which formed the basis of the 7% average annual price limit.

The price limit was expressed with reference to residential customers, as they represent the largest rate class in terms of total number of customers. However, the price limit was not set on the basis of residential customer impacts. It was based on the capital and operational investment requirements that were identified through the process described above, having regard to customer needs and preferences and other important considerations outlined in the evidence at Exhibit 2B, Section E2 and in Exhibit 4, Tab 1, Schedule 1.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-34

References: Exhibit 2B, Section A, Page 22

Preamble:

With respect to recent enhancement of the AM process:

QUESTION (A):

a) Please provide a copy of the 2020 ISO 55001 Gap Analysis.

RESPONSE (A):

Please see Appendix A to this response. Toronto Hydro is providing the most recently available gap analysis with the most current information on the utility's journey to achieving ISO 55001 certification.

QUESTION (B):

b) Between the completion of the ISO 55001 Gap Analysis and the capital planning process used for the purposes of the DSP and capital budgets in this application, what changes have been made by Toronto Hydro to move closer to meeting the ISO 55001 requirements?

RESPONSE (B):

Between the completion of the 2020 ISO 55001 Gap Analysis and the capital planning process used for the purposes of the Distribution System Plan ("DSP") and capital budgets in this application, the following changes have been made by Toronto Hydro to move closer to meeting the ISO 55001 requirements:

- The creation of a formal Asset Management ("AM") Policy and authorization of the AM Policy;
- AM Policy training for all key stakeholders;

- Enhancement of Asset Management Plans ("AMPs") for all key asset classes;
- Improved level of awareness and competence regarding AM throughout the organization;
- Development of competency framework – Toronto Hydro has mapped key roles, functions and capabilities against the organizational structure, in consultation with leadership of various stakeholder business units;
- Creation of the Asset Management Governance Committee;
- Development of AM Performance and Capability Objectives (see Exhibit 2B, Section D1); and
- Development of a draft Strategic Asset Management Plan.

QUESTION (C):

c) Please provide a copy of Toronto Hydro's internal Asset Management Policy document.

RESPONSE (C):

Please see Appendix B to this response.

AMCL+
LEADING ASSET MANAGEMENT

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-SEC-34
Appendix A
FILED: March 11, 2024
(18 Pages)

TORONTO HYDRO

Asset Management Gap Assessment

High-Level Score Refresh Report

Version: Final

Date: 8th February 2024

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EXECUTIVE SUMMARY

Toronto Hydro is on a journey to improve its asset management maturity, targeting ISO 55001 conformance and certification. To this end, AMCL conducted an ISO 55001 Gap Assessment in 2020. Following the 2020 ISO 550001 gap assessment, a rescore was performed in December 2023 to assess the progress made by Toronto Hydro. This report captures the key findings of that rescore. The rescore was not a full-scale deep dive into every ISO 55001 clause, but rather a high-level investigation into areas where Toronto Hydro indicated it had made advancements. To meet ISO 55001 requirements, Toronto Hydro needs to achieve an overall score of 3.0 on the ISO maturity scale (45%). The assessment result indicates a modest increase in the overall score for Toronto Hydro from 2.56 to 2.69 (38% to 40%).

Key areas that improved the score were the creation of the Asset Management Governance Committee (AMGC), the creation of a formal Asset Management Policy, AMGC review and authorization of the AM Policy, AM Policy training for all key stakeholders, a draft Strategic Asset Management Plan (SAMP), an Asset Management System Manual document, enhancement of Asset Management Plans (AMPs) for all key asset classes, and improved level of awareness and competence regarding Asset Management throughout the organization. As a result, scores for clauses 4.3 (Determining the Scope of the Asset Management System) 4.4 (Asset Management System), 5.2 (Policy), 7.2 (Competence) and 7.4 (Awareness) have improved. Toronto Hydro scores lowest for clauses 7.5 (Information Requirements) and 7.6 (Documented Information), indicating there is work to be done in these areas.

In our experience, organizations average between 2-3% per year in rate of improvement. While Toronto Hydro's progress is at the lower end of this range, key factors affecting this have been the recent rate application filing that resulted in the diversion of key Asset Management System (AMS) resources. As a result, the AMGC has been on a hiatus for the better part of the last year and has not formally convened recently. Leadership championing asset management is a key factor that has impacted progress made thus far and will have a bearing on progress planned in 2024.

The sections below discuss the above aspects in detail.

CHANGES IN SCORES BY CLAUSE

The table below shows the differences between the scores for the assessment that was conducted in 2020 versus the assessment conducted in December 2023. Of all the ISO 55001 clauses evaluated, there was a change in score for four clauses while scores for the other clauses remained unchanged. Toronto Hydro made important progress in the areas of defining the scope of the asset management system, developing, and implementing an asset management policy, and improving competence and awareness of asset management within the organization. Toronto Hydro's overall score has gone up from 2.56 to 2.69. On a percentage basis the score has gone up from 38% to 40%. It should be noted that although only five clauses have an increased score, various initiatives within Toronto Hydro will eventually raise the scores for several other clauses in 2024. Details behind the scores for each clause that has a changed score are discussed below.

ISO 55001 Clause	2020 Score	Percentage	2023 Score	Percentage	Change
4.1 - Understanding the organization and its context	3	45%	3	45%	▬
4.2 - Understanding the needs and expectations of stakeholders	3	45%	3	45%	▬
4.3 - Determining the scope of the Asset Management System	1.9	29%	**2.1**	32%	↑
4.4 - Asset Management System	2.17	33%	**3**	45%	↑
5.1 - Leadership and commitment	2.6	39%	2.6	39%	▬
5.2 - Policy	2.5	38%	**3**	45%	↑
5.3 - Organizational roles, responsibilities and authorities	3	45%	3	45%	▬
6.1 - Actions to address risks and opportunities for the Asset Management System	1.98	30%	1.98	30%	▬
6.2 - Asset Management Objectives and planning to achieve them	2.57	39%	2.57	39%	▬
7.1 - Resources	3	45%	3	45%	▬
7.2 - Competence	2.2	33%	**2.8**	42%	↑
7.3 - Awareness	2.4	36%	**3**	45%	↑
7.4 - Communication	3	45%	3	45%	▬
7.5 - Information requirements	1.44	22%	1.44	22%	▬
7.6 - Documented Information	1.9	29%	1.9	29%	▬
8.1 - Operational planning and control	2.72	41%	2.72	41%	▬
8.2 - Management of Change	2.88	43%	2.88	43%	▬
8.3 - Outsourcing	3	45%	3	45%	▬
9.1 - Monitoring, measurement, analysis and evaluation	2.94	44%	2.94	44%	▬
9.2 - Internal audit	2.58	39%	2.58	39%	▬
9.3 - Management review	2.63	39%	2.63	39%	▬
10.1 - Nonconformity and corrective action	3	45%	3	45%	▬
10.2 - Preventive action	3	45%	3	45%	▬
10.3 - Continual improvement	2.33	35%	2.33	35%	▬
Average	2.56	38%	2.69	40%	↑

HIGH LEVEL OBSERVATIONS BY CLAUSE

CLAUSE 4.1 – UNDERSTANDING THE ORGANIZATION AND ITS CONTEXT

The score for clause 4.1 is unchanged at 3.0, which means Toronto Hydro conforms to the requirements of the ISO 55001 standard. Toronto Hydro's latest rate application clearly outlines the organization's context, drivers, requirements, and constraints, both from an external and internal perspective, that impact its ability to deliver on its goals. The rate application also presents all the different aspects of legal, regulatory, customer, environmental, supplier, financial, resource and other constraints that impact its ability to provide service. The commentary on its internal and external environment provides a clear view of Toronto Hydro's organizational context. Toronto Hydro's rate application can be considered as serving the purpose of a Strategic Asset Management Plan (SAMP). It describes the organizational context and the implications for the asset management system. It also explains how the asset management policy was used to derive the asset management objectives. Although compliant with ISO requirements, Toronto Hydro is considering continual improvement actions, including determining if there is a need for a separate SAMP document that could document the full set of Toronto Hydro's asset management objectives.

CLAUSE 4.2 – UNDERSTANDING THE NEEDS AND EXPECTATIONS OF STAKEHOLDERS

The score for clause 4.2 remains unchanged at 3.0. Exhibit 1B in the rate application discusses key Toronto Hydro stakeholders, with a particular focus on external stakeholders. Discussion with stakeholders reveals key aspects important to them and sheds light on stakeholder requirements and expectations and key decision-making criteria that will affect the asset management system. Robust stakeholder management processes are in place, particularly for external stakeholders such as customers and regulators. While compliant with ISO requirements, Toronto Hydro is considering including a dedicated stakeholder analysis section in a separate SAMP document (refer to discussion in 4.1 above).

CLAUSE 4.3 – DETERMINING THE SCOPE OF THE ASSET MANAGEMENT SYSTEM

Clause 4.3 has been rescored from 1.9 in 2020 to 2.1. While this is a modest increase, it also illustrates that some progress has been made in this area. Since the 2020 gap assessment, Toronto Hydro has established an Asset Management Governance Committee (AMGC), which oversees the asset management system. The scope of the Asset Management System (AMS) has been defined and documented in the draft Asset Management System Manual (AMSM). The AMSM also outlines the key roles and responsibilities of achieving Toronto Hydro's asset management objectives. The AMS boundaries include all distribution system assets, SCADA systems and station buildings. Current AMSM documentation does not identify external and internal issues identified in clause 4.1, and the requirements in clause 4.2. and need to be reviewed and approved by the AMGC.

CLAUSE 4.4 – ASSET MANAGEMENT SYSTEM

Clause 4.4 has been rescored from 2.17 in 2020 to 3 in this latest assessment, indicating good progress made by Toronto Hydro since the last assessment. Based on information provided by Toronto Hydro, the Asset Management System manual includes details on the various documents related to the asset management system, and information on how they link with each other. Documents such as the SAMP (both the draft created by Toronto Hydro and documentation in the latest rate application) have been developed in accordance with the requirements of ISO 55001. As noted in clause 4.1 above, this documentation shows the external and internal issues identified in clause 4.1, the requirements identified in clause 4.2, and outlines the asset management objectives. Although a separate draft SAMP document has been developed, this rate application is deemed to serve the same purpose. In the future, if a separate SAMP document were to be formalized, it would be authorized and formally issued by the AMGC. At this time, it is determined that the requirements of clause 4.4 have been met.

CLAUSE 5.1 – LEADERSHIP AND COMMITMENT

There is no change to the scoring of clause 5.1 and the score stands at 2.6. After the assessment, Toronto Hydro created an Asset Management Governance Committee (AMGC) with overall responsibility for the governance of the AM System, chaired by the Executive Vice-President and Chief Planning & Modernization Officer. The chair is the owner of the AM system. There is on-going work to develop a competency framework that delineates key asset management roles and responsibilities and the resumption of regular AMGC meetings.

CLAUSE 5.2 – POLICY

Following the last assessment in 2020, Toronto Hydro created an Asset management policy in February 2022. The policy is updated every three years, and it has been reviewed and approved by the Asset Management Governance Committee (AMGC). The policy is housed on Toronto Hydro’s SharePoint and has been shared with all key stakeholders. All stakeholders were also required to undergo mandatory asset management policy training toward the end of 2022. The policy is in alignment with Toronto Hydro's organizational objectives as it was developed by taking the corporate goals into account. Due to these activities performed, Toronto Hydro’s score on clause 5.2 has been increased to a 3.0, which indicates that Toronto Hydro is compliant with the requirements of ISO 55001 for this clause.

CLAUSE 5.3 – ORGANIZATIONAL ROLES RESPONSIBILITIES AND AUTHORITIES

This clause has a score of 3, indicating that Toronto Hydro conforms with the requirements of ISO 55001. No change to the score is deemed necessary at this time. Key factors that have contributed to this score are establishment of the governance framework through the establishment of the AMGC, identification of key roles and responsibilities within the AMS for activities such as development and ownership of the SAMP, including asset management objectives, and development of asset management plans for all key asset classes. Key asset management processes within the AMS are mapped and have roles and responsibilities identified in the process documents.

CLAUSE 6.1 – ACTIONS TO ADDRESS RISKS AND OPPORTUNITIES FOR THE ASSET MANAGEMENT SYSTEM

Clause 6.1 had a score of 1.98 during the 2020 assessment. This score remains unchanged. The Enterprise Risk Management (ERM) framework at the corporate level is relatively mature and the current framework was developed in 2009. This framework aligns to ISO 31000. In 2018, there were upgrades to this enterprise framework, that now includes nine enterprise level risks, three Strategic and six Functional risks. One of the functional risks is Operations risk, which includes component risks such as Asset Management Risk and Supply Chain Risk. Every year, ERM conducts risk assessments on capital programs which are both qualitative and quantitative in nature. Thus, the ERM framework ensures a linkage between enterprise and the AMS risks. The Asset Management risk for ERM is measured using SAIDI and SAIFI, which also have associated corporate KPI’s. AMS risk frameworks are still in the development phase, with asset risk assessments that are descriptive and subjective in nature and not quantified or “mapped” using tools utilized by the ERM framework. Note that risk assessment methodologies are developed and detailed in Section D of the Distribution System Plan. The AMGC has not actively reviewed AMS risks. Strategic risks to achieving the asset management objectives have not been identified or evaluated. Project risks are identified and escalated to ERM through the Investment Planning & Portfolio Reporting (IPPR) process. Change management works with project leaders from IT and Business Units to ensure that the key risks in any project are identified and documented as part of the Project Status Report (PSR) and regularly reviewed, re-evaluated, managed, erased, or mitigated accordingly. Outsourcing risks, such as Supply Chain risk, are also captured and categorized under operational risk. Procurement risks are identified and addressed through the contractor pre-qualification program. Within the AMS, there isn’t a formal risk register or established risk targets. AMS risks are not measured using Impact and likelihood scales utilized by ERM. Asset health calculations (which feed into risk) are performed for several distribution assets but how this process feeds into the IPPR for investment planning and optimization could be improved.

CLAUSE 6.2 – ASSET MANAGEMENT OBJECTIVES AND PLANNING TO ACHIEVE THEM

Clause 6.2 had a score of 2.57 in the 2020 assessment. This score remains unchanged. Toronto Hydro has developed asset management objectives (AMOs) – both asset-focused objectives and asset management capability objectives. Asset objectives are categorized into customer service, reliability, safety, environment and financial. Asset Management capability objectives include developing a SAMP, enhancing Asset Management Plans (AMPs), and establishing Asset Risk indices for key asset classes, among others. The draft SAMP document lists all objectives and demonstrates alignment with corporate objectives. Asset management objectives have been reviewed and approved by AMGC, but they are not yet reviewed periodically. AMPs have been developed for all major asset classes to achieve the AMOs. However, the alignment between AMOs and AMPs is not clarified, and asset risks are not identified clearly. The process for planning capital and maintenance work is well documented. Process documentation is housed on SharePoint.

CLAUSE 7.1 – RESOURCES

Clause 7.1 was scored 3.0 in the 2020 assessment. This score remains unchanged. No additional actions are necessary at this time. Resource planning is an enterprise function. Toronto Hydro uses a mix of internal and external resources to perform work. The IPPR process feeds into the Execution Work Program (EWP) process to determine resourcing needs and allocate internal and external resources for programs and projects. Project Variance Analysis (PVA) is conducted for all projects/programs exceeding expected tolerance (-15% to +20%). The PVA investigates various factors that impact work, including the use of resources. As a continual improvement step, Toronto Hydro is in the process of developing models for long-term resource planning.

CLAUSE 7.2 – COMPETENCE

The score for clause 7.2 has improved from 2.2 to 2.8. The primary driver for this is a competency framework that was developed in 2022. In addition, key roles, functions, and capabilities have been mapped against the organizational structure, in consultation with leadership of various stakeholder business units. This helps to identify the key stakeholders associated with key capabilities within all major asset management processes.

CLAUSE 7.3 – AWARENESS

The score for clause 7.3 has improved from 2.4 to 3.0, which indicates that Toronto Hydro is in conformance with ISO 55001 requirements. The primary driver of this score was the recently implemented AM Policy training for all stakeholders related to the AMS. The training is a 30-minute online training on key aspects of Toronto Hydro AM policy. The training also requires certification, including testing on key concepts, to ensure that the participant understands the AM Policy. There is a three year recertification requirement for this training. This training platform and approach can be further expanded in the future to incorporate other asset management-related training.

CLAUSE 7.4 – COMMUNICATION

The score for this clause remains unchanged at 3.0, indicating continued conformance with ISO 55001 requirements. No additional action is necessary at this time.

CLAUSE 7.5 – INFORMATION REQUIREMENTS

The score for clause 7.5 remains unchanged at 1.44. An Asset Information Strategy draft is currently being developed but has not been finalized, nor has it been reviewed or approved by the AMGC. Asset data used for decision-making resides in several systems. SAP is the asset register for non-linear assets, while GIS (GEAR) is the asset register for both linear and non-linear assets. A new SAP WMS system records all warehouse transactions, including on-hand quantities and storage locations. There are processes in place to ensure valid linkage and alignment between SAP and GIS. However, the process of updating SAP with asset additions/removals is typically several months behind schedule and can create a discrepancy in SAP. The data from GEAR is used by the control center for operational needs to address this issue. Asset data is captured through change-out forms, which are digitized versions of paper forms. However, there is variation in the level of detail captured through these forms beyond the minimum required information. As a result, asset data quality varies across asset classes within the AMS. There are parallel efforts to clean up data or fill in gaps, but there is limited enforcement through processes, governance, or use of technology. Training has been performed with key stakeholders responsible for collecting and providing the data, but there are opportunities for further improvement. A roadmap that clearly outlines future data requirements and a plan to reach that future state has not been developed. Intelex is the Environment, Health & Safety management system utilized by EHS. This system also has a link with the AMS for assets involved in environmental incidents, but this capability is not proactively utilized for developing asset management planning. Alteryx is the data analytics tool utilized to consolidate electrical equipment data and asset information from the SAP and GEAR database such as asset identifiers, types, and installation dates. Additionally, Alteryx extracts similar data from other databases for meter information and from the SAP database for other asset types and consolidates these diverse data sets, extracting relevant columns to determine asset age and type. Toronto Hydro also has a data warehouse beyond Alteryx which pulls key AM information from various systems.

CLAUSE 7.6 – DOCUMENTED INFORMATION

The score for clause 7.6 remains unchanged at 1.9. This clause requires an organization to control its Documented Information (DI) across the DI lifecycle. The three types of documented information include information required by ISO 55001 standard, information referenced in clause 7.5 above and information required for legal and regulatory purposes. SharePoint is the repository for documented information required by ISO 55001 standards; this includes the AM Policy, draft SAMP including the Asset Management objectives, Asset Management Plans, among other documents. Although these documents or drafts exist, not all have been reviewed or approved by the AMGC, and the evidence to demonstrate information control across its lifecycle is limited. Refer to clause 7.5 for discussion on information related to the effectiveness of the AMS – there are opportunities for improvement for this information. Based on evidence gathered during the 2020 gap assessment, no concerns were identified relating to documented information management for legal and regulatory information. Limited progress has been made for this clause since the 2020 gap assessment, consequently, no changes in the score for this clause are warranted at this time.

CLAUSE 8.1 – PLANNING AND CONTROL

The score for clause 8.1 remains unchanged at 2.72. The key requirement is to demonstrate that all operational processes are controlled. Although close to the conformance score of 3.0, Toronto Hydro has several improvement projects on-going after the 2020 gap assessment that have yet to be completed. These include comparing the current operational planning and control requirements with what has been defined in the AMS and identify gaps, undertaking a self-evaluation of current planning and control requirements defined in the AMS, developing requirements based on the planning cycle, and implementing these requirements. Toronto Hydro has most of the key operational processes in place. Some processes such as end-to-end project planning through closeout have not been mapped as a single process but exist as several divided processes. All processes are backed by process documentation housed on Toronto Hydro's Intranet Site and are owned and updated by the enterprise program management office. Current process maps show departments rather than functions in the swim lanes – which is inconsistent with Toronto Hydro's process standard. The alignment of work execution to the Asset Management objectives is not articulated clearly enough.

CLAUSE 8.2 – MANAGEMENT OF CHANGE

The score for clause 8.2 remains unchanged at 2.88. Several actions were identified from the 2020 gap assessment that are still ongoing. These include reviewing the current policies of managing change and a gap assessment against the new AM System, reviewing existing internal change management, and submitting the updated Management of Change procedure for authorization to AMGC, and formally issue and brief out the Management of Change procedure. As none of these actions have been completed, the score does not warrant a change.

CLAUSE 8.3 – OUTSOURCING

The score for this clause remains unchanged at 3.0, indicating continued conformance with ISO 55001 requirements. No additional action is necessary at this time.

CLAUSE 9.1 – MONITORING, MEASUREMENT, ANALYSIS, AND EVALUATION

The score for this clause remains unchanged at 2.94. Although close to conformance, there are several pending actions that Toronto Hydro is working on. These include reviewing the current performance monitoring processes, developing a set of leading measures for the performance and condition of the assets, and defining a set of higher-level measures that will enable monitoring of the achievement of the asset management objectives.

CLAUSE 9.2 – INTERNAL AUDIT

The score for clause 9.2 remains unchanged at 2.58. Internal audit is an enterprise-wide function that involves auditing approximately thirty-six processes. Every year, processes are selected based on focus areas for executives and perceived risk areas for the organization. Auditing is a three-step process – planning, execution, and reporting. Planning involves identifying audit objectives and risks, coordinating with stakeholders, and analysis. Execution involves reviewing planning outputs in detail, additional analytics, walk-through conversations with key stakeholders, and developing recommendations for improvement. Reporting involves approval of the report from leadership, sharing action items with stakeholders and follow-up activities to ensure conformance. A formal audit committee oversees and governs the audit process. An external audit was performed for AMS processes in 2022 – an internal audit was not conducted to avoid duplication. Another audit for AMS related processes is planned for 2026. Follow up actions after the 2020 gap assessment included developing and submitting an AMS audit plan for authorization to the AMGC and reporting progress to the AMGC on a regular basis.

CLAUSE 9.3 – MANAGEMENT REVIEW

The score for clause 9.3 remains unchanged at 2.63. No progress has been made on the activities identified after the 2020 gap assessment such as developing and submitting the AMS management review framework to the AMGC for approval, followed by implementation. Progress is expected after the AMGC resumes regular meetings in 2024.

CLAUSE 10.1 – NONCONFORMITY AND CORRECTIVE ACTION

The score for this clause remains unchanged at 3.0 indicating continued conformance with ISO 55001 requirements. No additional action is necessary at this time.

CLAUSE 10.2 – PREVENTIVE ACTION

The score for this clause remains unchanged at 3.0 indicating continued conformance with ISO 55001 requirements. No additional action is necessary at this time.

CLAUSE 10.3 – CONTINUOUS IMPROVEMENT

The score for this clause remains unchanged at 2.33. The AMGC has not convened in a year due to competing priorities such as the recent rate application. Therefore, limited progress has been made against the asset management roadmap, developed following the 2020 gap assessment, and management review of these activities.

APPENDICES

APPENDIX 1 – DOCUMENTATION REVIEWED

Category	Document Name
2020 Gap Analysis Report	THESL ISO 55001 Gap Analysis v3.0-FINAL
Org Charts	1. Customer Care, Electric Operations and Procurement
Org Charts	2. Human Resources and Safety
Org Charts	3. Regulatory Affairs and Legal
Org Charts	4. Engineering and Construction
Org Charts	5. Finance
Org Charts	6. IT Services
Organization & Competence	Job Profiles
Organization & Competence	OC 1 - TH_RACI_ISO Job Profiles
Organization & Competence	OC 2 - TH_COMPETENCY_FRAMEWORK
Processes & Procedures	2018-electricity-distributor-scorecard
Processes & Procedures	Engineering Portfolio Meeting Nov 2023
Processes & Procedures	ISO55001 Steering Committee Update - July 2022 v1.0
Processes & Procedures	major-event-report-july-8-2020
Processes & Procedures	PP 1&2 - L0 and L1 Business Process Design - v1.0
Processes & Procedures	PP 3 - L0 and L1 Business Process Guidance - v0.5
Processes & Procedures	PP 4 - Change Management Framework - v0.5
Rate Application	Consolidated Application
Rate Application	Customer Summary
Rate Application	Executive Summary
Rate Application	Exhibit 1C – Corporate Information
Rate Application	Exhibit 2A – Rate Base
Rate Application	Exhibit 2B – Distribution System Plan
Rate Application	Exhibit 3 – Operating Revenue
Rate Application	Exhibit 4 – Operating Expenses
Rate Application	Exhibit 5 – Cost of Capital and Capital Structure
Rate Application	Exhibit 6 – Revenue Requirement
Rate Application	Exhibit 7 – Cost Allocation
Rate Application	Exhibit 8 – Rate Design
Rate Application	Exhibit 9 – Deferral and Variance Accounts
Rate Application	Exhibit-1B-application-overview
Rate Application	Filing Cover Letter
Roadmap	ISO55001 Progress and Plan_16.11.2023
Roadmap	THESL - ISO 55001 Roadmap v2.0_Final
Strategy & Planning	SP 1 - SAMP Draft Phase 1 (2021-2022) v0.5
Strategy & Planning	SP 2 - AMSM Draft Phase 1 (2021-2022) v0.5

Systems & Information	CoE Enterprisers
Systems & Information	ISO55001 Information Model Data Elements v0.3 2021.10
Systems & Information	SI 1 - Asset Information Strategy - v0.5
Systems & Information	SI 2 - Conceptual Asset Information Model - v0.5
Systems & Information	TH ISO Information Model 2021.11.22 v0.11

APPENDIX 2 – ACRONYMS USED

Acronym	Description
AM	Asset Management
AMGC	Asset Management Governance Committee
AMO	Asset Management Objective
AMP	Asset Management Plan
AMS	Asset Management System
AMSM	Asset Management System Manual
DI	Documented Information
EHS	Environment, Health & Safety
ERM	Enterprise Risk Management
IPPR	Investment Planning & Portfolio Reporting
PSR	Project Status Report
PVA	Project Variance Analysis
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition

POLICY

Asset Management	**Policy Owner:** Executive Vice President, Planning & Chief Engineering and Modernization Officer
	Policy Approver: Policy Administration Steering Committee
	Version Approval Date: 2022-02-01
	Last Review by PASC: 2022-02-01
The most recent version of this policy can be obtained from http://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx	
The distribution of this policy is restricted to Toronto Hydro.	

Anthony Haines
President and CEO, Toronto Hydro Corporation

February 17, 2022
Date

TABLE OF CONTENTS

1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed every three years.

Version Number	Date of Review	Reviewed By	Brief Description of Change	Next Review Date
V1.0	2018-12-19	PASC	New Policy. V 1.0 approved by PASC.	December 2021
V2.0	2021-11-19 2022-02-01	AMGC PASC	Policy updated to reflect continuous improvement changes to the Asset Management System through the ISO55001 project.	November 2024

2 DISTRIBUTION HISTORY

Version Number	Date of Posting	Format of Distribution
V 1.0	2018-12-19	Toronto Hydro Intranet Site (Plugged In)
V 2.0	2022-02-22	Toronto Hydro Intranet Site (Plugged In)

3 POLICY OVERVIEW

The Asset Management Policy formalizes Toronto Hydro's Asset Management direction and establishes a framework to develop and continuously improve Toronto Hydro's Asset Management System.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	**DESCRIPTION**
AMGC	Asset Management Governance Committee - whose role is to provide oversight of the application, maintenance, and continuous improvement of the Asset Management System (AMS) at Toronto Hydro
Asset Management	Coordinated activity of an organization to realize value from its assets. This involves balancing costs, opportunities, and risks against the desired performance of assets to achieve the organization's objectives.[1]
Asset Management System	The management system for Asset Management whose function is to establish the Asset Management Policy and Asset Management objectives
Contractor	Any resource engaged through a third party agency or organization that is not directly employed by Toronto Hydro.
Employee(s)	Includes any individual employed by Toronto Hydro (including but not limited to individuals employed on a full-time, part-time,contract, or casual basis).
PASC	Policy Administration Steering Committee
Toronto Hydro	Toronto Hydro Corporation and its subsidiaies.

5 SCOPE

5.1 This policy applies to the Asset Management System, which comprises all Toronto Hydro distribution system assets, including stations buildings and SCADA systems.

5.2 This policy does not apply to Fleet, Tools, Facilities, or Information Technology assets.

5.3 This policy applies to all aspects of asset management, including the acquisition, operation, maintenance, and disposal of assets.

5.4 This policy applies to all employees, officers and directors of Toronto Hydro, as well as contractors and visitors to Toronto Hydro facilities and sites.

5.5 This policy is designed to augment other corporate policies and is not intended to replace or preclude them. Should an overlap arise between the application of this policy and any other policy, the policy most applicable to the situation will be applied.

[1] The Institute of Asset Management – www.iam.org

6 POLICY STATEMENT

Toronto Hydro's asset management policy is to ensure that it effectively manages its electricity distribution assets, across the complete asset lifecycle, in a safe, cost-effective, and sustainable manner, and that the management of those assets meets the needs of its customers and stakeholders, and provides a fair return to its shareholder. Toronto Hydro shall comply with all legal, regulatory and environmental requirements placed upon the organization and will prioritize the safety of its employees and the public.

This Asset Management Policy shall be achieved through the management and continuous improvement of an efficient, coordinated, systematic, and embedded Asset Management System that:

- develops and implements a **Strategic Asset Management Plan**;
- balances costs, risks, opportunities and performance by applying a holistic approach to decision-making while:
  - optimizing the distribution system's reliability performance in accordance with customer needs and preferences;
  - enabling growth, fostering electrification, and accommodating evolving consumer and stakeholder needs; and
  - striving for zero public and employee safety incidents.
- aligns with Toronto Hydro's corporate strategy as well as its safety and environmental management systems;
- collects and analyzes asset information to enable informed and holistic decision-making; and
- ensures the availability of the required resources to develop and implement Asset Management strategies and plans.

All employees and contractors shall comply with this policy and contribute towards the continuous improvement of the Asset Management System.

7 POLICY ADMINISTRATION OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

7.1 This policy is owned by the Executive Vice President, Planning & Chief Engineering and Modernization Officer

7.2 The Executive Vice President, Planning & Chief Engineering and Modernization Officer is responsible for

- Ensuring that this policy is comprehensive, clear and current
- Ensuring that this policy is implemented and communicated to the departments and staff that are impacted
- Ensuring ongoing compliance with this policy
- Approving any exceptions to this policy, as required
- Reviewing this policy as per the review frequency stated in Section 1 of this policy

Policy Approver

7.3 This policy is reviewed and updated by the AMGC.

7.4 The AMGC is responsible for oversight of the application, maintenance, and continuous improvement of the Asset Management System at Toronto Hydro. The AMGC will formally review and update this Asset Management Policy before formal review by the PASC.

7.5 The PASC is responsible for:

- Considering the impact of the proposed policy on corporate risks
- Reviewing and approving this policy as per the review frequency stated in Section 1 of this policy

Designated Responsible Person (DRP)

7.6 This policy is managed by the Director, Integrated Planning & Modernization

7.7 The Director, Integrated Planning & Modernization is responsible for:

- Immediately communicating any exceptions or violations of this policy to the Executive Vice President, Planning & Chief Engineering and Modernization Officer for review and remedial action
- Reviewing this policy as per the review frequency stated in Section 1, and recommending changes as required

8 POLICY COMMUNICATION

COMMUNICATION TRIGGER	TYPE OF COMMUNICATION	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT
Policy review and approval	PASC meeting	Director, Integrated Planning & Modernization	PASC members	PASC minutes
Policy update	Post on Intranet	Business Law and Corporate Governance Department	All employees	N/A
Policy update	Senior Engagement Meetings	Integrated Planning & Modernization	Senior Leaders	N/A
Policy update	Email Memo	Integrated Planning & Modernization	All Employees	N/A
Policy update	People Connect Training Attestation	Sustainability & Training	All Employees	Attestation
New employee hire	Onboarding	Direct Leader	New hire	N/A

9 POLICY COMPLIANCE AND VIOLATIONS

9.1 All Toronto Hydro employees, officers, directors and contractors are required to comply with this policy

9.2 Failure to comply with this policy will pose significant financial, operational, environmental, legal, regulatory, safety, and reputational risks to Toronto Hydro and its employees

9.3 The Director, Integrated Planning & Modernization is responsible for tracking and collecting applicable data, measuring compliance and reporting in such format as may be required

10 RELATED LAWS, REGULATIONS AND DOCUMENTATION

10.1 External legislation and standards that affect this policy include:

- *The Electricity Act, 1998*
- *Electricity Distribution Safety, Ontario Regulation 22/04*
- *Ontario Energy Board Act, 1998*
- Ontario Energy Board's Distribution System Code ("DSC")
- Toronto Hydro's Distribution Licence
- Electricity Utilities Safety Rules (EUSR)
- Relevant City of Toronto by-laws
- Relevant Ministry of the Environment, Conservation and Parks Statutes Regulations

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-35

References: **Exhibit 2B, Section C**

<u>Preamble:</u>

With respect to reliability performance:

QUESTION (A):

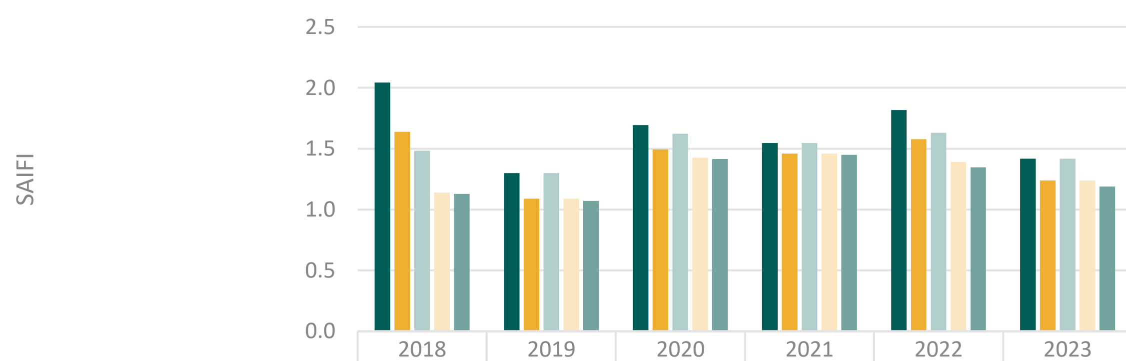
a) Please update the following figures and tables to provide 2023 information:

i. Figure 1, 2, 12, 13, 20, 21, 22, 23, 24, 25

ii. Tables 3, 4, 5, 6

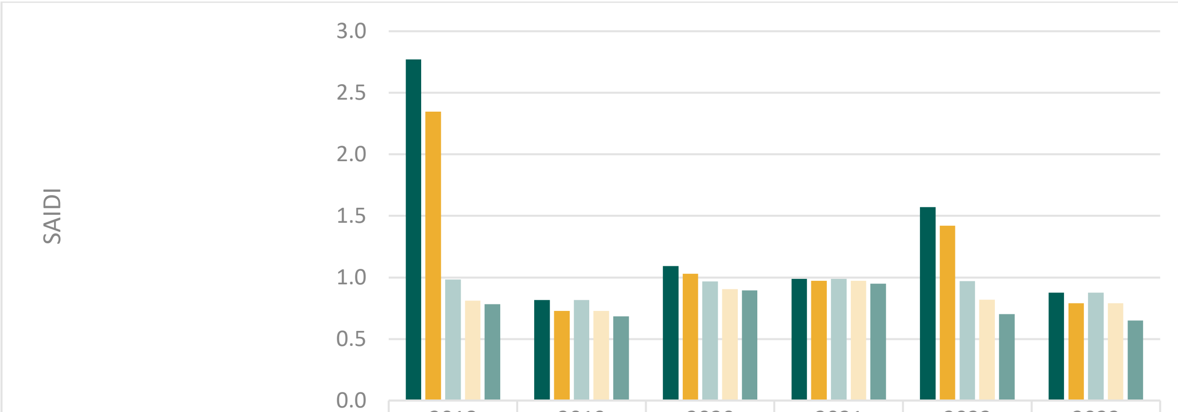
RESPONSE (A):

Please see Figures 1-12 and Tables 1-4 below. Toronto Hydro included Figures 10 and 11 from Exhibit 2B, Section C as well for completeness. The original figure and table numbers from Section C are noted in the captions for convenience.



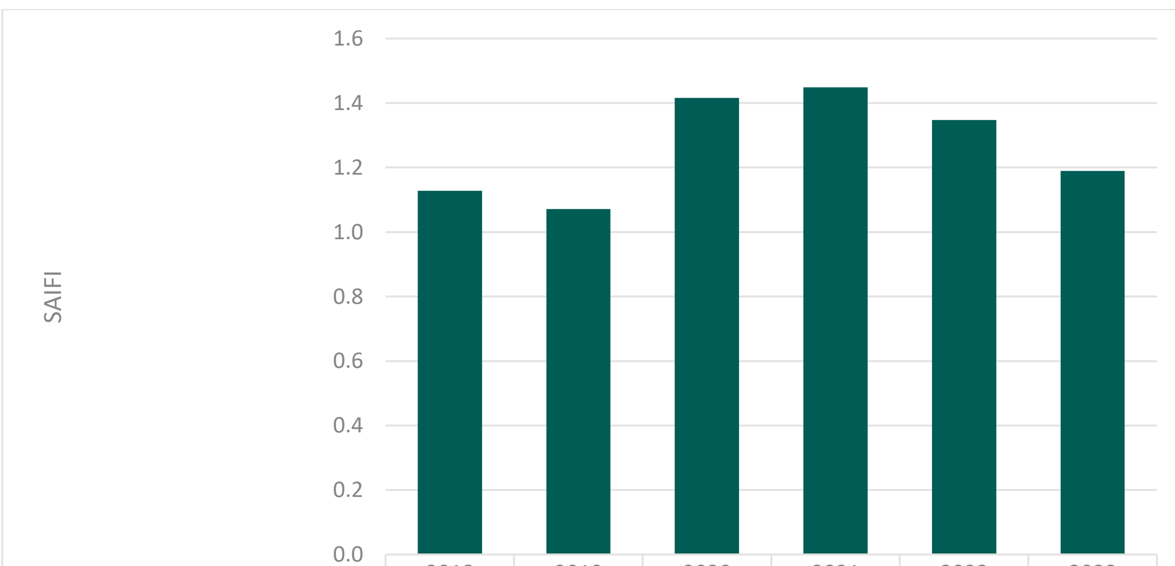
	2018	2019	2020	2021	2022	2023
Total SAIFI	2.04	1.30	1.69	1.55	1.82	1.42
SAIFI Excluding LOS	1.64	1.09	1.50	1.46	1.58	1.24
SAIFI Excluding MED's	1.48	1.30	1.62	1.55	1.63	1.42
SAIFI Excluding MED's and LOS	1.14	1.09	1.42	1.46	1.39	1.24
SAIFI Excluding MED's, LOS and Scheduled Outages	1.13	1.07	1.42	1.45	1.35	1.19

Figure 1: System Level SAIFI (Figure 1)



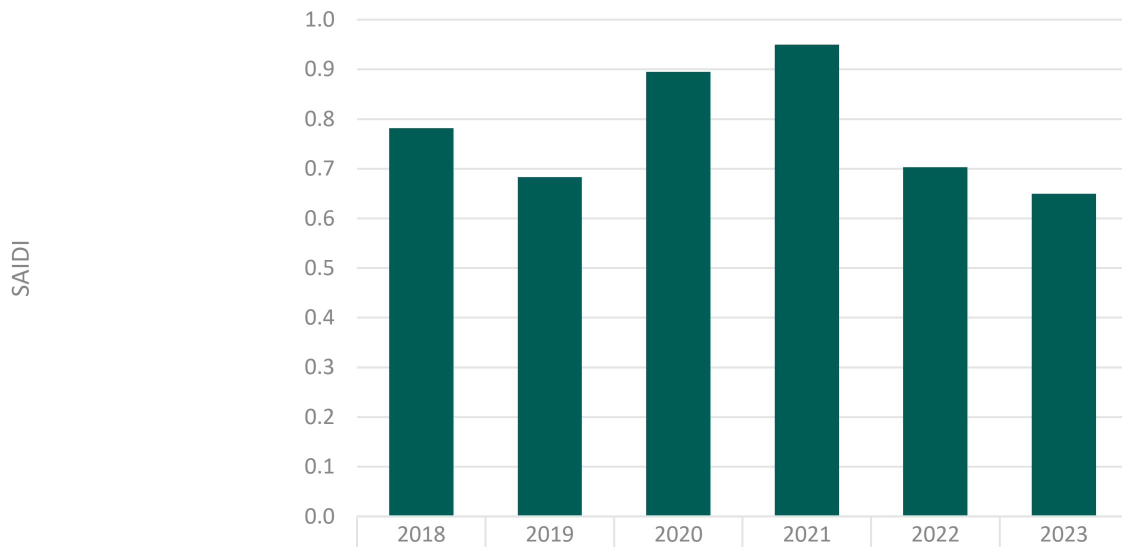
	2018	2019	2020	2021	2022	2023
Total SAIDI	2.77	0.82	1.09	0.99	1.57	0.88
SAIDI Excluding LOS	2.35	0.73	1.03	0.97	1.42	0.79
SAIDI Excluding MED's	0.98	0.82	0.97	0.99	0.97	0.88
SAIDI Excluding MED's and LOS	0.81	0.73	0.90	0.97	0.82	0.79
SAIDI Excluding MED's, LOS and Scheduled Outages	0.78	0.68	0.90	0.95	0.70	0.65

Figure 2: System Level SAIDI (Figure 2)



	2018	2019	2020	2021	2022	2023
SAIFI Excluding MED's, LOS and Scheduled Outages	1.13	1.07	1.42	1.45	1.35	1.19

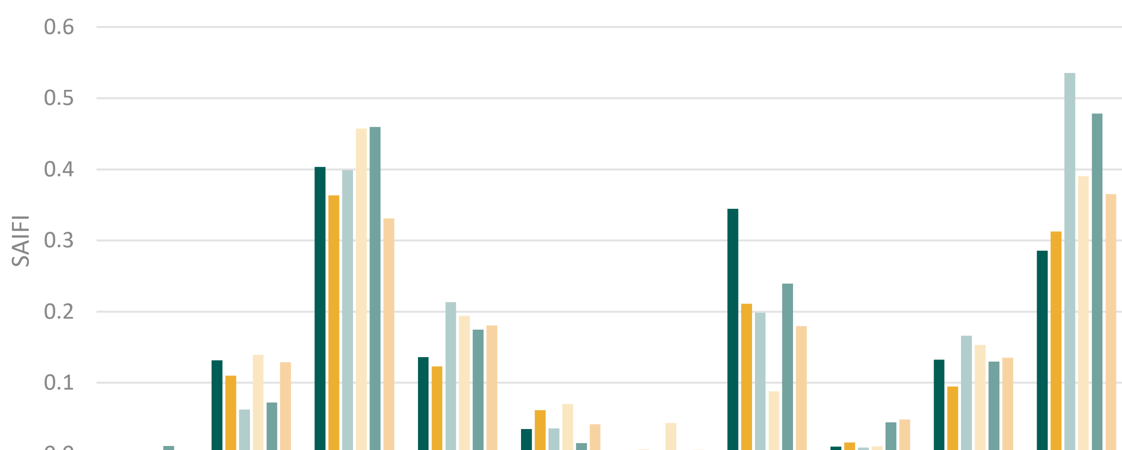
Figure 3: System SAIFI Excluding MEDs, Loss of Supply, and Scheduled Outages (Figure 10)



	2018	2019	2020	2021	2022	2023
SAIDI Excluding MED's, LOS and Scheduled Outages	0.78	0.68	0.90	0.95	0.70	0.65

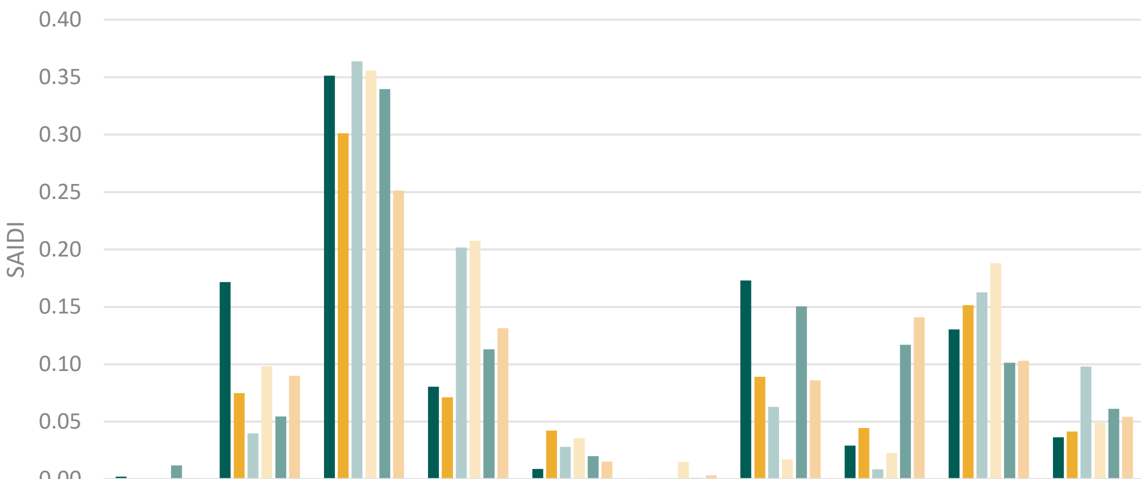
1 **Figure 4: System SAIDI Excluding MEDs, Loss of Supply, and Scheduled Outages (Figure 11)**

2



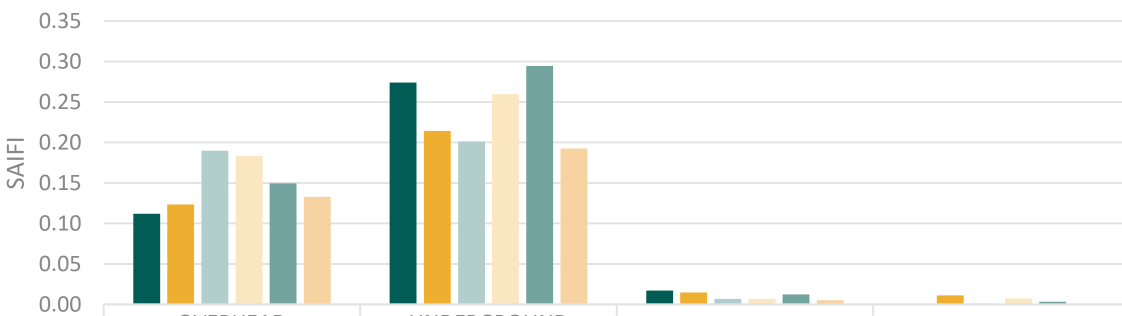
	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.13	0.40	0.14	0.04	0.00	0.34	0.01	0.13	0.29
2019	0.00	0.11	0.36	0.12	0.06	0.01	0.21	0.02	0.10	0.31
2020	0.00	0.06	0.40	0.21	0.04	0.00	0.20	0.01	0.17	0.54
2021	0.00	0.14	0.46	0.19	0.07	0.04	0.09	0.01	0.15	0.39
2022	0.01	0.07	0.46	0.17	0.02	0.01	0.24	0.04	0.13	0.48
2023	0.00	0.13	0.33	0.18	0.04	0.01	0.18	0.05	0.14	0.37

3 **Figure 5: SAIFI Cause Code Breakdown (Excluding MEDs) (Figure 12)**



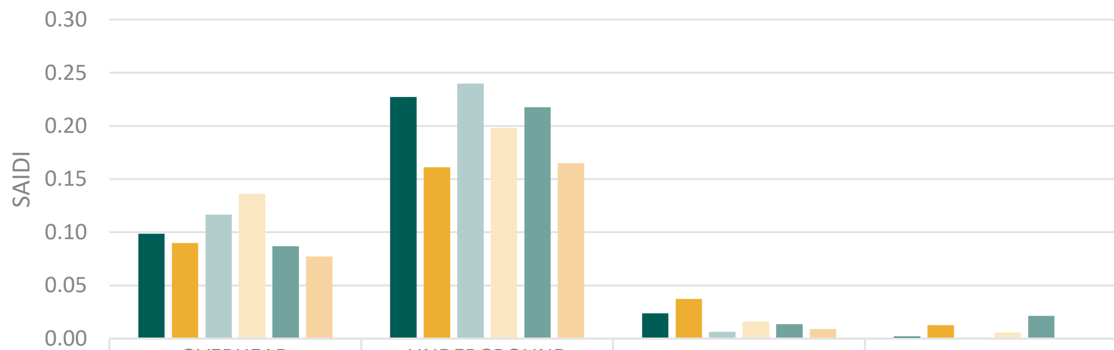
	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.17	0.35	0.08	0.01	0.00	0.17	0.03	0.13	0.04
2019	0.00	0.07	0.30	0.07	0.04	0.00	0.09	0.04	0.15	0.04
2020	0.00	0.04	0.36	0.20	0.03	0.00	0.06	0.01	0.16	0.10
2021	0.00	0.10	0.36	0.21	0.04	0.02	0.02	0.02	0.19	0.05
2022	0.01	0.05	0.34	0.11	0.02	0.00	0.15	0.12	0.10	0.06
2023	0.00	0.09	0.25	0.13	0.02	0.00	0.09	0.14	0.10	0.05

Figure 6: SAIDI Cause Code Breakdown (Excluding MEDs) (Figure 13)



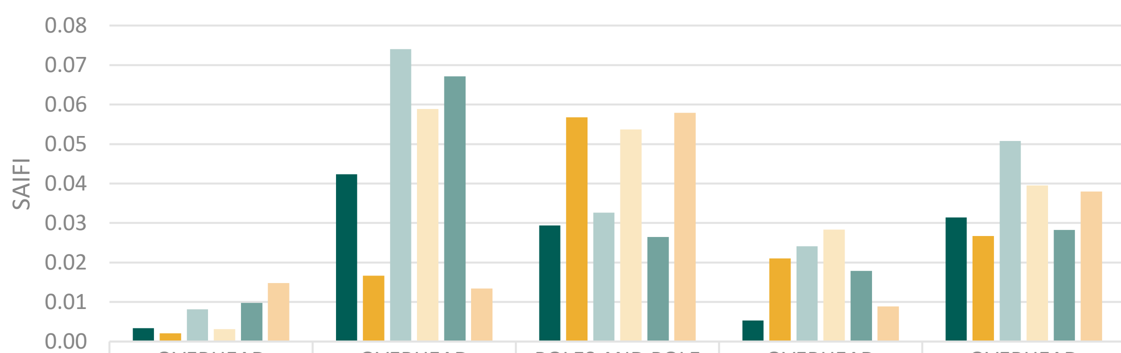
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.11	0.27	0.02	0.00
2019	0.12	0.21	0.01	0.01
2020	0.19	0.20	0.01	0.00
2021	0.18	0.26	0.01	0.01
2022	0.15	0.29	0.01	0.00
2023	0.13	0.19	0.01	0.00

Figure 7: Defective Equipment SAIFI (Excluding MEDs) (Figure 20)



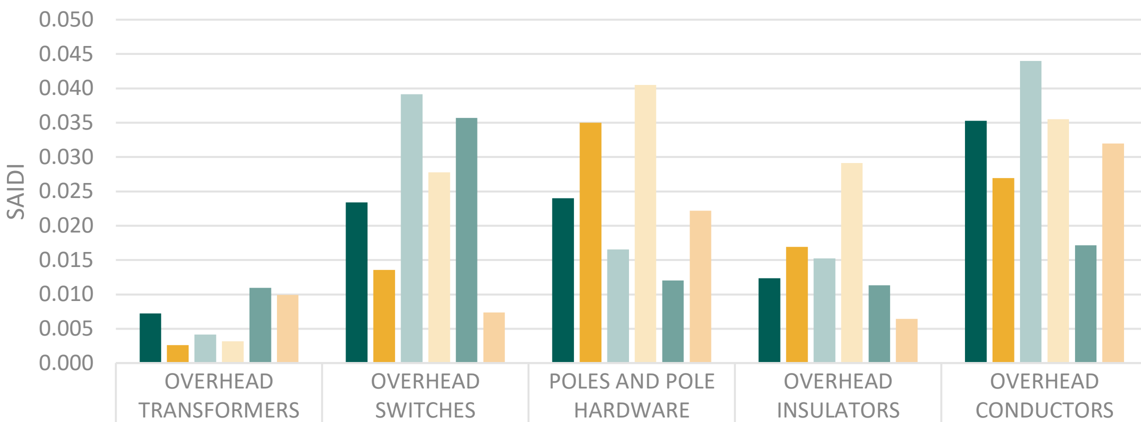
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.10	0.23	0.02	0.00
2019	0.09	0.16	0.04	0.01
2020	0.12	0.24	0.01	0.00
2021	0.14	0.20	0.02	0.01
2022	0.09	0.22	0.01	0.02
2023	0.08	0.17	0.01	0.00

Figure 8: Defective Equipment SAIDI (Excluding MEDs) (Figure 21)



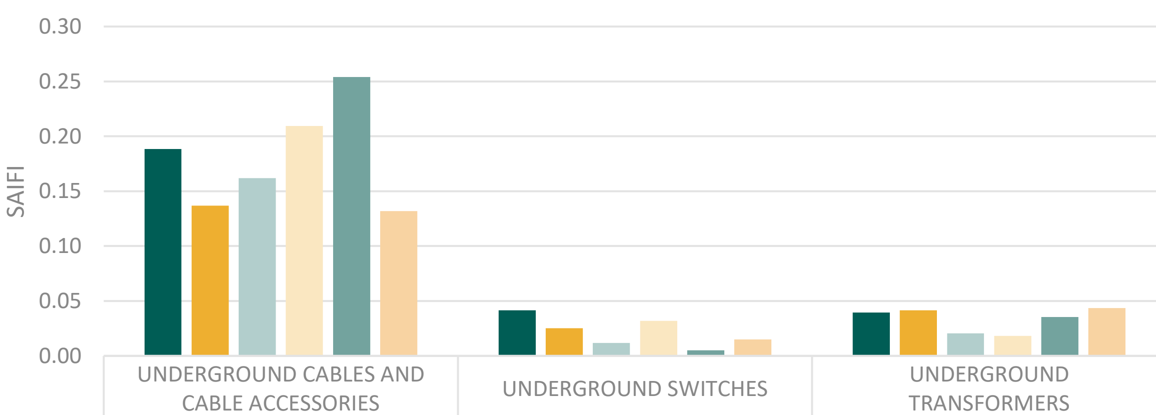
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.04	0.03	0.01	0.03
2019	0.00	0.02	0.06	0.02	0.03
2020	0.01	0.07	0.03	0.02	0.05
2021	0.00	0.06	0.05	0.03	0.04
2022	0.01	0.07	0.03	0.02	0.03
2023	0.01	0.01	0.06	0.01	0.04

Figure 9: Defective Equipment SAIFI – Overhead (Excluding MEDs) (Figure 22)



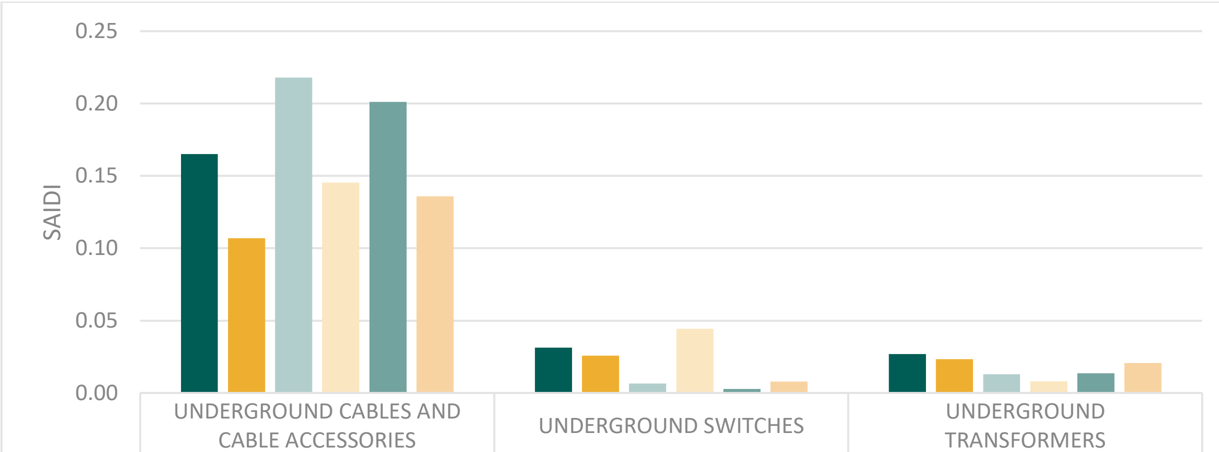
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.01	0.02	0.02	0.01	0.04
2019	0.00	0.01	0.03	0.02	0.03
2020	0.00	0.04	0.02	0.02	0.04
2021	0.00	0.03	0.04	0.03	0.04
2022	0.01	0.04	0.01	0.01	0.02
2023	0.01	0.01	0.02	0.01	0.03

Figure 10: Defective Equipment SAIDI – Overhead (Excluding MEDs) (Figure 23)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.19	0.04	0.04
2019	0.14	0.03	0.04
2020	0.16	0.01	0.02
2021	0.21	0.03	0.02
2022	0.25	0.01	0.04
2023	0.13	0.01	0.04

Figure 11: Defective Equipment SAIFI – Underground (Excluding MEDs) (Figure 24)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.17	0.03	0.03
2019	0.11	0.03	0.02
2020	0.22	0.01	0.01
2021	0.15	0.04	0.01
2022	0.20	0.00	0.01
2023	0.14	0.01	0.02

Figure 12: Defective Equipment SAIDI – Underground (Excluding MEDs) (Figure 25)

Table 1: Five-Year (2019-2023) Average SAIFI and SAIDI Contribution by Cause Code (Excluding MEDs) (Table 3)

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
UNKNOWN	27.7%	6.6%
DEFECTIVE EQUIPMENT	26.7%	34.9%
LOSS OF SUPPLY	12.2%	8.8%
FOREIGN INTERFERENCE	11.8%	15.7%
TREE CONTACTS	9.0%	15.3%
ADVERSE WEATHER	6.8%	7.7%
HUMAN ELEMENT	3.0%	3.1%
SCHEDULED OUTAGE	1.7%	7.2%
LIGHTNING	0.8%	0.5%
ADVERSE ENVIRONMENT	0.2%	0.3%

Table 2: Number of Interruptions by Cause Code (Excluding MEDs) (Table 4)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	8	1	4	3	17	7
Adverse Weather	129	57	49	79	80	80
Defective Equipment	441	330	334	364	484	461
Foreign Interference	144	123	151	169	212	227
Human Element	19	24	23	38	31	24
Lightning	4	3	2	22	5	5
Loss of Supply	34	21	18	10	42	34
Scheduled Outage	143	102	137	142	907	1,416
Tree Contacts	81	48	70	104	120	124
Unknown/Other	135	135	224	145	233	199
Grand Total	**1,138**	**844**	**1,012**	**1,076**	**2,131**	**2,577**

Table 3: Number of Customer Interruptions by Cause Code (Excluding MEDs) (Table 5)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	988	5	2,164	249	8,786	229
Adverse Weather	100,462	84,803	48,318	108,474	56,744	101,381
Defective Equipment	308,064	279,474	308,633	354,985	359,936	260,459
Foreign Interference	103,812	94,716	165,199	150,885	136,878	142,256
Human Element	26,929	47,271	27,811	54,623	12,029	32,801
Lightning	1,738	4,346	273	33,840	4,151	4,771
Loss of Supply	263,344	162,433	153,684	68,259	187,464	141,510
Scheduled Outage	7,993	12,452	6,897	8,398	35,004	38,330
Tree Contacts	101,329	73,108	128,667	118,879	101,713	106,394
Unknown/Other	218,398	240,491	414,343	303,457	374,813	287,442
Grand Total	**1,133,057**	**999,099**	**1,255,989**	**1,202,049**	**1,277,518**	**1,115,573**

Table 4: Number of Customer Hours Interrupted by Cause Code (Excluding MEDs) (Table 6)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	1,664	9	116	420	9,353	563
Adverse Weather	131,115	57,672	30,890	76,673	42,846	70,779
Defective Equipment	268,452	231,449	281,347	276,297	265,983	197,717

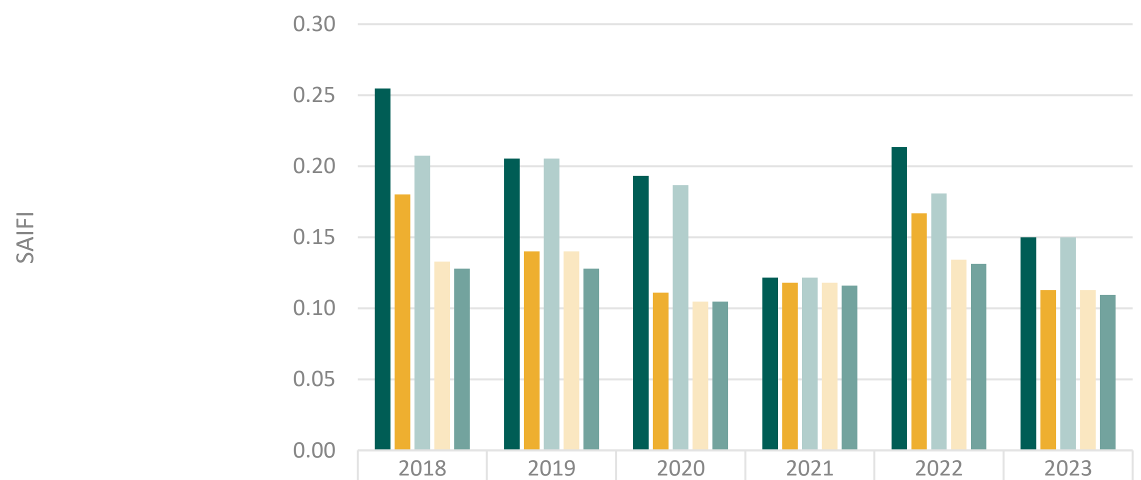
Cause Code	2018	2019	2020	2021	2022	2023
Foreign Interference	61,487	54,799	155,980	161,211	88,595	103,426
Human Element	6,837	32,542	21,656	27,607	15,633	12,023
Lightning	346	601	630	11,684	914	2,690
Loss of Supply	131,949	68,436	48,574	13,329	117,641	67,719
Scheduled Outage	22,465	34,377	6,770	17,662	91,633	110,968
Tree Contacts	99,505	116,665	125,859	146,037	79,471	81,096
Unknown/Other	27,880	31,812	75,791	38,041	48,000	42,759
Grand Total	**751,700**	**628,362**	**747,611**	**768,962**	**760,069**	**689,741**

QUESTION (B):

b) Does Toronto Hydro track reliability data separately for its Downtown and Horseshoe areas? If so, please provide a revised version of the data requested in part (a) broken down into the two areas.

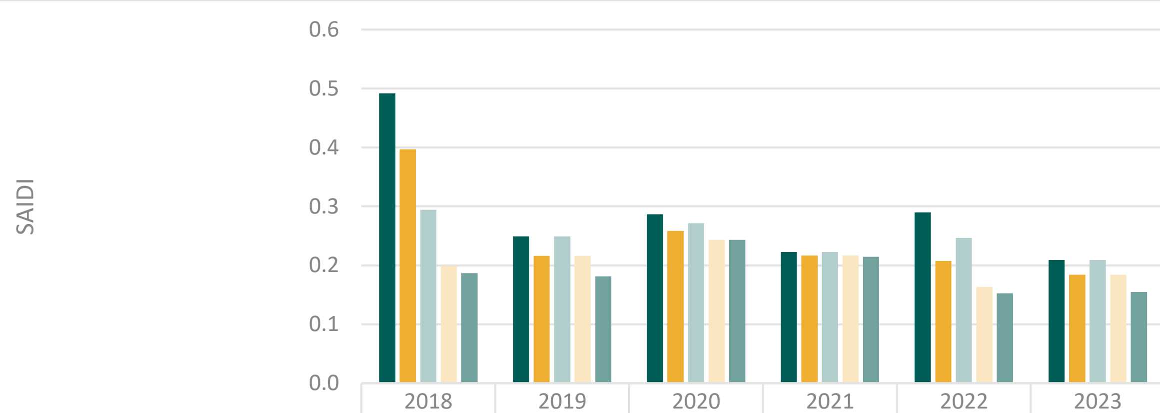
RESPONSE (B):

Please see Figures 13-36 and Tables 5-12 below for the broken-down contributions from the Horseshoe and Downtown Core.



	2018	2019	2020	2021	2022	2023
Total SAIFI	0.25	0.21	0.19	0.12	0.21	0.15
SAIFI Excluding LOS	0.18	0.14	0.11	0.12	0.17	0.11
SAIFI Excluding MED's	0.21	0.21	0.19	0.12	0.18	0.15
SAIFI Excluding MED's and LOS	0.13	0.14	0.10	0.12	0.13	0.11
SAIFI Excluding MED's, LOS and Scheduled Outages	0.13	0.13	0.10	0.12	0.13	0.11

Figure 13: System Level SAIFI (Downtown)



	2018	2019	2020	2021	2022	2023
Total SAIDI	0.49	0.25	0.29	0.22	0.29	0.21
SAIDI Excluding LOS	0.40	0.22	0.26	0.22	0.21	0.18
SAIDI Excluding MED's	0.29	0.25	0.27	0.22	0.25	0.21
SAIDI Excluding MED's and LOS	0.20	0.22	0.24	0.22	0.16	0.18
SAIDI Excluding MED's, LOS and Scheduled Outages	0.19	0.18	0.24	0.21	0.15	0.15

Figure 14: System Level SAIDI (Downtown)

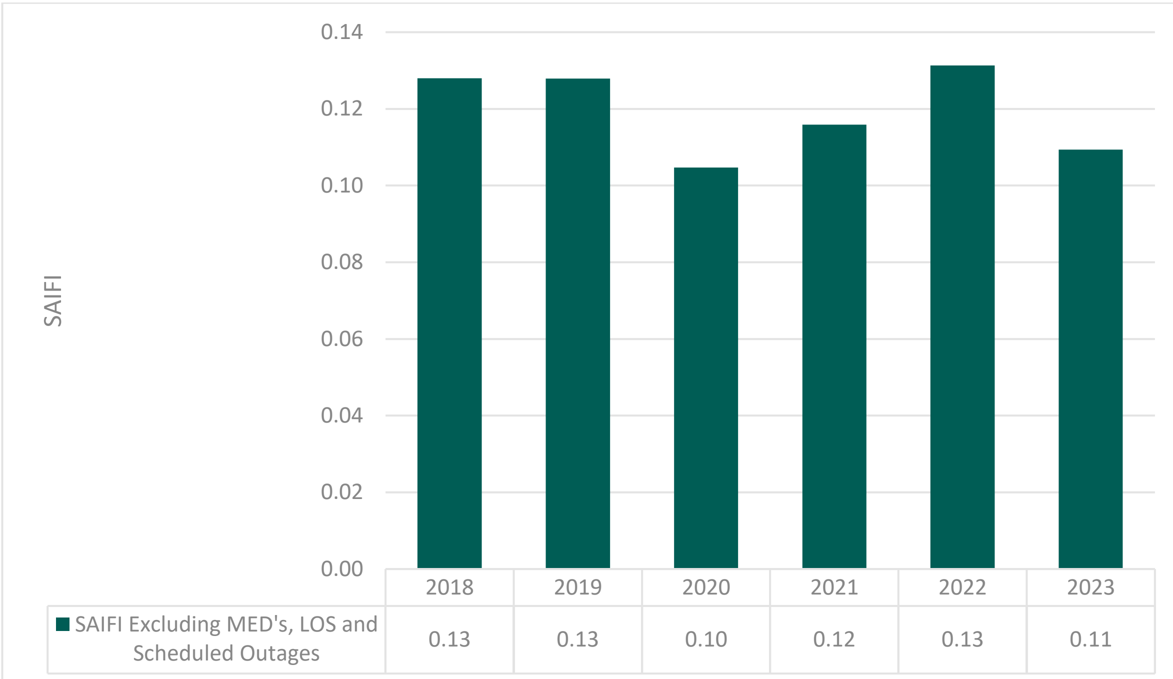


Figure 15: System SAIFI Excluding MEDs, Loss of Supply, and Scheduled Outages (Downtown)

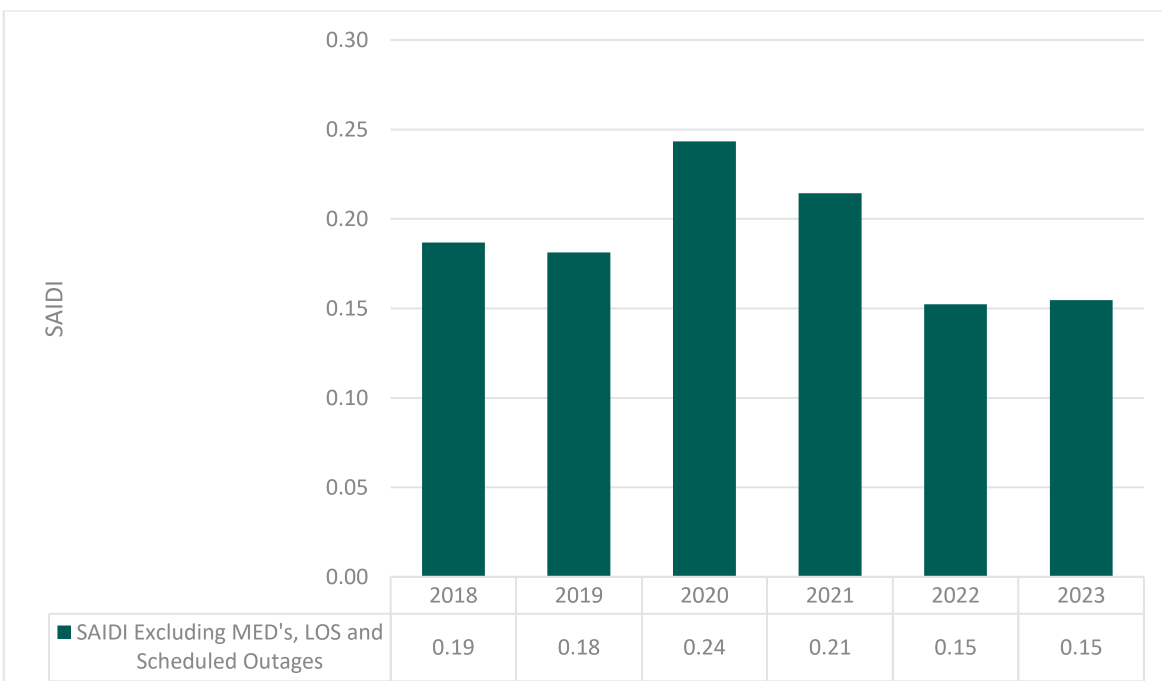
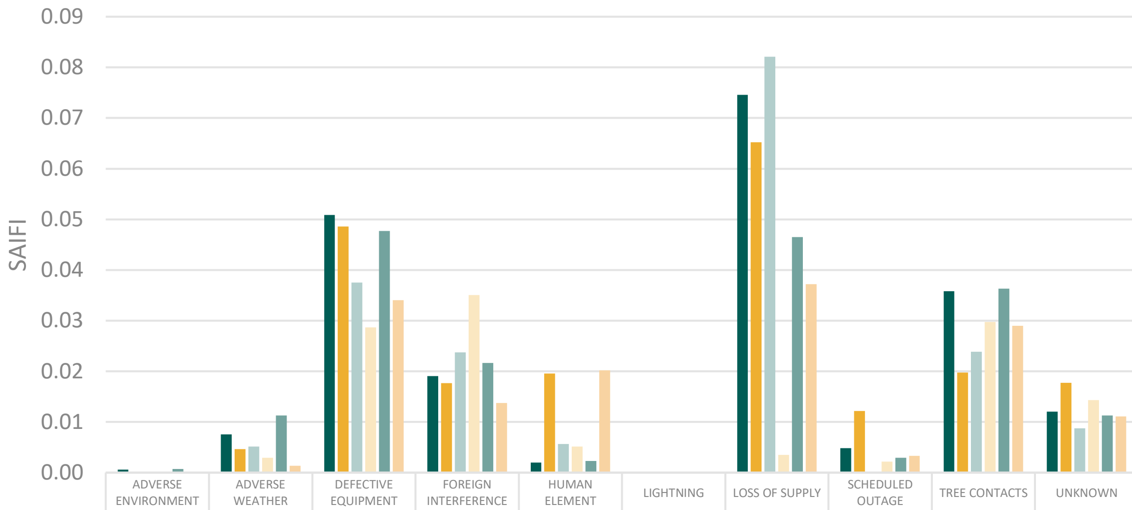
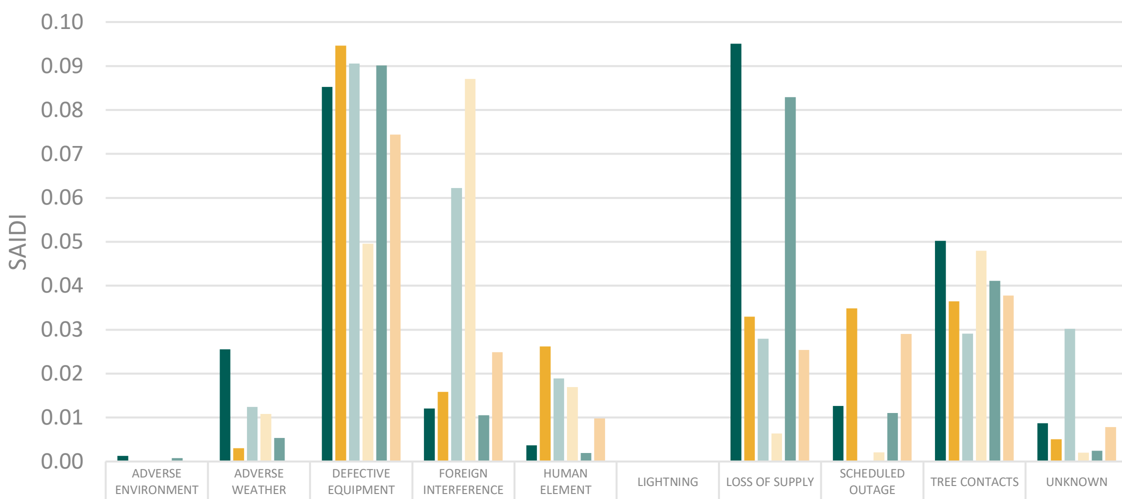


Figure 16: System SAIDI Excluding MEDs, Loss of Supply, and Scheduled Outages (Downtown)



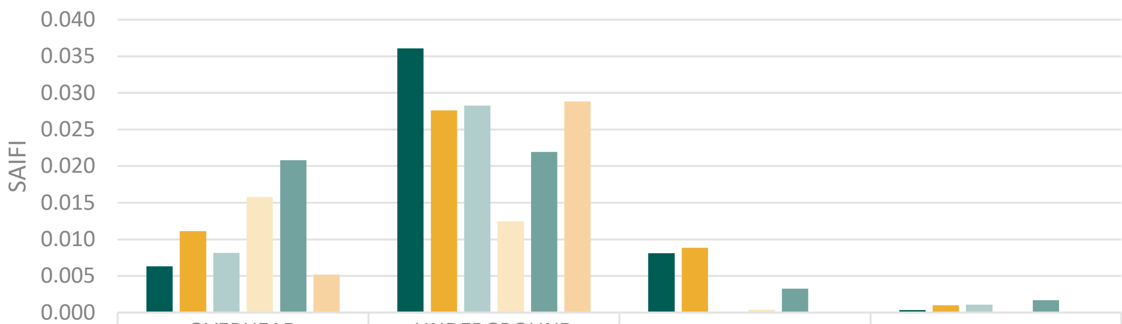
	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.01	0.05	0.02	0.00	0.00	0.07	0.00	0.04	0.01
2019	0.00	0.00	0.05	0.02	0.02	0.00	0.07	0.01	0.02	0.02
2020	0.00	0.01	0.04	0.02	0.01	0.00	0.08	0.00	0.02	0.01
2021	0.00	0.00	0.03	0.04	0.01	0.00	0.00	0.00	0.03	0.01
2022	0.00	0.01	0.05	0.02	0.00	0.00	0.05	0.00	0.04	0.01
2023	0.00	0.00	0.03	0.01	0.02	0.00	0.04	0.00	0.03	0.01

Figure 17: SAIFI Cause Code Breakdown (Excluding MEDs) (Downtown)



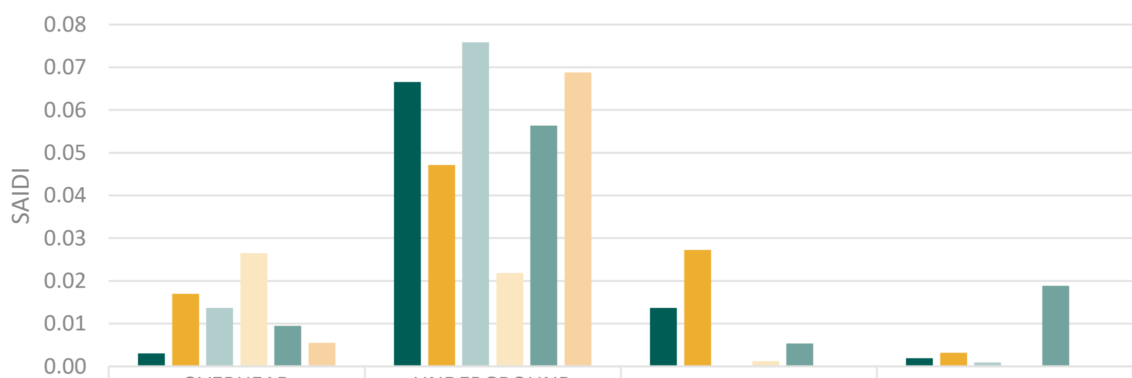
	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.03	0.09	0.01	0.00	0.00	0.10	0.01	0.05	0.01
2019	0.00	0.00	0.09	0.02	0.03	0.00	0.03	0.03	0.04	0.01
2020	0.00	0.01	0.09	0.06	0.02	0.00	0.03	0.00	0.03	0.03
2021	0.00	0.01	0.05	0.09	0.02	0.00	0.01	0.00	0.05	0.00
2022	0.00	0.01	0.09	0.01	0.00	0.00	0.08	0.01	0.04	0.00
2023	0.00	0.00	0.07	0.02	0.01	0.00	0.03	0.03	0.04	0.01

Figure 18: SAIDI Cause Code Breakdown (Excluding MEDs) (Downtown)



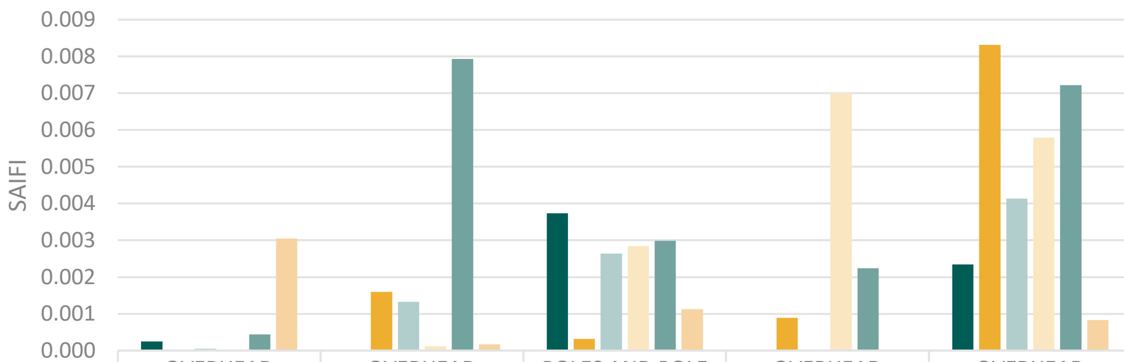
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.01	0.04	0.01	0.00
2019	0.01	0.03	0.01	0.00
2020	0.01	0.03	0.00	0.00
2021	0.02	0.01	0.00	0.00
2022	0.02	0.02	0.00	0.00
2023	0.01	0.03	0.00	0.00

Figure 19: Defective Equipment SAIFI (Excluding MEDs) (Downtown)



	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.00	0.07	0.01	0.00
2019	0.02	0.05	0.03	0.00
2020	0.01	0.08	0.00	0.00
2021	0.03	0.02	0.00	0.00
2022	0.01	0.06	0.01	0.02
2023	0.01	0.07	0.00	0.00

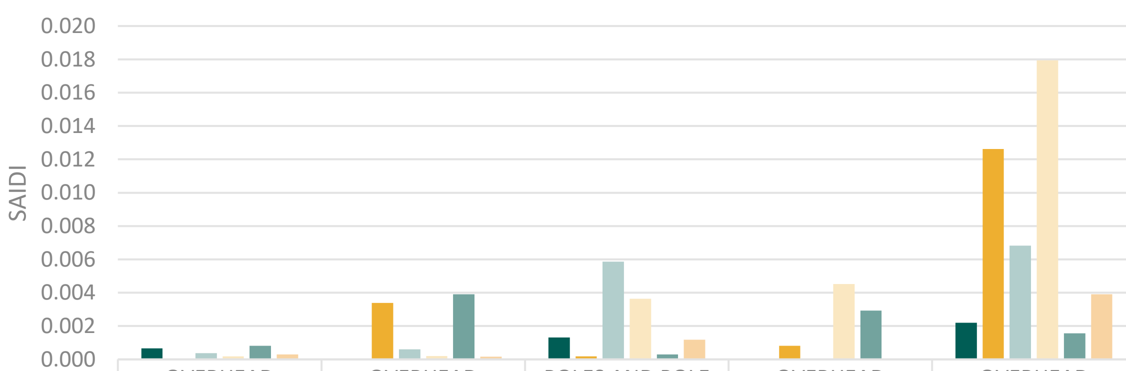
Figure 20: Defective Equipment SAIDI (Excluding MEDs) (Downtown)



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.01
2020	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.01	0.01
2022	0.00	0.01	0.00	0.00	0.01
2023	0.00	0.00	0.00	0.00	0.00

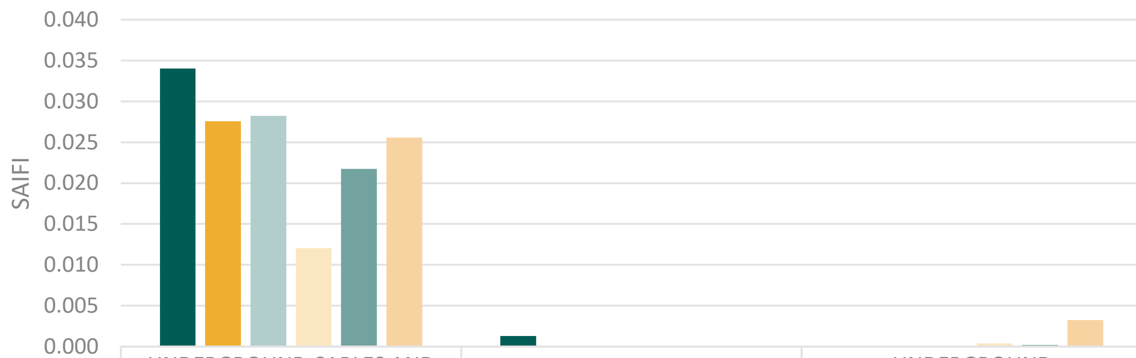
1 **Figure 21: Defective Equipment SAIFI – Overhead (Excluding MEDs) (Downtown)**

2



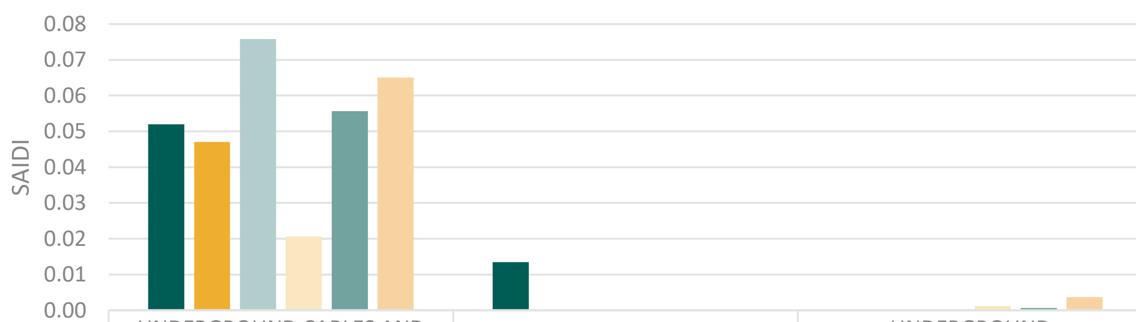
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.01
2020	0.00	0.00	0.01	0.00	0.01
2021	0.00	0.00	0.00	0.00	0.02
2022	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00

3 **Figure 22: Defective Equipment SAIDI – Overhead (Excluding MEDs) (Downtown)**



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.03	0.00	0.00
2019	0.03	0.00	0.00
2020	0.03	0.00	0.00
2021	0.01	0.00	0.00
2022	0.02	0.00	0.00
2023	0.03	0.00	0.00

Figure 23: Defective Equipment SAIFI – Underground (Excluding MEDs) (Downtown)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.05	0.01	0.00
2019	0.05	0.00	0.00
2020	0.08	0.00	0.00
2021	0.02	0.00	0.00
2022	0.06	0.00	0.00
2023	0.07	0.00	0.00

Figure 24: Defective Equipment SAIDI – Underground (Excluding MEDs) (Downtown)

Table 5: Five-Year (2019-2023) Average SAIFI and SAIDI Contribution by Cause Code (Excluding MEDs) (Downtown)

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
LOSS OF SUPPLY	27.8%	14.6%
DEFECTIVE EQUIPMENT	23.3%	33.3%
TREE CONTACTS	16.4%	16.1%
FOREIGN INTERFERENCE	13.2%	16.7%
UNKNOWN	7.5%	4.0%
HUMAN ELEMENT	6.3%	6.2%
ADVERSE WEATHER	3.0%	2.6%
SCHEDULED OUTAGE	2.4%	6.4%
ADVERSE ENVIRONMENT	0.1%	0.1%
LIGHTNING	0.0%	0.0%

Table 6: Number of Interruptions by Cause Code (Excluding MEDs) (Downtown)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	2	0	0	0	3	0
Adverse Weather	11	2	3	2	3	1
Defective Equipment	72	72	61	59	63	48
Foreign Interference	15	13	9	22	23	19
Human Element	3	4	2	8	12	5
Lightning	0	0	0	0	0	0
Loss of Supply	13	10	5	2	27	9
Scheduled Outage	8	8	0	6	9	5
Tree Contacts	20	10	8	13	16	19
Unknown/Other	16	20	10	13	18	20
Grand Total	160	139	98	125	174	126

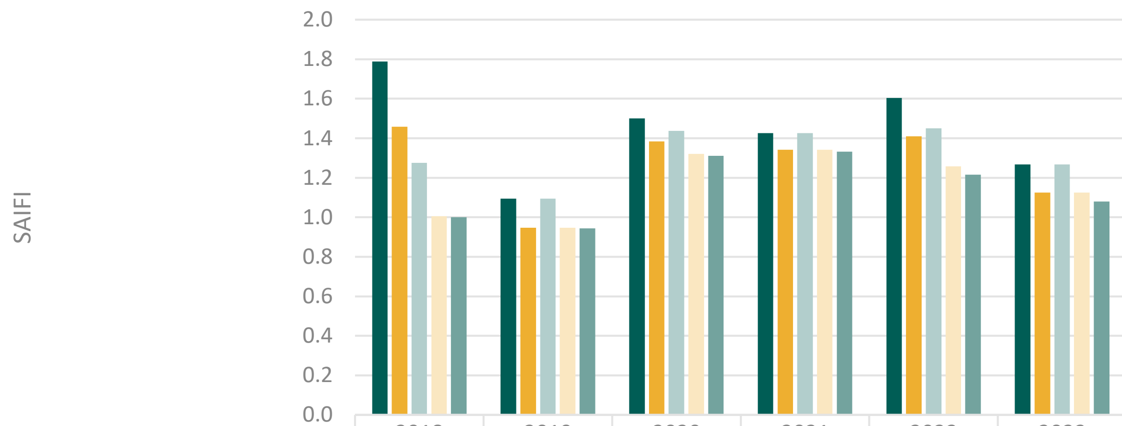
Table 7: Number of Customer Interruptions by Cause Code (Excluding MEDs) (Downtown)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	477	0	0	0	565	0
Adverse Weather	5,772	3,592	3,992	2,302	8,832	1,050
Defective Equipment	38,870	37,370	29,007	22,264	37,345	26,770

Cause Code	2018	2019	2020	2021	2022	2023
Foreign Interference	14,585	13,604	18,343	27,241	16,938	10,794
Human Element	1,528	14,996	4,386	4,029	1,819	15,888
Lightning	0	0	0	0	0	0
Loss of Supply	56,880	50,160	63,491	2,736	36,447	29,239
Scheduled Outage	3,684	9,385	0	1,700	2,313	2,628
Tree Contacts	27,332	15,165	18,439	23,119	28,425	22,816
Unknown/Other	9,196	13,651	6,784	11,143	8,858	8,744
Grand Total	**158,324**	**157,923**	**144,442**	**94,534**	**141,542**	**117929**

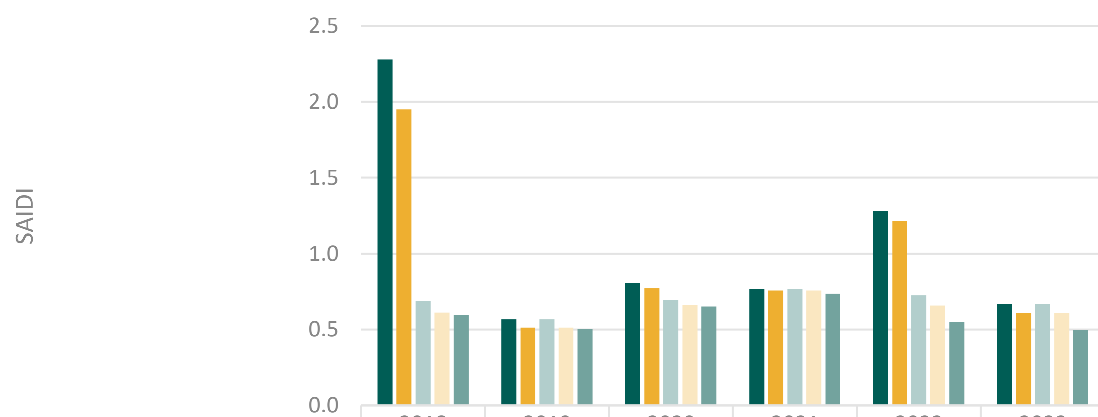
Table 8: Number of Customer Hours Interrupted by Cause Code (Excluding MEDs) (Downtown)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	1,002	0	0	0	606	0
Adverse Weather	19,498	2,337	9,610	8,472	4,172	53
Defective Equipment	65,126	72,811	69,970	38,564	70,574	58,538
Foreign Interference	9,196	12,193	48,025	67,561	8,260	19,555
Human Element	2,839	20,101	14,628	13,160	1,542	7,713
Lightning	0	0	0	0	0	0
Loss of Supply	72,494	25,330	21,587	4,949	64,867	19,921
Scheduled Outage	9,689	26,833	0	1,606	8,615	22,870
Tree Contacts	38,330	28,052	22,497	37,247	32,203	29,751
Unknown/Other	6,683	3,877	23,336	1,574	1,887	6,168
Grand Total	224,857	191,534	209,654	173,133	192,726	164568



	2018	2019	2020	2021	2022	2023
Total SAIFI	1.79	1.09	1.50	1.43	1.60	1.27
SAIFI Excluding LOS	1.46	0.95	1.38	1.34	1.41	1.13
SAIFI Excluding MED's	1.28	1.09	1.44	1.43	1.45	1.27
SAIFI Excluding MED's and LOS	1.01	0.95	1.32	1.34	1.26	1.13
SAIFI Excluding MED's, LOS and Scheduled Outages	1.00	0.94	1.31	1.33	1.22	1.08

Figure 25: System Level SAIFI (Horseshoe)



	2018	2019	2020	2021	2022	2023
Total SAIDI	2.28	0.57	0.81	0.77	1.28	0.67
SAIDI Excluding LOS	1.95	0.51	0.77	0.76	1.21	0.61
SAIDI Excluding MED's	0.69	0.57	0.70	0.77	0.72	0.67
SAIDI Excluding MED's and LOS	0.61	0.51	0.66	0.76	0.66	0.61
SAIDI Excluding MED's, LOS and Scheduled Outages	0.60	0.50	0.65	0.74	0.55	0.49

Figure 26: System Level SAIDI (Horseshoe)

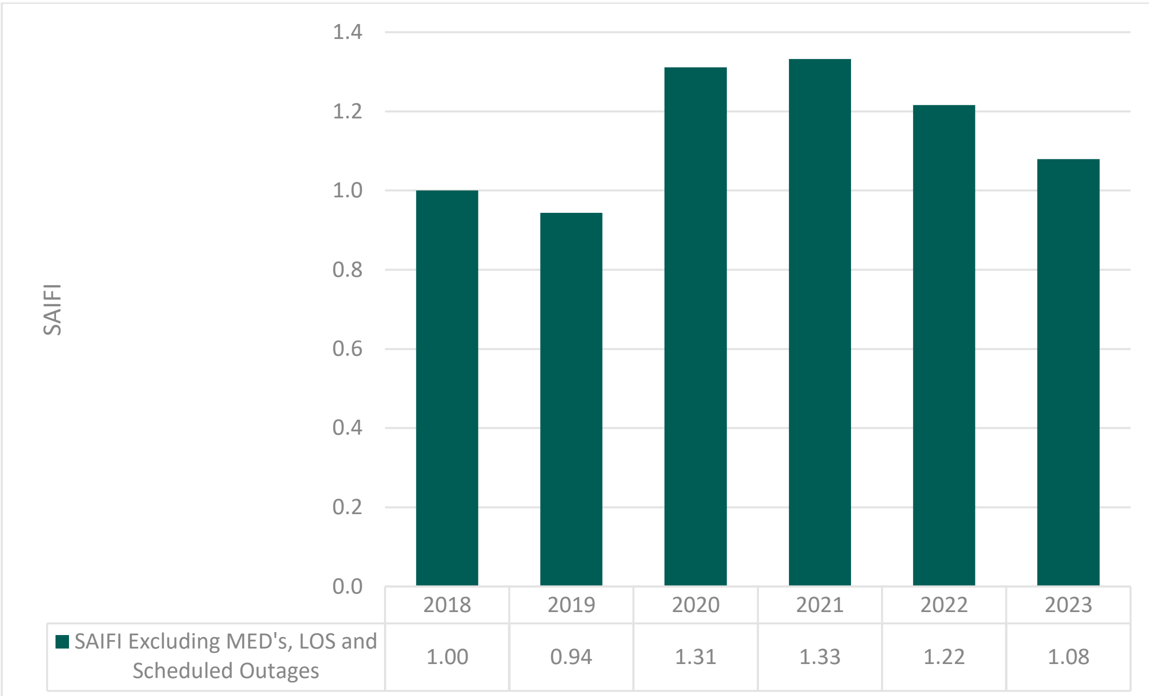


Figure 27: System SAIFI Excluding MEDs, Loss of Supply, and Scheduled Outages (Horseshoe)

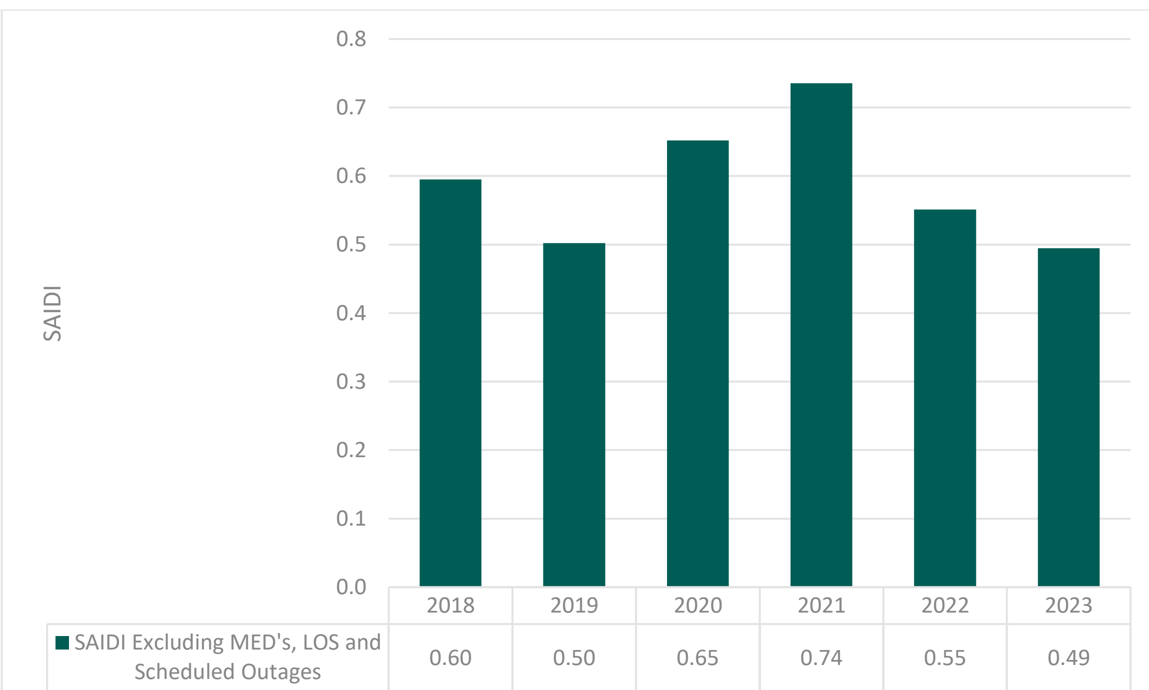
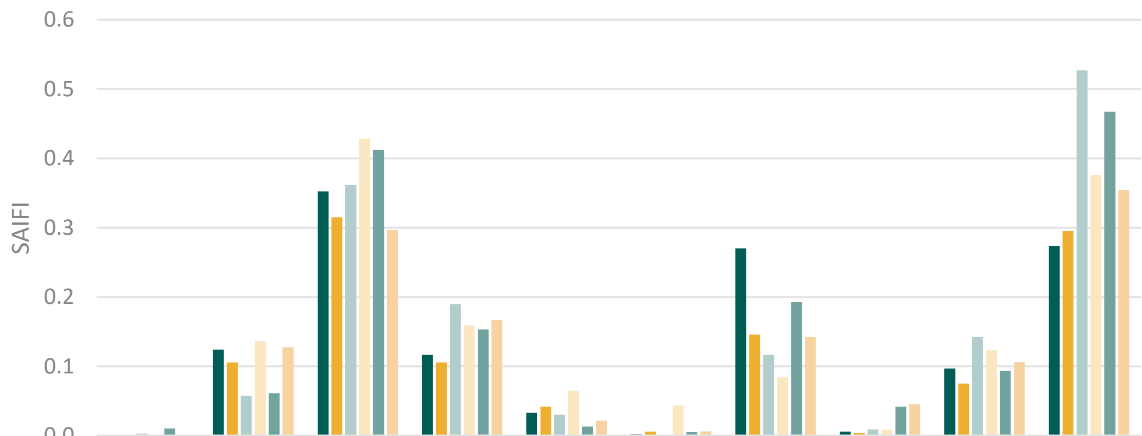
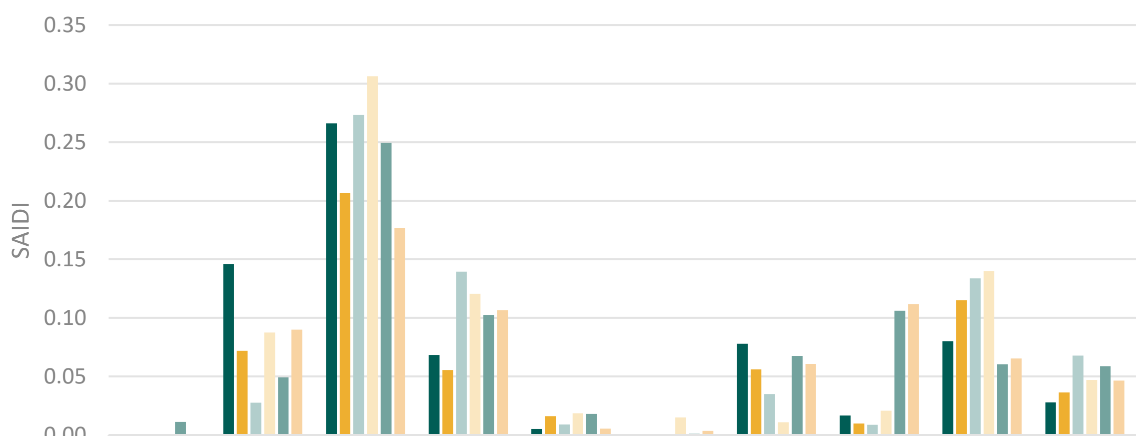


Figure 28: System SAIDI Excluding MEDs, Loss of Supply, and Scheduled Outages (Horseshoe)



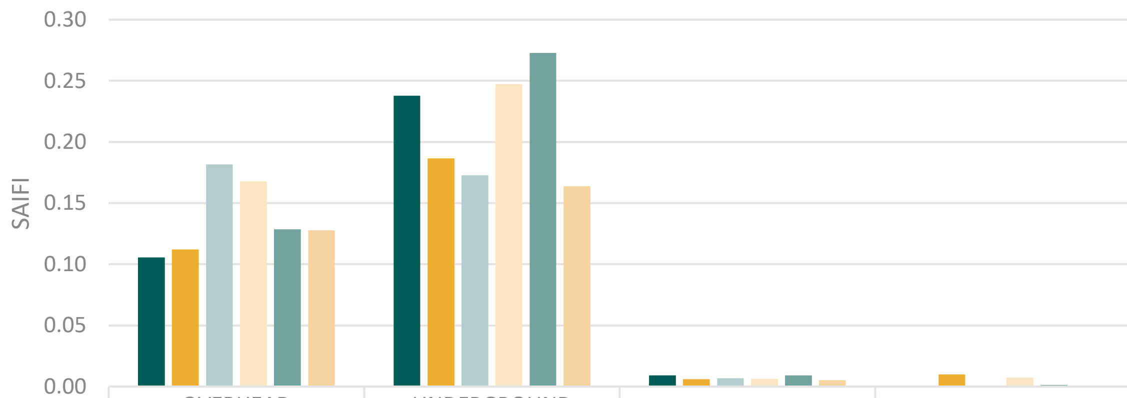
	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.12	0.35	0.12	0.03	0.00	0.27	0.01	0.10	0.27
2019	0.00	0.11	0.31	0.11	0.04	0.01	0.15	0.00	0.08	0.30
2020	0.00	0.06	0.36	0.19	0.03	0.00	0.12	0.01	0.14	0.53
2021	0.00	0.14	0.43	0.16	0.07	0.04	0.08	0.01	0.12	0.38
2022	0.01	0.06	0.41	0.15	0.01	0.01	0.19	0.04	0.09	0.47
2023	0.00	0.13	0.30	0.17	0.02	0.01	0.14	0.05	0.11	0.35

Figure 29: SAIFI Cause Code Breakdown (Excluding MEDs) (Horseshoe)



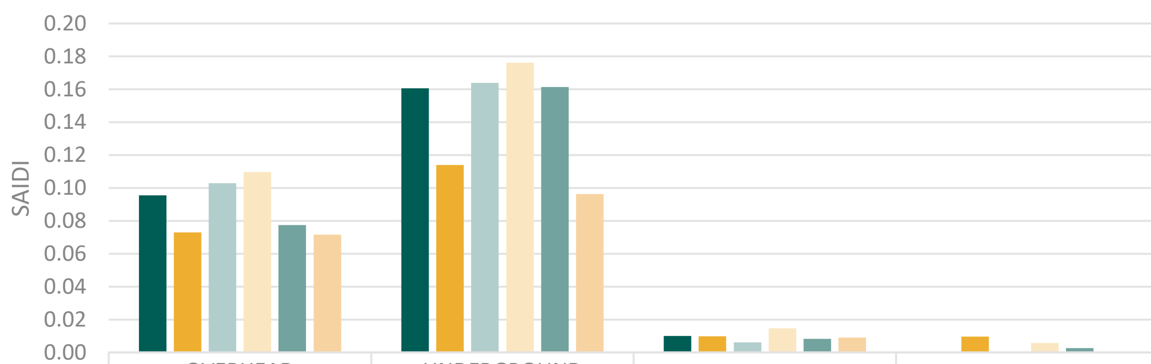
	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.15	0.27	0.07	0.01	0.00	0.08	0.02	0.08	0.03
2019	0.00	0.07	0.21	0.06	0.02	0.00	0.06	0.01	0.12	0.04
2020	0.00	0.03	0.27	0.14	0.01	0.00	0.03	0.01	0.13	0.07
2021	0.00	0.09	0.31	0.12	0.02	0.02	0.01	0.02	0.14	0.05
2022	0.01	0.05	0.25	0.10	0.02	0.00	0.07	0.11	0.06	0.06
2023	0.00	0.09	0.18	0.11	0.01	0.00	0.06	0.11	0.07	0.05

Figure 30: SAIDI Cause Code Breakdown (Excluding MEDs) (Horseshoe)



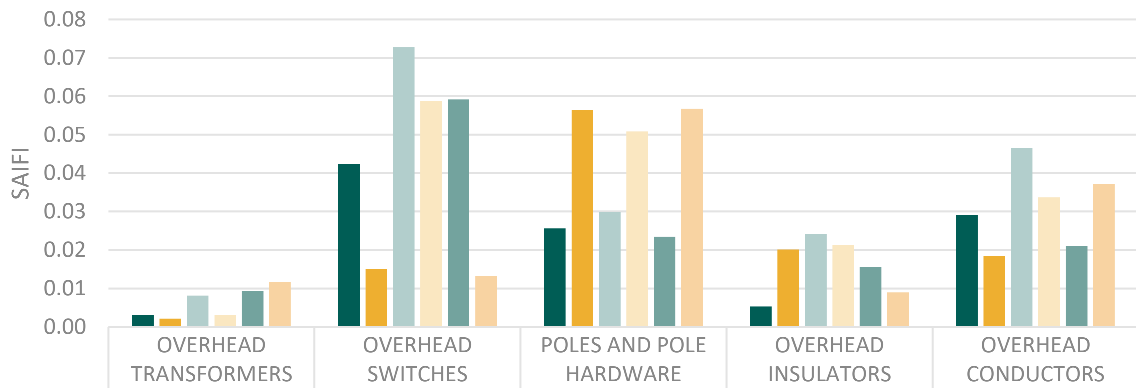
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.11	0.24	0.01	0.00
2019	0.11	0.19	0.01	0.01
2020	0.18	0.17	0.01	0.00
2021	0.17	0.25	0.01	0.01
2022	0.13	0.27	0.01	0.00
2023	0.13	0.16	0.01	0.00

Figure 31: Defective Equipment SAIFI (Excluding MEDs) (Horseshoe)



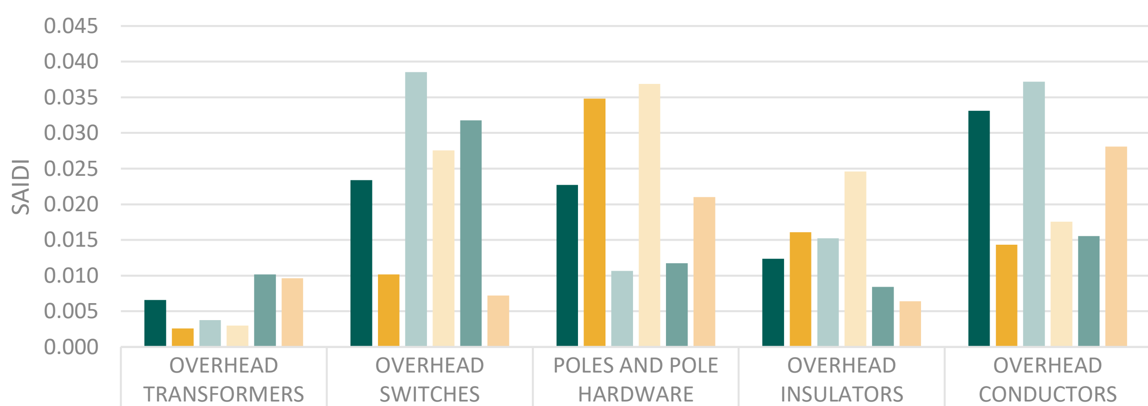
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.10	0.16	0.01	0.00
2019	0.07	0.11	0.01	0.01
2020	0.10	0.16	0.01	0.00
2021	0.11	0.18	0.01	0.01
2022	0.08	0.16	0.01	0.00
2023	0.07	0.10	0.01	0.00

Figure 32: Defective Equipment SAIDI (Excluding MEDs) (Horseshoe)



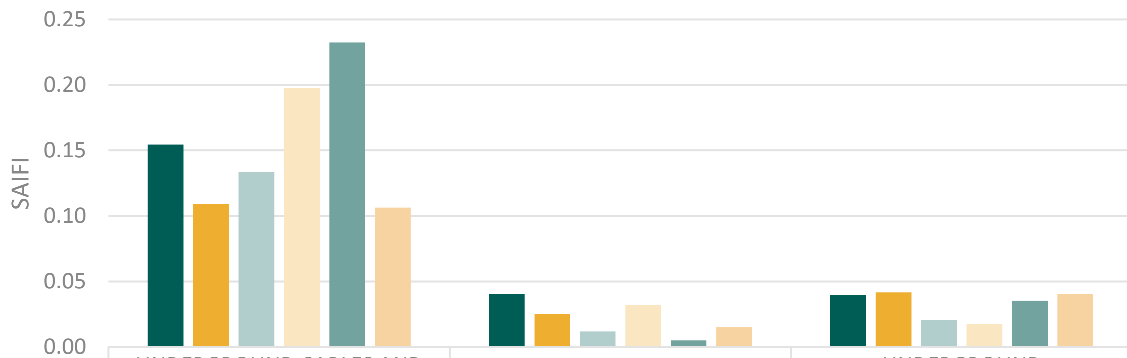
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.04	0.03	0.01	0.03
2019	0.00	0.02	0.06	0.02	0.02
2020	0.01	0.07	0.03	0.02	0.05
2021	0.00	0.06	0.05	0.02	0.03
2022	0.01	0.06	0.02	0.02	0.02
2023	0.01	0.01	0.06	0.01	0.04

Figure 33: Defective Equipment SAIFI – Overhead (Excluding MEDs) (Horseshoe)



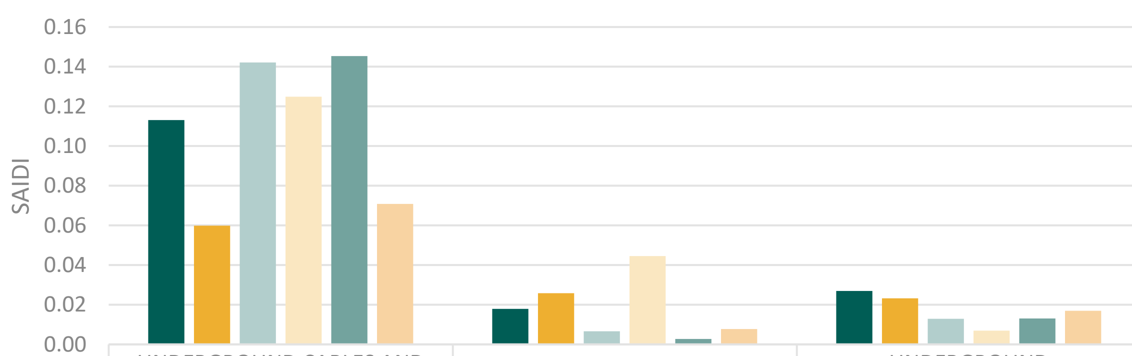
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.01	0.02	0.02	0.01	0.03
2019	0.00	0.01	0.03	0.02	0.01
2020	0.00	0.04	0.01	0.02	0.04
2021	0.00	0.03	0.04	0.02	0.02
2022	0.01	0.03	0.01	0.01	0.02
2023	0.01	0.01	0.02	0.01	0.03

Figure 34: Defective Equipment SAIDI – Overhead (Excluding MEDs) (Horseshoe)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.15	0.04	0.04
2019	0.11	0.03	0.04
2020	0.13	0.01	0.02
2021	0.20	0.03	0.02
2022	0.23	0.01	0.04
2023	0.11	0.01	0.04

Figure 35: Defective Equipment SAIFI – Underground (Excluding MEDs) (Horseshoe)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.11	0.02	0.03
2019	0.06	0.03	0.02
2020	0.14	0.01	0.01
2021	0.12	0.04	0.01
2022	0.15	0.00	0.01
2023	0.07	0.01	0.02

Figure 36: Defective Equipment SAIDI – Underground (Excluding MEDs) (Horseshoe)

Table 9: Five-Year (2019-2023) Average SAIFI and SAIDI Contribution by Cause Code (Excluding MEDs) (Horseshoe)

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
UNKNOWN	30.3%	7.5%
DEFECTIVE EQUIPMENT	27.2%	35.4%
FOREIGN INTERFERENCE	11.6%	15.3%
LOSS OF SUPPLY	10.2%	6.7%
TREE CONTACTS	8.1%	15.0%
ADVERSE WEATHER	7.3%	9.5%
HUMAN ELEMENT	2.6%	2.0%
SCHEDULED OUTAGE	1.6%	7.5%
LIGHTNING	0.9%	0.6%
ADVERSE ENVIRONMENT	0.2%	0.4%

Table 10: Number of Interruptions by Cause Code (Excluding MEDs) (Horseshoe)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	6	1	4	3	14	7
Adverse Weather	118	55	46	77	77	79
Defective Equipment	369	258	273	305	421	413
Foreign Interference	129	110	142	147	189	208
Human Element	16	20	21	30	19	19
Lightning	4	3	2	22	5	5
Loss of Supply	21	11	13	8	15	25
Scheduled Outage	135	94	137	136	898	1,411
Tree Contacts	61	38	62	91	104	105
Unknown/Other	119	115	214	132	215	179
Grand Total	978	705	914	951	1,957	2,451

Table 11: Number of Customer Interruptions by Cause Code (Excluding MEDs) (Horseshoe)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	511	5	2,164	249	8,221	229
Adverse Weather	94,690	81,211	44,326	106,172	47,912	100,331
Defective Equipment	269,194	242,104	279,626	332,721	322,591	233,689

Cause Code	2018	2019	2020	2021	2022	2023
Foreign Interference	89,227	81,112	146,856	123,644	119,940	131,462
Human Element	25,401	32,275	23,425	50,594	10,210	16,913
Lightning	1,738	4,346	273	33,840	4,151	4,771
Loss of Supply	206,464	112,273	90,193	65,523	151,017	112,271
Scheduled Outage	4,309	3,067	6,897	6,698	32,691	35,702
Tree Contacts	73,997	57,943	110,228	95,760	73,288	83,578
Unknown/Other	209,202	226,840	407,559	292,314	365,955	278,698
Grand Total	**974,733**	**841,176**	**1,111,547**	**1,107,515**	**1,135,976**	**997,644**

Table 12: Number of Customer Hours Interrupted by Cause Code (Excluding MEDs) (Horseshoe)

Cause Code	2018	2019	2020	2021	2022	2023
Adverse Environment	662	9	116	420	8,747	563
Adverse Weather	111,618	55,334	21,280	68,201	38,674	70,726
Defective Equipment	203,327	158,638	211,376	237,733	195,409	139,179
Foreign Interference	52,292	42,606	107,955	93,650	80,335	83,871
Human Element	3,998	12,441	7,027	14,447	14,091	4,310
Lightning	346	601	630	11,684	914	2,690
Loss of Supply	59,455	43,107	26,987	8,381	52,774	47,798
Scheduled Outage	12,776	7,544	6,770	16,057	83,017	88,099
Tree Contacts	61,175	88,613	103,362	108,789	47,269	51,345
Unknown/Other	21,197	27,935	52,454	36,468	46,113	36,591
Grand Total	**526,844**	**436,829**	**537,958**	**595,829**	**567,343**	**525,173.2**

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-36

Reference: Exhibit 2B, Section D1, Page 14

Please provide a list of assets that Toronto Hydro has and does not have condition-based models. Please provide the total capital spending on assets that does and does not have condition-based models.

RESPONSE:

Please see Table 1 below for the list of Toronto Hydro's major system assets and whether a condition-based model exists.

Table 1: Major System Assets and Presence of Condition-Based Model

Major Asset Class	Conditional-based Model Present (Y/N/Partial)
OH Conductor-Primary	N
OH Conductor-Secondary	N
OH Switches	Partial
OH - Transformer	N
Wood Poles	Y
Concrete Poles	N
UG Primary Cable	N
UG Secondary Cable	N
UG Duct Bank	N
UG Switches	Y
UG Transformers	Y
Network Protector	Y
Network Transformer	Y
Cable Chamber	Y
Station Power Transformers	Y
Circuit Breakers	Y

Major Asset Class	Conditional-based Model Present (Y/N/Partial)
Substation Switchgear	N
UG Vaults	Y
Meters	N

Based on the above asset classes, the total capital spending on asset types that have a condition-based model is approximately 37%.

Underground Primary Cable, Underground Duct Banks and Meters are the three largest contributors to the total spending on assets that do not have a condition model, amounting to approximately 42% of total expenditures. Cables and ducts are buried in the earth and generally not conducive to inspection.[1] Please refer to 2B-Staff-144 regarding condition for Meters.

[1] The exception is cable testing. However, given the cost and intrusive nature of cable testing, it can only be applied to a very small population of high priority cables each year.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-37

Reference: Exhibit 2B, Section D1, Page 21

Please explain how senior management tracks progress on execution of its overall capital plan? For example, is there weekly or monthly reporting on capital plan execution and progress? If so, please provide a copy of the most recent version of all reporting materials.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-AMPCO-29 parts (b) and (c).

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-38

Reference: **Exhibit 2B, Section D1, Page 22**
Exhibit 2A, Tab 4, Schedule 1

Please explain when corrective or emergency maintenance activities/spending are capitalized.

RESPONSE:

Corrective and maintenance activities/spending are typically capitalized when the repair of a major asset is determined to be insufficient and a replacement is required. Please refer to Toronto Hydro's Capitalization Policy filed in Exhibit 2A, Tab 4, Schedule 1 for more details.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-39

Reference: Exhibit 2B, Section D1, Page 26

Please provide a copy of the three most recent executive performance reports.

RESPONSE:

Please see 2B-AMPCO-29 part (c).

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-40

References: Exhibit 2B, Section D3, Page 13

Has Toronto Hydro undertaken any assessments of how different levels of sustainment and stewardship category expenditures impacts operations and maintenance expenditures? If so, please provide details.

RESPONSE:

Toronto Hydro has not undertaken any specific assessment of how different levels of sustainment and stewardship category expenditures impacts operations and maintenance ("System O&M") expenditures. Generally, the interrelationships between Sustainment and Stewardship expenditures are complex and nuanced in nature. Capital expenditures that are focused on like-for-like replacements are not expected to have a material impact on system maintenance costs because a significant portion of Toronto Hydro's maintenance programs are cyclical inspections to meet requirements set forward by the Distribution System Code. Renewal of assets may help reduce Corrective maintenance if done at a high enough pace, but a younger asset base that is more conducive to repairs rather than replacement may also increase corrective expenditures. The elimination of substandard equipment helps reduce maintenance requirements, but introduction of new asset technologies may increase maintenance requirements. Toronto Hydro routinely considers these and other interdependencies between capital expenditures and System O&M as detailed in Exhibit 2B, Section E4.1.6.1.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-41

Reference: Exhibit 2B, Section D3, p.35-37

Please confirm that while Toronto Hydro is in the process of implementing environmental, safety and financial consequences of failure into its risk assessment process, it has not done so yet for the purposes of assessing the impact of the investments included in this application.

RESPONSE:

Toronto Hydro confirms that it is in the process of implementing environmental, safety, and financial consequences of failure into its fully quantified value framework models to support risk-based project valuation and portfolio optimization within its Engineering Asset Investment Planning platform (further discussed in Exhibit 2B, Section D1 at page 14). Toronto Hydro is on track to complete this significant multi-year analytics project in advance of its next major capital planning cycle in 2025.

Please refer to Exhibit 2B, Section D3 for a discussion of various risk factors in Toronto Hydro's long-term planning process and how they have been reflected in the utility's 2025-2029 Distribution System Plan. Further details on risk and planning can be found in the various detailed investment program narratives in Exhibit 2B, Sections E5-E7.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-42

Reference: Exhibit 2B, Section D3, Page 39

QUESTION (A):

With respect to Toronto Hydro's reliability projections:

a) Please provide a copy of the detailed explanation of the methodology, including all assumptions, regarding Toronto Hydro's reliability projections.

RESPONSE (A):

Please find below a general overview, along with a more detailed explanation of the methodology, including relevant assumptions regarding Toronto Hydro's reliability projections.

<u>General Overview of Reliability Projection ('RP') Methodology</u>

As outlined in the evidence (Exhibit 1B, Tab 3, Schedule 1, Pg. 9 and Exhibit 2B, Section D3, Pg. 39), the projections in Figures 1 and Figure 2 (Exhibit 1B, Tab 3, Schedule 1, Pg. 10 and 17) are informed by the utility's reliability projection methodology, which is built up from projected performance across various cause codes. Toronto Hydro modeled Defective Equipment outages based on asset demographics and included the expected benefits of the utility's 2025-2029 planned sustainment investments. It also included projections for expected benefits of the reliability-related Grid Modernization investments. The utility assumed a historical five-year average for other cause codes (e.g. tree contacts).

The methodology models Defective Equipment outages by projecting failures and outage impacts at an asset class level based on:

1. asset demographics data and associated failure projections;
2. historical reliability performance; and
3. planned program investments.

Detailed Overview of RP Methodology

Toronto Hydro produces the Reliability Projection ('RP') by calculating an expected performance of individual reliability cause codes. The RP includes a detailed projection of the Defective Equipment cause code at an asset class level, a historical five-year average for other cause codes (e.g., Tree Contacts), and a projection of Grid Modernization investments, specifically the reliability benefits of new SCADA switches and mid-line reclosers (refer to Contingency Enhancement segment under Exhibit 2B, Section E7.1). These investments are expected to materially drive reliability performance, including SAIDI (Excluding Loss of Supply, Major Events, and Scheduled Outages) and SAIFI (Defective Equipment) performance over the 2025-2029 rate period.

Table 1, below, provides a breakdown of the Major Cause Codes considered in the RP along with a brief description of the forecast method applied.

Table 1: Breakdown of the Major Cause Codes

Major Cause Code	Forecasting Method for 2025-2029
Adverse Environment	5-Year Average (2018-2022)
Adverse Weather	5-Year Average (2018-2022)
Defective Equipment	Failure Projection Methodology
Foreign Interference	5-Year Average (2018-2022)
Human Element	5-Year Average (2018-2022)
Lightning	5-Year Average (2018-2022)
Tree Contacts	5-Year Average (2018-2022)
Unknown	5-Year Average (2018-2022)

In developing its approach, Toronto Hydro assessed climate related impacts on SAIDI performance, using observation data from Toronto Pearson International Airport of max wind gusts greater than 70 Km/h and total precipitation above 2mm, from 2014 to 2022. Although yielding strong correlation ($R^2 > 0.7$) using a 2nd degree polynomial fit, due to very low granularity in forecasted wind speeds (Exhibit 2B, Section D2, Appendix A, Pg. 11-12), Toronto Hydro excluded such factors from its forecasting methods for 2025-2029. The limited information available on changes to climate parameters, that typically take place over long time horizons, pose a challenge to integrating such information into relatively shorter-term reliability projections.

The impacts of Grid Modernization investments were then integrated into the resultant output on outage frequency and duration as a percentage improvement (further explanation provided below).

Defective Equipment Projections

Defective Equipment cause code projections cover all major asset classes contributing to reliability performance. The RP calculates the expected number of outages per major asset class based on asset demographics, failure curves, failure modes, and replacement volumes. For assets with limited historical data and/or those deemed to pose a low risk to system-wide reliability metrics such as SAIDI and SAIFI (i.e. Network, Secondary Distribution, etc.), a five-year historical average was utilized. The RP multiplies the asset demographics for each asset class by failure curves, resulting in asset failure counts in a particular year. The projected asset failures are translated into system outages based on the established outage failure mode as a percentage of total failure and right-sized with Toronto Hydro's historical outage experience for that asset class. Reactive failures and proactive replacement volumes (as submitted under prominent System Renewal programs), are used to establish year-over-year changes to the underlying asset population.

Outage durations and frequencies are estimated by converting the number of system outages into SAIDI and SAIFI contributions. This involves using a five-year average (2018-2022) to analyze how each asset class has affected system reliability (SAIDI/SAIFI) in recent years.

The inputs for each asset class include:

- Asset class age demographics. A snapshot of asset demographics is specified for the initial year of the analysis. This entails quantifying the number of asset units or km of asset by age.
- Asset additions. An asset addition plan which specifies a schedule for continual growth of the asset class with new assets.

- Asset replacements. Asset replacement volumes for an asset class for the 2023-2029 period, based on the 2025-2029 Distribution System Plan.
- Asset failure curves each major asset class.

The following key assumption are made:

- Asset additions are estimated based on historical averages and adjusted for future plans if applicable.
- Asset replacement profiles sampled from project data are leveraged to inform a distribution of annual replacements.
- An outage failure mode for the asset class is calibrated to the ratio of the average historic system outages by total expected asset failures.

Disclaimer on Interpreting Projected Performance:

- The RP model cannot predict Force Majeure events, unforeseeable circumstances, or events beyond the utility's control such as Major Events.[1]

Disclaimer on Model Outputs and Interim Calculations:

- The aim of the Defective Equipment projection methodology is to establish a reasonable, quantifiable link between investments in System Renewal programs and their impact on SAIDI and SAIFI outcomes. This model constructs this relationship through foundational calculations, such as the anticipated number of asset failures, which are essential for establishing the base framework of this investment-outcome relationship. It is crucial to understand that these internal calculations serve as initial steps in the modeling process, setting the stage for the relationship between investment and reliability metrics; the outputs of the internal calculations are not appropriate for direct use or interpretation as model outputs themselves. The true strength of the model is realized through subsequent

[1] "Major Event" is defined as an event that is beyond the control of the distributor and is: a) unforeseeable; b) unpredictable; c) unpreventable; or unavoidable. "Beyond the control of the distributor" means events that include, but are not limited to, force majeure events and Loss of Supply events.
Ontario Energy Board. Electricity Reporting and Record Keeping Requirements (March 8, 2023).

calibration phases, where it is applied to historical asset demographics to verify its accuracy in reproducing historical SAIDI and SAIFI figures. Should there be discrepancies, the model undergoes extensive calibration, as necessary, to align with historical data. This iterative process ensures that the model not only predicts future performance based on investment but also aligns with proven historical outcomes, thereby providing a reliable tool for strategic planning and decision-making with respect to SAIDI and SAIFI metrics.

Anticipated Grid Modernization Improvements

In addition to leveraging the RP for forecasting expected performance of individual reliability cause codes, Toronto Hydro evaluated reliability improvements expected from Grid Modernization initiatives, particularly ones established by the System Enhancements program under the Contingency Enhancement segment. Under the Contingency Enhancement segment, reliability improvements were evaluated for the installation of SCADA switches, as well as the installation of mid-feeder reclosers.

The quantification was performed using historical interruption data from Toronto Hydro's Interruption Tracking Information System ("ITIS"). Feeder level outages were considered with MEDs, Loss of Supply, and Scheduled Outages excluded. Additional steps were taken to exclude for cases that would not result in a Contingency Enhancement benefit. This includes removing outages under a hold-off condition, and situations where SCADA switching would be proven ineffective at improving outage duration, including significant storms and bus level outages below the MED threshold.

1. *Mid-Recloser Installations*

To evaluate the recloser reliability benefits, a theoretical analysis was performed using S&C's technical paper on *Improving Medium-Voltage Main-Feeder Reliability by Increasing Fault-Sectionalizing*[2]. As part of the technical paper, S&C outlines the theoretical reliability improvements

[2] S&C Electric Company. Improving Medium-Voltage Main-Feeder Reliability by Increasing Fault-Sectionalizing. https://www.sandc.com/globalassets/sac-electric/documents/public---documents/sales-manual-library---external-view/technical-paper-766-t112.pdf?dt=638348867590192672

based on the number of feeder segments utilized for fault-sectionalizing. This scenario is based on an unsegmented radial feeder with uniform fault and customer distribution and fault-repair times.

Using the planned Contingency Enhancements volumes for recloser installations from 2023 to 2029, the projected benefits for 1 recloser per feeder (2 feeder segments) was produced based on an average SAIFI and SAIDI per feeder in the horseshoe region (excluding 4 kV). It was assumed the benefits from the program would be reflected in the year following the recloser installation. Operational factors which would limit reclosing capabilities were considered, such as outages that occurred under a Hold Off condition (i.e., manual intervention would be required by the power system operator for restoration under such occurrences).

In order to account for inefficiencies, an efficiency factor was added to adjust the overall improvements from the theoretical maximum. There are a few factors that may lead to inefficiencies including uneven distributions of faults across the region, uneven distribution of faults on a feeder, and uneven distribution of customers along a feeder. This was evident from Toronto Hydro's own experience based on a pilot recloser installation (ORC0003) on 502-M29 feeder, located half-way along the feeder trunk. Over the 2-year pilot period, ORC0003 operated 25% of the time when interruptions occurred on the feeder trunk (i.e., at 50% efficiency). All else being equal, ORC0003 should have theoretically operated 50% of the time. Given this result, limited operational experience with mid-line reclosers, and the system inefficiencies stated above, Toronto Hydro elected to use a conservative 30% efficiency factor to forecast the benefits from the installation of mid-line reclosers for purposes of reliability projections.

2. SCADA Switch Installations

SCADA switch installations improve reliability at the feeder level by minimizing the duration of outages. SCADA switches, operated remotely by a power system controller, lead to a reduction in SAIDI. However, they do not reduce SAIFI without Distribution Automation ('DA'), i.e., self-healing capability. DA was not considered in this analysis, since the technology is only expected to be operational beginning in 2030. As such this analysis considered improvements to SAIDI only. This quantification was developed by observing the Customer Minutes Out ('CMO') reduction before and after a specific sectionalizer and tie count were installed on a feeder (e.g., 0 sectionalizers, 0 ties on feeder vs. 1 sectionalizer, 1 tie on a feeder).

Based on this analysis, leveraging asset information from Toronto Hydro's GIS, an installation benefit curve was derived to quantify the estimated benefits for any given feeder that are expected to increase from their baseline count of SCADA switches. The SCADA switch installation benefit curve was then applied to the planned volume anticipated for specific feeders over the 2025-2029 rate period.

The anticipated Grid Modernization improvements factored into the reliability projections would be reflective of the combined benefits of mid-line recloser and SCADA-switch installations.

The aggregation of these cause code level projections produces the final system level Outage Duration and Outage Frequency reliability projections, as presented in Exhibit 1B, Tab 3, Schedule 1, Pg. 10 and 17.

QUESTION (B):

b) Please provide a full copy of the reliability projection model.

RESPONSE (B):

The RP methodology is a model developed in Alteryx. The model relies on direct integration with various Toronto Hydro databases, and as such Toronto Hydro is unable to provide a full copy. For a visual depiction of the model for an asset class (in this case Wood Poles), please see Appendix A to this response.

QUESTION (C):

c) Please provide a forecast of Toronto Hydro's reliability performance based on the expenditures laid out in the application.

RESPONSE (C):

Toronto Hydro filed its original projections for reliability performance for Outage Duration and Outage Frequency in Exhibit 1B, Tab 3, Schedule 1, (Pg. 8 to 21).

In the process of preparing various interrogatory responses, Toronto Hydro identified corrections associated with the unit measure for population and replacement volume inputs used within the Reliability Projection ('RP') Methodology for underground cables (i.e. inconsistent use of conductor length vs. circuit length). Additionally, the pacing of overhead transformer replacements for the years 2025-2029 was updated, consistent with the correction provided under Integratory 2B-PWU-15. The updated Figures 1 and 2 below (originally filed under Exhibit 1B, Tab 3, Schedule 1, Pg. 10 & 17) are corrected accordingly, resulting in minor improvements to projected five-year SAIDI and SAIFI results as of 2029.

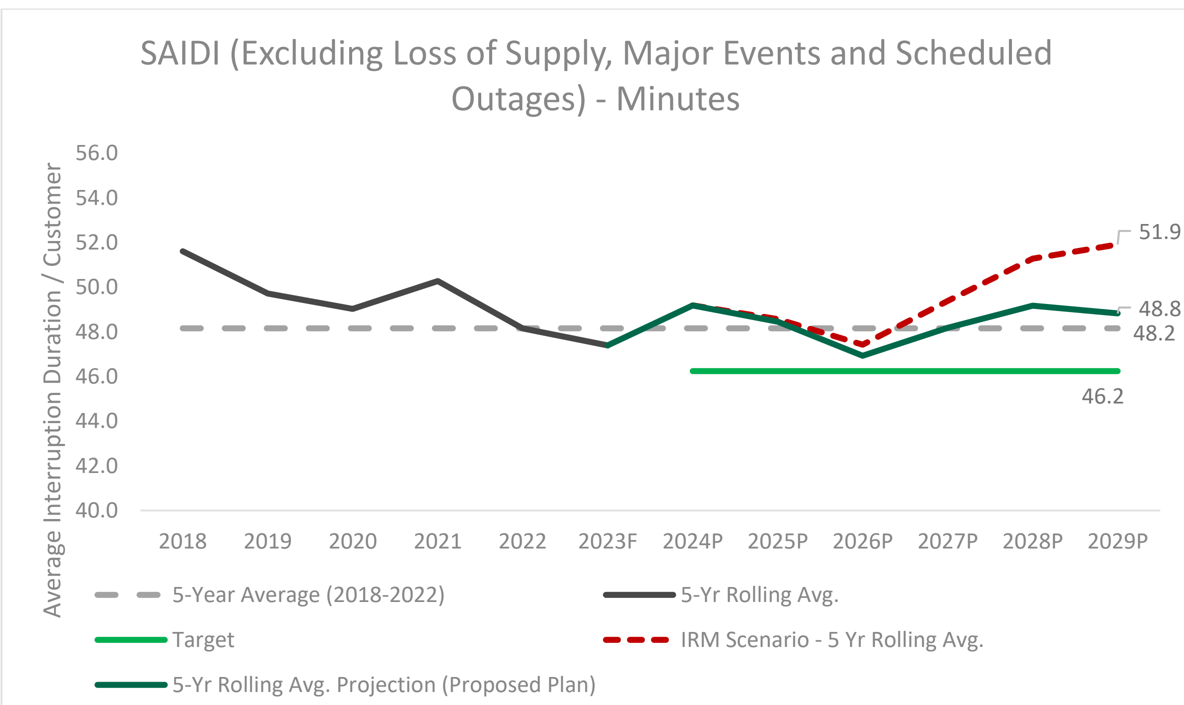
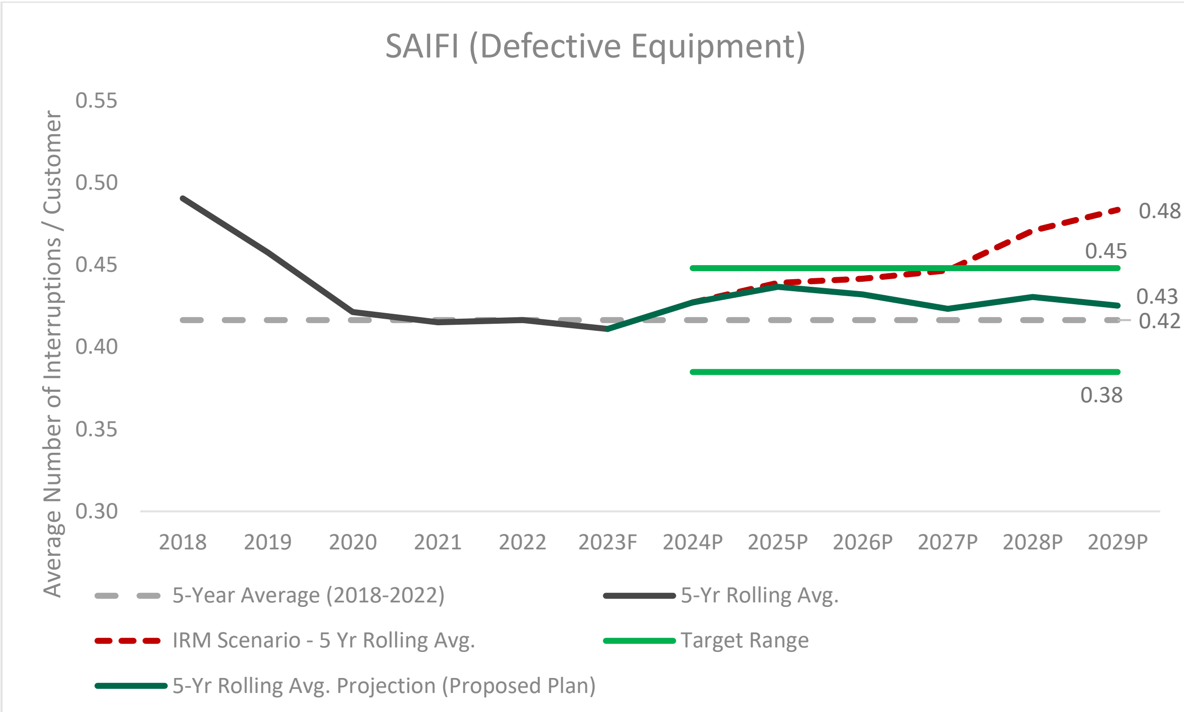


Figure 1: Historical and Projected SAIDI (excluding LoS, MEDs and scheduled outages)



1 **Figure 2: Historical and Projected SAIFI (Defective Equipment)**

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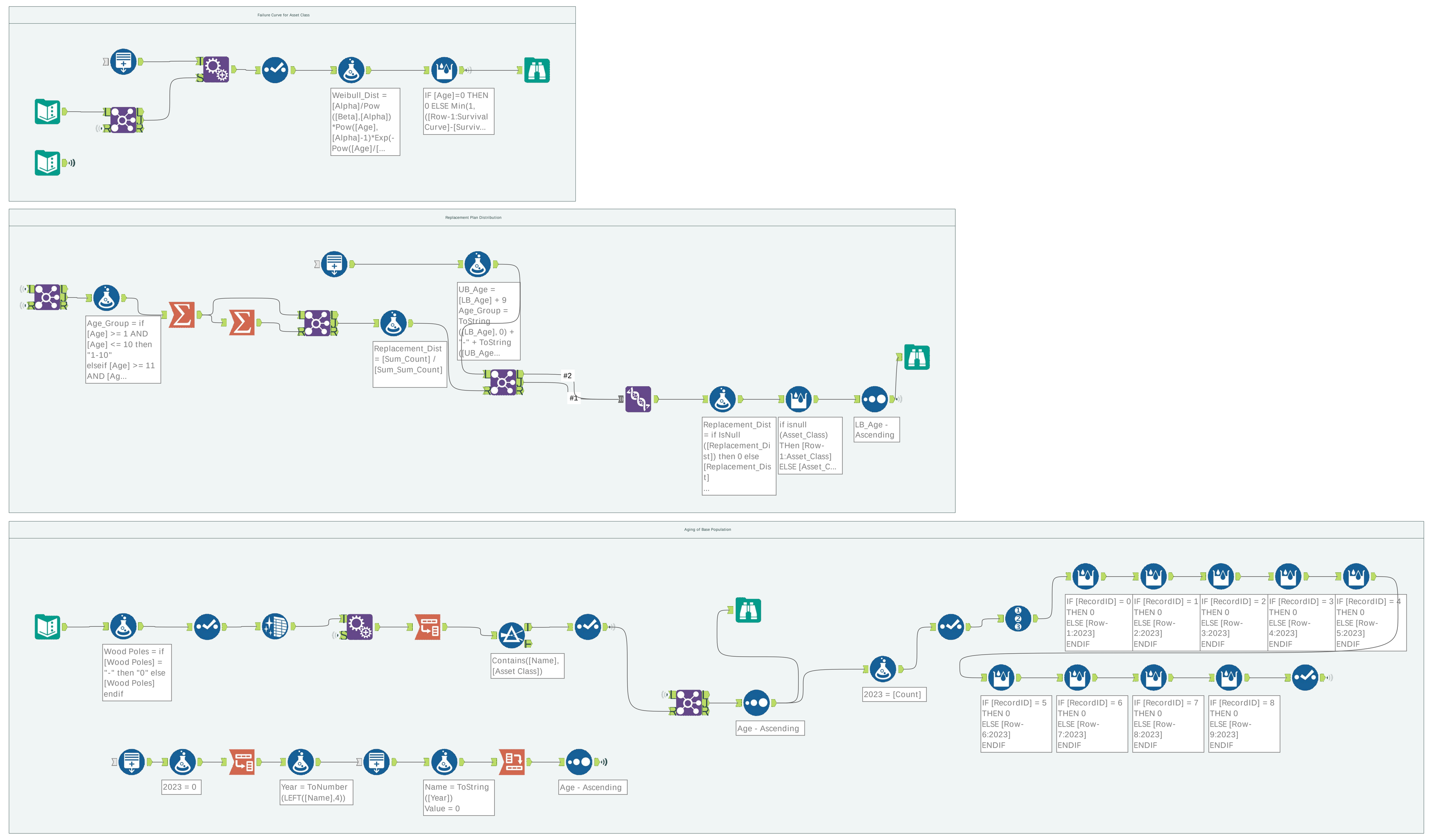
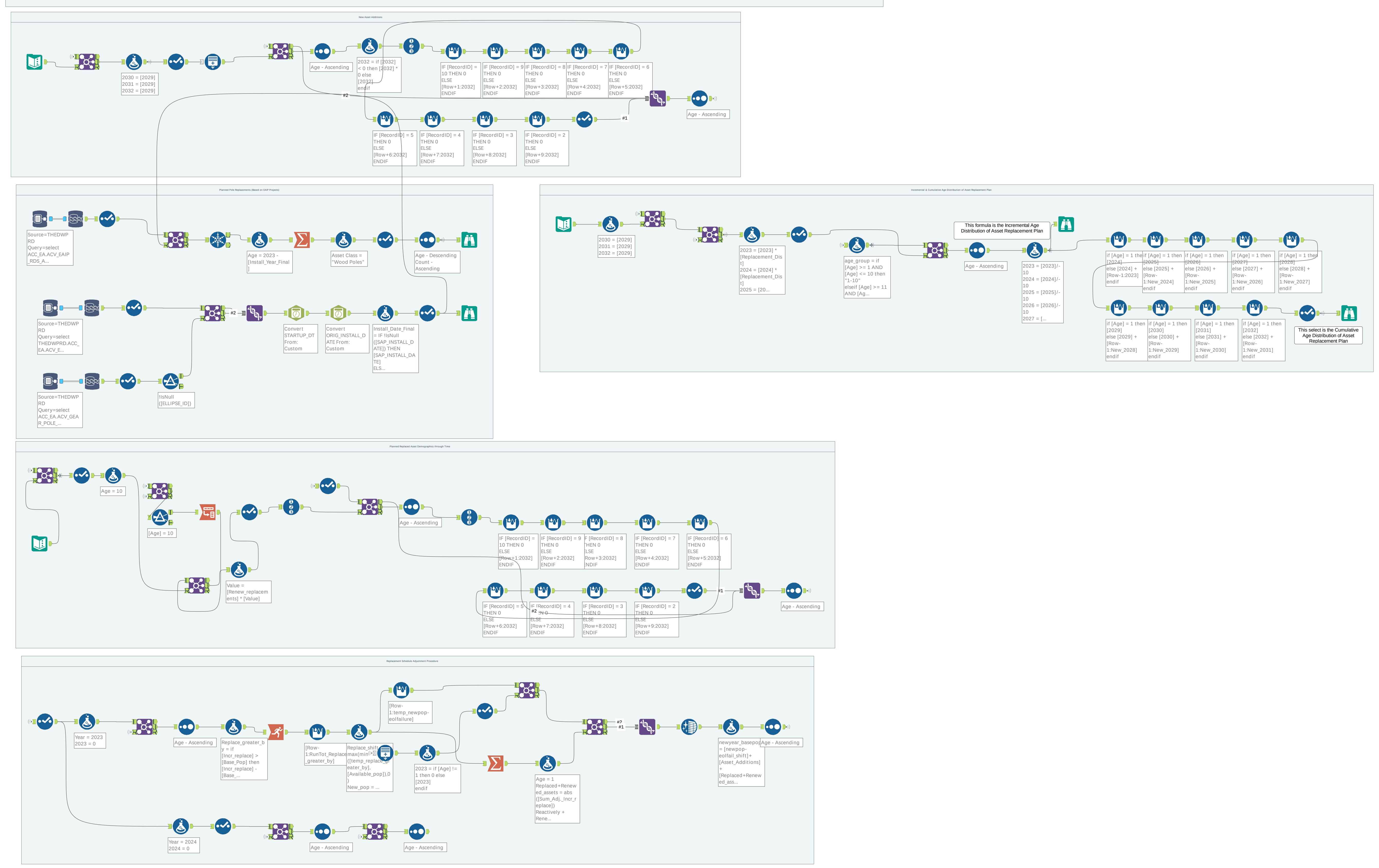
FILED: March 11, 2024
(1 Page)





RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-43

Reference: Exhibit 2B, Section D3, Page 41]

Does Toronto Hydro have a corporate risk register (or similar document)? If so, please provide a copy.

RESPONSE:

Please refer to the attached Appendix A.

Toronto Hydro-Electric System Limited
EB-2023-0195
1B-SEC-43
Appendix A
FILED: March 11, 2024
(10 Pages)

Enterprise and Component Risk Tree

STRATEGIC RISKS

Governance
- Shareholder Risk
- Community Representatives Risk
- City Operations Oversight Risk
- Municipal Policy Risk
- City Accountability Oversight Risk

Oversight
- Emerging Government Policy
- Application and Proceedings
- Emerging OEB Policy and Regulatory Framework
- Emerging IESO Policy

Franchise
- Customer
- Brand and Reputation
- Competitive

FUNCTIONAL RISKS

Cyber Security
- Electricity Distribution Grid
- Customer and Employee Private Information
- Intellectual Property
- Critical Business Operations

Safety
- Occupational Health and Safety
- Public Safety

Financial
- Capital Structure
- Financial Management
- Counter-Party Default
- Market Economic

Operations
- Asset Management Risk
- Business Interruption
- Customer Management
- Physical Security
- Supply Chain

Human Capital
- Attraction and Retention
- Internal and External Resource Management
- Labour Relationship

Compliance
- Regulatory
- Environment
- Finance and Governance
- Health and Safety
- Privacy and Cyber Security
- Labour and Employment
- Other

Governance Risk
Overview

Definition: Risk that municipal activity (laws, policies, or intervention) impedes Toronto Hydro's effective performance, and ability to meet its objectives and serve its customers.

Component Risks	
Shareholder Risk	Risk that TH's governance relationship with its shareholder is suboptimal and therefore impacts the corporation's ability to govern itself, deliver effective and efficient operations, and meet its business objectives.
Community Representatives Risk	Risk that negative interactions and prolong/difficult issues management process with City Councillors will increase negative attention to TH.
City Operations Oversight Risk	Risk that increased volume of city-building activities (e.g. large developments, waterfront) will impair TH's ability to effectively engage with the City and find mutually-acceptable resolution of issues.
Municipal Policy Risk	Risk that TH does not fully leverage its relationship with the Mayor, City councilors, administration, agencies, boards and commissions, and therefore the utility's ability to positively influence municipal policy application and decision-making is impacted. Risk that the strategic direction of the City of Toronto is not aligned with TH's strategic direction, thereby leading to the development of municipal policies or amendments to the Shareholder Direction that could impede TH business
City Accountability Oversight Risk	Risk that insufficient time and resources will result in the inability for TH to respond effectively to the City.

Oversight Risk

Overview

Definition: Risk that provincial government or regulator activity (laws, frameworks or policies) impedes Toronto Hydro's effective performance, and its ability to meet its objectives and serve its customers.

Component Risks	
Emerging Government Policy	Risk that emerging Ontario energy and utility policies create barriers to TH achieving its strategic objectives
Application and Proceedings	Risk of disallowance of a significant portion of TH's funding request for its Rate Application, or other negative decision in relation to a regular or issue-specific (e.g. Z-factor) application for rates, or other leave requiring express OEB approval (e.g. license amendment application, MAAD application, etc.)
Emerging OEB Policy and Regulatory Framework	Risk that OEB's regulatory model, manner of regulation and/or policy framework does not fit TH's business direction and may adversely impact the organization's strategic goals and financial results
Emerging IESO Policy	Risk that the IESO creates policies that do not align with or impede TH's business operations and strategic goals

Franchise Risk

Overview

Definition: Risk that restrictions in LDC's business model and/or external conditions impede its ability to maintain and grow its legal right to be the sole provider of electricity distribution and connection services in the city of Toronto (its franchise) and serve electricity customers.

Component Risks	
Customer	Risk that TH fails to identify and meet its customers' needs and expectations causing them to seek out alternative solutions involving lessened reliance on the distribution grid
Brand and Reputation	Risk that inaction by Toronto Hydro or restrictions placed upon it will impair its image in the community, public confidence or brand and lead to greater acceptance by governments that its monopoly position should be challenged
Competitive	Risk of development of competitive pressures from technology solutions providers and other unregulated entities, and the capacity of the organization to respond to those pressures

Cyber Security Risk

Overview

Definition: Risk that Toronto Hydro is unable to adequately safeguard digital information assets, connections to digital infrastructure, physical assets and people from threats or vulnerabilities.

Component Risks	
Electricity Distribution Grid	Risk that the Electrical Distribution Assets utilized to distribute electricity to Toronto Hydro customers is compromised by an unauthorized third party.
Customer & Employee Private Information	Risk that an unauthorized third-party gains access to personal information deemed private including driver's license, data of birth, electricity usage data, SIN, credit card, etc.
Intellectual Property	Risk that an unauthorized third-party gains access to Toronto Hydro's proprietary and confidential business information.
Critical Business Operations	Risk of critical business operational processes being compromised by a cyber security incident.

Safety Risk
Overview

Definition: Risk to Toronto Hydro employees or the general public of critical/fatal injuries and illnesses relating to or impacting upon Toronto Hydro activities.

Component Risks	
Occupational Health and Safety Risk	The risk that Toronto Hydro’s employees, and others for whom it is responsible at law, may be exposed to serious or fatal injuries or illness as a result of the work environment in which they operate.
Public Safety Risk	The general public may be exposed to serious or fatal injuries and safety issues as a result of Toronto Hydro's actions, inactions or the adequacy of its infrastructure and facilities.

Financial Risk
Overview

Definition: Risk that Toronto Hydro is unable to maintain its financial health and performance at acceptable levels.

Component Risks	
Capital Structure	Toronto Hydro is not able to optimize debt to equity structure to ensure market confidence and support
Financial Management	Risk that Toronto Hydro mismanages its financial accounting, budgeting, tax planning and internal controls, negatively impacting its profitability
Counter-Party Default	Risk that Toronto Hydro’s customers or other credit counterparties are unable or unwilling to settle payments or fulfill contractual obligations
Market Economic	Risk that deterioration of the macro economic factors in the electric utilities space and more generally may impact TH's ability to access financing at reasonable rates to execute its capital program and achieve strategic objectives

Operations Risk
Definition

Definition: Risk that Toronto Hydro is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the distribution grid at acceptable levels.

Component Risks	
Asset Management Risk	The inability to maintain reasonable levels of reliability for its customers due to failure of existing distribution infrastructure and assets and the inability to replace/expand infrastructure in an optimal timeframe.
Customer Management Risk	TH fails to accurately measure customer consumption, respond to and address customer service issues or correctly bill customers on time (includes meter to cash management).
Business Interruption Risk	The inability to maintain continuing and sustainable business operations, or recover from business interruption after an incident that is beyond normal operations.
Physical Security Risk	The inability to adequately safeguard assets and people.
Supply Chain Risk	Risk that Toronto Hydro is unable to acquire critical equipment and material from its suppliers, impeding the Corporation's ability to operate at acceptable levels and meet the needs of its customers.

Human Capital Risk
Overview

Definition: Risk that Toronto Hydro is unable to maintain necessary resource talent and skilled resources.

Component Risks	
Attraction & Retention	Risk that TH is unable to attract and develop qualified employees or retain individuals who are strongly contributing to TH objectives and future needs
Internal and External Resource Management	Risk that Toronto Hydro is unable to effectively develop and manage the relationship with contractors to ensure resource flexibility, proper operationalization of resources, and maintenance of the right balance between outside and inside resources to address customer and distribution system needs
Labour Relationship	Risk that TH is not effectively managing matters related to the negotiation, development and enforcement of its collective agreements or its relationships with its labour unions and organized staff, so that all work situations are not adequately staffed and fulfilled.

Compliance Risk
Overview

Definition: Risk that Toronto Hydro does not meet its material compliance obligations under legal and regulatory instruments.

Component Risks	
Regulatory	Federal and provincial electricity and utility-related legislation and regulations. OEB Codes, rules, policies, and IESO's Market rules.
Environment	Federal and provincial policies, legislation, regulations and standards related to the protection of the environment.
Finance & Governance	Financial reporting & disclosure requirements, tax filing requirements, and governance obligations established under law.
Health & Safety	Federal and provincial regulations regarding rights and responsibilities of employees and employers in the workplace and the protection of the public's safety.
Privacy & Cyber Security	Federal or provincial laws and regulations related to the protection of personal information and access to our data, software and hardware.
Labour & Employment	Labour and employment laws and regulations.
Other	Federal or provincial laws and regulations including those related to consumer protection, record keeping, access for people with disabilities, etc.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-44

Reference: Exhibit 2B, D3, Appendix A

With respect to the Asset Condition Assessment: Methodology Update and 2022 Results Analysis, please provide a revised version of Table 5 that shows the future health index projected for year-end 2029, based on the work forecast in Toronto Hydro's proposed application.

RESPONSE:

Predicting the asset age and condition demographics as of year-end 2029 based on Toronto Hydro's proposed 2025-2029 investment plans is not possible without knowing which assets will be replaced over the entirety of the rate period. This requires discrete, project-level details which are not available for most asset classes. Toronto Hydro forecasts its executable capital plan on a rolling 30-month basis, and usually produces detailed scopes of work 12-18 months in advance of construction. This reality is part of Toronto Hydro's dynamic and programmatic approach to managing its assets, which has been tailored through decades of experience to efficiently manage risk and performance in a dense, dynamic and growing urban service territory.

When creating detailed and geographically bounded project scopes and designs for System Renewal programs, Toronto Hydro identifies the need for asset replacement based on three major factors:

1. The **Probability of Failure**, which is represented at the highest level by a health score, but at the project engineering and design level will also be informed by a detailed review of maintenance records and historical failure records (e.g., feeder regions with XLPE cables that have previously faulted and been repaired; number of splices in a run of PILC cable). For the small handful of major assets that would trigger a renewal project and which do not have Condition Based Risk Management ("CBRM") condition models (e.g., primary

underground cable), probability may also be informed by age and the specific type of asset. (Though to be clear, an asset is not replaced simply because it is beyond "useful life.") Note that there are certain major assets that generally do not trigger projects on their own, unless there is a reason to do so unrelated to reliability performance (e.g., eliminating pole top transformers at risk of containing PCBs). Please see Section D3.1.2 for more details.

2. The **Criticality of Failure**, i.e., the anticipated consequences should an asset or part of the system experience a failure. Depending on where an asset is on the system, the impact of failure on reliability, safety, and the environment will vary. Criticality is an important element in assessing risk and can result in the strategic replacement of assets that are not in the worst condition. For example, a wood pole holding up multiple trunk circuits on a street corner is more critical than a wood pole holding up a secondary service line on a residential side street. The criticality of the trunk pole represents the type of circumstance that could lead to an asset being replaced prior to reaching HI5 or even HI4 condition, especially in circumstances when that asset is connected to other assets in the immediate area that require intervention. Assessment of criticality at the project engineering stage is a detailed exercise that varies depending on the investment program. For example, for Horseshoe programs dealing with large volumes of assets, planners will look at the aforementioned trunk vs. lateral distinction, the size of the equipment and number of connected customers, the presence of critical loads, whether the next failure will impact an area that is already experiencing poor performance, whether an asset is of a particular vintage type that will cause a more extensive outage response than another type, whether the area of the system has relatively strong protection and switching capacities to reroute and restore power in the event of failure, etc. For more discrete asset classes that are of a higher criticality in general (e.g., stations power transformers), Toronto Hydro will also consider engineering factors such as what the impact of failure would be on the state of contingency of the system, the ability to transfer load between transformers, busses, and stations, and various environmental and safety impacts of different vintages and types.

3. The final factor in determining which assets will be replaced is the broad category of **Design Considerations.** This category refers to the various drivers that can result in the scope of work for projects extending beyond the narrower set of assets that may have triggered the initial decision to intervene in an area. Design considerations are a particularly significant factor for a utility like Toronto Hydro, operating in a dense, growing, and ever-changing urban environment, with various on-the-ground challenges such as utilities conflicts, clearance issues and other space restrictions, a heavy and expanding tree canopy, etc. When Toronto Hydro determines that it is necessary to intervene on an asset or group of assets in an area, a number of design factors come into play, including an assessment of the available rights-of-way and how they should be used for the long-term, the condition and age of assets in the contiguous surroundings, an assessment of loading in the area and whether the equipment needs to be upsized for the next 30-40 years of service, an assessment of area performance and system design, including whether as part of the project it is economical to introduce additional switching and protection capabilities or to generally reconfigure or reroute the area, etc. Any one of these additional drivers can trigger changes and additional considerations for another driver. Finally, standards and obsolescence also come into play. For example, if a larger transformer is required on a pole, this may require a taller pole, which in turn may require the replacement of adjacent poles, and so on. Another example is the obsolete 4 kV system. When it comes to the point where a critical mass of equipment needs to be replaced in a 4 kV area, this necessarily triggers the need to rebuild the entire area to standard, at either 13.8 kV or 27.6 kV. Overall, applying these and many other design considerations at the project level is a complex exercise that is project specific and does not lend itself to simplified asset demographic projection modelling such as determining asset population health seven years into the future.

Projected Health Demographics with Investment

Toronto Hydro has provided the above preamble as important context for understanding and interpreting the results of the following tables and the more detailed Appendix A (Excel) attached. What Table 1 below presents for asset classes with CBRM health score models is the following:

1. Asset health demographics as of 2022
2. Asset health demographics projected to 2029 without any intervention
3. Asset health demographics projected using a simplistic (i.e., unrealistic) assumption that the utility will put all of its planned investment volumes for 2023-2029 toward *only* the worst condition assets (i.e., eliminate all the HI5s, and then move on to HI4s, etc.).

The only exceptions Toronto Hydro has made to the simplistic assumptions in item number three above is to (i) account for the PCB at-risk equipment that the utility expects to remove in 2023-2025, and (ii) account for specific assets that have been identified as part of the Area Conversions program. This results in specific impacts on the HI1-HI5 condition bands in the projection with investment. It is also important to note that these projections do not account for the various other programs that impact asset demographics. For example, growth-related programs such as Customer Connections, Load Demand, and Externally Initiated Plant Relocations drive many asset replacements that are not related to failures and failure risk. Investments in these categories will impact assets across a broad range of age and condition values. Furthermore, the Reactive Capital program contributes to future health demographics for a number of asset classes. While there is a general correlation between the health and age of assets and the probability that they could need to be replaced reactively, it is also the case that assets can and do fail at any age and observed condition, and given the large overall population of assets in HI1-HI3 health bands, the utility would expect a number of assets to fail in these condition bands.

For the reasons discussed in the introduction to this interrogatory response, the figures in the final column of Table 1 should not be taken as a forecast, a target, or an achievable result. These figures are presented for further context and to be responsive, on a best-efforts basis, to the various questions asked regarding 2029 asset age and condition with investment. Toronto Hydro offers additional notes on the results seen in Table 1 later in this interrogatory response.

Table 1: Summary of Simplistic 2029 Health Demographic Projections

ACA Assets	Renewal Program		Sum HI4 & HI5 at Year End		
			2022	2029 w/o Investment	2029 w/ Investment (Simplistic Scenario)
Overhead Gang Operated Switches	Overhead Renewal, Area Conversions	Overhead Switches	40	446	N/A[1]
SCADAMATE Switches					
Wood Poles		Wood Poles	9,459	32,158	19,732
Network Transformers	Network Renewal	Network Units[2]	43	149	-
Network Protectors					
Network Vaults		Network Vaults[3]	91	137	90
Submersible Transformers	Underground Renewal (Horseshoe and Downtown)	Underground Transformers[2]	695	2,699	1,133
Vault Transformers					
Padmount Transformers					
SF6 Insulated Padmount Switch		Underground Switches	94	284	105
Air Insulated Padmount Switch					
SF6 Insulated Submersible Switch					
Air Insulated Submersible Switch					
Cable Chambers		Cable Chambers[3]	592	1,113	838
URD Vaults		URD Vaults	8	13	4

<u>Notes Regarding the Figures in Table 1</u>

The results in Table 1 for the "simplistic" projection of 2029 results with investment show a wide variability in outcomes across asset classes. For example, wood pole condition is expected to

[1] Please see discussion regarding Overhead Switches below.
[2] For underground and network transformers, total units changed in Health Index Bands include removal of at-risk of PCB
[3] For cable chamber and network vaults, total units changed in Health Index Bands is sum of units for rebuild and abandonment

deteriorate, even under this unrealistically optimistic scenario, while all HI4/HI5 Network Units would theoretically be eliminated. Additional context for these outcomes is provided here:

- **Overhead Assets:** Exhibit 2B, Section D3, Table 2, summarizes Toronto Hydro's approach to replacing overhead system assets.
  - **Wood Poles:** As shown in Figure 19 of Exhibit 2B, Section E6.5, Toronto Hydro has, in reality, experienced substantial deterioration of its wood pole population since 2018 and this is one of the reasons Toronto Hydro intends to increase investment in the Overhead System Renewal program in 2025-2029.[4] The utility looks forward to refocusing on condition and reliability-driven investment in the Overhead Circuit Renewal program in 2026 following completion of the PCB at-risk equipment elimination activities in 2025. Investments in the Area Conversions program will also contribute to pole condition improvements.

    The number of HI4/HI5 wood poles nearly doubles by 2029 in Table 1. As discussed in 2B-Staff-226, Toronto Hydro recognizes that the projection aspect of its wood pole condition model is a continuing work in progress, and, despite recent adjustments that the utility has made to dampen the rate of deterioration in these projections, may (or may not) be predicting a somewhat accelerated rate of deterioration in the Future Health Scores. The utility is proposing to adjust its maintenance strategies and to continue monitoring and studying the model to address some of the inherent challenges with modelling future states in this asset class. Toronto Hydro notes that its ability to recognize the need for these maintenance adjustments is a reflection of the benefits of introducing the CBRM approach in 2017, which not only supports better asset replacement decisions, but

[4] The statement regarding observed deterioration in wood pole condition since 2018 is based exclusively on the number of HI4 and HI5 assets (Current Health Scores). While there is some discussion in the EA Technology report regarding the accuracy of the Normal Expected Life value for the wood pole condition model, Toronto Hydro would like to re-emphasize that the Current Health Score of an asset cannot exceed HI3 without observed condition data to support it.

provides a basis for investigating broader asset management strategies and trends for the relevant asset classes.

Should Toronto Hydro continue to experience significant deterioration in the wood pole asset class over the 2025-2029 period, this will be a factor in determining longer-term rates of investment (i.e., 2030+). Overall, the utility does expect a continued deterioration in wood pole condition over the 2025-2029 period, which it intends to manage by prioritizing the worst condition and most critical poles and by adjusting its inspection strategy.

- **Overhead Switches:** There are multiple types of overhead switch, of which only gang operated and SCADAMATE switch types have asset condition models. Toronto Hydro does not yet know the specific breakdown of switch replacements between asset type over the full 2025-2029 period and therefore cannot accurately allocate expected switch replacements between ACA and non-ACA supported types in Table 1. The utility notes that the number of switches in HI4 and HI5 condition is expected to increase by upwards of 400 units between 2022 and 2029. The utility is planning to replace over 650 switches between 2023 and 2029 in the Overhead System Renewal program, plus additional switches within the Area Conversions program as well as other programs that are not related to System Renewal. As noted, the extent to which these units are applied to switches with asset health models is yet to be determined. (Note that the switch types with asset health models account for approximately 25% of the total overhead switch population.) Furthermore, as discussed in the preamble to this response, there are several factors that result in the decision to replace an asset as part of an area rebuild, and both asset criticality and system design considerations are important influences when it comes to overhead switches. Toronto Hydro's goal for the overhead switch population in 2025-2029 is to maintain health. The utility does not expect to see improvements in health, and there is some risk that asset health demographics could deteriorate. As with wood poles, the utility will manage the performance risk stemming from this potential deterioration by prioritizing the worst condition and most critical switches.

- **Network Units and Vaults:** The network system is exhibiting a slower rate of deterioration compared to 2018, and with Toronto Hydro's proposed investment plan for 2025-2029, there is an opportunity to potentially improve the health demographics of network units. As discussed in Exhibit 2B, Section E2.2.1.1, there are considerations beyond the current and 2029 health demographics involved in the chosen pacing of unit renewal: (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. With respect to network vaults, there are specific project-level criticality and engineering and design considerations that will drive the ultimate demographic distribution of assets that are rebuilt over the 2025-2029 period. For example, the specific location of a network vault must be considered as the hazards associated with failure will vary. Furthermore, if a network vault needs to be rebuilt in the exact same location, the network units must first be removed from the vault. This requires nearby network units to be upsized to compensate, with the potential result that network units in lower health bands are replaced. There are also efficiency considerations (i.e., given the combined condition of the unit and vault, and the need to take planned outages on critical parts of the network, it may be most cost-effective to replace and rebuild both simultaneously, even if one of the two is not in HI4/HI5 condition), as well as engineering and design considerations (e.g., space restrictions or reconfiguration needs could result in both a vault and network unit having to replaced or relocated, even if the project need was triggered by only one of the assets).

- **Underground Assets:** Exhibit 2B, Section D3, Table 3, summarizes Toronto Hydro's approach to replacing underground system assets.

  - **UG Horseshoe:** While in recent years, Toronto Hydro has been focused on PCB at-risk transformer replacement, the utility is looking forward to returning to the primary purpose of this program in 2026, which is the replacement of underground primary cables and switches at risk of failure. As discussed in Exhibit 2B, Section 6.2, underground cables are the single greatest contributor to outages caused by defective equipment on Toronto Hydro's system. The Underground System Renewal Horseshoe program is also a key example of the impact of design considerations on asset replacement. As Toronto Hydro rebuilds underground areas with large concentrations of direct-buried cable and cable in PVC conduit, it is generally the case that the targeted sections of feeder will need to be rebuilt in their entirety (often on the opposite side of the street from where the existing direct buried plant is being removed and abandoned). This means that when these cables are replaced, new transformers and switches will be installed at the same time, bringing the entire area up to modern standards and capacities simultaneously. Bearing this in mind, while the "simplistic" 2029 results for UG transformers and switches (Table 1) suggest that – after accounting for reactive replacement volumes and other drivers of replacement (e.g., switch replacements in the downtown renewal program) – there could be an opportunity to maintain or even improve condition in these asset classes, it is much more likely that Toronto Hydro will maintain condition or see moderate deterioration. However, by applying the logic of criticality to its decision-making processes (especially for any planned spot replacements of padmount switches outside of cable rebuild projects), the utility can maintain asset risk and performance within the 2025-2029 period, even if health demographics moderately deteriorate.
  - **UG Downtown**: As shown in Table 1, cable chamber condition deteriorates even in the simplistic scenario where all cable chamber units addressed by the Underground System Renewal Downtown program are HI4 and HI5. Toronto Hydro chose to take a

restrained approach to cable chamber renewal in the 2025-2029 period, and will continue to leverage a combination of the downtown renewal program and the Reactive Capital program to manage risks associated with the cable chambers that are observed to be in the worst condition and in the most critical locations of the system.

Regarding Underground Residential Distribution ("URD") assets, as discussed in Exhibit 2B, Section E6.3, Toronto Hydro's goal for 2025-2029 Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by these assets. The utility aims to achieve this by targeting the worst condition and most critical assets.

Table 2 below provides results for the set of major discrete asset classes for which Toronto Hydro can forecast a more precise outcome with respect to 2029 asset condition demographics with the application of its proposed 2025-2029 investment plan. For a detailed discussion of the asset management strategies that drive these 2029 outcomes, please refer to Exhibit 2B, Section E6.6.

Table 2: Summary of 2029 Health Demographic Projections (Stations)

ACA Assets	**Renewal Program**		**Sum HI4 & HI5**		
			2022	**2029 w/o Investment**	**2029 w/ Investment**
Station Power Transformers	Stations Renewal	MS Power Transformers[5]	8	13	5
Air Magnetic Circuit Breaker AirBlast Circuit Breaker Oil Circuit Breaker Oil KSO Circuit Breaker SF6 Circuit Breaker Vacuum Circuit Breaker		MS Air Magnetic Circuit Breaker[6]	14	210	165
		TS Switchgear Breakers	40	239	211
		TS Outdoor Breakers	5	24	9

[5] Represents subset of ACA Asset Class Population
[6] Represents subset of ACA Asset Class Population

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-45

References: Exhibit 2B, Section D3, Appendix B

Preamble:

With respect to the EA Technology, Review of ACA Modelling Enhancements and Customisations:

QUESTION (A):

a) [p.15] Please provide further details regarding the rationale for the calculation of H in the probability of failure formula, specifically, why is it appropriate that if the health score is less than 4 (i.e. it is in better health than an asset with health score of 4) it is given a score of 4.

RESPONSE (A):

Please refer to Toronto Hydro's response to interrogatory 2B-Staff-151 parts (a) and (b).

QUESTION (B):

b) [p.23] EA says: "A small number of ACA models including the SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF6 Circuit Breakers have been calibrated to align health score derivations with THESL's tactical asset management practices." Please provide details regarding this calibration process and why it is appropriate.

RESPONSE (B):

As part of Toronto Hydro's maintenance work, when deficiencies are identified on SCADAMATE switches and station circuit breakers through inspections, Toronto Hydro attempts to repair the asset immediately as assets are already de-energized for inspection purposes. As such, in the asset condition models, Toronto Hydro applies a reduced calibration score which results in a lower health score as the deficiency was addressed at the time of inspection.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-46

Reference: Exhibit 2B, Section D4

With respect to capacity planning:

QUESTION (A) :

a) [p.6] Please provide a copy of the results of the Monte-Carlo Simulation.

RESPONSE (A):

Please see Table 1 for the outputs of the Monte-Carlo Simulation (10^{th}, 50^{th} & 90^{th} percentile: P10, P50, and P90). P50 results were used as Toronto Hydro's System Peak Demand Forecast. Please note that the 10-year System Peak Demand Forecast does not include the decarbonization of heat as modelled load.

Table 1 : Monte-Carlo Simulation Results (MVA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
P10 - Summer system Non-Coincident Peak Demand	4768	4944	5097	5243	5329	5510	5666	5759	5843	5924
P10 - Winter system Non-Coincident Peak Demand	4708	4884	5037	5184	5271	5417	5512	5556	5583	5621
P50 - Summer system Non-Coincident Peak Demand	4905	5080	5229	5383	5475	5659	5835	5941	6029	6136
P50 - Winter system Non-Coincident Peak Demand	4812	4988	5142	5290	5383	5537	5642	5699	5740	5795
P90 - Summer system Non-Coincident Peak Demand	5258	5435	5590	5739	5840	6054	6236	6347	6469	6607
P90 - Winter system Non-Coincident Peak Demand	4960	5137	5292	5442	5543	5709	5829	5906	5969	6060

QUESTION (B) :

b) [p.11] Please provide system peak demand for each year between 2022 and 2031, broken down by the categories included in Figure 4.

RESPONSE (B):

Please see table below.

Table 2: Toronto Hydro System Peak Demand Forecast by Driver (MVA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Forecast	4870	5017	5133	5223	5226	5298	5388	5436	5473	5527
Electric Vehicle	5	10	18	28	45	67	90	114	138	167
Electrified Transit	0	0	0	4	47	114	116	118	118	118
Municipal Energy Plans	0	6	4	10	15	19	60	72	84	96
Data Centres	30	47	74	116	142	162	182	201	216	228
Total Forecast	**4905**	**5080**	**5229**	**5383**	**5475**	**5659**	**5835**	**5941**	**6029**	**6136**

QUESTION (C) :

c) [p.12] Please provide Figure 5 in tabular format. Please also provide in Excel.

RESPONSE (C):

Please see table below. The Excel is attached as an appendix to this IR.

Table 3: Comparison of Planning Forecasts and Future Energy Scenarios (MVA)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Toronto Hydro 2022 Peak Demand[1]	5463	5749	6140	6242	6455	6610	6732	6829	6906	6994
Toronto Hydro 2023 Peak Demand	4760	4905	5080	5229	5383	5475	5659	5835	5941	6029
Regional Planning - Needs Assessment - NET	5667	5934	6259	6297	6458	6541	6604	6643	6676	6707

[1] Note that the 2022 Peak Demand Forecast has general alignment with FES over the 2025-2029 rate period.

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Future Energy Scenarios – CT Low	5638	5974	6334	6565	6746	6903	7041	7149	7260	7378
Future Energy Scenarios - CT	5591	5879	6187	6364	6496	6600	6681	6730	6776	6822

QUESTION (D) :

d) [Appendix A, p.11] Please provide the following figures in tabular format: Figure 3 and 4. Please also provide in Excel.

RESPONSE (D):

Please refer to 2B-Staff-158 parts (a) and (b) for the tabular format. The Excel spreadsheet is attached as an appendix to this response entitled *"2B-SEC-46_Appendix A.xlxs"*.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-47

Reference: Exhibit 2B, Section D5, Page 15

Toronto Hydro cites results of implementation of FLSIR projects by other utilities. If those results (reduce CIs and CMIs) were applied to Toronto Hydro beginning in 2030, after full implementation, what would the forecast reduction in SAIDI and SAIFI be?

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 2B-Staff-162.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-48

Reference: Exhibit 2B, Section D5.5, Page 5, footnote 5

QUESTION:

Does Toronto Hydro have an internal Grid Modernization Roadmap. If so, please provide a copy.

RESPONSE:

The Grid Modernization roadmap is reflected in the Grid Modernization Strategy evidence submitted as part of the 2025-2029 Distribution System Plan in Exhibit 2B, Section D5. The strategy is the product of a multi-year, cross-functional investment planning effort and includes a variety of specific capability building objectives across a number of domains for the 2025-2029 period (e.g., prepare 90% of the Horseshoe distribution system for automatic FLISR implementation beginning in 2030; establish a robust "digital backbone" to create the foundation for the expanded and enhanced application of data analytics and automation solutions in 2025-2029 and beyond). These objectives and the underlying plans to achieve them are built upon Toronto Hydro's lived experience successfully delivering large modernization programs (e.g., Network Condition Monitoring & Control enhancements)[1] and discrete technology enhancement roadmaps (e.g., the continued roll-out of enhancements to customer experience and service tools highlighted in Exhibit 1B, Tab 4, Schedule 1, at pages 10-11). Toronto Hydro's mature corporate and asset management systems provide the tools and frameworks which ensure that various departments involved in delivering these strategic technology objectives remain coordinated and that risks to project and roadmap delivery are appropriately managed over various time horizons.

[1] Exhibit 2B, Section E7.3

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-49

Reference: Exhibit 2B, Section D5, Page 29

Please provide a copy of Figure 6 in tabular format.

RESPONSE:

Year	2021	2022	2023	2024	2025
FES - Low	149	164	179	189	195
FES - Medium	149	172	194	216	231
FES - High	149	178	207	263	300
Rate Application	132	135	182	200	212

Year	2026	2027	2028	2029	2030
FES - Low	203	211	221	232	244
FES - Medium	246	263	282	303	325
FES - High	337	376	420	466	520
Rate Application	225	240	258	280	-

Year	2031	2032	2033	2034	2035
FES - Low	257	270	284	299	314
FES - Medium	349	374	402	432	465
FES - High	574	634	701	771	845
Rate Application	-	-	-	-	-

Year	2036	2037	2038	2039	2040
FES - Low	327	341	355	370	385
FES - Medium	495	531	572	618	667
FES - High	904	965	1,029	1,095	1,163
Rate Application	-	-	-	-	-

Year	2041	2042	2043	2044	2045
FES - Low	401	417	435	454	475
FES - Medium	718	771	825	881	939
FES - High	1,232	1,303	1,375	1,448	1,523
Rate Application	-	-	-	-	-

Year	2046	2047	2048	2049	2050
FES - Low	497	523	551	583	617
FES - Medium	999	1,060	1,123	1,188	1,253
FES - High	1,599	1,676	1,755	1,834	1,914
Rate Application	-	-	-	-	-

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-50

Reference: Exhibit 2B, Section D5, Page 55

Toronto Hydro states: "Toronto Hydro is exploring opportunities to leverage analytics in predictive maintenance for its electric assets as well. For example, the utility is currently running a pilot project that will explore the use of high-resolution satellite imagery and artificial intelligence as a basis for creating a risk-based decision-support tool for the Vegetation Management program." Please provide further details regarding what opportunities Toronto Hydro is exploring, as well as further details regarding the referenced pilot project.

RESPONSE:

Toronto Hydro is using analytics tools such as Alteryx to analyze inspection data within its predictive maintenance programs in order to get better insights into its assets. The utility is also exploring AI/ML opportunities to assess feasibility of applying these algorithms to better assess condition of its assets.

Toronto Hydro is exploring the opportunity to implement an Intelligent Vegetation Management System (IVMS) that utilizes satellite/aerial imagery, advanced analytics, and AI-driven algorithms to enhance the efficiency and effectiveness of its vegetation management efforts. Through this innovative approach, the utility aims to accurately identify hazardous trees encroaching upon power lines, ultimately improving the reliability and safety of its electrical infrastructure. As part of this exploration, Toronto Hydro has successfully implemented a pilot project utilizing the IVMS. This project leverages high-resolution satellite imagery and artificial intelligence to create a risk-based decision-support tool specifically tailored for the utility's Vegetation Management program. The IVMS enables the utility to forecast the risk of tree contacts, recommend feeder-specific tree-trimming schedules, and identify high-risk segments that could benefit from spot trimming. In 2024, Toronto Hydro has made progress in integrating the IVMS data and insights into its cycle trim plan line. This integration is a crucial step towards Toronto Hydro's efforts to modernize and optimize its vegetation management practices.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-51

Reference: Exhibit 2B, Section D7

What specifically has Toronto Hydro's shareholder required of Toronto Hydro regarding the implementation of the City of Toronto TransformTO Net Zero strategy.

RESPONSE:

In April 2021, Toronto City Council requested that Toronto Hydro prepare an action plan regarding what more Toronto Hydro could do to support the City's TransformTO vision and related climate action targets with a focus on electric vehicles (EVs) charging infrastructure, outdoor lighting, renewable energy and storage, and attracting revenue through non-rate solutions. Toronto Hydro submitted its Climate Action Plan[1] in September 2021 and its first Climate Action Plan Status Report in 2022.[2] In July 2022, Toronto City Council approved new climate action mandates for Toronto Hydro[3] as described in the 2022 Climate Action Plan Status Report, including the following mandate for a new (non rate-regulated) climate advisory services business:

> **Climate Advisory Services**
>
> 2. City Council, on behalf of the City of Toronto as shareholder, request Toronto Hydro to expand its business activities beyond electricity distribution services by:
>   a. establishing a new stream of non-rate regulated operations within its regulated business, specifically Climate Advisory Services (the climate action opportunity that excludes Toronto Hydro owning and operating

[1] Toronto Hydro Climate Action Plan, web: https://www.torontohydro.com/documents/20143/74105431/climate-action-plan.pdf/8fe4406c-7675-76a7-00c9-c0c4e58ae6df?t=1638298942820.

[2] Toronto Hydro Climate Action Plan Status Report, web: https://www.torontohydro.com/documents/20143/74105431/climate-action-plan-status-report.pdf/7fd07b3b-c0da-df7c-7815-2c464b5f8919?t=1658951621213.

[3] City of Toronto Item – 2022.EX34.9, web: https://secure.toronto.ca/council/agenda-item.do?item=2022.EX34.9.

assets), in keeping with the proposal set out in Toronto Hydro's Climate Action Plan received by City Council at its meeting on December 2021 and the Toronto Hydro Climate Action Plan Status Report; and

b. working through the Council-approved Net-Zero Climate Leadership Table to ensure coordination and enhanced investment while avoiding duplication with City programs and services, such as the Home Energy Loan Program and the Mayors Green Will, when implementing Climate Advisory Services.

5. City Council, on behalf of the City of Toronto as shareholder, request Toronto Hydro to deliver publicly to the Executive Committee through the City Manager, the Chief Financial Officer and Treasurer, and the Deputy City Manager, Corporate Services, an annual report on the progress, key performance indicators, and next steps of Climate Advisory Services.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-52

Reference: Exhibit 2B, Section D8, Appendix A

With respect to the Gartner, Toronto Hydro Enterprise IT Cost Benchmark & Functional Maturity Assessment Final Report:

QUESTION (A):

a) What was Toronto Hydro's purpose for undertaking the study? If it was for internal use, as opposed to support for its rate application, please explain how it informed the IT spending included in the plan.

RESPONSE (A) PREPARED BY TORONTO HYDRO:

As discussed in this evidence, Toronto Hydro commissioned Gartner Consulting ("Gartner") to perform a comprehensive benchmarking study to obtain an independent and objective expert evaluation of the process maturity levels within Toronto Hydro's IT functions and establish a baseline for IT spending and various metrics when benchmarked against peer organizations. Toronto Hydro's objective was to leverage this assessment to validate Toronto Hydro's overarching business and IT strategic goals, thereby supporting the continuous improvement of IT capabilities in areas directly impacting IT and business objectives. As discussed in subsection E8.4.4 "Expenditure Plan" of Exhibit 2B, Section E8.4,[1] Gartner concluded that Toronto Hydro's IT expenditures as a 2022 benchmark is competitive against industry peers confirming the utility's IT expenditures are appropriately balanced.

[1] At p. 17-18.

For more information on the study please refer to section 4 "Benchmarking Studies" and in particular subsection 4.3 of Exhibit 1B, Tab 3, Schedule 3,[2] subsection E8.4.4 "Expenditure Plan" of Exhibit 2B, Section E8.4,[3] and Appendix A to Exhibit 2B, Section D8.[4]

QUESTION (B):

b) [p.17] Please list the Custom Peer Group and ITKMD Utilities.

RESPONSE (B) – PREPARED BY GARTNER:

The custom peer group companies used for comparative purposes is a subset of Gartner's IT Key Metrics Data (ITKMD) for the Utilities Industry. Gartner cannot name the members of the peer group due to confidentiality agreements with the peer organizations that are standard for all our benchmarking clients.

QUESTION (C):

c) [p.17] How many companies' that are included in the Custom Peer Group and ITKMD Utilities are: i) distribution only utilities, ii) transmission only utilities, iii) generation only utilities, iv) distribution and transmission only utilities, or v) other?

RESPONSE (C) – PREPARED BY GARTNER:

Gartner has the world's largest data set for organizational IT spending and staffing. Gartner's objective when developing a peer group is to identify between 8 and 12 organizations that are as similar as possible to the client. Having a peer group of 8 to 12 makes it statistically relevant, while maintaining client "likeness". The methodology for peer selection is multidimensional, with nature of operations (e.g., generation / transmission / distribution) being only one of the criteria. Other factors that are considered when selecting organizations for a peer group include Total Revenue, Total Operating Expenses, Total Number of Employees and Geographical location.

[2] At p. 29.
[3] At p. 17-18.
[4] At p. 9.

Given there were not enough "distribution only" utilities in the database that also satisfied the additional criteria discussed above, some organizations with generation and/or transmission operations were included. The mix of the 8 utilities organizations in the peer group are as follows:

- Distribution only = 3
- Generation & Distribution = 2
- Generation, Transmission & Distribution = 2
- Transmission only = 1

QUESTION (D):

d) [p.4] Please confirm that Toronto Hydro's total revenue includes revenue related to pass-through costs (i.e. commodity, transmission, etc.) in addition to distribution revenue.

RESPONSE (D) PREPARED BY TORONTO HYDRO:

Confirmed.

QUESTION (E):

e) [p.4] Please revise the table to show IT Spend as a % of Distribution Revenue only.

RESPONSE (E) – PREPARED BY GARTNER:

This information is not available as Gartner does not collect revenue breakdown from our peer groups. Only the total revenue data point is collected. Therefore, IT spend as a % of distribution revenue is not available for the Peer Group Average and ITKMD Utility Industry.

RESPONSE (E) PREPARED BY TORONTO HYDRO:

Please refer to Toronto Hydro's response to 2B-AMPCO-67(a) for a calculation of the utility's IT spend as a percentage of its distribution revenue and revenue offset.

QUESTION (F):

f) [p.34] For each functional area, please provide the full maturity level description/criteria.

RESPONSE (F) – PREPARED BY GARTNER:

Descriptions for each functional area included in the assessment are as follows:

- Chief Information Officer (CIO): activities performed by the Office of CIO including engaging business and leadership stakeholders, strategy development & planning, innovation, IT finance and IT governance

- Applications: activities performed by the Application Development and Support teams including building and customizing applications, integrating platforms, products and applications, managing the product and application portfolio and managing vendor relationships

- Data & Analytics: activities performed by the Data & Analytics team including creating vision and strategy, aligning to business outcomes, developing organization, creating and maintaining analytics content, integrating and managing data and governing data and analytics assets

- Enterprise Architecture (EA) & Technology Innovation: activities performed by the EA & Technology Innovation team including structuring business strategy, facilitating innovation, planning and managing the IT portfolio, enabling solutions delivery and establishing EA frameworks and tools

- Infrastructure & Operations (I&O): activities performed by the I&O team including evaluating, planning and designing solutions, measuring and optimizing operations, transitioning and operating IT services

- Program & Portfolio Management (PPM): activities performed by the PPM team including partnering with stakeholders, managing strategic portfolios, managing frameworks and standards, driving transformation initiatives, enabling initiative management and delivery

- Security & Risk Management: activities performed by the Security & Risk Management team including engaging and supporting stakeholders, assessing and managing risk, protecting the infrastructure, managing security operations and delivering assurance

QUESTION (G):

g) [p.55] How does Toronto Hydro plan to address each of the Top 25 improvement opportunities?

RESPONSE (G) PREPARED BY TORONTO HYDRO:

The top 25 improvement opportunities identified by Gartner have helped to validate Toronto Hydro's Information Technology Investment Strategy outlined in Exhibit 2B, Section D8. For example, Toronto Hydro intends to address improvement opportunities in the area of data analytics (D&A) by improving reporting, data sharing and making data more accessible.[5] To address the improvement opportunities in the infrastructure & operation (I&O) area, the utility considers forecast capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. To address the improvement opportunities in the security and risk management (SRM) area, Toronto Hydro will explore and invest in new technology and defence mechanisms to ensure the security of its digital assets.[6] Toronto Hydro's IT Investment Planning Process, the application of Enterprise Technology Portfolio ("ETP") framework[7] and Project Governance Framework[8] will enable the utility to effectively align and prioritize investments and in these areas.

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[5] Exhibit 2B Section E8.4.3.2 at p. 13.
[6] Exhibit 2B Section E8.4 and Exhibit 4A Schedule 2 Tab 17 Section 5.1
[7] Exhibit 2B, Section D8 at p. 7-10.
[8] Exhibit 2B Section D8.5.2

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-53

Reference: Exhibit 2B, Section E2, Page 6

Please provide a table that shows, for each year between 2025 and 2029, and by program, the 3 investment strategy options (low, high, draft plan).

RESPONSE:

Please see Table 1, Table 2, and Table 3 below for the investment option low, high, and draft plan respectively.

1 **Table 1: Low Option – 2025-2029 Capital Expenditures Forecast ($ Millions)**

OPTION: LOW		2025-2029 Total Capex Expenditure					
Category	**Programs/Category**	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
System Access	**Customer and Generation Connections**	$ 87.7	$ 97.4	$ 109.5	$ 117.8	$ 128.0	$ 540.3
System Access	**Externally Initiated Plant Relocations & Expansion**	$ 6.8	$ 7.0	$ 7.3	$ 7.6	$ 7.9	$ 36.7
System Access	**Load Demand**	$ 35.6	$ 28.5	$ 26.3	$ 19.9	$ 25.1	$ 135.4
System Access	**Metering**	$ 67.9	$ 56.2	$ 25.4	$ 34.8	$ 8.9	$ 193.2
System Access	**Generation Protection, Monitoring and Control**	$ 0.3	$ 0.3	$ 1.4	$ 2.6	$ 0.3	$ 4.8
System Access	**System Access Total Expenditures**	**$ 198.2**	**$ 189.4**	**$ 169.9**	**$ 182.7**	**$ 170.2**	**$ 910.3**
System Renewal	**Area Conversions**	$ 71.7	$ 73.9	$ 17.1	$ 19.9	$ 14.9	$ 197.4
System Renewal	**Underground Renewal - Horseshoe**	$ 97.1	$ 74.1	$ 49.8	$ 56.2	$ 55.2	$ 332.4
System Renewal	**Underground Renewal - Downtown**	$ 27.1	$ 28.5	$ 30.2	$ 31.3	$ 32.1	$ 149.3
System Renewal	**Network System Renewal**	$ 11.7	$ 12.8	$ 12.8	$ 12.0	$ 12.5	$ 61.8
System Renewal	**Overhead System Renewal**	$ 42.6	$ 39.6	$ 52.8	$ 64.3	$ 78.8	$ 278.2
System Renewal	**Stations Renewal**	$ 39.2	$ 45.2	$ 44.2	$ 47.3	$ 49.6	$ 225.7
System Renewal	**Reactive and Corrective Capital**	$ 56.7	$ 58.7	$ 61.4	$ 62.6	$ 64.4	$ 303.9
System Renewal	**System Renewal Total Expenditures**	**$ 346.2**	**$ 333.0**	**$ 268.4**	**$ 293.5**	**$ 307.5**	**$ 1,548.6**
System Service	**System Enhancements**	$ 8.4	$ 8.5	$ 41.3	$ 42.2	$ 46.2	$ 146.6
System Service	**Non-Wires Solutions**	$ -	$ 2.2	$ 2.3	$ 2.3	$ 3.5	$ 10.3
System Service	**Network Condition Monitoring and Control**	$ 4.4	$ -	$ -	$ -	$ -	$ 4.4
System Service	**Stations Expansion**	$ 45.0	$ 41.6	$ 27.8	$ 73.9	$ 11.2	$ 199.4
System Service	**System Service Total Expenditures**	**$ 57.8**	**$ 52.3**	**$ 71.3**	**$ 118.3**	**$ 60.9**	**$ 360.7**
General Plant	**Facilities Management and Security**	$ 20.6	$ 21.5	$ 22.2	$ 23.1	$ 23.9	$ 111.2
General Plant	**Enterprise Data Centre**	$ 5.5	$ 5.6	$ 5.7	$ 5.9	$ 6.0	$ 28.7
General Plant	**Fleet and Equipment**	$ 12.1	$ 11.9	$ 14.4	$ 15.8	$ 16.2	$ 70.4
General Plant	**IT/OT Systems**	$ 50.7	$ 53.4	$ 55.6	$ 52.5	$ 58.3	$ 270.5
General Plant	**General Plant Total Expenditures**	**$ 88.9**	**$ 92.4**	**$ 98.0**	**$ 97.2**	**$ 104.4**	**$ 480.8**
Other	**AFUDC**	$ 4.8	$ 6.2	$ 7.9	$ 7.7	$ 7.1	$ 33.8
Other	**Other Total Expenditures**	**$ 4.8**	**$ 6.2**	**$ 7.9**	**$ 7.7**	**$ 7.1**	**$ 33.8**
Total	**Total CAPEX (2025-2029)**	**$ 695.8**	**$ 673.3**	**$ 615.5**	**$ 699.5**	**$ 650.1**	**$ 3,334.2**

Table 2: High Option – 2025-2029 Capital Expenditures Forecast ($ Millions)

OPTION: HIGH		2025-2029 Total Capex Expenditures					
Category	**Programs/Category**	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
System Access	**Customer and Generation Connections**	$ 96.9	$ 114.7	$ 124.4	$ 123.9	$ 129.9	$ 589.8
System Access	**Externally Initiated Plant Relocations & Expansion**	$ 22.6	$ 16.7	$ 12.0	$ 12.1	$ 12.6	$ 76.1
System Access	**Load Demand**	$ 63.3	$ 66.9	$ 60.0	$ 56.6	$ 65.2	$ 312.0
System Access	**Metering**	$ 71.7	$ 60.0	$ 33.4	$ 51.6	$ 7.2	$ 223.9
System Access	**Generation Protection, Monitoring and Control**	$ 3.9	$ 4.2	$ 4.3	$ 4.4	$ 0.9	$ 17.7
System Access	**System Access Total Expenditures**	**$ 258.5**	**$ 262.6**	**$ 234.0**	**$ 248.7**	**$ 215.8**	**$ 1,219.6**
System Renewal	**Area Conversions**	$ 91.1	$ 90.2	$ 26.1	$ 26.4	$ 21.8	$ 255.7
System Renewal	**Underground Renewal - Horseshoe**	$ 131.7	$ 102.5	$ 107.4	$ 80.4	$ 83.7	$ 505.7
System Renewal	**Underground Renewal - Downtown**	$ 50.1	$ 54.0	$ 58.1	$ 58.5	$ 61.2	$ 281.9
System Renewal	**Network System Renewal**	$ 26.3	$ 25.5	$ 26.1	$ 26.9	$ 26.8	$ 131.6
System Renewal	**Overhead System Renewal**	$ 84.1	$ 73.0	$ 86.3	$ 98.8	$ 113.6	$ 455.9
System Renewal	**Stations Renewal**	$ 59.1	$ 61.7	$ 63.1	$ 65.5	$ 69.9	$ 319.4
System Renewal	**Reactive and Corrective Capital**	$ 61.6	$ 63.5	$ 65.9	$ 67.5	$ 69.5	$ 328.0
System Renewal	**System Renewal Total Expenditures**	**$ 504.0**	**$ 470.6**	**$ 433.0**	**$ 424.0**	**$ 446.6**	**$ 2,278.2**
System Service	**System Enhancements**	$ 42.0	$ 56.5	$ 90.3	$ 90.4	$ 94.4	$ 373.5
System Service	**Non-Wires Solutions**	$ -	$ 7.7	$ 7.9	$ 9.2	$ 9.4	$ 34.3
System Service	**Network Condition Monitoring and Control**	$ 4.3	$ 0.2	$ 0.4	$ 0.6	$ 0.6	$ 6.0
System Service	**Stations Expansion**	$ 45.0	$ 41.6	$ 37.8	$ 83.9	$ 16.2	$ 224.4
System Service	**System Service Total Expenditures**	**$ 91.2**	**$ 106.0**	**$ 136.3**	**$ 184.0**	**$ 120.6**	**$ 638.2**
General Plant	**Facilities Management and Security**	$ 36.1	$ 37.4	$ 38.8	$ 40.3	$ 41.8	$ 194.3
General Plant	**Enterprise Data Centre**	$ 13.8	$ 14.1	$ 14.4	$ 14.7	$ 15.0	$ 71.9
General Plant	**Fleet and Equipment**	$ 25.8	$ 15.3	$ 16.3	$ 17.2	$ 9.6	$ 84.3
General Plant	**IT/OT Systems**	$ 59.5	$ 62.3	$ 64.8	$ 62.2	$ 66.0	$ 314.7
General Plant	**General Plant Total Expenditures**	**$ 135.2**	**$ 129.0**	**$ 134.3**	**$ 134.3**	**$ 132.4**	**$ 665.2**
Other	**AFUDC**	$ 4.8	$ 6.2	$ 7.9	$ 7.7	$ 7.1	$ 33.8
Other	**Other Total Expenditures**	**$ 4.8**	**$ 6.2**	**$ 7.9**	**$ 7.7**	**$ 7.1**	**$ 33.8**
Total	**Total CAPEX (2025-2029)**	**$ 993.8**	**$ 974.3**	**$ 945.6**	**$ 998.8**	**$ 922.5**	**$ 4,835.1**

1 **Table 3: Draft Plan – 2025-2029 Capital Expenditures Forecast ($ Millions)**

DRAFT PLAN		2025-2029 Total Capex Expenditure					
Category	**Programs/Category**	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
System Access	**Customer and Generation Connections**	$ 87.4	$ 95.3	$ 103.5	$ 113.5	$ 122.8	$ 522.5
System Access	**Externally Initiated Plant Relocations & Expansion**	$ 22.6	$ 16.7	$ 12.0	$ 12.1	$ 12.6	$ 76.1
System Access	**Load Demand**	$ 44.7	$ 48.4	$ 40.6	$ 37.2	$ 46.2	$ 217.0
System Access	**Metering**	$ 60.5	$ 68.0	$ 71.6	$ 21.2	$ 7.3	$ 228.7
System Access	**Generation Protection, Monitoring and Control**	$ 3.9	$ 4.2	$ 4.3	$ 4.4	$ 0.9	$ 17.7
System Access	**System Access Total Expenditures**	**$ 219.1**	**$ 232.6**	**$ 232.0**	**$ 188.5**	**$ 189.9**	**$ 1,062.0**
System Renewal	**Area Conversions**	$ 68.0	$ 69.5	$ 21.6	$ 26.3	$ 26.2	$ 211.5
System Renewal	**Underground Renewal - Horseshoe**	$ 90.7	$ 79.3	$ 90.1	$ 97.0	$ 100.9	$ 458.0
System Renewal	**Underground Renewal - Downtown**	$ 19.9	$ 24.5	$ 30.5	$ 39.0	$ 42.3	$ 156.1
System Renewal	**Network System Renewal**	$ 13.4	$ 14.4	$ 29.6	$ 30.2	$ 31.9	$ 119.5
System Renewal	**Overhead System Renewal**	$ 49.2	$ 58.9	$ 74.8	$ 82.2	$ 81.0	$ 346.1
System Renewal	**Stations Renewal**	$ 54.7	$ 59.8	$ 56.6	$ 56.7	$ 58.7	$ 286.5
System Renewal	**Reactive and Corrective Capital**	$ 61.7	$ 63.3	$ 65.2	$ 67.0	$ 68.7	$ 325.9
System Renewal	**System Renewal Total Expenditures**	**$ 357.5**	**$ 369.7**	**$ 368.4**	**$ 398.4**	**$ 409.7**	**$ 1,903.7**
System Service	**System Enhancements**	$ 12.7	$ 19.4	$ 47.9	$ 45.3	$ 51.7	$ 176.9
System Service	**Non-Wires Solutions**	$ -	$ 7.7	$ 7.9	$ 9.2	$ 9.4	$ 34.3
System Service	**Network Condition Monitoring and Control**	$ 4.4	$ 0.2	$ 0.4	$ 0.6	$ 0.6	$ 6.2
System Service	**Stations Expansion**	$ 26.0	$ 40.6	$ 47.8	$ 81.9	$ 12.2	$ 208.4
System Service	**System Service Total Expenditures**	**$ 43.0**	**$ 67.9**	**$ 104.0**	**$ 137.0**	**$ 73.9**	**$ 425.7**
General Plant	**Facilities Management and Security**	$ 32.4	$ 26.7	$ 27.7	$ 30.8	$ 34.7	$ 152.2
General Plant	**Enterprise Data Centre**	$ 13.8	$ 14.1	$ 14.4	$ 14.7	$ 15.0	$ 71.9
General Plant	**Fleet and Equipment**	$ 15.0	$ 16.0	$ 15.2	$ 16.2	$ 16.4	$ 78.8
General Plant	**IT/OT Systems**	$ 57.5	$ 60.3	$ 62.8	$ 65.9	$ 64.0	$ 310.4
General Plant	**General Plant Total Expenditures**	**$ 118.7**	**$ 117.0**	**$ 120.0**	**$ 127.6**	**$ 130.1**	**$ 613.4**
Other	**AFUDC**	$ 4.8	$ 6.2	$ 7.9	$ 7.7	$ 7.1	$ 33.8
Other	**Other Total Expenditures**	**$ 4.8**	**$ 6.2**	**$ 7.9**	**$ 7.7**	**$ 7.1**	**$ 33.8**
Total	**Total CAPEX (2025-2029)**	**$ 743.0**	**$ 793.4**	**$ 832.3**	**$ 859.2**	**$ 810.6**	**$ 4,038.6**

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-54

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

Toronto Hydro states: "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." Please provide each capital expenditure plan that was generated as part of the iterative process.

RESPONSE:

Table 1 below details the program level changes and rationale from the initial plan to the draft plan that formed the basis of Phase 2 customer engagement. Table 2 below details the program level changes and rationale from the draft to the final plan that was filed in November 2023. Subsequent to filing the draft plan the utility filed an evidence update on January 29, 2024 reducing its capital expenditures plan by approximately $73.9M.[1]

Table 1: Initial and Draft Capital Expenditure Plans

Draft and Final 2025-2029 Total Capital Expenditures			
Programs/Category	**Initial Plan ($M)**	**Draft Plan ($M)**	**Reason for Change**
Customer and Generation Connections	716.5	522.5	Refined the forecasting methodology and assumptions to achieve a better balance in planning for expected increases in load connections.
Externally Initiated Plant Relocations & Expansion	76.1	76.1	N/A
Load Demand	213.3	217.1	Minor adjustments to estimates
Metering	209.7	215.7	Minor adjustments to estimates
Generation Protection, Monitoring and Control	17.7	17.7	N/A
System Access Total	**1,233.3**	**1,049.1**	

[1] EB-2023-0195, Evidence Update Cover Letter (January 29, 2024)

Draft and Final 2025-2029 Total Capital Expenditures			
Programs/Category	**Initial Plan ($M)**	**Draft Plan ($M)**	**Reason for Change**
Area Conversions	246.7	211.7	Reduced pace of investment in converting rear lot customers, extending the overall time horizon over which rear lot locations will be completed. Refinement to cost estimates also resulted in reductions.
Underground Renewal - Horseshoe	505.9	458.4	Reduced program in order to balance reliability and cost pressures by reducing the pace of direct buried cable replacement and feeder conversions within the rate period.
Underground Renewal - Downtown	179.6	156.3	Reduced Cable Chamber Renewal program to manage rate impacts and overall strategic parameters. The program is scaling back the number of poor condition assets addressed in the next rate period and managing failure risk by concentrating on asset locations that carry the highest level of potential failure consequences.
Network System Renewal	115.7	119.5	Minor adjustments to estimates
Overhead System Renewal	341.7	346.3	Minor adjustments to estimates
Stations Renewal	281.0	286.1	Minor adjustments to estimates
Reactive and Corrective Capital	320.7	325.4	Minor adjustments to estimates
System Renewal Total	**1,991.4**	**1,903.7**	
System Enhancements	342.6	145.9	Constrained investment in Contingency Enhancement to manage execution risks and rate impacts. A substantial reduction for Downtown Contingency, made possible by focussing on creating station switchgear ties between Copeland Station and Esplanade Station to manage a subset of contingency concerns within the downtown system. Toronto Hydro expects to pilot innovative solutions such as the Automated Primary Closed Loop distribution system which has the capability to provide a more effective and relatively economical solution to establish feeder ties between stations.[2]
Non-Wires Solutions	65.3	65.3	N/A
Network Condition Monitoring and Control	6.0	6.2	Minor adjustments to estimates
Stations Expansion	209.4	208.4	Minor adjustments to estimates

[2] For more information, please see Exhibit 2B, Section E2 at page 8

Draft and Final 2025-2029 Total Capital Expenditures			
Programs/Category	**Initial Plan ($M)**	**Draft Plan ($M)**	**Reason for Change**
System Service Total Expenditures	**623.3**	**425.7**	
Facilities Management and Security	163.6	152.2	Toronto Hydro adopted a managed deterioration strategy for its head office during the next rate period.[3]
Enterprise Data Centre	71.9	71.9	N/A
Fleet and Equipment	78.8	78.8	N/A
IT/OT Systems	310.4	310.4	N/A
General Plant Total Expenditures	**624.7**	**613.4**	
AFUDC	33.8	33.8	N/A
Non-EWP Metering	12.8	12.8	N/A
Other Total Expenditures	**46.7**	**46.7**	
Total CAPEX (2025-2029)	**4,519.4**	**4,038.6**	

Table 2: Financial Planning – Draft and Final Capital Expenditure Plans

2025-2029 Total Capital Expenditures			
Programs/Category	**Draft Plan ($M)**	**Final Plan ($M)**	**Reason for Change**
Customer and Generation Connections	522.5	476.5	Refined assumptions and estimates for the load connections segment based on 2022 actuals and updates to the basic connection allowance.
Externally Initiated Plant Relocations & Expansion	76.1	76.0	Minor adjustments to estimates.
Load Demand	217.1	236.3	Increase due to emerging need, resulting in additional scope required to be completed in 2025-2029 as well as refined estimates.
Metering	215.7	234.5	Deferral of work from 2020-2024 carrying over into 2025-2029 due to supply chain delays in procuring AMI2.0 meters.
Generation Protection, Monitoring and Control	17.7	35.0	Increase in program expenditures driven by DER Forecast Change (Net Metering from FIT Program) and updated volumes expected for antenna and switch buybacks.
System Access Total	**1,049.1**	**1,058.3**	

[3] Please see Exhibit 2B, Section D6 at page 7.

2025-2029 Total Capital Expenditures			
Programs/Category	**Draft Plan ($M)**	**Final Plan ($M)**	**Reason for Change**
Area Conversions	211.7	236.7	Increase in scope within the Box Construction segment to complete full conversion of feeders with box framed poles (note, box framed poles are still targeted to be completed by 2026). Inflation-related cost increases for Rear Lot projects.
Underground Renewal - Horseshoe	458.4	475.7	Adjustments to estimates.
Underground Renewal - Downtown	156.3	165.1	Adjustments to estimates.
Network System Renewal	119.5	123.4	Adjustments to estimates.
Overhead System Renewal	346.3	358.4	Adjustments to estimates.
Stations Renewal	286.1	282.7	The following changes resulted in reduction to the program: • Scope refinement resulting in reduced spending in Stations Control & Monitoring • Increase in Sump Pump and AC Panel costs; increase in scope in order to address additional Stations Service Transformers • Scope refinement and reprioritization of work resulting in decreased renewal work at MS Stations • Increase in switchgear unit costs based on updated information from manufacturers, partly offset by a deferral of Station Building work
Reactive and Corrective Capital	325.4	328.1	Refinements to forecast methodology leading to minor reductions, offset by minor adjustments to estimates.
System Renewal Total	**1,903.7**	**1,970.3**	
System Enhancements	145.9	151.2	Minor adjustments to estimates and pacing to begin work earlier in the rate period for system observability investments to allow Toronto Hydro to collect additional data to support future system planning decisions with a focus on new devices integral to support grid modernization.

2025-2029 Total Capital Expenditures			
Programs/Category	**Draft Plan ($M)**	**Final Plan ($M)**	**Reason for Change**
Non-Wires Solutions	65.3	22.5	Reduction in program expenditures due to scope reduction to focus on Renewable Enabling Battery Energy Storage System based on latest experience and execution challenges faced during the current rate period within the Energy Storage segment. Transfer of Advanced Grid Pilots and related investments to an Innovation Fund.
Network Condition Monitoring and Control	6.2	6.0	Minor adjustments to estimates.
Stations Expansion	208.4	173.2	Reduction in investments within this program through the deferral of the second phase of expansion at Basin TS. Updated pacing for Downsview TS, resulting in minor estimate adjustments.
System Service Total	**425.7**	**353.0**	
Facilities Management and Security	152.2	145.5	Refined estimate for reactive repairs and maintenance for the Head Office and reductions to program expenditures in response to Phase 2 Customer Engagement feedback by more reactively managing asset risks.
Enterprise Data Centre	71.9	72.0	Minor adjustments to estimates.
Fleet and Equipment	78.8	43.7	Removal of approximately $32M due to an error for how fleet electrification was accounted for in the initial plan. Reductions to pace of the program in response to Phase 2 Customer Engagement feedback.
IT/OT Systems	310.4	301.3	Reduction in program expenditures due to: • Reallocation of costs from CAPEX to OPEX within the IT Cybersecurity segment resulting from an increase in managed services, cloud security services and associated maintenance and subscription costs. • Minor pacing adjustments within the IT Software program to align with expected S/4 HANA Go Live date. • Reduction in IT Software program in response to Phase 2 Customer Engagement results.
General Plant Total	**613.4**	**562.5**	

2025-2029 Total Capital Expenditures			
Programs/Category	**Draft Plan ($M)**	**Final Plan ($M)**	**Reason for Change**
AFUDC	33.8	44.6	Increases to AFUDC cost estimates due to updated timing of contributions to HONI and associated ISA and updated timing of Downsview TS delaying ISA timing.
Non-EWP Metering	12.8	12.8	N/A
Other Total	**46.7**	**57.4**	
Total CAPEX (2025-2029)	**4,038.6**	**4,001.4**	

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-55

Reference: Exhibit 2B, Section E2

With respect to Toronto Hydro's capital program:

QUESTION (A):

a) For each OEB category (system access, renewal, service, general plant), please provide the percentage of capital spending that has, or is forecast, to be undertaken by external contractors annually between 2020 and 2029.

RESPONSE (A):

Please see table below for a percentage of actual and forecast costs of external contractors compared to total capital expenditures. Toronto Hydro notes that for the forecast years, the percentage of external contractor cost will depend on the mix of work executed each year.

Table 1: 2020-2029 Annual Percentage of Capital undertaken by External Contractors

	Actual				Bridge	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
System Access	64%	64%	65%	59%	62%	62%	61%	59%	59%	58%
System Renewal	51%	52%	50%	53%	53%	53%	53%	53%	54%	54%
System Service	72%	83%	85%	63%	72%	52%	46%	54%	66%	63%
General Plant	43%	55%	53%	59%	49%	55%	58%	60%	61%	56%

QUESTION (B):

b) With respect to its more programmatic capital work undertaken as part of the system access and renewal categories, please discuss how Toronto Hydro decides if the work will be carried out by third-party contractors or internal resources.

RESPONSE (B):

Toronto Hydro determines the appropriate mix of internal and external work based on maintaining a core internal capability to carry out a work mix that includes planned capital, reactive, customer and maintenance work across the City of Toronto. Please refer to Exhibit 4, Tab 4, Schedule 3, 4.2.4.

Internal crews are allocated work until their available hours for work are balanced to assigned work. Once internal crews are balanced, remaining work is assigned to contracted resources. Work is assigned until all capital portfolios (e.g., load demand, overhead renewal, underground renewal, customer connections, external initiated plant, reactive etc.) and maintenance programs (e.g., preventive, corrective, emergency, customer) are fully allocated for a given time period.

As civil construction is not considered a core capability and as these skills and capabilities are readily available on the market, Toronto Hydro does not maintain its own internal civil construction workforce.

QUESTION (C):

c) Does Toronto Hydro similarly use third-party contractors for its preventive and corrective maintenance programs? If so, for each program, please provide the percentage of spending undertaken, or forecast to be undertaken, by external contractors annually between 2020 and 2029.

RESPONSE (C):

Yes, Toronto Hydro utilizes third-party contractor services for preventive and corrective maintenance programs in a similar manner as other work programs. Table 2, provides the percentage of spending undertaken and forecasted to be undertaken by external contractors annually between 2020-2029.

Table 2: Percentage of External Contractor Spend (%) by Maintenance Programs

Programs	Actual				Bridge	Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Preventative and Predictive Overhead Line Maintenance	64%	64%	65%	59%	62%	62%	61%	59%	59%	58%
Preventative and Predictive Underground Line Maintenance	51%	52%	50%	53%	53%	53%	53%	53%	54%	54%
Preventative and Predictive Station Maintenance Program	72%	83%	85%	63%	72%	52%	46%	54%	66%	63%
Corrective Maintenance	43%	55%	53%	59%	49%	55%	58%	60%	61%	56%

QUESTION (D):

d) Please explain the contractual arrangements that Toronto Hydro has with its major third-party contractors.

RESPONSE (D):

Toronto Hydro undertakes a rigorous procurement process for all OM&A and Capital services contracted out as detailed in the Procurement Policy (Exhibit 4A, Tab 3, Schedule 1, Appendix A). Through the competitive procurement process, all bid submissions are assessed using a comprehensive evaluation matrix which is set prior to the Request for Proposal (RFP) or Request for Quote (RFQ) going out to market and includes a detailed cost analysis. The results of the assessment are benchmarked between participants to the procurement process and against any existing contracts to ensure a favourable acquisition cost and the successful respondent's ability to meet or exceed Toronto Hydro's quality, safety and environmental requirements.

In Capital Construction, for example, work assignment to major third-party contractors are completed through the Term Contract Scope Assignment Offer (TCSAO), which is a process that assesses elements such as work scope's geographical location, synergies with scopes in the vicinity, Contractor's capability, capacity and overall cost effectiveness.

Toronto Hydro continues to utilize Unit Price Contract Management System (UPCMS) to ensure cost effectiveness and containment.

QUESTION (E) :

e) Has Toronto Hydro undertaken any recent analysis regarding the cost effectiveness of in-house or third-party contractors? If so, please provide that analysis.

RESPONSE (E):

Toronto Hydro engaged UMS Group to conduct a unit cost benchmarking study which compared average unit costs for major asset classes and maintenance activities. As further detailed in Exhibit 1B, Tab 3, Schedule 3, Section 4.6 and Appendix C, the results of this study showed that Toronto Hydro's unit cost performance was comparable or better than the peer group.

A composition of Toronto Hydro internal crews and utilizing third-party Contractors is an operational model that has been successfully utilized by Toronto Hydro historically and the Utility intends to continue with this hybrid model in this rate application period.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-56

Reference: Exhibit 2B, Section E3, Pages 9-11

Please explain how a feeder can be restricted due to short circuit capacity, but have no connected customers.

RESPONSE:

The short circuit capacity is based on the station bus limit. As described in the above reference, it's the system or component's capacity to withstand high levels of electrical energy congregated on that point or location without permanent damage. Therefore, once the station bus is at its capacity limit, DER projects can no longer be connected to any of its feeders as all generation sources connected to the bus would contribute to the short circuit current on the bus, in the event of a fault. As such, if a feeder is on a restricted bus, it cannot connect any DERs, regardless of the amount of load connected to it.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-57

Reference: Exhibit 2B, Section E4, Page 7

Please provide a revised version of Appendix 2-AA, that shows Toronto Hydro's annual internal budget (as opposed to the OEB approved budget) for each year between 2020 and 2024.

RESPONSE:

Toronto Hydro declines to provide the requested information on the basis that it is not relevant and does not have probative value in deciding how the utility performed relative to the plan in the last application. The relevant information is provided in the table referenced by the question, which includes a comparison of the 2020-2024 plan, which was approved by the OEB on an envelope basis, as well as the actuals and forecasts for the same period by investment category. Toronto Hydro believes that this information is comprehensive, consistent with Filing Requirements, and appropriate for the OEB to evaluate the utility's execution of the 2020-2024 plan.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-58

Reference: Exhibit 2B, Section E4, Page 7

Toronto Hydro states that one of the reasons of the increase in system access spending was "unforeseen emergence of large connections across a broad spectrum of market segments". Please explain why these large connections were unforeseen.

RESPONSE:

The increase in system access spend as a result of large connections (greater than 5MVA demand) were unforeseen including but not limited to the following reasons:

- Emergence of a new segment of customers in the data centre/cloud computing sector, with limited prior investments in the Toronto area and limited-to-no relationship with Toronto Hydro.
- The scale and volume of large connections like hyperscale data centres were unprecedented prior to the 2020-2024 period. Each connection is unique and is highly variable based upon a number of factors including customer specific type, size, required demand load, geographical location of customer's site, geographical availability of Toronto Hydro's distribution system in relation to the customers site and available distribution system infrastructure and capacity provisions. See Exhibit 2B, E5.1 p.7.
- The number of projects submitted to the City of Toronto have remained consistent over the years, however the number of residential units proposed and the overall Gross Floor Area (GFA) has increase substantially over the years, where projects have become larger and more complex overall. See Exhibit 2B, E5.3, p.7.
- New transit mandates, announcements and targets as well as new obligations under *The Building Transit Faster Act, 2020* ("BFTA"). See Exhibit 2B, E5.2.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-59

References: Exhibit 2B, Sections E5, E6, E7, E8

For each program, Toronto Hydro includes an 'Options Analysis'. Many of the options analysis do not include the cost impact of the non-selected option. Please provide a table that shows for each program, the forecast cost of each option between 2025 and 2029.

RESPONSE:

Toronto Hydro developed alternative pacing strategies for its programs through its planning process as described in Exhibit 2B, Section E2. This produced low- and high-side scenarios in addition to the Draft Plan, which formed the basis of Phase 2 engagement. In most cases, these expenditure plan options tie conceptually to the range of options examined in the 'Options Analysis' sections for the programs and should provide a reasonable sense of the cost range associated with the alternatives. Please see Toronto Hydro's response to 2B-SEC-53 for a detailed breakdown of the high, low, and Draft Plan options for the programs in Exhibit 2B, Sections E5 to E8.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-60

Reference: Exhibit 2B, Section E

SEC seeks to understand the relationship between capital expenditures and in-service additions. Please complete Excel file 2B-SEC-60.

RESPONSE:

Please see the completed Excel spreadsheet titled "*2B-SEC-60_AppendixA.xlsx*". Toronto Hydro notes that the Capital Expenditures have been adjusted to include AFUDC costs for each investment category to be comparable to the in-service additions populated in the provided table.

For Distribution capital programs[1], where discrete projects and completion dates are not known, Toronto Hydro applies conversion factors derived from a historical five-year average ratio (2018-2022) to capital expenditures and subsequent CWIP balances. As such, in presenting the in-service additions in the requested format (multi-year in-service additions specific to each Capital Expenditure stream), certain amounts are presented as being in-service in 2030 or later.

Toronto Hydro notes that the Excel file does not capture CWIP balances prior to 2025. Please see Exhibit 2B, Section E4.1.7 and Exhibit 2B, Section E4.2.7 for CWIP balances for the 2020-2024 and 2025-2029 periods respectively.

[1] Distribution capital programs refers to most programs within System Access, System Renewal and System Service investment categories, excluding large projects.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-61

Reference: Evidence Update (January 29, 2024)

On January 29, 2024, Toronto Hydro filed an evidence update. As SEC understands Toronto Hydro updated, among other aspects, the capital expenditures forecast as a result of an update to its system peak demand forecast.

QUESTION (A):

a) Please provide further details regarding the update to the peak demand forecast, including what drove the changes.

RESPONSE (A):

In addition to regular annual updates to reflect 2022 actuals and updates to its feeder request database,[1] Toronto Hydro made the following updates to the System Peak Demand Forecast:

1. **Weather Normalization**: aligned the weather normalization with the Load Forecast Guideline for Ontario published by the Regional Planning Process Advisory Group.[2]
2. **EV Managed Charging**: reduced the system peak to account for the impact of managed charging and the ultra-low overnight electricity rate for light-duty EVs.
3. **Load Refinements**: Refined assumptions between base load growth trends and customer connection requests to ensure no double counting.
4. **Load Materialization Rates**: Toronto Hydro extended its customer load materialization assumptions from a 3-year timeframe to a 5-year timeframe, which resulted in more gradual load growth.

[1] Toronto Hydro notes that the 2025-2029 forecast for customer connections expenditures provided in Exhibit 2B, Section E5.1.4 does include the impact of the 2022 actuals.

[2] Toronto Hydro follows the methodology outlined in Section 6.1.4 with one exception. Toronto Hydro uses the daily maximum temperature rather than the 3-day rolling average of historical daily maximum temperature.

QUESTION (B) :

b) Please explain in detail how the update in the peak demand forecast, resulted in the specific changes to the forecast capital programs costs.

RESPONSE:

The updated System Peak Demand Forecast yielded an overall lower system peak for the 2025-2029 rate period, which reduced the need for investment in the Stations Expansion (Exhibit 2B, Section E7.4) and the Load Demand (Exhibit 2B, Section E5.3) programs by $51.3 million and $19.2 million, respectively. The changes were as follows:

- Prior to the evidence update, the Stations Expansion Program included the proposed construction of a new DESN at Scarborough TS ("Scarborough TS Expansion") over 2026-2030. Following the update, the System Peak Demand forecast showed that capacity needs in this area could be managed in the next decade without upgrading the station.[3] As a result, the Scarborough TS project was removed from the program, resulting in a $51.3 million decrease to the 2025-2029 budget.
- Please note that both prior to and following the evidence update, the Sheppard TS Bus Expansion project has been and is proposed with the same scope of work, schedule, and cost estimate. However, the driver of the project has changed. Prior to the update, the driver was thermal capacity constraints, and following the update the driver is DER enablement.
- Prior to the evidence update, the Load Demand Program needed to make the following investments to manage forecasted growth: (i) undertake bus load transfers at 17 stations that were forecasted to become overloaded during the 2025-2029 rate period, and (ii) relieve the load on 23 priority feeders in the Horseshoe area and 49 in the Downtown area. Following the evidence update, Toronto Hydro needs to: (i) undertake bus load transfers at 11 stations that are forecasted to become overloaded during the 2025-2029 rate period, and (ii) relieve load on 15 priority feeders in the Horseshoe area and 64 in the Downtown

[3] Due to the Golden Mile Secondary Development Plan, the load of the Scarborough area is anticipated to grow substantially over the next 20 years. As a result, long term needs for Scarborough TS and its surrounding area are still being considered as part of Regional Planning.

area. The priority feeders in the downtown area increased due to forecasted increase in customer load in downtown station areas as seen through updates in the feeder request database.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-62

Reference: Exhibit 2B, Section E5.1

With respect to Customer Connections:

QUESTION (A)

a) [p.11-12] Please update Table 4 and 5 to include 2023 information.

RESPONSE (A):

Please see updated tables below.

Table 1: Cumulative Existing Generation Connections by type (Updated Table 4)

Type	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Renewable	1296	1547	1749	2072	2094	2126	2185	2280	2492
Energy Storage	1	4	4	10	11	22	24	28	28
Non-Renewable	35	38	44	54	60	87	112	116	118
Total	**1332**	**1589**	**1797**	**2136**	**2165**	**2235**	**2321**	**2424**	**2638**

Table 2: Cumulative Existing Generation Capacity (in MW) by type (Updated Table 5)

Type	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Renewable	71.9	86.6	96.6	108.7	110.0	111.3	114.1	116.2	120.2
Energy Storage	0.7	0.7	0.7	4.5	9.1	17.6	18.2	18.7	22.7
Non-Renewable	91.9	98.4	114.4	119.6	127.7	157.4	169.5	170.0	173.1
Total	**164.5**	**185.6**	**211.6**	**232.8**	**246.8**	**286.3**	**301.8**	**304.9**	**316.1**

QUESTION (B):

b) [p.14] Please explain how Toronto Hydro is currently or planning to use DER generation capacity as a system benefit.

RESPONSE (B):

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. Toronto Hydro does not procure energy (kWh) from DERs.

DER capacity is considered in Toronto Hydro's forecast for flexibility services and accounted for when making planning decisions. For more information about the flexibility services, please see Exhibit 2B, Section 7.2. In addition, Toronto Hydro will consider DER capacity when assessing capability to connect to the Toronto Hydro Grid.

QUESTION (C):

c) [p.15] Please explain the basis of Toronto Hydro's generation connections/capacity forecast.

RESPONSE (C):

As explained in Exhibit 2B, Section E5.1, Toronto Hydro's DER forecast was based on recent and anticipated growth patterns, considering a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of forecast.

QUESTION (D):

d) [p.20] Toronto Hydro proposes to increase the Basic Connection Fee allowance.
   i. What is meant by Rate Class 1 to 5?
   ii. For each year between 2025 and 2029, please provide the increase in net capital expenditures as a result of the increase in the Basic Connection Fee allowance.

RESPONSE (D):

i. The Rate Class 1 to 5 are based on customer type and demand load as follows:
   - Class 1: Residential (single service)
   - Class 2: General Service (0<50kW)

- Class 3: General Service (50kW to 999KW)
- Class 4: General Service (1000kW to 4999kW)
- Class 5: General Service (5000kW and above)

ii. See below table for the 2025-2029 net capital expenditure increase as a result of the net capital expenditures as a result of the increase in the Basic Connections Fee allowance.

Table 1: Basic Connection Fee allowance net capital expenditures ($ Millions)

	2025	**2026**	**2027**	**2028**	**2029**
Basic Connection Fee Allowance	3.4	3.4	3.4	3.4	3.4

Toronto Hydro notes that shortly before the application was filed, Ontario Energy Board ("OEB") Staff issued a bulletin regarding the basic connection for residential customers.[1] The utility notes that the net increase only reflects the impact of new connections (which have been steady over the last few years) and not to upgrades (which are trending upward). Should the Basic Connection Fee allowance be applied to upgrades, this would require an increase to the proposed spend. At this time, Toronto Hydro is not proposing to deal with the impact of this change as the variances could be tracked under the DRVA.

[1] OEB Staff Bulletin re: Residential Customer Connections & Service Upgrades (August 24, 2023)

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-63

References: Exhibit 2B, Section 5.3, Page 27

Toronto Hydro states that "Based on studies and analysis, the Station Load Forecast considered factors with a probabilistic approach when forecasting for peak loads of all Toronto Hydro buses of the station within the City of Toronto." Please describe the studies and analysis that Toronto Hydro undertakes and provide a copy of any of those studies or analysis (or internal summaries if they are undertaken on a bus-by-bus basis).

RESPONSE:

Please refer to Section D4.1.1 System Peak Demand, where the studies and analysis used for the basis of the Station Load Forecast are explained in detail.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-64

Reference: Exhibit 2B, Section E5.4

Preamble:

With respect to Metering:

QUESTION (A):

a) [p.9] By meter type used by Toronto Hydro, please provide their: i) expected useful life, and ii) failure rate by their year of service (i.e. failure rate of meter in each of year 1, year 2, etc.).

RESPONSE (A):

The expected useful life for all meter types is 15 years.[1]

The following table shows the number of meters replaced due to failures in the 2020-2023 period:

Table 1: Meter Replacements due to Failures 2020-2023

	2020	2021	2022	2023	Total
Residential Meters	4,323	2,430	1,963	3,087	**11,803**
Suite Meters	534	751	421	606	**2,312**
Commercial Meters	494	526	464	745	**2,229**
Total	**5,351**	**3,707**	**2,848**	**4,438**	**16,344**

QUESTION (B):

b) [p.10] What analysis has Toronto Hydro undertaken to determine what the actual end of useful life is for these meters are.

[1] Exhibit 2A, Tab 2, Schedule 1, Appendix D "2022 Depreciation Study" by Concentric Advisors, at pages 3-20-3-21.

RESPONSE (B):

Toronto Hydro's asset management practices with respect to metering assets entail the replacement of meters that are at or beyond their expected useful life. As discussed in the response to 2B-Staff-144(a), Toronto Hydro does not operate its metering assets on a run-to-fail basis, since the operational and regulatory compliance risks, as well as the customer inconvenience, associated with such an approach would be significant. As noted in the response to 2B-Staff-144(b), the condition of metering assets is determined on a pass or fail basis and there is no intermediate health status, unlike most other utility assets. When meters fail, consumption data is lost and replacement takes time, putting the accuracy and timeliness of customer billing are at risk. In addition to the asset failure risk, Toronto Hydro's fleet of smart meters are technologically obsolete and therefore pose a barrier to the achievement of AMI 2.0 and associated benefits until the majority are replaced, as discussed in 2B-Staff-194. In Toronto Hydro's assessment, these risks are material enough to justify proactive replacement of meters exceeding their expected useful life, regardless of the hypothetical possibility of the meters far outlasting their lifespan.

QUESTION (C):

c) [p.10] Please provide a copy of the internal business plan for AMI 2.0.

RESPONSE (C):

Toronto Hydro began replacing its current generation of smart meters in the 2020-2024 rate period, as laid out in the 2020 rate application.[2] The continuation of that plan in the context of the AMI 2.0 initiative is discussed in Exhibit 2B, Section E5.4 of this proceeding.

The utility also consulted with Ernst & Young ("EY") to develop a strategic plan for the AMI 2.0 initiative to prioritize potential benefits and use cases of most value to Toronto Hydro. The utility is in the process of obtaining disclosure consent from EY and will file the strategic plan report as an appendix to this response as soon as reasonably possible.

[2] EB-2018-0165, Exhibit 2B, Section E5.4, at p. 8-11.

QUESTION (D):

d) [p.16-17] Please provide a version of Table 5 and 6 that show for each segment, the number of meters replaced pear year.

RESPONSE (D):

Please refer to the below tables, which indicate historical and planned proactive meter replacements, which exclude reactive meter replacements shown in part (a).

Table 2: Historical and Planned Meter Replacements 2020-2024

	2020	2021	2022	2023	2024	Total
Residential and Small C&I Meter Replacement	421	0	0	0	104,370	**104,791**
Suite Metering	4,924	2,974	2,559	3,576	2,581	**16,614**
Large Customer and Interval Metering	10	2	2	4	4	**22**
Remote Disconnect	2,742	2,627	1,389	1,388	3,022	**11,168**
Sampling/Meter Replacement	16,587	6,628	15,653	4,326	12,962	**56,156**
Wholesale Metering	4	10	0	2	2	**18**
System Upgrades	NA	NA	NA	NA	NA	NA
Total	**24,688**	**12,241**	**19,603**	**9,296**	**122,941**	**188,769**

Table 3: Planned Meter Replacement 2025-2029

	2025	2026	2027	2028	2029	Total
Residential and Small C&I Meter Replacement	157,893	173,710	179,708	68,985	0	**580,296**
Suite Metering	2,623	2,363	2,131	1,924	1,740	**10,781**
Large Customer and Interval Metering	8	20	18	17	13	**76**
Sampling/Meter Replacement	10,464	13,201	14,783	15,396	11,311	**65,155**
Wholesale Metering	0	2	0	0	0	**2**
System Upgrades	NA	NA	NA	NA	NA	NA
Total	**170,988**	**189,296**	**196,640**	**86,322**	**13,064**	**656,310**

RESPONSE (E):

e) [p.22] Did Toronto Hydro undertake a competitive procurement for the AMI 2.0 program? If so, please provide details.

RESPONSE (E):

Yes, Toronto Hydro is nearing the end stages of a competitive procurement process for the AMI 2.0 program, which involved issuing a request for proposals from all major meter manufacturers which have a presence in Canada. Prior to issuing the RFP, Toronto Hydro undertook a market assessment of AMI capabilities to align the RFP with the utility's strategic objectives. This assessment was completed by UtilAssist and can be found in Appendix A to this response.

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-SEC-64
Appendix A
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AMI 2.0 Technology Assessment Report for Toronto Hydro

December 15, 2021

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Confidentiality Statement

This document has been prepared by Util-Assist Inc. to provide Toronto Hydro with an introduction to Advanced Metering Infrastructure (AMI) 2.0 technology, a summary of the current market offerings from leading AMI vendors, and a preliminary financial assessment of replacement AMI costs. This document is intended to be used for planning and educational purposes only and should not be construed as a recommendation of any vendor or vendors over others. The representations of vendor products and capabilities are informed by publicly available information, as well as knowledge gained by Util-Assist in the course of its business. The content of this report represents Util-Assist's best understanding and interpretation of the information available but may not represent what vendors can or would propose to Toronto Hydro should it undertake a formal request for proposal process.

This report has been generated solely for use by Toronto Hydro and because of the sensitive nature of the information and statements contained in the report, the entirety of this report is confidential, and no part of this document may be distributed to or used by any other person or entity other than its intended recipients without prior written permission from Util-Assist Inc. Recipients of this report should take all reasonable measures to prevent unauthorized disclosure of the confidential and proprietary information contained within this document.

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Section 1: Executive Summary

This document introduces the next generation of advanced metering infrastructure (AMI) and summarizes the current market offerings for Toronto Hydro (referred to as the "Utility") as it prepares to replace its current AMI system. This document includes information on the leading AMI vendors and their current technology, summarizes the components and capabilities of newest generation AMI as compared to the previous generation, and provides a financial assessment and estimate of replacement AMI costs for the Utility's consideration.

Over a decade ago, the first generation of AMI Technology ("AMI 1.0") changed the operational landscape of Ontario's electricity distribution utilities. The transition from conventional meter reading and automated meter reading (AMR) to AMI transformed virtually the entire meter-to-cash process with new operational benefits. The next generation of AMI, commonly referred to as AMI 2.0, is poised to replace AMI 1.0 with another leap in benefits available to utilities and their customers as the older technology reaches the end of its service life.

AMI 1.0 Technology focused on basic operational capabilities using two-way communications to support the meter-to-cash process and some exception management activities such as enhanced outage detection and remote meter disconnect/reconnect. Incremental to these capabilities, AMI 2.0 delivers secure, standards-based, big-data analytics, and distributed intelligence (DI) to support new use cases and provide greater "future proof" interoperability.

AMI 2.0 will allow utilities to meet new and evolving expectations of consumers for the next 15 to 20 years, who are now more environmentally conscious and digitally mature with interests in home energy management technology and personalized energy services. AMI 2.0 offerings are interchangeable platforms that allow utilities to support enhanced Distribution Automation (DA), Demand-Side Management (DSM), smart streetlights, smart cities initiatives, Industrial Internet of Things (IIoT) applications, and behind-the-meter opportunities. AMI 2.0 expands integration with third-party solutions from industry standards such as Multi-Speak and CMEP to web services and JMS queues.

Where AMI 1.0 use cases relied on using external systems to analyze metering and operational data, AMI 2.0 software can include pre-built analytics in addition to enabling standards-based integration with third-party analytics solutions within the utility enterprise. AMI 2.0 "distributed intelligence" framework is a significant development as it extends analytics out to the network edge (i.e., at meter or sensor level) providing both faster operational insight with a higher trust level due to greater data granularity (i.e., 1 second grid edge data in AMI 2.0 compared to 1 hour data from AMI 1.0) and vastly lower latency and network traffic.

Standards developed by government agencies, industry alliances and manufacturing groups have always played a key role in the safe, reliable, and secure operation of Ontario's electricity distribution network. These standards cover the full range of AMI hardware and software functions, including meter and/or system accuracy, interoperability, data, protocol, security, and safety. AMI 2.0 further embraces both legacy and emerging industry standards such as Wi-SUN, IPv6, 6LoWPAN and IEEE 802.15.4 to ensure safe and secure operation, as well as device interoperability across the AMI and other networks to future-proof significant utility investments in AMI. These emerging industry standards opens the proprietary networks from the past allowing vendor innovation and interoperability to be achieved by the utility severing the dependency on their AMI partner to be their sole source of innovation over the life (15 to 20 years) of this new investment.

With current AMI technology rapidly approaching end-of-life in Ontario, an investment in AMI 2.0 is needed as part of regular asset lifecycle management. Current economic and market conditions have provided a strong incentive for AMI vendors to improve the value proposition of the technology. This document is intended to provide the Utility with an overview of the AMI 2.0 technology offerings that can position them to address a near end-of-life AMI 1.0 system, future operational requirements, and respond to a changing consumer and energy marketplace.

Section 2: AMI Technology

Since its initial mass deployment in North America nearly two decades ago, AMI has advanced much the way other consumer and communications technologies have, in terms of both hardware and software capabilities. As a result, AMI offerings have evolved from the incumbent AMI "1.0" technology, and the latest generation of AMI technology on the market represents a fundamentally different product, often referred to as AMI 2.0. This section will summarize the technology fundamentals and highlight the differences between AMI 1.0 and AMI 2.0.

2.1. Current AMI Technology Fundamentals

North American utilities began transitioning from manual reading and AMR systems to AMI in earnest just after the turn of the century and in Ontario more specifically, between 2004 and 2010. AMI 1.0 technology introduced true, two-way communications and sophisticated capabilities to integrate within the distribution network as part of grid modernization initiatives across North America. Toronto Hydro transformed its electromechanical meter fleet into an Elster AMI 1.0 fleet as part of Ontario's government mandated migration to AMI.

Originally, conventional metering (electromechanical) devices measured only consumption and/or demand and were read manually or via drive-by systems typically once a month. Currently, AMI 1.0 infrastructure collects meter data including registers, intervals, and events via two-way communication with the utility's "smart" meters and sends that information back to the utility.

Figure 1: Electromechanical Meter vs. AMI meter

2.2. Next Generation AMI Technology Fundamentals

AMI 2.0 is the "next generation" metering solution. It provides a communication medium that leverages open standards-based communication to ensure interoperability of additional systems and applications. These capabilities allow utilities to respond to new challenges, expectations, and opportunities within their service territories.

AMI technology has now become the new norm and is widespread across North America. As of 2018, Natural Resources Canada estimated that 82% of electric meters in Canada were smart meters, and the U.S. Energy Information Administration estimated that electric AMI meter saturation reached 70% of the market as of 2020.

The prevalence of AMI and the data it provides has in turn increased customer expectations and awareness of energy usage. In its article, “AMI 2.0: A Catalyst for Expanding Consumer Relationships and Benefits”, the National Association of Regulatory Utility Commissioners discusses the maturing consumer and how 52 percent of its consumers are interested in home energy management technology, and close to 62% percent are interested in receiving customized reports with energy-saving tips[1]. Consumers are a key driver of the increasing implementation of AMI 2.0, which can help manage distributed energy resources (DER) and distributed intelligence (DI) to deliver the “right information at the right place at the right time so utilities can meet the demands of new use cases and create value for the customer.”[2]

AMI 2.0 is the “next generation” of smart metering technology, which includes more advanced metering hardware as well more advanced software in vendors’ head end systems and available modules and applications. Some of AMI 2.0’s key capabilities include wider interoperability using a standards-based solution, greater options for remote meter disconnect/reconnect, distributed intelligence, cloud and data analytics, advanced outage detection, integrated distribution automation network support, smart city applications/support, remote power quality monitoring, and mass personalization.

Some of the operational benefits offered to utilities through AMI 2.0 include the following:

- Ability to leverage data for improved outage/restoration notifications
- Support of customer energy disaggregation functionality
- Ability to leverage the meter fleet as advanced end of line sensors for distribution monitoring and analytics
- Improved operational performance
- Improved reliability

Some of the primary advanced AMI 2.0 use cases and components include:

- Distributed intelligence
- Home automation
- Distribution automation
- Smart cities and extended use applications (e.g., connected streetlights, traffic monitoring, etc.)

---

[1] Source: *AMI 2.0: A Catalyst for Expanding Consumer Relationships and Benefits*, the National Association of Regulatory Utility Commissioners.
[2] Source: *The Possibilities of Distributed Intelligence are Endless*, PowerGrid International, 2020

As first-generation AMI meters reach their end of life and are replaced with AMI 2.0 meters and supporting technology, utilities will be able to support customers' demands for a more fulsome digital experience and facilitate organizational changes that can capitalize on digital maturity and the exponential increase in quality data for data-driven decision making.

Section 3: AMI 2.0 Suppliers

The AMI market is occupied by many vendors but dominated by a few primary competitors. This report focuses on the market-leading AMI vendors in North America, and compares the technology offered by these vendors. While many vendors claim AMI 2.0 capabilities in their products only a few offer the stability, scale, and maturity required to support large-scale utility projects. This section introduces the five primary AMI 2.0 providers – the vendors are not ranked and are discussed in alphabetical order.

3.1. Honeywell Elster (Honeywell)

Honeywell, founded in 1885, is a Fortune 100 diversified technology and manufacturing company whose global portfolio includes aerospace products and services, building technology, performance materials and technologies and safety and productivity solutions. Elster, who was an early producer of gas meter technology, was acquired by Honeywell in 2016.

Honeywell's end-to-end electricity, water and gas offerings include advanced meters/sensors, secure communications, data collection, grid management, and analytics. They also provide solutions for demand response, DA, smart street lighting, data disaggregation and more.

In 2004, Honeywell was first-to-market with a full two-way AMI system and has since deployed over 200 AMI projects in North America. Honeywell solutions can be found in 150 million residential homes, 10 million small business buildings and 1000+ commercial and industrial sites.

Further information about Honeywell can be found at the following website:

https://www.honeywell.com/us/en

3.2. Itron

Itron was founded in 1977 by a small group of engineers who were intent on finding more efficient ways to read meters in Hauser Lake, Idaho. Today, their portfolio consists of smart networks, software, services, meters, and sensors enabling cities and utilities to better manage energy and water.

Itron's product offerings include measurement and sensing hardware, network hardware, software, and services, all which enable AMI, advanced meter reading, analytics, distributed energy management, distributed intelligence, DA, meter data management (MDM), smart city solutions and industrial IoT solutions. Utilities have the option of managing their own solutions or can take advantage of Itron's Managed Services offerings.

In 2005, Itron had 45 million meters automated worldwide as well as 3000 utility customers in 65 countries. Today, they have over 250 partners and now 200+ million communicating endpoints with 8,000+ customers in more than 100 countries. As a pioneer for distributed intelligence, Itron's utility customers have also deployed 2 million DI-enabled endpoints with another 6 million under contract. In early 2018, Itron completed the acquisition of Silver Spring Networks as a wholly owned subsidiary of Itron, Inc. and have taken steps to integrate the Silver Spring Networks' platform and solutions into a comprehensive smart utility, smart city, and industrial IoT solution offering.

Further information about Itron is available at the following website:

https://www.itron.ca/na

3.3. Landis+Gyr (L+G)

In 1896, Landis+Gyr was founded in Zug, Switzerland where they began manufacturing electricity meters for European utility companies. They became a global company in 1924 with the creation of their first overseas offices in New York and Melbourne, Australia. They developed and launched their first range of digital meters in 1981. Since then, Landis+Gyr continues to develop quality metering products but also provides other energy management products and services.

Landis+Gyr's product offerings include gas, electric and water meter hardware, streetlight sensors and controllers, network hardware and load control switches. It also offers a wide range of software solutions such as smart grid applications, demand-management technologies, data analytics, and renewables integration. Some Landis+Gyr applications, such as its MDM, can be owned and run by the utility or can be run as Software as a Service (SaaS).

Over 60 million AMI endpoints have been deployed or are under contract worldwide at hundreds of utilities. Additionally, with its Gridstream RF Mesh IP solution implementation and deployment of over 5 million smart grid devices at Tokyo Electric Power (TEPCO), Landis+Gyr has built the largest IoT network in the world.

Further information about Landis+Gyr can be found at the following website:

https://www.landisgyr.com

3.4. Sensus

Sensus has been a global force in the meter industry for more than 100 years. Over the last several decades it has transitioned from a metering business to a provider of telecommunications, metering, and DA for utilities. Today, Sensus offers many hardware and software solutions which enable AMI, AMR, cathodic protection, conservation voltage reduction, customer portal, data analytics, DR, DER, DA, ERT meter reading, leak management, lighting control, non-revenue water, outage management, PLC migration and pressure regulation. The Sensus managed services include options for both SaaS and Network as a Service (NaaS).

Sensus' FlexNet AMI solution debuted in 2006 and has now been deployed at nearly 1,000 utilities across North America. Today, Sensus has deployed 20 million+ FlexNet endpoints, 20,000 Sensus DA devices as well as 80 million metering devices. They have also been a partner in 655 FlexNet AMI projects, 500 SaaS projects and over 200 DA projects.

Further information about Sensus can be found at the following website:

https://www.sensus.com

3.5. Trilliant

Trilliant was founded in 2004 and introduced the world's first 2.4 GHz wireless mesh AMI platform in 2005. Trilliant supplies the necessary network infrastructure, endpoints, and software to support analytics, demand response, lighting control, suite metering, AMI, and DA. Their products are meter and endpoint agnostic which allows market leaders in metering equipment such as Itron, Landis+Gyr and Aclara to deploy their meters using the Trilliant communications platform.

Trilliant has more than 75 customers in 10 countries around the world. They have more than 30 million consumer endpoints deployed, including 12 million endpoints in the United Kingdom.

Further information about Trilliant can be found at the following website:

https://www.trilliant.com

Section 4: AMI 2.0 Technology

AMI 2.0 technology is an end-to-end solution consisting of meters, network infrastructure, and software. This report additionally assesses the operational data, integration, security, and enabling capabilities recognizing that these capabilities could span each of the primary components of an AMI 2.0 network.

4.1. Metering

The aggregate cost of meters is by far the largest line item in an AMI investment, in some cases greater than 70%. As a key lesson learned from AMI 1.0, utilities will focus on future-proofing their AMI 2.0 investment with a more detailed assessment of meter hardware. The combination of meter compute (processor), memory, and bandwidth with industry standards has become a key criterion to assess a solution's ability to evolve with the industry over a 20-year lifecycle.

AMI 2.0 meters differ greatly from AMI 1.0 at the architecture-level. Suppliers have embraced **standards-based technologies** with **more powerful hardware** in their AMI 2.0 meters. Standards enable interoperability, flexibility and extensibility across an AMI network that could include metering, in/at-home, Smart City, and DA devices. Improved hardware supports needs for higher fidelity data and distributed intelligence to enable new capabilities at the network edge.

In addition to meter safety and performance standards, several AMI 2.0 suppliers have moved to embed **industry standard operating systems (OS)** including Linux and RTOS in the meter. This moves away from a proprietary OS and provides more flexibility to the future use of a meter's intelligence hardware. It aligns with the global software industry and developer ecosystem and supports extensibility of AMI meters through development and implementation of AMI 2.0 distributed intelligence.

A similar move to **industry standard communication** options is found in AMI 2.0. Suppliers have begun introducing support for Wi-SUN FAN, Wi-Fi IEEE 2030.5, ZigBee SEP 2.0, and in some cases optional Bluetooth xxx PAN which provide the key to interoperability for in/at-home devices and Smart City initiatives. The Network Interface Cards (NICs) supporting these standards are incorporated into the AMI 2.0-meter hardware, contributing to the overall meter cost. When considering communication standards, the incremental up-front cost (if any) of hardware to support a standard against costs for a potential future field retrofit (i.e., remove/replace) in the future must be carefully assessed.

Capability	Honeywell	Itron	L+G	Sensus	Trilliant
User-to-Network Interface (UNI)[3]					
UNI-N1 – 802.15.4g Wi-SUN 1.0 Mesh	Yes	Yes	Yes	No	Yes
UNI-N2 – 802.11 Wi-Fi Direct	No	No	Yes	No	No
UNI-N3 – 802.15.4 ZigBee	Yes	Yes	Yes	No	Yes
UNI-N4 – 802.3 Ethernet	No	Yes	Yes	No	No
UNI-N5 – Serial (RS232/RS485) Interface	Yes	Yes	No	No	Yes
FAN Network-to-Network Interfaces (NNI)					
NNI-F1 – 802.15.4g Wi-SUN Mesh	Yes	Yes	Yes	No	Yes
NNI-F2 – IEEE P1901.2 Powerline Carrier	No	Yes	No	No	No
WAN Network-to-Network Interfaces (NNI)					
NNI-W1 – Cellular data	Yes	Yes	Yes	No	Yes
NNI-W2 – Ethernet/IPv4/IPv6	Yes	Yes	Yes	No	Yes

Table 1: Network Interface Protocols

Advances in hardware technology have benefitted the AMI industry through more powerful on-board processors, memory, and network interface hardware. AMI 2.0 suppliers are moving to **RISC** (reduced instruction set computer) based CPUs from Advanced RISC Machines (ARM) that operate at **higher speeds** (up to 600MHz) to support high-speed waveform data, sampling adaptive communication path (re-) routing, true IPV6 addressing and distributed intelligence at the network edge. When assessing the relative compute power, its important to consider the level, speed and type required by each offering to support both current operational Service Level Agreements (SLAs) and future initiatives.

Memory architecture within AMI 2.0 meters typically consists of RAM, NVRAM and Flash found within the metrology and DI boards and NIC. This memory is utilized for temporary storage, persistence, and re-writable space for firmware (respectively). While the memory configurations vary widely between AMI 2.0 suppliers, when considering on-board memory options, utilities should require the **meter memory to maintain** 35 days, 4 channels of 15-minute Interval data plus Event and Alarm data as a minimum.

In addition to embracing communication standards, AMI 2.0 NICs support full two-way communications for over-the-air (OTA) firmware management and active disconnect/reconnect/load limiting tasks. NICs available in AMI 2.0 meters support higher bandwidth (data transfer rate), and shorter latency (time delay) at the NAN and WAN level than most AMI

[3] UNIs intended to interface locally between end equipment and associated AMI 2.0 device (e.g., meter)

applications require today. While these performance characteristics have improved, utilities should consider that implementing improved security measures such as IPsec and TLS to secure connected assets, conversely **slow the (improved) bandwidth** requirements by a factor of 2-3 times [4].

Unlike the headend or network equipment, the utility gets one chance at selecting the right meter hardware due to the expected 20-year life and high costs of premature field replacement. A higher-level review of the meter hardware is critical to ensure assets will achieve the merging goals of the utility in the coming years based on business needs. Examples include, ensuring the bandwidth is upgradable to keep up with standards (e.g., 300 Kbps to 2.4 Mbps[5]), ensuring the memory and processor have enough headroom for future firmware upgrades (e.g., 2x the size of the initial deployment), and planning for hardware to support DI applications that will allow the loading of future vendor or third-party applications to support evolving utility business case needs. The following figure shows network bandwidth use and latency for common AMI 2.0 and smart city applications.

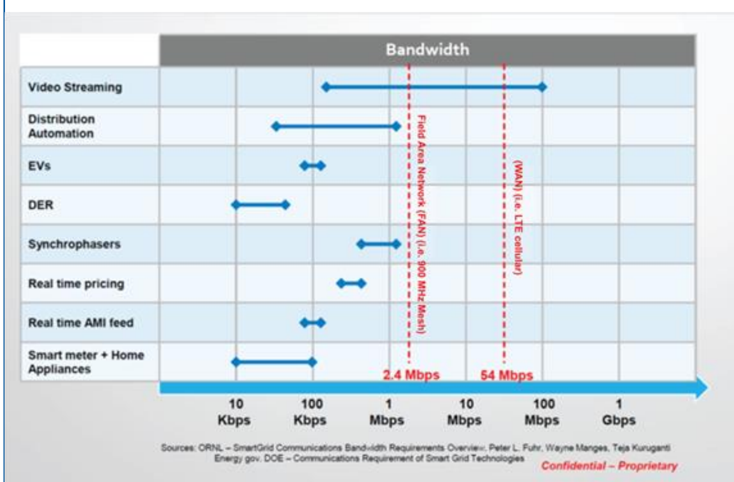
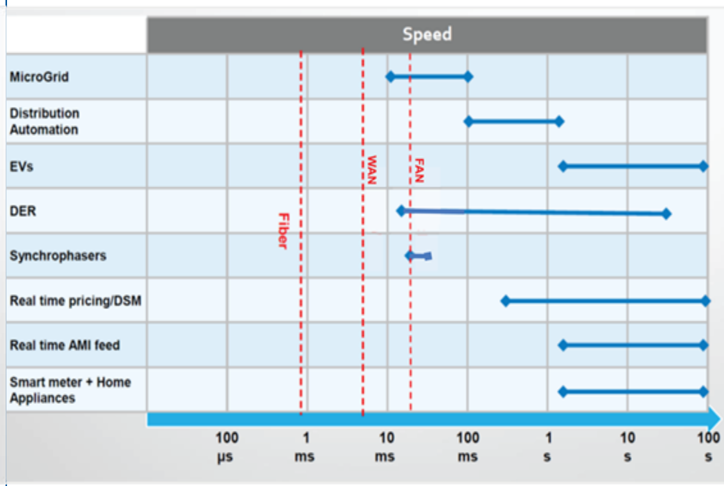
Network Utilization: Bandwidth	Network Utilization: Latency
	

Figure 2: Smart Grid Communications Bandwidth and Latency

It should be noted that suppliers offer AMI 2.0 devices in most meter forms (see Appendix C) to satisfy North American electric services. However, Toronto Hydro is an example of an electric utility that operates (~7,000) 600V-Delta services

---

[4] Reference: *Bandwidth and Security Requirements for Smart Grid*, 2020 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe)

[5] As a guiding principle or, "rule of thumb" the bandwidth **must be upgradable** beyond what is required to support today's Use Cases to allow for future memory requirements to support undefined Use Cases although the cost of field replacement must be also considered.

which is unique to Canada and in particular older services. Two electric meter manufacturers have offered this meter type in the past, but they are not among the AMI 2.0 suppliers addressed in this report and this offering may no longer be available.

Therefore, if Toronto Hydro requires a single, cohesive AMI platform, Toronto Hydro would need to incorporate the requirement for these meters into an RFP, and assess the options proposed by AMI providers. Based on experience, the option most likely to be proposed would be an AMI 2.0 module fitted on a specialty meter, which would likely be more costly in terms of hardware and integration and would also be limited in its capabilities compared to a fully integrated AMI 2.0 meter.

4.2. Distributed Intelligence

Distributed Intelligence is an AMI system's capability to locate specific elements ("apps") of its analytic processing anatomy at any node within its architecture. Technology advances found in the compute, memory, and bandwidth of AMI 2.0 meters combined with non-proprietary operating systems allow the utility to deploy **discrete**, analytic applications onboard the meter, reducing latency, storage, and network traffic overhead. Multiple apps can be deployed to AMI 2.0 meters as needed, which operate simultaneously locally while reporting to the utility back office for centralized action (e.g., further analysis, workflow) or storage.

Apps can be **developed by the utility, AMI supplier, or third parties** with specialized skillsets and expertise through partnership programs using Software Development Kits (SDK) / development environments created and provided by AMI suppliers. Meters with non-proprietary operating systems such as Linux, offer a **large developer ecosystem** which the utility could leverage more easily for development of DI apps than meters with a proprietary OS.

Submission, acceptance, and certification of apps are performed by the suppliers (or third-party certifiers) to ensure performance, operability, security, and privacy requirements remains in compliance. **Risk to the utility** related to the use of 3rd party DI apps is equivalent to use of existing app marketplaces in other technology sectors. App marketplaces provide the submission, certification, monitoring and control workflow for the supplier, app developer, and utility. Before an app can be deployed to an AMI 2.0 meter, the utility can approve it for use by its respective operating groups (depending on licenses purchased).

A particularly innovative AMI 2.0 capability that distributed intelligence can leverage is the AMI 2.0 meter's **location awareness** (where offered). Using Power Line Carrier (PLC), AMI 2.0 meters can identify the distribution transformer to which it's connected along with other characteristics (e.g., phase angles) as individual meters or single representative of meters downstream of the transformer. This allows AMI 2.0 meters to form analytic "clusters" at the distribution transformer level to support true real-time, active grid operations such as feeder phase balancing and real-time maintenance of GIS connectivity models.

Apps are managed (licensing, policy, versioning, monitoring etc.) and delivered through competitive app **marketplaces** managed and maintained by the supplier, styled after the Apple App Store or Google Workspace Marketplace models. This allows developers of certified apps to market to specific or all utilities.

At this stage of the Utility's AMI 2.0 journey, it is important for any considered AMI hardware and platforms to support apps without the obligation to purchase them immediately. Future DI apps should be driven by a utility business case with a clear understanding of the AMI supplier's governance model for app certification. The Utility should also ensure that future AMI analytics capabilities through apps can be **downloaded without any firmware code** or meter configuration changes. To this end, utilities should require that AMI 2.0 suppliers offering DI apps **include pilot projects** to familiarize themselves with the technology and approach (vs. traditional, centralized analytics models).

The table below shows the current state of the five primary vendors' meter app offerings. "Roadmap" items are areas where vendors do not have offerings currently on the market but have indicated they are pursuing these as roadmap items for future.

	Honeywell	Itron	L+G	Sensus	Trilliant
Distributed Intelligence Apps	Roadmap	Yes	Yes	Roadmap	Roadmap
App Marketplace	Roadmap	Yes	Yes	Roadmap	Roadmap
Software Development Kit	Roadmap	Yes	Yes	Roadmap	Roadmap
App Developer Program	Roadmap	Yes	Yes	Roadmap	Roadmap
Supplier Apps	Roadmap	Yes (19)	Yes (6)	Roadmap	Roadmap
Third-party App Developers	Roadmap	• Utilidata • Grid4C • Bsquare	• Sense • Utilidata	Roadmap	Roadmap

Table 2: Current Vendor DI and App Support

Four of the main suppliers currently or intend to provide and manage future grid edge capabilities with DI apps. Only Sensus currently plans to offer these capabilities through the alternate means of device firmware updates, which introduces risk because any changes to "software properties regulated by legal metrology[6]" may require Measurement Canada review. In general, Itron is leading the market with its app offerings, as it has the most mature "app store" with an open platform for third-party development and is the furthest along in terms of apps that are presently available for utility use. Landis+Gyr is in the process of enhancing its app offerings, but its app store is still in development with no apps that are commercially available as of the time of writing.

DI apps offer low latency local analytics on high-fidelity data (1 second) and peer-to-peer capabilities that are not possible with a centralized analytics model where data and resulting decisions must transit the network. **Where immediate action is required** based on analytics results, the fully distributed model is the best choice to leverage speed and discrete

[6] Reference: *Measurement Canada S-EG-05 - Specifications for the approval of software-controlled electricity and gas metering devices*.

conditions. Real time action requirements such as immediately opening the meter's disconnect switch when detecting a broken neutral or performing active load control based on load reduction targets are examples where DI apps alone is appropriate.

However, a centralized analytics model can offer incomparable scalability, processing power, storage, user tools and access to enterprise data completely impractical for field deployment. In some cases, the centralized model can be a necessary 2nd tier of analytics that consumes DI app results **with other enterprise data** to make decisions or inform the enterprise of data integrity issues. Engaging with consumers with more informed targeted marketing programs by identifying high usage appliances through load disaggregating or identifying GIS data integrity issues through location awareness are examples where a centralized analytics model is appropriate.

The choice between centralized and distributed analytics models is use case dependent and depends on the action required. DI apps alone do not necessarily offer the end-to-end solution and DI app results may require additional analysis or manipulation centrally in cases when logic is split between edge and back office. It is likely that a hybrid approach is more appropriate as multiple DI apps can operate on one or more meters simultaneously and the utility creates and evolves its DI app network.

4.3. Suite-Metering

Urban centers typically include multi-unit residential and/or commercial complexes served by a bulk metered service by individual, discrete consumers. Originally, consumer billing obligations were apportioned by property owners either based on a proportional calculation (square foot of suite) or un-sanctioned measurement system which led to discrepancies and inequities. As part of Ontario's Energy Consumer Protection Act, suite metering has been legal since about 2009.

Of the five primary AMI competitors, **only Trilliant offers its own suite-metering solution** for which they recently acquired the Canadian and international rights from Quadlogic. Trilliant has described a strategic roadmap that would merge its suite-metering and AMI strategies, but these could be integrated through conventional digital mechanisms.

Trilliant's suite metering solution is available for all three commodities (electric, water, gas) with most voltage configurations (120, 220, 240, 277, 347, 380, 480, **600 Delta** or Wye 50/60 Hz) and, compliant with ANSI (C12.1, C12.16), IEC 687, Measurement Canada (AE-1042, AE-1148) and UL-C (E 204142) certifications. The inter-building communication system uses Power Line Carrier to a hosted Data Management Services center through Ethernet, Telco, RS-232, and RS-485.

The lack of suite-metering solution alternatives to Trilliant presents an imbalance to compare to the other primary, North American AMI 2.0 suppliers. However, considering the independence between Trilliant's AMI 2.0 and Suite Metering offerings the other AMI 2.0 suppliers could justifiably claim similar integration capabilities with third-party suite metering partners.

4.4. Network

The network consists of wireless network components that enable meters and other devices to communicate to the AMI software installed on poles, streetlights, etc., to increase range and reduce impact on the customer's premises during troubleshooting. AMI 2.0 networks incorporate technology and methods that ensure **simple**, **secure**, **interoperable**, and **resilient** operation using traffic segmentation, adaptive routing, communication standards, automation, automatic fail-over, and redundancy.

Generally, AMI networks consist of three network levels:

1. Neighbourhood Area Networks (NAN) used for local communications in primarily point-to-point with some point-to-multipoint topologies.
2. Field Area Networks (FAN) primarily used for communications between meters, clients, repeaters, and routers in primarily point-to-multipoint topologies.
3. Wide Area Networks (WAN) primarily used to communicate from backend systems to FAN connected field devices in primarily point-to-point (e.g., cellular meters) with some point-to-multipoint topologies

The AMI 2.0 NANs allow communications between meters and in-home display units or field-technician devices and with their peer meters. NAN security zones can be configured to **enforce and secure**[7] traffic flow such as control signals or in-home display messages to consumers. Support for standards at the NAN provides the flexibility to expand beyond AMI into other utility operational or smart city networks. Leveraging onboard intelligence, AMI 2.0 meters can communicate peer-to-peer wirelessly, or alternatively, some offer PLC communications options for creating behind-the-distribution-transformer communication networks for hard-to-reach or multi-suite dwellings.

To help simplify the process of network growth and management, AMI 2.0 FANs can support automated configuration and neighbour discovery, streamlining some administrative tasks. The **resilience** of these networks relies on the Routing Protocol for low-powered lossy networks (RPL) to adapt to unplanned outages, enact bandwidth restrictions, and prioritize network traffic to respect data sensitivities. To maintain communication **interoperability** across AMI network nodes, FANs are certified with the Wi-SUN FAN 1.0 certification by Wi-SUN Alliance and use Differentiated Services Code Point over IPv6/6LowPAN per Wi-SUN 1.0 as a Quality of Service (QoS) mechanism. AMI 2.0 suppliers use Low Power Wide Area Networks (LPWAN) to communicate with hard-to-reach devices such as those located in underground or basements.

WANs utilize existing large scale private or public networks ("backhauls") to enable the communication from backend systems to FAN connected field devices. Regardless of network choice (private versus public), AMI 2.0 WANs should

[7] Traffic should be encrypted via AES256 to defend against/mitigate threat vectors.

support **redundant** WAN providers with automatic fail over to ensure **resilience** of the network with a target of 99.7% availability (annually) or better. Cellular networks of the three primary Canadian providers (Bell, Rogers, Telus) used as the WAN system should have the ability to extend network from a location with good cellular data coverage to an area without coverage up to 15 km away with Line of Sight (LoS) or 5 km in non-Line of Sight (nLOS) conditions.

For interoperability, security, and performance, all levels within AMI 2.0 networks comply with industry standards and protocols. Viewing these networks from the perspective of the ISO OSI model, the standards these networks comply with are found in the table below:

Number	Layer	Standards		
		NAN	**FAN**	**WAN**
7	Application	• ANSI C12.22 • ANSI C12.21	• ANSI C12.22 • ANSI C12.21	
6	Presentation			
5	Session			
4	Transport	• TCP • UDP	• TCP • UDP	• TCP • UDP
3	Network	• IPv4, IPv6 • 6LowPAN • RPL • ICMPv6	• IPv6/6LowPAN/RPL (IETF RFC 6550)/ ICMPv6 • IPv4 (for interfacing non-IPv6 devices) • DNP3 (legacy devices) • Modbus (legacy devices)	• IPv4 • IPSec • ICMPv4
2	Data Link	• Mesh – IEEE 802.15.4g Wi-SUN TPS, 900 MHz PHY • Wi-Fi – IEEE 802.11 • Optical – ANSI C12.18 • ZigBee - 802.15.4 • PLC - IEEE 1901.	• Mesh – IEEE 802.15.4g Wi-SUN compliant, 900 MHz PHY • SCADA over serial link: DNP3 to IP protocol translation	

Number	Layer	Standards		
		NAN	FAN	WAN
1	Physical	• Mesh – IEEE 802.15.4g Wi-SUN TPS, 900 MHz PHY • Wi-Fi – IEEE 802.11 • Optical – ANSI C12.18 • ZigBee - 802.15.4 • PLC - IEEE 1901.2		

Table 3: Standards Compliance by Network Level

4.5. AMI Headend Software

Commonly referred to as the AMI Headend System (HES), this software is offered by all vendors as an on-premises[8], subscription, or hybrid model. The HES can provide a central, **multi-tenant** operations platform of, in some cases, multiple **time-synched** applications for use by outside organizations. AMI 2.0 headend software can provide **automation** of regularly performed tasks and **business intelligence** and **analytics** capabilities to support self-serve models and extract further value from AMI metrology or network data collected.

To support future initiatives, the HES should support a true multi-tenant model for separation of systems and capabilities. In some cases, **data cannot be co-mingled,** or **security access** factors restrict how and what in the HES is available by users from outside organizations. For example, in a smart city initiative, the Utility may provide another organization (e.g., City of Toronto) access to data or capabilities within the HES that relates to smart streetlighting. Multi-tenant capabilities allow segregation of data and access between organizations.

The HES can consist of multiple, separate applications using a platform approach depending on the supplier's design including data collection, configuration (device, rate, and network), task execution and limited data validation. When separate applications are operationalized, it is critical that **time synchronization** is maintained across all applications using a standard protocol such as Simple Network Time Protocol (SNTP). Examples of flawed AMI designs have been observed in which multiple vendor applications do not maintain time synchronization causing delays and frustration for the utility operators.

[8] It is worth noting that ~ 90% of Sensus current customers use the Sensus hosted or managed services model.

Once fully operational, daily operations and device management tasks occupy the bulk of activities performed by HES users. To streamline repetitive sequence of tasks, the HES should provide a mechanism to **automate the workflows** of configuring, collecting, processing, and exception management.

Each of the primary AMI 2.0 suppliers offer a reporting or Business Intelligence (BI) solution to provide value to operations or customer service. Integration of these solutions (if required) with the AMI system offers the obvious benefit of a **single supplier with a unique insight** into characteristics of the data. However, a disadvantage of this integrated approach is equally obvious as a **lack of supplier choice** may mean the reporting or business intelligence solution does not meet utility requirements.

The HES[9] should support the secure management of Universal Service Delivery Point (UDSP) relationships including current and historical relationships. The HES User Interface should allow users to view, create, void, and modify the UDSP and, track date/time and user performing the change. HES should have the ability to update the UDSP relationships by importing the IESO MDM/R Incremental Sync Files and produce detailed failure reports. The HES should validate unique USDP-meter relationship for both a given and overlapping time slices and produce detailed failure reports.

The HES should securely support running user-prioritized Tasks (e.g., Meter Interrogation Schedule) on a schedule as frequently as every 4-hours and on demand through a single interface to view, modify, run, delete, and cancel tasks.

Device parameters should be managed through the HES over the AMI network and the HES should have a method to import a Comma Separated Value (csv) file to add or remove single or mass volume of devices from HES groups. The HES should also support upgrade and downgrade of firmware on all devices and produce detailed failure reports. Firmware upgrades should occur automatically without impacting meter data collection and, users should be able to control firmware versions/releases to the individual asset level.

The HES will allow users to set which events are transmitted in real time to the HES (i.e., “alarms”) and support delivery of real time events from all devices. Users should be able to view events that were received in real time vs. standard download and over the air versus collected locally from the meter. The HES should also track the performance of Network Equipment and Read Interval Success highlighting any equipment that failed throughout its life, what has failed and number of failure types per asset. The HES will allow download of all missing metering registers and intervals and network diagnostic data.

The HES should allow users to perform the following basic functions on the AMI network:

- Meter Ping function

[9] This report only includes information gathered from publicly available information, as well as knowledge gained by Util-Assist during its business. It does not provide a feature-by-feature comparison by supplier.

- Retrieve current read (e.g., KWH, KW, KVAR, KVA, V).
- Determine current switch state.
- Collect current demand read and reset demand remotely
- Collect the meter's time
- Reconfigure meter over the air (as allowable by Measurement Canada)
- Operate disconnect switch in a Remote Disconnect Meter

4.6. Operational Data

The current AMI technology introduced utilities to significantly larger volumes and a richer variety of metering data made available at higher velocity, but many utilities struggled to capitalize and manage its scale. AMI 2.0 leverages technology advances to sample faster, analyze, and store more data locally to create more granularity and reduce network traffic. **Choice** and **configuration** of network devices is critical as they generate most of the data and are costly to change once deployed as is the state of data (raw, transformed) when made available.

As noted, (see Section 4.1 Metering) the meter represents an AMI investment's largest line item, so the assessment of optional meter hardware features must consider the need for Operational Data **dependent on the feature**. As an example, distribution network outages can be identified through Outage Alarm (Operational) data but requires that meters include the ability to transmit the alarm before or while losing power. If the Outage Alarm ability requires an optional feature, the feature becomes mandatory.

Beyond the library of Operational Data that AMI 2.0 suppliers make available, the way they are provided to the HES is important to consider. More specifically, can the data be consumed as is or does it first require **other transformation or handling** for consumption by other operational systems (e.g., OMS)? As an example, Outage Alarm (operational) data is typically broadcast as a series of messages in the hope that one (or more) messages reach the HES. However, receiving more than one (1) message may "confuse" an OMS and require that middleware be created to filter out these duplicates. Additional or middleware processing increases complexity and costs.

A list of AMI 2.0 Events and Alarms is provided in Appendix A - Operational Data Examples as an indication of the typical Operational Data made available by the AMI 2.0 suppliers. However, when considering data that is available, utilities should begin the analysis with their requirement and request that suppliers create a solution to meet this standard within the terms of a Service Level Agreement.

4.7. Enterprise Integration

While AMI headend software offers powerful and sophisticated capabilities, investment in existing, very specialized software almost always requires that the AMI systems and data be integrated into a utility's IT enterprise. AMI 2.0 software offers industry standard mechanisms to enable this integration. Each integration mechanism has its own pro and con list, but choice is typically dictated by **existing IT environment** or **software being integrated.**

4.7.1. Data Export/Import

Using a legacy text file export/import approach is simple but may not support use cases requiring low latency response. Use cases that do not require low latency responses are better suited to the text file export/import approach form of Enterprise Integration. This mechanism is not appropriate for low latency integration requirements such as Outage Management System (OMS) and only offer a snapshot in time.

Files exported from the AMI headend software in CSV or XML formats can be queued on secure FTP sites or other IT zones for consumption by Operational Data Storage (ODS) or Meter Data Management System (MDMS) in cases where urgency is not important. Files made available by other systems can be consumed by the AMI Headend to ensure synchronization with other systems such as updates from Asset Management.

Many of these mechanisms have become industry accepted standards used in the utility and other industries as typical in the evolution of standards. The following table identifies the industry-accepted standard data export formats available from each supplier's AMI Headend software. Data contained within these export formats originates in the meter, network, or other sources (e.g., CMEP administrative data "Direct Access Service Requests").

Export Formats	Honeywell	Itron	L+G	Sensus	Trilliant
CIM – Common Information Model	No	Yes	Yes	Yes	Yes
CMEP – California Metering Exchange Protocol	Yes	Yes	Yes	Yes	Yes
COMTRADE – Common format for Transient Data Exchange	No	No	No	No	Yes
CSV – Generic file including Registers and Intervals	No	Yes	Yes	Yes	Yes
HHF – Itron Handheld file	No	Yes	No	Yes	Yes
Itron Import Reading XML	No	Yes	Yes	Yes	Yes
MDEF – Meter Data Exchange Format	No	No	No	No	Yes
MultiSpeak XML	Yes	Yes	Yes	Yes	Yes
PQDIF – Power Quality Data Interchange Format	No	No[10]	No	No	Yes

Table 4: Vendor HES Data Export Formats

[10] Requires incremental hardware/software cost.

4.7.2. Web Services

Web service APIs including XML 1.0, SOAP 1.1 over HTTPS are more sophisticated to set up but may not be supported by the software being integrated. Industry standard messaging protocols such as Java Message Service (JMS) are offered to integrate with messaging solutions and back-office interface mechanisms. Most suppliers also offer integration through exposure of the MultiSpeak 4.1 integration interface API.

These protocols are capable of bi-directional communication between systems and provide low-latency communications where near-real-time action is required. As a best-practice, Web Service messages are typically transported across a commercially available Enterprise Service Bus (ESB) that abstracts between the AMI headend software and back-office system such as Customer Information, Meter Data Management or Outage Management.

Access to a suppliers' **full library of web service APIs** represents another important factor to utilities to **future-proof** their AMI investments. While many of the use case applications and related benefits will be evident early in the systems' lifecycle, it is important for utilities to have access to the API library to use future APIs as their needs change and library evolve.

4.8. Security

AMI 2.0 offerings use many different and layered standards, technologies, and approaches to secure the data, device, field tool, network, and headend software landscape. Securing software employs encryption to conceal message contents, access control to prohibit unauthorized users, and authentication to ensure validity of all users and requests.

AMI 2.0 offerings use **public key infrastructure (PKI) digital certificates** to prevent malicious or unintentional interference on the data, device, field tools, and network of AMI networks. PKI certificates based on ITU X.509 manage the identity and security for AMI 2.0 data, devices, and networks. Certificates apply AES-256 encryption with message integrity using keyed message authentication codes (HMAC). Across the Wide Area Network between FAN and back-office, AMI 2.0 network traffic can be encrypted and authenticated within a discrete VPN with end-to-end IPsec tunnels.

The use of digital certificates requires that the AMI 2.0 supplier have a clearly defined and illustrated capability to securely create, assign, and input digital certificates to devices and headend systems from the supplier's factory to field. The system should be capable of managing device certificates over-the-air (OTA) via an automated process for efficiency and security.

The HES architecture should employ port connectivity restrictions and encrypted channels to prevent unauthorized applications from intercepting data. Secure HTTPS connections to presentation layers and SOAP-based web services over the HTTPS transport between presentation and application layer should be implemented. HES tasks should be captured in audit logs along with security related logs available for capture by a Security Information and Event Management (SIEM) solution.

Access control for Wi-Fi enabled AMI network devices is implemented through Wi-Fi Protected Access II (WPA2) certification which includes the benefit of AES encryption. In addition, MAC, or IP Access Control Lists (ACL) are used to further control access to the network for individual AMI 2.0 devices based on these addresses.

At the HES user level, AMI 2.0 leverages enterprise user/network resource directory services to authenticate users for Single-Sign On (SSO) against corporate Microsoft Active Directory/LDAP services. SSO combined with role-based access prevents user access to unauthorized functions. AMI 2.0 solutions should comply with the confidentiality and privacy of data found in the AMI-SEC Task Force, System Security Requirements and in particular, sections related to confidentiality and privacy.

For SaaS, hosted or managed service HES offerings, suppliers need to have security controls and procedures necessary to attain data center and security industry certifications including ISO 27001, SSAE 18 SOC 1 and SOC 2 Type 2 audits. In addition, suppliers should have attestations for applicable controls for colocation data center services PCI DSS 3.2, HIPAA, and FISMA Moderate based on the NIST Special Publication 800-53.

4.9. Smart Cities

The AMI 2.0 network can be extended beyond metering operations to enable smart city services for utilities and municipalities, including smart lighting, transportation, economic development, emergency response, health, and public safety. AMI 2.0 systems offer software and hardware solutions that leverage existing municipality assets to build out a safer, healthier, and more efficient community.

Maximizing the value of existing infrastructure is a particularly interesting area of opportunity for utilities and municipalities, which together can create smart city platforms where sensors and gateways are installed on light poles and a shared network infrastructure is leveraged for non-pole-based systems. The figure below shows some of the most common smart cities use cases, using both connected devices and light-pole mounted hardware.

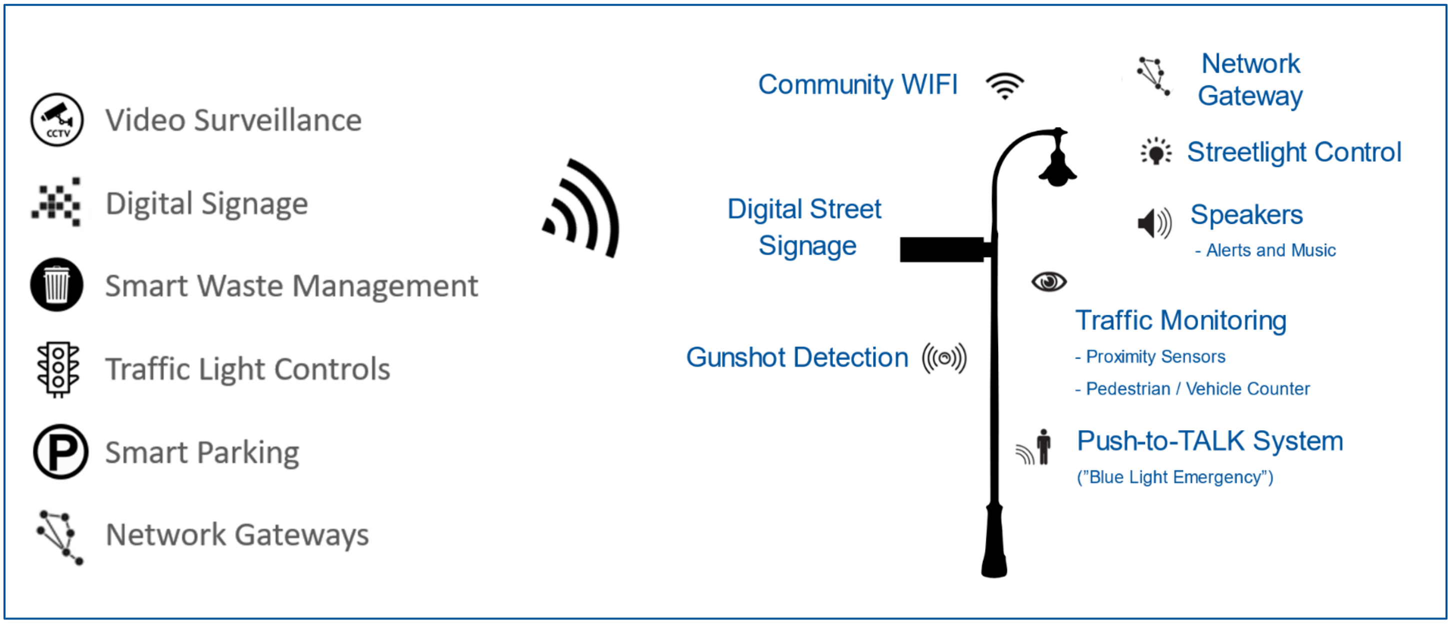


Figure 3: Common Smart Cities Use Cases

4.9.1. Lighting

Intelligent lighting found in a smart city implementation offers municipalities the ability to schedule or manually control ON/OFF status or dimming of individual or lighting device groups using the AMI 2.0 network. This helps lower energy consumption, maintenance costs, and enhance wellbeing for residents and businesses. Some systems have been built on the TALQ smart city device network communication and Open Smart City Protocol to communicate securely and provide future opportunities to extend and integrate with other smart city lighting solutions.

Some suppliers offer retrofit devices that enable communication on their AMI 2.0 network for existing lighting control nodes. This approach allows the utility to avoid stranding lighting control assets in the field, but obviously requires a field visit to perform the retrofit. These retrofit devices operate as nodes on the AMI 2.0 network like other meters, routers etc. from a network traffic perspective. Deployment and management of intelligent streetlighting can be coordinated through centralized platforms that can integrate with CMS, GIS, asset management systems. This integration provides access to inventory, location, and work crew information with mobile capabilities.

AMI 2.0 suppliers may provide their own hardware or have **partnerships** allowing third-party nodes to connect and communicate with the network. In October 2021, Itron acquired SELC, which produces network lighting controllers for an end-to-end solution while Sensus and L+G have indicated their own hardware is available.

Additionally, recognizing the need to accurately measure usage, many streetlight nodes now include measurement capabilities with 0.5%-1% revenue grade metrology depending on supplier. In early September 2020, MC provided a draft policy on granting conditional permission for the installation and use of metering without approval, verification, and sealing for streetlight luminaires incorporating adaptive controls **with embedded metrology**. Suppliers are following the progress, and some intend to meet accuracy requirements and conditions for installation upon the finalization of policies.

4.9.2. Public Services

Passive or active video surveillance programs have been implemented widely for high-crime or otherwise sensitive areas. These programs can leverage the AMI 2.0 network footprint to expand the coverage areas without having to deploy additional network infrastructure such as gunshot detection use cases. To support these Public Safety initiatives, push-to-talk or Blue Light Emergency can also use the same AMI 2.0 network.

Some AMI 2.0 suppliers have partnered with domain experts to incorporate gunfire detection in AMI 2.0 networks. Using acoustic sensor arrays mounted on walls, poles or embedded into lighting, these systems can detect gun shots, approximate the location and in some cases weapon type and trajectory. This data plus optional video or still imagery can be transmitted over the AMI 2.0 networks (and mobile if configured) in real time (<5 seconds).

Digital signage of real-time public service and emergency messaging using Flash or HTML5 provides sophisticated and flexible messaging platforms across AMI networks. Alerts to the public of Amber Alerts, Blue Alerts, Weather Alerts and Traffic Alerts can be delivered locally and messaging content and format managed centrally using tools of 3rd parties with which some AMI 2.0 suppliers have aligned.

Using shared or municipal infrastructure such as light poles, community Wi-Fi can be offered to the public. In this case, Wi-Fi network traffic can utilize the AMI 2.0 network overlapping the public area where the light poles are located to interconnect with its own back-haul networks to the Internet.

4.9.3. Health

Air quality monitoring is essential in the effort to understand the environment and changes in pollutant levels in urban areas. Some AMI 2.0 suppliers have partnered with 3rd parties that have expertise in environmental sensory technology to provide solutions that perform measurement of noxious gases such as hydrogen sulfide and other environmental elements including carbon dioxide, ozone, nitrogen dioxide etc. These sensors leverage the AMI network to provide measurements in real time to 3rd party software solutions.

4.9.4. Transportation

Smart parking deployments have shown how drivers can find available on-street parking more efficiently using data from sensors monitoring on-street parking spaces, ensuring less congestion and emissions. The intelligence includes the ability to discern special parking such as accessible spaces or delivery zones to ensure availability as required.

The proliferation of electric vehicles has brought with it the need for distributed charging stations. These systems not only need to be connected to the distribution grid but also monitored and managed as intelligent devices for software maintenance, account reconciliation, smart-charging controls etc. Pilots using the AMI 2.0 networks to allow communication with EV charging stations are becoming more prevalent across North America. Open Charge Point Protocol (OCPP) is the standard communication protocol used between EV charging stations and a central management system in Europe, and it is approved throughout North America, although the debate for a set standard is ongoing.

4.9.5. Vendor Smart City Offerings

To satisfy customer needs, the Utility should consider smart city partnerships and an ever-expanding "platform-ready" partner ecosystem of domain-centric expert partners. AMI 2.0 suppliers are building out their partner models with non-traditional supply chain partners to support global smart city initiatives. The table below highlights the most common applications of smart city technology and which suppliers are currently offering devices and/or services in these areas.

Item	Honeywell	Itron	L+G	Sensus	Trilliant
Digital Signage	Yes	Yes	No	No	Yes
Environmental/Air Quality Measurement	Yes	Yes	Yes	No	Yes
Gas Meter Network	No	Yes	Yes	Yes	Yes
Gunshot Detection	Yes	Yes	Yes	No	Yes
Lane, Speed, and Vehicle Detection	No	Yes	Yes	No	Yes
Parking Monitoring	Yes	Yes	No	No	Yes
Streetlight Controls	Yes	Yes	Yes	Yes	Yes
Support for CCTV	Yes	TBD	TBD	TBD	Yes
Waste Management	Yes	Yes	TBD	TBD	Yes
Water Meter Network	Yes	Yes	Yes	Yes	Yes

Table 5: Vendor Smart City Offerings

4.10. Distribution Automation

While automation of the electrical distribution network is a mature market and technology, these systems operate discretely from AMI 1.0 systems with separate communication networks and command and control software. Devices that a utility distribution operation group manages such as RTUs, line sensors, and capacitor bank controllers require a **much**

higher degree of security and **lower latency** response capabilities. The reliability and stability of these operational assets ranks higher than AMI 1.0 metering systems as their operational failures have a wider-reaching impact on the consumer base.

Today, AMI 2.0 offerings enable utilities to share the AMI network between their metering and distribution operation group **while complying with the security and latency requirements**. Through field located AMI 2.0 DA equipment and centrally located software, these AMI 2.0 DA solutions allow DA device command and control traffic to securely traverse the AMI 2.0 network with priority to satisfy low latency requirements. AMI 2.0 suppliers offer solutions that support centralized models through a utilities SCADA Master Station and peer-to-peer, de-centralized solutions through equipment typically located at utility substations. As DA devices can communicate using one of many different protocols, these AMI 2.0 DA solutions support industry standards such as IPv6/IPv4, serial DNP3 and Modbus. With support for more stringent security and standards, the sensitivity of the DA device command and control traffic is protected while within the AMI network. DA traffic is secured using AES-256 encryption with integrity checking using keyed-HMAC/SHA2-256.

The priority of DA device command and control traffic is respected by AMI 2.0 DA solutions through **network cooperation and prioritization**. Using peer-to-peer capabilities of AMI 2.0 DA equipment, DA device command and control traffic can be routed across the AMI 2.0 network avoiding congestion or outages. Prioritization configuration settings and AMI 2.0 DA equipment monitoring allow utilities to ensure that latency sensitive DA traffic is prioritized over regular meter readings.

Section 5: AMI Technology Standards

Utilities have long depended on standards to operate safely within acceptable levels of performance. As utilities embrace new technologies including the latest AMI releases, they face challenges which have led the industry to consider and debate the benefits and drawbacks of industry-wide standards; however, while there are both pros and cons for adhering to specific standards compliance for communication has become prevalent because its key upsides include ensuring interoperability and security of multi-domain network communications and multi-vendor device fleets.

This section provides an overview of current industry standards, highlights some of the standards active or under review in the context of AMI, compares vendor interoperability standards compliance, and provides recommendations for how utilities can future proof their investment in next generation AMI.

5.1. Standards and Future Proofing

Because AMI represents a critical fifteen to twenty-year investment, utilities need to ensure that the investment is protected from risk and obsolescence for the lifetime of the solution. This protection, often referred to as "future-proofing," involves making sure that the solution is purchased and implemented in a way that makes it compatible with and adaptable to future changes in protocol.

The first step is taken in the contracting phase, where contract and warranty terms with the AMI vendor ensure that the AMI will remain operational and supported for the lifetime of the assets. In terms of system design and implementation, industry standards for both hardware and software play a key role in ensuring solution compatibility with future releases and upgrades from the AMI vendor and third-party vendors.

5.2. Scope of Standards in AMI Networks

A wide range of standards are both active and under-review to ensure a safe, secure electricity and communication network that perform and interoperate as expected. One key smart grid trend and best practice is the move away from proprietary communication protocols to industry-wide standards. This ensures that the AMI meters and network are compatible with the widest range of future releases and third-party devices.

Compliance with other standards for device manufacturing, operation and safety, data management, and metrology can ensure that the purchased solution is as robust, flexible, secure, and resilient as possible at the time of implementation. The table below shows the key industry and manufacturing groups and government agencies that are active in the metering and AMI industry to provide an overview of the key standards that apply to AMI.

Standard or Organization	Description	Examples
Wi-SUN	**International non-profit association** composed of industry members that promotes certified communication standards to coordinate wireless systems and provide interoperability on smart utility network.	Wi-SUN FAN 1.0 Wi-SUN FANWG
Distributed Management Task Force's (DMTF)	**International non-profit association** composed of member companies and alliance partners that creates open manageability standards for IT infrastructures.	CIM 2.54
American National Standards Institute (ANSI)	**Private non-profit organization** composed of industry and government stakeholders that provide frameworks for fair standards development and quality conformity assessment systems.	ANSI C12.1 ANSI C12.10 ANSI C12.18-22
Standards Council of Canada (SCC)	**Government Corporation** that promotes the value of standards and conformity assessment including electricity metering.	CAN/CSA-C22.2 60950-22:17 CAN3-C17
International Electrotechnical Commission	**International non-profit association** composed of technical experts delegated by their Country's National Committee that prepares and publishes standards for all electrical, electronic, and related technologies.	IEC 60068-x IEC 61000-x IEC 62053-x IEC 62059-x

Standard or Organization	Description	Examples
Institute of Electrical and Electronics Engineers (IEEE)	**Professional association** for electronic engineering and electrical engineering with standards for metrology, power quality monitoring, surge resistance and handling, and communication.	IEEE 1159 IEEE 802.11 IEEE C62.x
Internet Engineering Task Force (IETF)	**Open standards organization** composed of network designers, operators, vendors, and researchers that develops and promotes voluntary Internet and communications standards, in particular the Internet protocol suite.	IETF RFC 4301 IETF RFC 4443 IETF RFC 5905 IETF RFC 791
International Organization for Standards (ISO)	**International organization** composed of representatives from various national standards organizations that develops and publishes worldwide technical, industrial, and commercial standards.	ISO/IEC 16388 ISO 8601
Measurement Canada	**Government agency** that approves and inspects measuring devices and investigates related complaints	MC LMB-EG-07 MC PS-E-18 MC S-E-06
National Institute for Standards and Technology (NIST)	**Government agency** that promotes innovation and industrial competitiveness in measurement science, standards, and technology.	NISTIR 7823
Underwriter Laboratories (UL)	**International safety certification company** that sets and certifies safety standards for electric utility meters	UL 2735C UL 508 UL 60950-1

Table 6: Key AMI-Related Standards Organizations

Key standards that apply to AMI 2.0 networks and the advantages over current AMI systems are referenced throughout this document. Illustrated in the diagram below are the three key layers of the AMI network and which organizations set the primary standard for safety, performance, security, and interoperability at each layer.

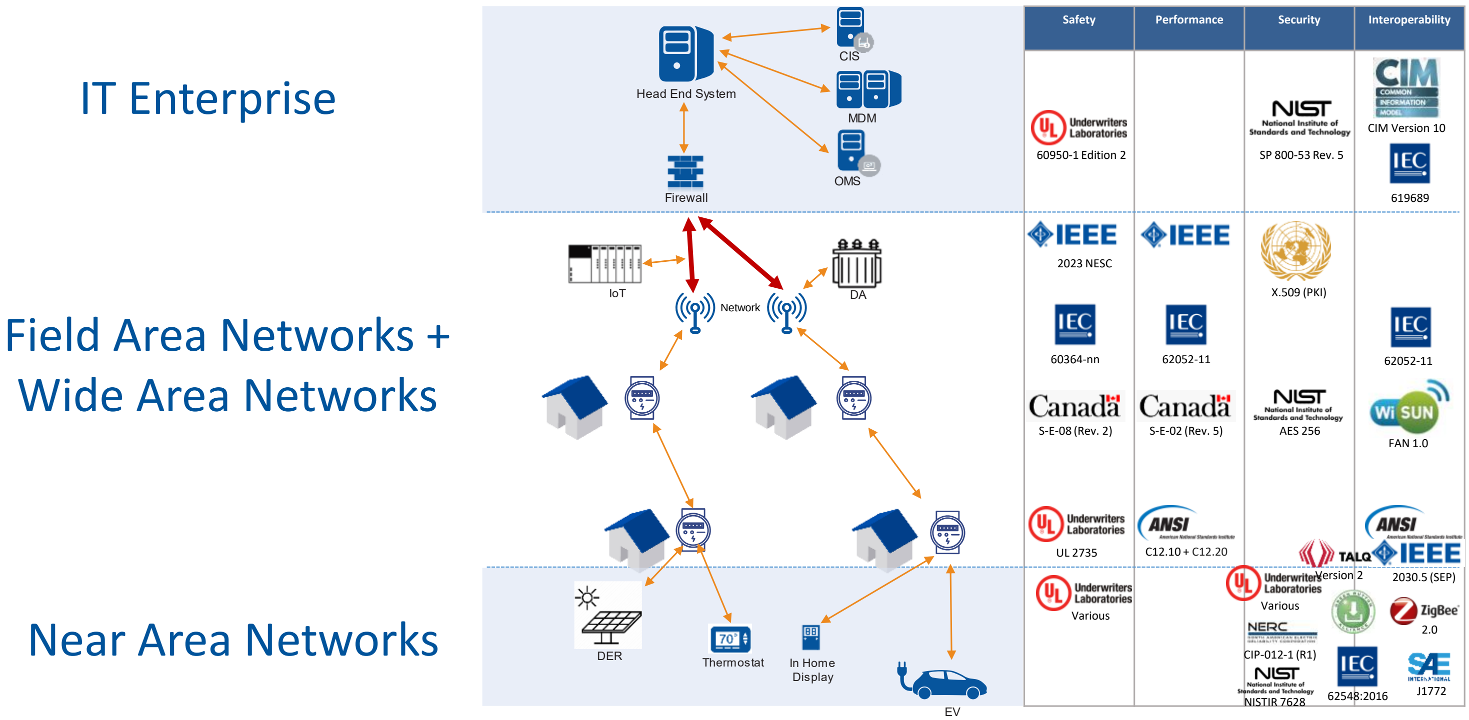


Figure 4: Standards Organizations Governing AMI

5.3. Current Standards

Standards governing AMI continue to evolve as the technology and its use continues to change. Each government agency, industry association and manufacturing group continues to monitor industry changes and respond to input from their constituent members or customers to adapt their standards. However, the table below can be used as a reference of the current key standards across four basic categories applicable to AMI 2.0.

Category	Organization	Domain	Current Standard
	MC	Meter install	S-E-08 (Rev. 2)
Safety	UL	IT Enterprise	60950-1 Edition 2
	UL	FAN - Meters	UL 2735

Category	Organization	Domain	Current Standard
Performance	MC	FAN - Meters	S-E-02 (Rev. 5)
	ANSI	FAN - Meters	C12.10, C12.20
Security	NIST	IT Enterprise	SP 800-53 Rev. 5
	NIST	FAN	AES 256
	ITU	Multiple	X.509 (PKI)
	IEC	FAN - Meters	61850
Interoperability	NERC	NAN	CIP-012-1 (R1)
	ANSI	FAN	C12.19 + C12.22
	IEC	IT Enterprise	619689
	Wi-SUN Alliance	FAN	Wi-SUN FAN 1.0
	DMTF	IT Enterprise	CIM 2.54

Table 7: Key Current AMI Standards

As one would expect, most critical applicable standards are indeed standard across the industry and the AMI market leaders are vigilant to stay compliant with most of them. There are some minor variances in compliance and commitment to standards between vendors, which can be assessed in detail during evaluation of AMI vendor proposals. As an example, while Itron, Landis+Gyr, and Trilliant are all promoter members of the Wi-SUN alliance, Itron is currently fully compliant with Wi-SUN, but Trilliant is still in the early stages of commitment to the Wi-SUN standards. However, where vendors are not compliant to a given standard, they are proactive in offering alternatives or roadmap solutions to the item in question. For example, Landis+Gyr is partnered with Cisco, and through this partnership is able to offer a Wi-SUN compliant network immediately, which they would not be able to do solely with their own technology and solution. Where specific standards are deemed critical by a utility, vendors will do their best to meet utility these standards or else commit to a timeline or propose an alternate approach (e.g., a proprietary protocol that achieves the same specifications) to meet utility needs.

Section 6: Value Proposition of AMI Technology

The scope of an AMI 2.0 business case extends beyond operational processes and financial benefits to include customer-focused programs and services, and next-generation capabilities like enhanced data analytics. While each utility's AMI business case and value proposition will vary based on a variety of factors including the utility's size, structuring, needs, financial inputs, and the solution it implements, there is value in examining trends in other utilities' business cases to see overall trends in costs and values.

In the transition from manually read meters or AMR to AMI, a lot of the benefits realized were around the labour that would be no longer required under an automated meter reading system. To demonstrate the benefits and costs realized in the first generation of AMI, Util-Assist compared total costs and benefits included in four other publicly available AMI business cases. This comparison includes business cases from three Canadian utilities—New Brunswick Power (2018), Nova Scotia Power (2018) and BC Hydro (2011) - and two American utilities: Con Edison (2015) and National Grid (2018)[11]. The following table shows a summary of the implementations' key project, financial, and benefit metrics. Note that quantified benefits shown in the table were normalized on a per-meter basis for comparison between utilities.

An AMI 2.0 implementation will provide broad benefits across Toronto Hydro's current and future operations, as well as provide benefits to its end customers. However, the business cases and overarching value propositions will differ between AMI 1.0 and AMI 2.0 implementations in several ways. The increased memory and RAM of the newer meters allows the utility to integrate applications at the meter level that allow for enhanced insights related to outages, connectivity, and theft. From a customer perspective, the enhanced metering hardware allows customers to view detailed insights into their energy consumption through load disaggregation and allows the utility to offer a wider ability of self-serve functionality.

[11] Dollar values for Con Edison and National Grid were adjusted from USD to CAD at a rate of 1.3280

AMI Business Case Comparative Summary (All dollar figures shown in CAD)	BC Hydro	Con Edison	National Grid	Nova Scotia Power	NB Power
Year of AMI Application	2011	2015	2018	2018	2019
Number of Meters	1,930,000	4,700,000	2,330,000	495,000	360,000
Meter Type	Electric	Electric & Gas	Electric & Gas	Electric	Electric
Successful Application	YES	YES	NO	YES	TBD
Financial Metrics					
All-In Cost Per Meter	$404	$353	$282	$269	$304
All-In Savings Per Meter	$844	$590	$358	$385	$372
Discount Rate Used	8.00%	6.10%	6.45%	6.96%	5.25%
Opt-Out Rates	N/A	<1%	1%	1-2%	N/A
Notable Financial Differences					
Net Savings Per Meter	$440	$237	$50	$116	$86
BCA Ratio	2.09	1.67	1.27	1.43	1.28
NPV Forecast (years)	20	20	20	20	15
Top Five Benefit Streams (total benefit per meter over the project term)					
Reduced Manual Meter Reading	$115	$147	$21	$117	$111
Avoided Cost of Meter Replacements	$32	$116	$145	$49	$61
Conservation Voltage Reduction	$108	$98	$9	$0	$45
High Bill Alert	$114	$0	$70	$27	$43
Distribution Network Losses	$379	$110	$29	$20	$42
Benefits with Notable Differences (total benefit per meter over the project term)					
Outage Restoration (Crew Management)	$5	$24	$3	$33	$4
Unbilled/Uncollectable Accounts	$0	$21	$17	$15	$3
Reduced Overtime for Meter Service Orders	$24	$67	$47	$0	$2
Voluntary Time of Use Rates	$57	$25	$78	$55	$0
Uncommon Benefit Streams (total benefit per meter over the project term)					
Meter Services Manager Salary	$0	$0	$0	$0	$5
Avoided Cost of Meter Reading Vehicles	$0	$0	$0	$0	$5
Avoided Cost of Handheld System	$0	$0	$0	$0	$4
Avoided Cost of Meter Reading Supervisor	$0	$0	$0	$0	$3
Remaining Benefit Streams (total benefit per meter over the project term)					
Meter Accuracy Losses	$0	$139	$0	$0	$32
Load Research Meters	$3	$0	$0	$0	$14
Net Metering	$0	$10	$6	$9	$13
Reduced Customer Inquiries	-$1	$16	$6	$9	$4

Table 8: Summary of Five Utilities' Business Cases

Section 7: AMI 2.0 Financial Assessment

This AMI 2.0 financial assessment will provide lower and upper bounds for the estimated capital and operation, maintenance, and administration (OM&A) costs associated with procuring an AMI 2.0 solution. The scope of the financial assessment is limited to the estimated AMI procurement cost only and excludes meter installation costs and all other ancillary cost categories associated with the business case.

7.1. Market Pricing for AMI 2.0 Technology

The methodology used for determining market pricing for the AMI 2.0 technology was estimated with vendor market prices for recent AMI 2.0 procurements, pro-rated for Toronto Hydro's scale at 686,774 meters. Meter capital costs were estimated using a pricing grid subcategorized by form type and quantity as provided in the Toronto Hydro meter inventory.

Network equipment capital and OM&A costs were estimated based on the required wireless pole mounted and phone line/socket mounted collectors, repeaters, cellular meters, and phone line connected meters as provided in the Toronto Hydro Meter Inventory. Headend system capital and OM&A costs were estimated on a per-meter basis, with one-time costs incurred for HES setup and configuration. Professional services costs were estimated on an hourly-cost basis, with the quantity of hours proportionately adjusted for Toronto Hydro's relative size.

7.2. Pricing Estimate for Toronto Hydro

Depending on project size and timing, Ontario utilities can transition to the next generation of AMI and enable new capabilities at an estimated price of $127.67 to $202.78 (CAD) for all-in vendor capital costs per meter[12]. Cost estimates for Toronto Hydro, including the capital and first-year OM&A estimates for a current generation AMI technology platform, are summarized in the table below. Dollar figures were calculated from an aggregate collection of vendors and are shown in CAD, converted from vendor USD pricing to CAD at a rate of 1.28 USD/CAD.

[12] Estimated prices not including installation; converted from American dollar estimates to Canadian dollars at 1.28 USD/CAD.

Category	Low Estimate (Capital)	High Estimate (Capital)	Low Estimate (1st Year OM&A)	High Estimate (1st Year OM&A)
New Electric Meters	$82,193,920	$118,986,240[13]	N/A	N/A
Network Equipment	$1,318,400[14]	$8,435,200	$5,632	$6,784
Headend System	$2,023,680[15]	$3,729,920	$537,984	$657,408
Professional Services	$2,140,160[16]	$8,112,640	N/A	N/A
Total	**$87,676,160**	**$139,264,000**	**$543,616**	**$664,192**

Table 9: Estimated AMI Pricing for Toronto Hydro.

[13] Assumes latest generation meter with DI board (~US$50/meter) and remote disconnect capabilities
[14] Assumes point-to-point network
[15] An option exists with the incumbent vendor that this cost will be negligible
[16] Assumes that the incumbent vendor is chosen, and professional service hours do not need to encompass a solution built from scratch

Section 8: Strategies for Transition to AMI 2.0

During Ontario's implementation of AMI 1.0, utilities executed sector-by-sector[17] acceptance processes as conventional meters were removed, and AMI networks installed and operationalized. The transition from AMI 1.0 to AMI 2.0 will require a more carefully orchestrated deployment and sector acceptance process as implementation of the AMI 2.0 network affects the operational integrity and service levels of the existing AMI 1.0 network. A detailed and well executed transition plan will be required in advance of operationalizing the first AMI 2.0 device.

8.1. High-Level Best Practices

High-level best practices for AMI-to-AMI transition include:

- Plan to have meters complete activation as soon as possible after installation, e.g., compete meter to cash integration activities before meter deployment starts
- Plan and continuously analyze deployment activities to identify in advance meters and areas that may have trouble connecting to the network
- Develop a proactive plan to address sites and meters that will have connectivity issues
- Develop a response plan to address any unforeseen communication gaps that arise

Utilities need to work with the AMI vendor to develop a deployment plan and network stabilization plan that carefully balance the needs of both the new network and the old. The deployment vendor and potentially system integrator will also have to be involved in planning, as their activities and responsibilities will also factor into the final deployment and network plan. While all parties on the project should be aligned with the overall common goal of project success, each vendor may have different restrictions or priorities in their planning and performance of day-to-day activities. For example, a deployment vendor may look to prioritize deployment routes and processes that maximize how quickly meters can be exchanged, along logical walking and driving routes for its field personnel. However, the deployment may have to proceed in a less direct or more restricted manner to accommodate network and stabilization activities.

In general, guidelines for effective transfer from an existing AMI network to a new one is as follows:

When removing the old network:

- Focus on removing all old meters in one sector

[17] A sector is a legacy, industry term used to identify a regional sub-set (typically) of the utility service territory which historically consisted of Meter Reading Routes (or "walks") defined by the utility in terms of geographic size and number of meters. Sectors should be used to manage and control AMI Network Performance Acceptance processes for Service Level Agreement compliance by isolating groups ("Sectors") of AMI meters.

- Within the sector, remove meters moving inward, i.e., starting with the devices furthest from the collectors and moving inward

When deploying the new network:

- Ensure all network collectors are installed and activated before meter deployment begins
- Deploy meters moving outward, i.e., starting with meters closest to the collector and moving outward

The figure below shows the ideal meter exchange and collector placement pattern. With a new collector installed roughly in between two old collectors, meters can be exchanged outward from the new collector and inward towards the old collectors, which is ideal for the stability of both networks.

Figure 5: AMI to AMI Deployment Pattern

In areas with low meter density, it may make sense for the new collectors to be installed in the same general locations as the old collectors as they were likely installed in the best positions to cover the region with the least amount of infrastructure. In these situations, meters would be exchanged from the outer, least dense areas inwards towards the new collectors to avoid disrupting the original mesh, and would be planned for completion in a relatively short time frame to avoid stranding new meters at the edges of the collector's service area.

8.2. Sector and Deployment Planning

In general, AMI vendors recommend having three sectors in active deployment at any one time: one in planning and assessment, one in mass deployment, and one in sector acceptance. There will need to be concessions and exceptions made to the guidelines above, for logistical, communications, or other reasons. To ensure connectivity during deployment, vendors may recommend providing a resource to conduct a radio frequency analysis or deployment and connectivity simulation for each new deployment area, or on a set schedule (e.g., weekly, or bi-weekly). In any areas where new meters are expected to have connectivity issues based on this analysis, the proactive mitigation plan can be deployed.

At a high level, AMI vendors can help plan the new network device locations and possible meter deployment routes using the following methodology:

1. Existing meter and network device locations can be mapped and analyzed by the AMI vendor
2. Using radio frequency communications modelling software, the vendor can simulate the existing network's connectivity layout and determine its functional statistics
3. The proposed new network design (i.e., collector and repeater locations) can be overlaid on the map, and the service territory can be divided into appropriate sectors or deployment zones based on density, geography, network device locations and connectivity, etc.
4. Specific deployment routes can be formulated for individual areas or neighbourhoods in the sector, which account for both old and new network device locations in attempting to minimize potential connectivity issues for both old and new meters

The following are basic steps used in planning an area before its deployment, and assessing it for potential connectivity issues:

1. Approximately four weeks before an area is to undergo meter changes, the utility provides the AMI vendor with the following data about the meters in the area:
   - Meter location coordinates and notes (e.g., indoor/outdoor, etc.)
   - Meter types to be deployed
   - Anticipated exchange date
2. The meter and network device connectivity for the area is simulated to help refine the best deployment routes and to identify any potential connectivity issues.
3. Based on timing factors and projections, like how long meters may be without connectivity and how quickly the network will be built out in the area, the AMI vendor and utility can decide whether mitigation measures should be taken to pre-empt or address the predicted connectivity issues. These measures could include the installation of temporary network access points or use of manual meter reading to collect meter reads for the problem meters until they can be covered by the new network.

8.3. Mitigation of Connectivity Issues

The primary mitigation method offered by AMI vendors to address any expected or encountered connection issues is the use of temporary network access points, (e.g., meter socket mounted access points), to fill gaps in the mesh until the network can be fully saturated in the area. In the case of socket access points, these temporary devices are installed in a meter socket and can provide cellular, or mesh backhaul communication for several hundred meters within range. These access points can help bridge the gap and provide connectivity to meters until adequate mesh coverage is achieved by other meter installations, at which point the socket access point can be removed and redeployed as needed.

AMI vendors may also offer software and professional services to perform endpoint management and network optimization. These services and software help diagnose and fix connectivity issues including those for meters that were registered on the new network but lose connectivity over time. Endpoint management activities can help restore connectivity remotely, or else direct activities for restoration, for example by using temporary network devices in the field. In rare circumstances, it may be necessary to read meters that aren't connecting using a reading device during a field visit, which, while not ideal, is another available temporary reactive measure to ensure reading continuity until the new mesh can be saturated and stabilized.

In general, a successful transition from AMI 1.0 to AMI 2.0 from a network perspective requires an added layer of planning and contracting, particularly with the chosen AMI vendor. Advanced planning will ensure there are mitigation strategies in place, both for preventing instances of stranded meters, and for addressing connectivity issues if they should arise unexpectedly. Careful discussion and contracting with the AMI vendor will ensure that there is accountability for maintaining the required network service levels throughout the deployment and allow the vendor to plan for and quote both the hardware (e.g., temporary network devices) and the resources (e.g., an engineer to anticipate and address connection issues) necessary to ensure stable communications and continued reading capabilities throughout the deployment of the new AMI.

8.4. AMI 2.0 Supplier Transition Experience

Assessing the experience level of AMI 2.0 suppliers in migrating from an automated meter reading infrastructure to AMI 2.0 is more nuanced than it first appears. While this report highlights the primary differences between AMI 1.0 and 2.0, much of the nuance is created by both the definition of AMI 2.0 and the state of automation in place.

To-date, over 100 million[18] smart meters (AMI 1.0) have been deployed across North American utilities including those in Ontario, California, and Texas, which led the move to AMI. As this older technology reaches the end of its service life, utilities in these jurisdictions are evaluating the upgrade to AMI 2.0 or are in late stages of supplier selection. Currently, there is not an adequate sample of suppliers experienced in the move from AMI 1.0 to 2.0.

However, similar challenges related to sector acceptance, operational integrity and service levels of the existing network exist in older meter reading systems. The state of meter reading automation **from which a utility transitions** should include AMI 1.0 and fixed-wireless[19] automated meter reading systems (pre-AMI) in this assessment.

Also, this report includes Distributed Analytic Applications, Interoperable-Standard Communications and Robust Network performance as differentiating pillars of AMI 2.0. As expected, alignment with this specific distinction is not comprehensive

[18] Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2021 Update), Edison Foundation

[19] Drive-by or walk-by AMR operations do not require a fixed wireless network and are therefore not subjected to the same transition challenges as fixed network AMR.

across AMI suppliers. Therefore, the definition of AMI 2.0 **to which a utility transitions** has room for interpretation. AMR or AMI 1.0 systems from which utilities are transitioning include:

- Silver Spring Networks to L+G
- Itron ERT to L+G
- Itron ERT to Itron
- L+G (Cellnet) to Itron

While there is currently inadequate evidence of experience in current, mass migrations from electric AMI 1.0 to 2.0, Itron and L+G have ongoing projects moving from fixed-wireless, automated meter reading systems to their respective AMI 2.0 offering. These vendors also have stated experience in smaller scale transition projects, for example helping a utility deploy a newer AMI solution when the utility determined that the solution, they were in the middle of deploying would be insufficient to meet its needs. Including these projects, the vendors have experience facing the following challenges, which are relevant to full-scale replacements of an old AMI solution with a new AMI 2.0 solution:

- Overlapping HES instances, with the new eventually replacing the old
- Co-occurring AMI solutions and service level maintenance during transition
- Network to network migration during meter deployment
- Back-office system and protocol migration to new standards

Appendix A - Operational Data Examples

1. Tamper Cleared
2. High Temperature Detection
3. Hot Socket Detection
4. Dead Battery
5. Meter Status/Self-Test Errors
6. Measurement Error
7. Time Change
8. Security Change
9. Various Logs Cleared Flag (History Log, Event Log)
10. Disconnect Switch Closure
11. Demand Reset
12. Disabling of Communications
13. Outage
14. Restoration
15. Time Changed
16. Set Time
17. Clock Drift
18. Clock Lost
19. Low Battery
20. DC Detected
21. Loss of Phase
22. Phase Voltage Deviation
23. Inactive Phase Current
24. Cross Phase
25. Phase Angle Displacement

Appendix B - Glossary of Terms

Acronym	Description	Definition
ASN	Advance Shipping Notice	A document that supplies specific information about an expected delivery, including time, type of item, weight, and amount being shipped.
	Alarm	An alarm is an event at a device that has been configured to notify the HES in real-time.
ANSI	American National Standards Institute	A private non-profit organization that presides over the development of voluntary consensus guidelines for services, products, systems, and processes.
	AMI System	The entire AMI system, inclusive of all components (e.g., HES, meters, network equipment, software, firmware)
CMEP	California Metering Export Protocol	An industry standard data formats first mandated by the State of California in 1998. CMEP is intended to transmit gas and electric utility metering, billing, and administrative information between companies. It is a common file format for export of meter data from the AMI.
COMTRADE	Common format for Transient Data Exchange	The general configuration for data files and exchange channels. Utilized for the interchange of multiple types of faults, test, or simulation data for electrical power systems.
CIS	Customer Information System	System used to manage customer, account, consumption, and billing data.
DER	Demand Energy Response	Demand Energy Response refers to the tools and processes to operate programs designed to change the utility's power consumption, to better match the demand for power with the supply.
	Device	This refers to all field-deployed hardware (including, but not limited to meters, repeaters, collectors, DA devices, external antennas).
DSCP	Differentiated Services Code Point	The field in an IP packet that specifies the per hop behavior for a given flow of packets and enables varying levels of service to be assigned to network traffic.
DA	Distribution Automation	Real-time adjustment to changing loads, generation, and failure conditions of the distribution system, usually without operator intervention.
DMS	Distribution Management System	Used to monitor, control, and analyze the distribution network, a DMS provides improved operator awareness and decision-making, and improves safety and protects assets.
EMS	Element Management System	We use the term Element Management System as a generic category, but do not intend it to define a separate solution. Any proponent may elect to fulfill these requirements natively within their core product.
	Endpoints	An endpoint is one end of a communication channel. In this context, it describes all field mounted devices excluding those that only serve a communication purpose (i.e., includes meters, DA devices, but not repeaters).
	Event	An event is an occurrence on the device that is tracked. It may be configured to notify the HES when interrogated, immediately (as an alarm), or both.
FAN	Field Area Network	The FAN is primarily used for communications between meters, clients, repeaters and routers within an area that reaches further than the NAN. The intended network topology will be point-to-multipoint for this segment.
	FAN Hop Path	The network path in which the device, meter or network equipment, is associated within FAN.
HES	Headend System	A headend system is hardware and software that receives the stream of meter data brought back to the utility through the AMI.

Acronym	Description	Definition
	Hot Socket	A condition where the connection between the meter and meter base experiences an elevated temperature and causes a potential fire hazard. This may be due a variety of conditions such as loose wire termination, meter blade not seated in socket jaw, exceeding socket capacity, etc.
IESO	Independent System Operator	Runs the exchange for the sale and purchase of electricity and oversees electricity system operations in Ontario. IESO is responsible for the Smart Metering Initiative and oversees the MDM/R.
ISM	Industrial, Scientific, and Medical	Radio bands that are dedicated for international use on radio frequency energy specifically intended for scientific, medical, and industrial needs and not communication.
IED	Intelligent Electronic Device	Microprocessor-based controllers of power systems equipment
	Interval	An Interval Meter measures how much (electricity) is being used, and when it is being used. An interval is a pre-configured slice of time across a day (e.g., a meter may be configured to twenty-four hourly intervals or ninety-six 15-minute intervals each day)
	Interval Overflow	This occurs if the energy consumption in any interval exceeds the meter's ability to capture the consumption in that interval.
IDE	Integrated Development Environment	An integrated development environment (IDE) is a software suite that consolidates basic tools required to write and test software.
LOS	Line Of Sight	A kind of propagation that is used to transmit and receive data between transmit and receive stations that are in clear view of each other and without any physical interference.
	Line Sensor	A device installed on a feeder that is used to determine the real-time voltage, current and identify line fault conditions.
LQI	Link Quality Index	A process where measurements of signal quality are made, assessed, and analyzed.
	Load Interruption	This feature would allow the utility to disconnect a customer remotely for a defined period of time.
	Load Limit	This feature would limit the amount of power the customer may utilize at one time, below the nameplate rating of the meter.
	Mesh	A mesh network is a local network topology in which the infrastructure nodes (i.e., bridges, switches, and other infrastructure devices) connect directly to as many other network devices as possible and cooperate with one another to efficiently route data from/to the HES.
MDEF	Meter Data Exchange Format	Consists of binary files enclosed with channel header data, meter header data, interval data, and trailer record.
NAN	Neighbourhood Area Network	The NAN is primarily used for local communications. The primary purpose of this network is to allow clients/users to access their devices locally (e.g., in home display, field technician device, etc.). The intended network topology will primarily be point-to-point; point-to-multipoint topologies may be supported depending on implementation.
NNI	Network-to-Network Interface	NNI's are intended to provide connectivity between networks as defined by the different segments. They are not intended to provide direct user/client connectivity to the device but allow for an overall path such that a utility server can access the device. The overall path will consist of a mix of different network technologies, as such, NNIs will be connected across different physical (Layer 1) and hardware (Layer 2) mediums while maintaining consistency at upper layers of the network.
PLC	Power Line Carrier	A communication technology that enables carrying data on a conductor that is also used for electric power transmission.

Acronym	Description	Definition
PQ	Power Quality	A power quality meter is used to measure electric power signals to determine the load's ability to function properly with that electric power
	Register	A register shows a meter's total cumulative consumption from the date the meter was manufactured.
	Register Read	A register read shows the total cumulative consumption at a particular point in time.
RDR	Remote Disconnect/Reconnect	This feature allows the utility to disconnect and reconnect a premise OTA.
	SCADA Master	The term refers to a single computer responsible for communicating with the field devices.
	Takeout Point	A takeout point is any connection point that connects back via the WAN.
	Throughput	Total number of packets received as measured between source and destination.
TOU	Time of Use	TOU refers to the sale of electricity based on rates established for certain times of day, days of week, and/or season.
USDP	Universal Service Delivery Point	This refers to the point at which delivery is metered or calculated. The USDP is the point at which billing occurs based on input from one or more smart meters.
UNI	User-to-Network Interface	UNIs are intended to interface locally between end equipment and the associated AMI 2.0 device (e.g., meter). UNI's do not have direct routing access to other parts of the AMI 2.0 network (e.g., the user-connected device does not become part of the AMI 2.0 network). Given the point-to-point nature of this connectivity, a single network technology will be used per instance of an UNI.
WAN	Wide Area Network	Primarily used to communicate from the backend systems, which reside at the utility's data centers, to the field devices attached to the FAN across the province. The network topology is anticipated to be mainly point-to-point on this network segment, though point-to-multipoint topologies could work on certain technologies.

Appendix C - Available Meter Forms

Form	Current Rating	Honeywell	Itron	Landis+Gyr	Sensus	Trilliant
12S	200	RexU	Gen5 Riva	Revelo (Residential)	1θ - I-210+c (Aclara)[20] 3θ - A3 (Honeywell)	Libra
12S (No Disconnect)	320	N/A[21]	Gen5 Riva	N/A	A3 (Honeywell)	Libra
16S	200	A4CI	N/A	N/A	A3 (Honeywell)	Libra
16S (No Disconnect)	320	A4CI	N/A	N/A	A3 (Honeywell)	Libra
1S	200	RexU	Gen5 Riva	Revelo (Residential)	N/A	Libra
1S	100	N/A	N/A	N/A	I-210+c (Aclara)	N/A
1S	200/320	N/A	N/A	N/A	A3 (Honeywell)	N/A
25S	200/320	N/A	Gen5 Riva	Revelo (Residential)	I-210+c (Aclara)	N/A
2S	200	RexU	Gen5 Riva	Revelo (Residential)	I-210+c (Aclara)	Libra
2S (No Disconnect)	320	N/A	Gen5 Riva	N/A	I-210+c (Aclara)	N/A
2S	200/320	N/A	N/A	N/A	A3 (Honeywell)	N/A
2SE	320	N/A	N/A	Revelo (C+I)	N/A	N/A
35S	20	A4CI	N/A	N/A	A3 (Honeywell)	Libra
36S	20	N/A	N/A	N/A	A3 (Honeywell)	N/A

[20] Sensus AMI communications incorporated into electric meter manufactured by another supplier.
[21] In this table, "N/A" indicates that this meter type / configuration was not available at the time of publishing this report.

Form	Current Rating	Honeywell	Itron	Landis+Gyr	Sensus	Trilliant
4S	20	RexU	N/A	N/A	A3 (Honeywell)	Libra
4S (No Disconnect)	20	N/A	N/A	N/A	A3 (Honeywell)	N/A
9S	20	A4CI	N/A	N/A	A3 (Honeywell)	Libra
35S/45S	20	N/A	N/A	N/A	N/A	Libra
36S/46S	20	N/A	N/A	N/A	N/A	Libra
3S	20	RexU	Gen5 Riva	Revelo (Residential)	1θ - I-210+c (Aclara)[22] 3θ - A3 (Honeywell)	Libra
5S	20	A4CI	Gen5 Riva	N/A	I-210+c (Aclara)	N/A

[22] Sensus AMI communications incorporated into electric meter manufactured by another supplier.

AMI 2.0 Strategy

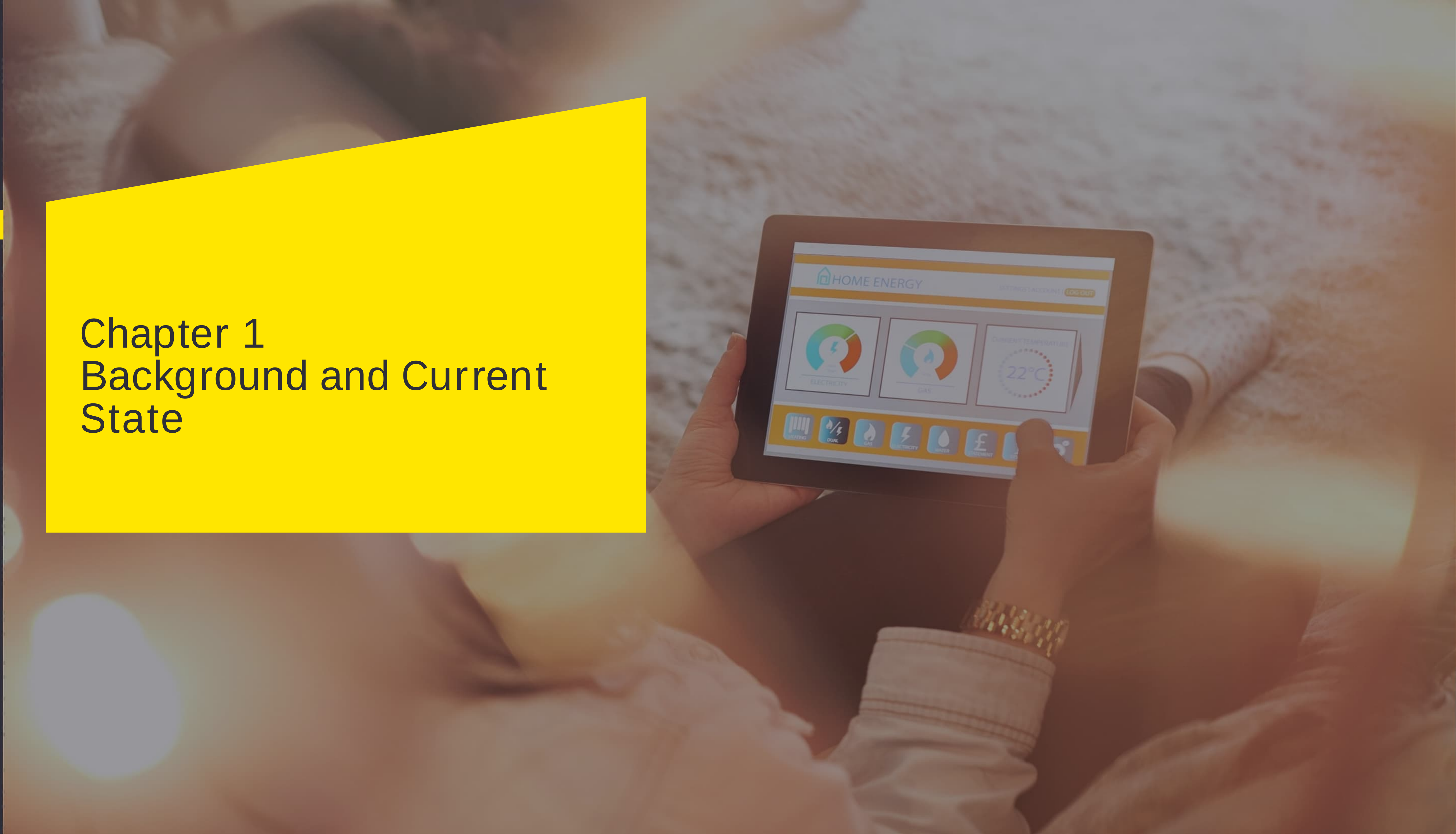
November 2022

The better the question. The better the answer.
The better the world works.

TORONTO HYDRO

EY
Building a better working world

Table of Content



Chapter 1
Background and Current State

Background

Background and context

Toronto Hydro owns and operates $5 billion of capital assets comprised primarily of an electricity distribution system that delivers electricity to approximately 787,000 residential, commercial and industrial customers in the City of Toronto.

Toronto Hydro operates approximately 686,000 Elster smart meters (640,000 residentials smart meters & 46,000 commercial smart meters) deployed across its service territory in a hybrid network of both point-to-point and mesh systems. These smart meters are used to gather energy consumption and demand data to ultimately bill its customers. Most of the smart meters were installed between 2006 to 2008 and have a useful life of 15 years. Those smart meters will reach their end of life or will have their seal expired between 2022 and 2027 and must be replaced. Without intervention, 90% of these meters will be operating beyond their expected useful life as of 2023, presenting an increased risk of failure.

Toronto Hydro intends to replace the current AMI system with modern metering infrastructure and establish the foundation for its grid modernization and customer experience enhancement strategic priorities. This will be done through a comprehensive AMI program over the next several years.

Report structure

As Toronto Hydro moves forward in its AMI 2.0 journey to replace its existing population of smart meters, EY was engaged by Toronto Hydro to provide consulting services focused on meter technology and Advanced Metering Infrastructure(AMI) upgrades from a strategic perspective, including opportunities, use case prioritization and deployment strategies. As part of this consulting engagement, Toronto Hydro participated in a collaborative facilitated workshop "EY Wavespace session". This report is an output from various discussions and workshops executed with Toronto Hydro participation. The report is structured into the following Chapters:

- Chapter 1: Background and Current State
- Chapter 2: AMI 2.0 Use Cases
- Chapter 3: Deployment Considerations
- Chapter 4: Program Structure Considerations
- Chapter 5: Next steps and Recommendations.

Current AMI capabilities

Toronto Hydro’s current smart metering system supports the following business capabilities:

- Remote Disconnect / Reconnect: Toronto Hydro currently has the capability for remotely disconnecting and reconnecting meters for specific meter types. This feature is being used only where the customers default on bill payment and Toronto Hydro is unable to reach such customers. Toronto Hydro is interested in using this capability.

- Remote meter pings: Toronto Hydro has deployed meter pinging capability. When a customer calls Toronto Hydro for a power supply issue, the dispatch group pings the meter using the Batch Request Tool feature to check the status of the meter, working backwards, to assess the extent of a potential outage.

- Meter alerts: Various meter alerts are received from the meter population. The volume of alerts is significant, and information provided is not used in a sustaining manner. Tamper alerts are not reliable.

Challenges to be managed while deploying AMI 2.0

While AMI 2.0 presents significant opportunities for utilities in their modernization journey, challenges will need to be addressed towards readiness for deployment.

Current Challenges for Toronto Hydro

Rapidly changing landscape :

- Current assets are required to be able to sustain long term growth with increasing DER penetration and EV growth

Regulatory requirements :

- Toronto Hydro (and other Ontario utilities) have a significant reliance on regulatory requirements, which change frequently

Supply Chain & Quality:

- With significant global supply chain issues, timely access to metering and communications equipment will need to be managed actively with the vendor
- Warehousing capacity of the install vendor will need to be considered in conjunction with Toronto Hydro warehousing capacity to align with inventory of meters to be maintained at any point

Privacy and Security:

- Customers are concerned that the utility owns a lot of information about them and don't know how they wish to use it. This may need to be factored into the Customer Engagement approach for smart meter deployment
- With increased reliance on data at the edge, security of data and prevention of unauthorized intrusion become critical requirements

Operational Agility

- Policy changes, frequent rate changes and regulation changes requires agility at an Operational level including a better ability to leverage data for insights
- Balancing operational agility with safety will continues to be a challenge and an area of focus

Analytics and Insights

- AMI will continue to enable downstream functions and insights. The ability to govern and manage data, including the ability to draw insights from data for grid and customer benefits will become central
- Customers require and need to be presented with actionable insights as active stakeholders

Chapter 2
AMI 2.0 Use Cases

The Chapter discusses AMI 2.0 Use Cases and capabilities required to enable AMI 2.0

AMI 2.0 Use Cases

With the digitization and rise in connected devices, the AMI network of the future is moving to become an IoT ‘platform’ which will connect ecosystems of utility and customer-owned devices and services.

AMI 2.0 expected to deliver base capabilities beyond AMI 1.0, which was predominantly focused on meter to cash efficiencies. These benefits include improved network range, enhanced security against cyber-threats, increased grid transparency, edge computing capabilities and improved customer experience. Beyond the base-case capabilities, AMI 2.0 will also deliver benefits for asset management and grid operations through advanced analytics capabilities, as well as integration of AMI data into smart grid systems such as ADMS, DERMS etc.

In addition to advanced benefits being enabled by AMI 2.0, new operating models are also emerging, with opportunities for Managed Services as opposed to the traditional in-house meter operations, as well as cloud-based AMI systems.

Smart base-case

Capabilities that come ‘out-of-the-box’ for Smart implementations

Sample capabilities:

- *Remote meter reading*
- *Remote connect / disconnect*
- *Interrogation / on demand read*
- *Remote asset management*
- *Billing / retail integration*

Data-driven insights

Insights & business value are delivered when applying analytics to Smart & other data

Sample analytics:

- *Theft detection*
- *Load profiling*
- *New connection sizing*
- *Meter mapping / LV visibility*
- *Transformer load management*
- *Outage calculation & trends*

Tech-enabled operations

Integrating Smart monitoring & command functionality into business operations

Example integrations:

- *Advanced Distribution Mgmt (ADMS)*
- *Distr. Energy Resource Mgmt (DERMS)*
- *Demand response (DRMS)*
- *Interactive Voice recog. (IVR)*
- *Call Center operations*

AMI 2.0 Use Cases

AMI 2.0 also provides utilities with opportunities to support the prosumer and meet new customer expectations and drive behaviours.

Do the basics well
Fix existing process issues to deliver an efficient process with reliable service

Enhance digital
Continue to enhance the range and functionality of our digital channels

Provide additional services
Integrate 3rd party solutions/services for an end-to-end experience

Saving money
Customers expect utilities to proactively offer solutions to help lower bills

Data availability
Provide customers with customized insights and options

Privacy and data security
Protect customers' personal information from misuse and hacking

Safety
Proactively monitor unsafe situations and alert customers

AMI 2.0 Use Cases: Expanded capabilities

AMI 2.0 will enable advanced capabilities to support grid modernization and customer experience agendas for utilities – over a period of time.

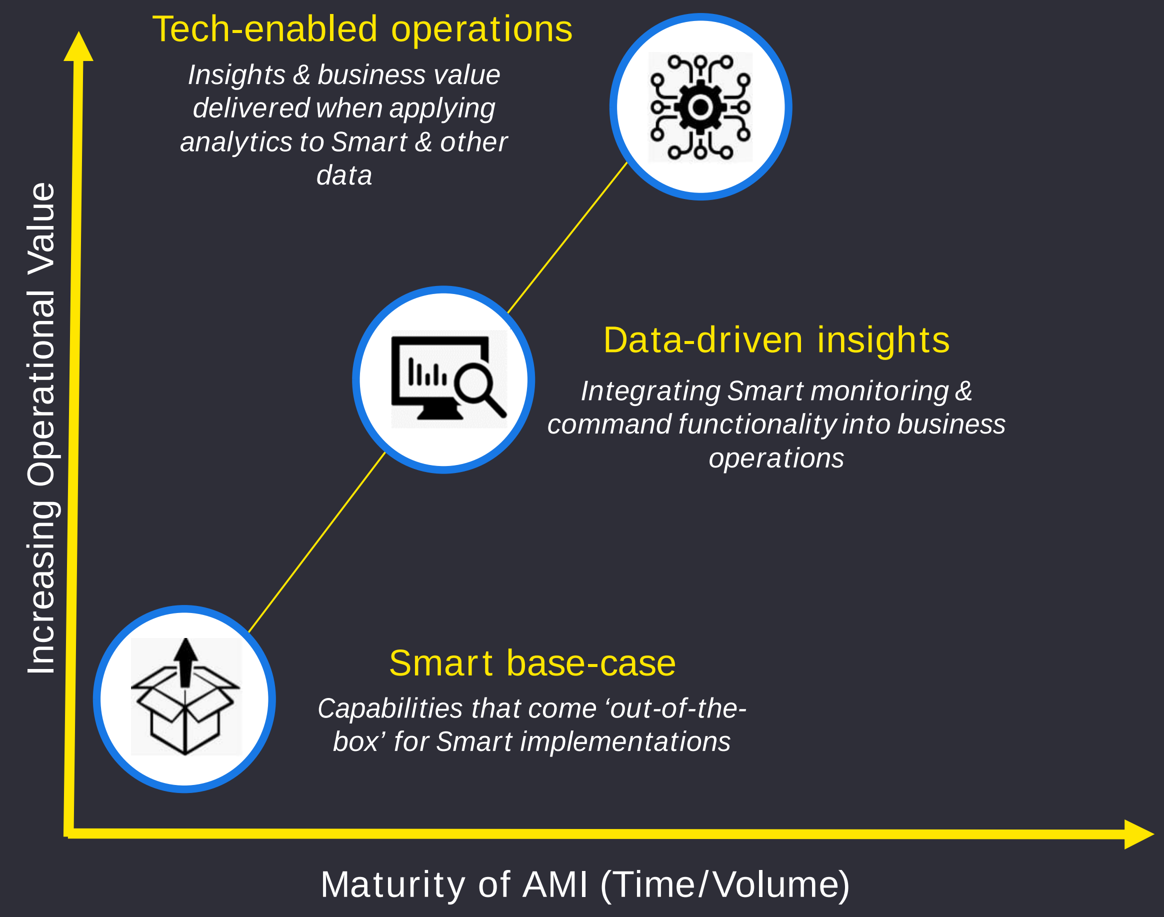
AMI 2.0 is expected to enable advance capabilities for utilities. These capabilities will be delivered as out-of-the-box, through enabling data-driven insights, as well as through leveraging AMI data in conjunction with operational systems.

Benefits associated with AMI 2.0 can start being rolled out with AMI 2.0 smart meters for base-case scenarios. Other benefits will require investment in technology (such as DERMS), development of organizational capabilities (such as advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized.

	Solve the Now	Explore the Next	Imagine the Beyond
Customer Insights	Virtual Energy Advisor (w/Load Disaggregation)	Appliance Health Monitoring; Enhanced Outage Notifications	Real Time Monitoring (w/Load Disaggregation)
Smart Transactions and Controls	Active Demand Response (Peak Load Mgmt.); Smart Prepay	Smart Rates; Virtual Sub-Metering; Smart Energy Optimizer	Distributed Energy Trading/Local Power Pool; Integration with C&I Control Systems
Grid Reliability	Outage Detection; Restoration Tracking; Outage Performance; PSPS Statistics	Distributed Generation Analysis; Cold Load Pickup; Voltage Loss Detection	Distribution transformer failure; Transformer loss of life analysis
Grid Operations	Phase Identification; Undocumented DER Alerts; Locate Momentary Grid Disturbances /Fault Detection; Theft Detection: Tamper	Theft detection: Service entrance & secondary connection; Location Awareness; Under-Frequency Load Shedding; Real-Time Voltage Control and Optimization (IVVO)	Active Transformer Load Management; Smart Safety Disconnect/ Unintentional Microgrid

AMI 2.0 Use Cases: A Transformational Journey

Realization of AMI 2.0 benefits beyond the out-of-box capabilities is a transformational journey, achieved over a period of time. This transformation will require Toronto Hydro to invest in technology and systems, as well as advance/mature its capabilities across several domains. Developing a list of use cases/benefits that Toronto Hydro elects to deliver over a specific time period is the first step. This will facilitate the identification of systems and capabilities required over a time horizon to ultimately realize the benefits.



Building AMI Operations Maturity – (indicative)

Increasing Operations Capability

- *Take the time to build learning and insight from operational experience*
- *Focus on key KPIs and business services only*
- *Look for quick wins to address the most critical problems*
- *Build the right resource and process structure*

- *Build out the number of services & reports within the operations center*
- *Build out more complex analytics and reporting services*
- *Support integration to additional systems and data sources*
- *Track benefits & improvements in operations*

- *Establish advanced analytics and automation to support the delivery of business operations*
- *Establish continuous improvement & sustainability initiatives*
- *Build out real-time services and processing capabilities*

- *Operations are automated and managed in real time.*
- *Continued benefit realization in business operations.*
- *Build out new technologies and services within the operations center.*

Time/Volume of Assets

AMI 2.0 : Toronto Hydro Use Cases

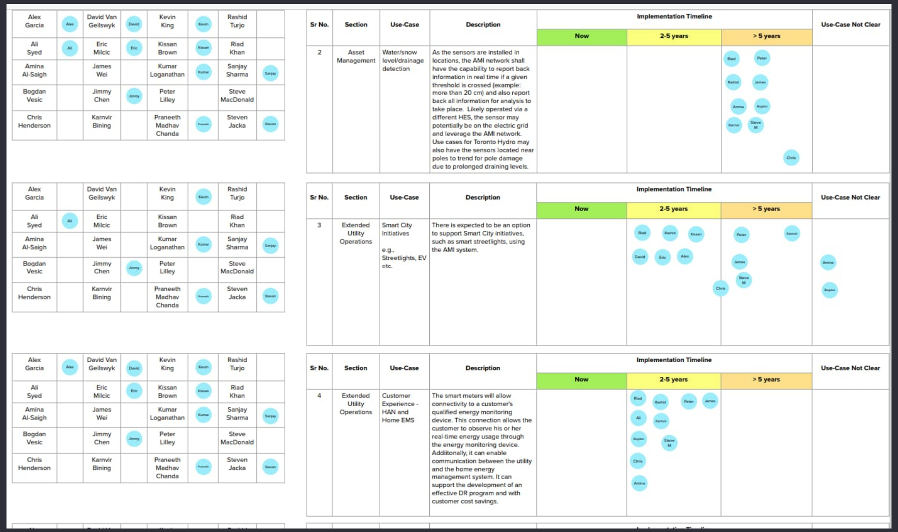
Toronto Hydro has identified 49 use cases as a part of their AMI 2.0 readiness activities

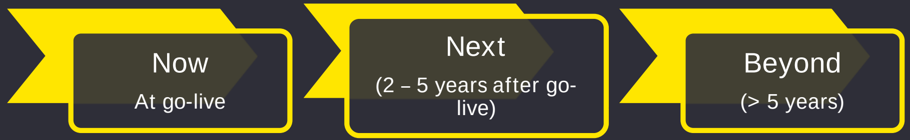
Toronto Hydro has identified 49 use cases, within the following domains – Core requirements, Asset Management, Operations/Extended Utility Operations, Network, Predictive Analytics, Smart City/Grid modernization and Smart Controls. In absence of a roadmap for the use cases & enabling capabilities, EY recommended a prioritization of the 49 use-cases over a timescale in preparation for the evaluation of responses from the AMI RFP . In addition, prioritization of the 49 use cases against Toronto Hydro's business strategy (customer and grid modernization strategies) as well as an analysis of additional complexity to implement the use cases will be informative towards evaluating the RFP responses, as well as defining a use-case roadmap.

Output of the preliminary prioritization exercise

- A cross-functional Toronto Hydro team reviewed and prioritized the 49 use cases over a "Now" / "Next" / "Beyond" timeline. Many of the use cases were split across 2 timelines. These use-cases have been placed under the timeline based on majority inputs.

- The output of this prioritization activity has been shared in the next page. The Figure to the right is a partial snapshot of the prioritization exercise. The full results are provided in the Appendix.

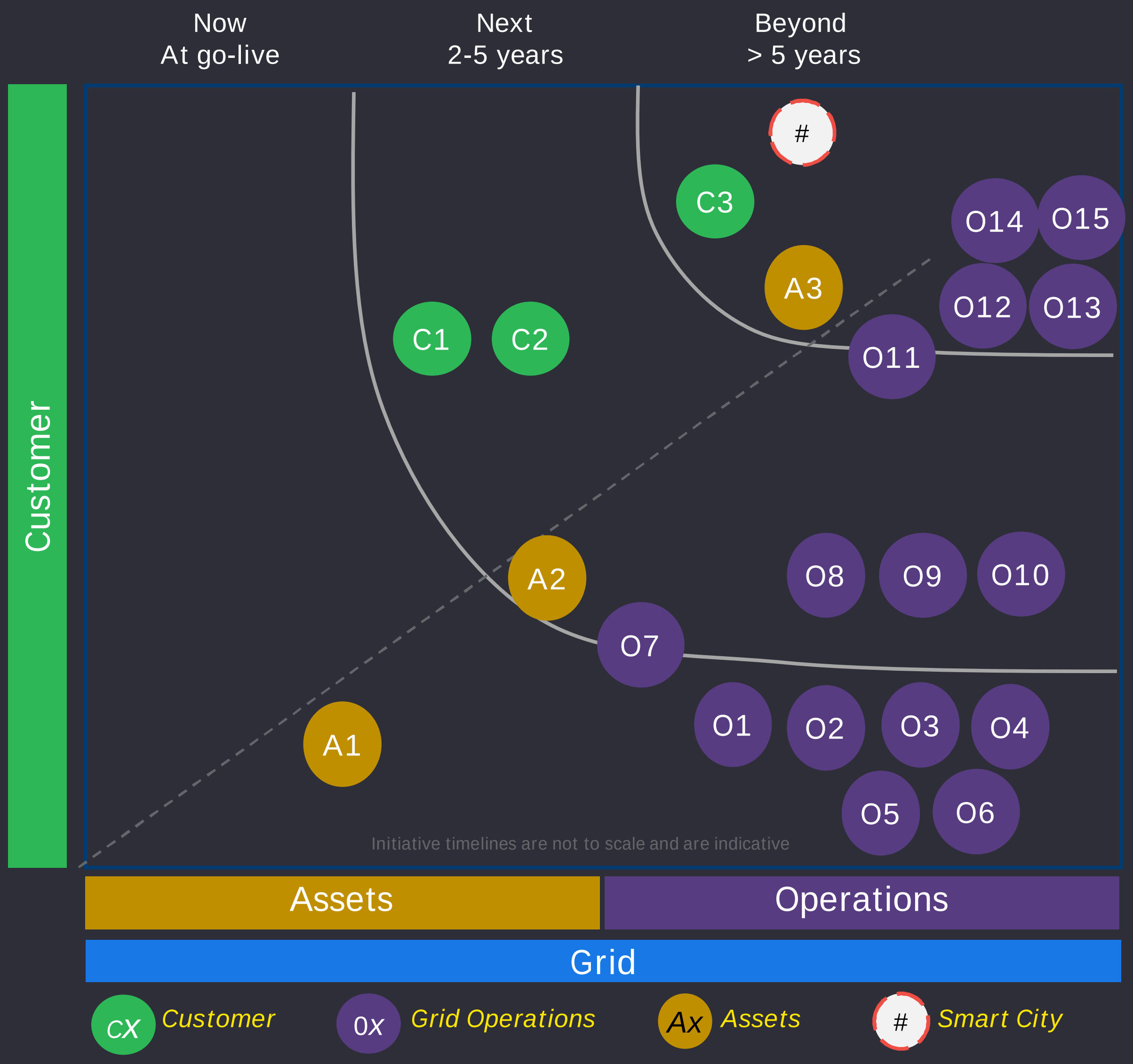




AMI 2.0 : Toronto Hydro Use Cases - Prioritized

The charts shown here reflect the results of Toronto Hydro's use cases prioritized over a time scale. The full list of Toronto Hydro Use Cases is provided on the next page.

AMI 2.0 use-cases			
Asset	A1	Non-technical Loss detection	Now
	A2	Feeder and Transformer Loading Analysis	Next
	A3	Pole damage monitoring	Beyond
Customer	C1	Home energy usage monitoring capability	Next
	C2	Energy budgeting and optimization	Next
	C3	Customer Safety Services	Beyond
Grid Operations	O1	Customer Load Data Disaggregation for load analysis	Now
	O2	Remote Disconnect/ Load Limiting/Load Interrupting capabilities	Now
	O3	Outage Management	Now
	O4	Phase identification analysis	Now
	O5	Power flow optimization	Now
	O6	EV control and monitoring capability	Now
	O7	Integration capability with customer DERs	Now/Next
	O8	Demand Response support capability	Next
	O9	Fault Location, Isolation, and Service Restoration (FLISR)	Next
	O10	Voltage Optimization	Next
	O11	Edge Network Computing	Next/Beyond
	O12	Cold Load Pick up capability	Beyond
	O13	Decentralized FLISR aggregation from meters	Beyond
	O14	Load/Demand Forecasting	Beyond
	O15	PSPS Statistics	Beyond



Note: Use- cases have been logically grouped into 3 categories: Customer, Asset and Grid Operations. All the use-cases that fall under 'Smart City' were prioritized under 'Beyond'. Customer Safety Services proposed as a "new" use- case.

AMI 2.0 : Toronto Hydro Use Cases - Mapping

The full list of Toronto Hydro Use Cases is highlighted under 5 categories in the below chart. All the use-cases that have been listed under ‘Smart City’ were mapped ‘beyond’ during the team exercise. The ‘Requirements’ form the baseline use-cases for AMI 2.0 implementation.

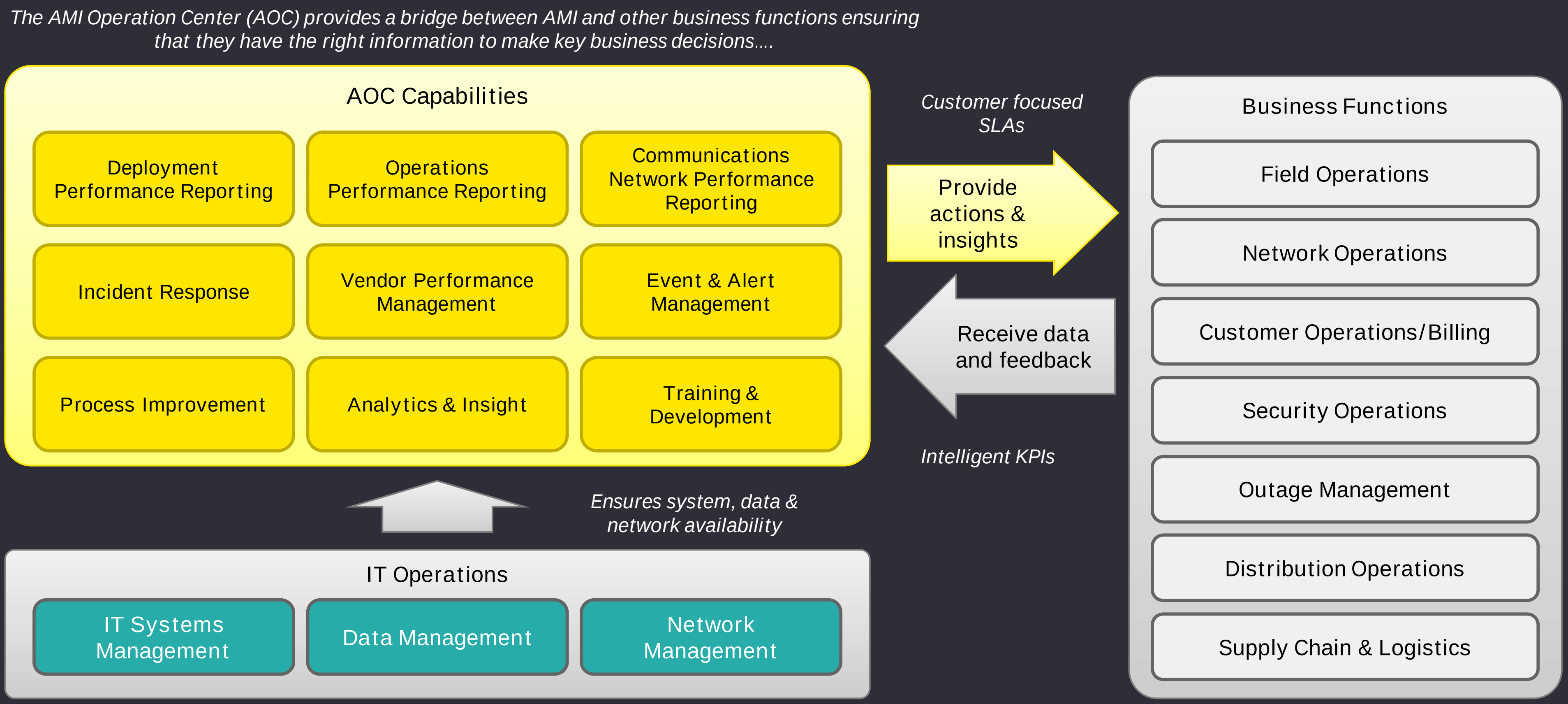
AMI 2.0 use-cases			TH Use-Case No.
Asset	A1	Non-technical Loss detection	20
	A2	Feeder and Transformer Loading Analysis	24
	A3	Pole damage monitoring	42
Customer	C1	Home energy usage monitoring capability	28
	C2	Energy budgeting and optimization	31
	C3	Customer Safety Services	New
Grid Operations	O1	Customer Load Data Disaggregation for load analysis	29,30
	O2	Remote Disconnect/ Load Limiting/Load Interrupting capabilities	8
	O3	Outage Management	14
	O4	Phase identification analysis	26
	O5	Power flow optimization	27
	O6	EV control and monitoring capability	19
	O7	Integration capability with customer DERs	17
	O8	Demand Response support capability	18
	O9	Fault Location, Isolation, and Service Restoration (FLISR)	23
	O10	Voltage Optimization	49
	O11	Edge Network Computing	2
	O12	Cold Load Pick up capability	15
	O13	Decentralized FLISR aggregation from meters	16
	O14	Load/Demand Forecasting	22
	O15	PSPS Statistics	25

AMI 2.0 use-cases			TH Use-Case No.
Smart City	S1	Leverage Lighting network for AMI	32
	S2	Street Light Dimming capability	33
	S3	Street Light controls capability	34
	S4	Street Light controls for emergency response capability	35
	S5	Parking Monitoring	36
	S6	Traffic Monitoring	37
	S7	Adaptive lighting capability	38
	S8	Community wi-fi capability	39
	S9	Digital Street Signage	40
	S10	Street lighting repair monitoring	41
	S11	Environmental/Air Quality Monitoring, CO2 detections	43,44
	S12	Video surveillance	45
	S13	Emergency support capability	46
	S14	Intrusion detection	47
	S15	Gun shot detection	48
	S16	Smart City Initiatives (Streetlight, EVs, etc.)	21
Requirement (Core)	R1	Remote troubleshooting and diagnostics tool	10
	R2	Remote configuration capability for PQ	13
	R3	Remote management capability for AMI devices	4
	R4	Self-diagnostics for failure identification	5
	R5	Alternatives to address RF sensitivity	6
	R6	Manual meter reading capabilities	9
	R7	Configuration and bi-directional metering capability	11
	R8	Meter Data Storage capability	12
	R9	Minimal human intervention for multi-layer network and data security	1
	R10	Separate path for DA traffic to back-end	3
	R11	DA devices as repeaters	7

Note: Customer Safety Services (temperature monitoring, arc monitoring, broken neutral, etc. for a meter at consumer premises, proposed as a “new” use- case.

AMI 2.0 business integration capabilities

AMI 2.0 will require advanced organizational capabilities to support metering infrastructure. In addition to Business Functions and IT Operations capabilities, utilities also need to establish capabilities and a focus on managing deployment performance, vendor performance, event and alert management etc, to support the metering infrastructure and drive value realization. The Figure below illustrates a typical set of capabilities required to support AMI.



AMI 2.0 business integration capabilities

The figure below is a current state representation of Toronto Hydro’s capabilities to support AMI 2.0. This view is based on direct input from Toronto Hydro business and IT stakeholders during the “Wavespace” session held on 19 August 2022. This view is not atypical of the readiness levels of utilities. Utilities should carefully assess their capability maturity in these areas carefully as they embark on their AMI journeys.

Key Focus Areas for AMI

- Events and Alert Management
- Analytics & Insights
- Outage Management
- Distribution Operations
- Supply Chain & Logistics
- Data Management

Legend: Doing great · Could be improved · Should be a focus

AMI 2.0 Case Studies

The following sub-section illustrates case studies from utilities across the globe with respect to how AMI has been used to enable business capabilities.

AMI 2.0 Case Studies: Capabilities deployed by Utilities globally

The table below provides a summary view of services and capabilities deployed by various utilities. Additional details for selected utilities are provided in the following pages.

#	Services/Capabilities	[redacted]									
1.	High Bill Alert to Customers	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
2.	Outage Alert to Customers	✓	✓	✓	✓	✓	✓	✓	✓		✓
3.	Net Energy Metering (Renewable Energy)	✓	✓		✓	✓	✓	✓	✓		✓
4.	Outage Integration with ADMS	✓				✓	✓	✓			
5.	Outage Visualisation		✓			✓		✓			✓
6.	Technical & Non-Technical Loss	✓	✓	✓		✓	✓	✓	✓	✓	✓
7.	Demand Response – Customer		✓	✓	✓	✓	✓	✓	✓	✓	
8.	Demand Response – Operations	✓						✓	✓	✓	
9.	Volt/ Var Optimisation		✓			✓	✓	✓	✓		
10.	Power Quality	✓	✓		✓	✓	✓			✓	✓
11.	Peer-to-peer (P2P)Trading				✓						

Note: Definitions of these services/capabilities are provided in the Appendix

AMI case study: [redacted]

[redacted] is involved in generation, transmission, distribution and retail of electricity [redacted] is headquartered in [redacted]

[redacted] Poles

[redacted] km transmission lines

[redacted] substations

[redacted] km distribution lines

Generation | Transmission | Distribution | Retail

Smart meters installed [redacted] million (as of 2021)

Capabilities

[redacted]

Source: utilities documents and website

AMI case study: [redacted]

[redacted] is involved in generation, transmission, distribution and retail of electricity. As of 2018, [redacted] reported [redacted] million customers.

[redacted] Poles

[redacted] km transmission lines

[redacted] substations

[redacted] km distribution lines

Smart meters installed
[redacted] million
(as of Jul'19)

Generation | Transmission | Distribution | Retail

Capabilities

[redacted]

Source: utilities documents and website

AMI case study [redacted]

[redacted]s an energy utility and through its subsidiaries is involved in electricity generation, transmission, distribution and retail. It provides its services in [redacted]. It is also involved in gas and distribution business.

[redacted] Poles

[redacted] area sub-stations

[redacted] of distribution lines

Smart meters installed (gas and electric)
[redacted] million
(as of Apr'21)

Generation | Transmission | Distribution | Retail

Capabilities

[redacted]

Source: utilities documents and website

AMI case study: [redacted]

[redacted] is a subsidiary of [redacted], and is involved in transmission and distribution of electricity through retail electric suppliers (RES) to [redacted] million customers. It is headquartered in [redacted]

Smart meters installed
[redacted] million
(as of 2021)

[redacted] Poles

[redacted] substations

[redacted] miles of power lines

Transmission Distribution

Capabilities

[redacted]

Source: utilities documents and website

AMI case study: [redacted]

[redacted] is an integrated utility which serves over [redacted] million customers globally. It operates via four business segments namely networks, renewables, generation and supply and other businesses including gas and real estate activity

[redacted] of electricity produced

[redacted] transformer substation

[redacted] distribution lines

Smart meters installed
[redacted] million
(as of 2021)

Generation | Transmission | Distribution | Retail

Capabilities

[redacted]

Source: utilities documents and website

AMI case study: [redacted]

[redacted]s is a wholly owned subsidiary of [redacted] that manages 95% of the electricity distribution network in [redacted]. It serves ~[redacted] million customers.

[redacted] of electricity distributed

[redacted] generation facilities connected to grid

[redacted] electric network

Smart meters installed
[redacted] million
(as of 2021)

Distribution

Capabilities

[redacted]

Source: utilities documents and website

Recommended next steps

- Continue to develop a prioritized list of use cases to secure value from AMI 2.0
- Develop a clear view of requirements (people/process/technology) to support the "Now" use cases
- Consider performing a maturity assessment of key capabilities required to support AMI 2.0 and develop a plan to address gaps

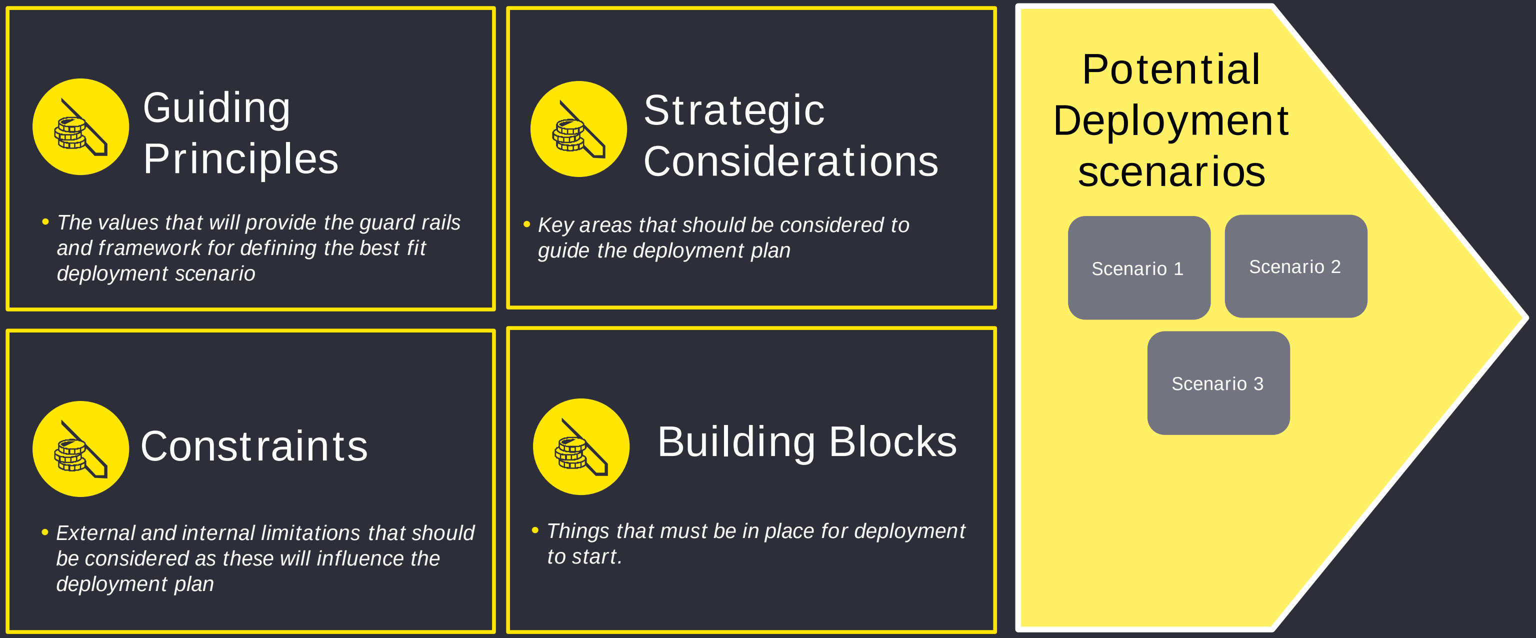
Chapter 3 Deployment Considerations

Deployment is a significant aspect in the roll-out of AMI implementations. There are many moving parts and AMI deployment requires discipline, to mitigate reputation risks. This Chapter discusses typical deployment considerations.

AMI 2.0 Deployment

Building a risk-informed Deployment Plan: Meter deployments costs are a significant portion of the total cost of an AMI project. As such, careful consideration should be given to deployment scenarios to arrive at the best-fit deployment plan for Toronto Hydro.

A deployment framework such as the one shared below provides a structured approach to evaluating deployment options and associated risk profiles. Careful consideration should be given to specific constraints, strategic considerations, things that must be in place (building blocks) to enable execution. Successful deployment planning and execution requires the engagement of multiple stakeholders – and using a framework such as the one below allows for stakeholder engagement in the definition of a Deployment Strategy.
In the following pages, we share some typical considerations for Toronto Hydro's review as you develop your Deployment Strategy.



Deployment Framework

AMI 2.0 Deployment Considerations

Illustrative

Guiding principles and a clear understanding of any constraints provide the guard rails to build a realistic, risk-managed deployment plan. The guiding principles and constraints articulated below are a starting /draft list for Toronto Hydro, and should be expanded.

Guiding Principles

- Billing accuracy metrics are maintained or improved
- New capabilities to be tested or piloted prior to roll-out
- AMI 2.0 will drive minimal customer impact as new smart meters are rolled out.
- Add
- Add

Constraints

- End of life meters will need to be prioritized for deployment
- Meter inventory and deployment resources will be required to support the deployment scenario
- Suite-meters.....
- 686,000 meters to be replaced
- Add

AMI 2.0 Deployment: Strategic Considerations

Illustrative

Strategic considerations need to be carefully reviewed to mitigate any deployment risks.

Segmentation

What is the approach for deploying the network across the Toronto Hydro territory

Toronto Hydro Current state: The current driver for meter deployment is meter life. Beyond replacing meters, the roll-out will be by geography, across all customers.

- Have all scenarios been considered, and risks identified and mitigated?
- Will deployment be executed across multiple geographies and customer segments in parallel? Or will the deployment be sequential?
- Supply chain considerations should be factored into the Deployment Plan – will meter inventory be matched to the deployment
- Install vendor capacity should be factored into the Deployment Plan

Meter/Network Deployment Strategy

What is the approach for the comms network to meter roll out

Toronto Hydro Current state: This will be driven by the outcome of the meter vendor.

- What is the proposed approach for upgrading the network ?
- What is the proposed approach for validating meter communications and issue resolution?

Customer Engagement Approach

What is the messaging strategy and customer communications strategy

Toronto Hydro Current state: Customer engagement strategy is being defined

- Changing customer demographics and customer expectations should be factored into the approach for managing customers as a part of AMI 2.0
- When will customer communications start? When will the strategy and plan for customer communications be established?
- How will customer segmentation impact the Deployment Strategy?

Revenue Assurance

What controls need to be established to mitigate potential billing issues

- End to end testing must be executed even if back-end systems are not changing
- Clear accountability should be assigned to assess field meter and communications issues to mitigate any downstream billing impacts

AMI 2.0 Deployment: Monitoring

Monitoring is a critical success factor for the effective management of deployment activities. Effective deployment also requires pre and post-instal activities across multiple domains, such as Finance, HR etc. The Figure below illustrates typical considerations to prepare for deployment execution. The chart on the next page illustrates the complex coordination of activities that are required for deployment, across different stakeholder groups. This level of complex coordination drives the need for effective program management as well.

Monitoring Dimensions	Pre-Install	Install	Post Install
Customers [Customer services]	Are customers engaged and bought in to the upgrade?	Does our customer journey positively impact customer satisfaction?	What is our approach to address customer concerns and queries?
Operations [Field, Supply Chain, Operations]	Is our scheduling function performing effectively?	Are we installing meters efficiently?	Is Field performance being effectively managed and continuously improved?
People	Are our people engaged and bought into smart?	Do our people have the right skills and training to fulfil their roles?	What is our approach to delivering change?
Finance	Are we operating at a level which is financially viable?	What is our unit cost per installation?	What are our major cost areas and revenue opportunities?
H&S and compliance	Are we operating safely?	Are we fully compliant with smart metering codes of conduct?	Are we on track with volume targets?

Illustrative

Typical KPIs to be tracked:

- Abandonment rate
- Customer complaints
- Installation and travel time
- Conversion rate
- Meter failures
- Customer eligibility
- Assets and logistics
- Staff headcount
- Response rate
- Unit cost

AMI 2.0 Deployment: Major Execution Activities

Illustrative

Business Process	Manage Deployment								
Value Chain	Plan to Pre-Install					Install to Enable			
Business Process Flow	Define Deployment Strategy	Plan Meter Deployment	Plan Network	Plan Operations	Execute Pre-Installation Activities	Prepare Meter Installation	Install Meter	Commission & Enable Meter	Manage Smart Meter Customer
Operational Process Flow	Set project objectives and targets	Develop deployment plan	Develop network plan	Manage asset plan	Develop Service Order (SO) plan	Execute SO plan	Perform site inspection	Manage post installation plan	Manage SRs & complaints
	Establish deployment strategy	Develop OPC list	System dimensioning	Manage supply chain (meter, network, installer etc)	Schedule appointment	Perform toolbox briefing	Perform meter replacement	Photo audit post installation	Manage adhoc customer queries and complaints
	Define network levers and requirements	Conduct customer analysis	Nominal design approval	Procurement of assets	Brief installers	Perform equipment checks	Log RTU cases (unable to complete work)	Manage meter commissioning and exceptions	Analyze VoC sentiments and feedback
	Define customer levers and requirements	Confirm network technologies for deployment areas	Line of sight study	Prepare list of addresses for letter rendering	Commission network sites	Log RTU cases (unable to access meters)	Perform quality check	Monitor and report AMI network health	Monitor social media
	Define change management levers and requirements	Engage customers for RF pole installation	Finalize network design	Install network	Verify network coverage		Perform QA (Supervisor spot check)	Assess tuning readiness	Educate customers on smart meter offerings
	Define technical levers and requirements	Engage customer (planning, engagement, unlock)	Network design approval	Assign manpower according to plan	Print customer letters		Manage meter scrap	Perform network tuning	Manage billing and invoicing
	Set project KPIs	Conduct stakeholder analysis	Handle stakeholder rejection (AMI Network)		Render letter		Meter discovery	Manage updates to business	Monitor bill estimation
		Conduct change impact assessment	Develop engagement plan		Inform business stakeholders		Monitor meter healthiness (e.g registry read, load profiles etc)	Manage business escalations and feedback	
		Register master monitoring parameter	Execute engagement		Obtain network status for planned deployment areas		Process daily SitRep data	Transition areas / meters to BAU	
		Consolidate integrated project plan	Confirm SMOC and IT&S alignment on monitoring plan					Manage global key exchange exceptions	
		Engage internal and external stakeholders						Commission, clear alarm, GKE etc	Prepare management reports and review
								Manage meter enablement	Monitor budget

Recommended next steps

- Execute a thorough analysis of areas requiring meter replacements.
- Develop a robust deployment plan taking all scenarios and factors into consideration.

Chapter 4
AMI 2.0 Program Structure Considerations

AMI programs are more than an infrastructure roll out or upgrade. They drive change across the organization. The level of change is driven by the business capabilities proposed to be deployed by the Utility as well as fundamental business process changes required by an AMI 2.0 implementation. Careful consideration should be given to the anticipated change, and an AMI project execution organization should be established to implement and sustain AMI 2.0. This chapter identifies a typical AMI 2.0 program organization for Toronto Hydro’s consideration.

Typical AMI Program Organization Model

Functional structure during peak rollout volumes

01 AMI PMO

02 *AMI Solution Delivery*

- Business Integration Lead
  - Customer operations / Billing
  - Customer call center
  - Asset Manager/Network Operator
  - Metering
  - Customer Communications
  - Change management
- System Integration Lead
  - Enterprise system admin. (GIS, CIS, Asset Mgmt.)
  - Network management & supporting services
  - Infrastructure management & supporting services
  - Security Operations Center (SOC)

Deployment Operations Centre (DOC)

- **03** Deployment Operations Lead
  - Deployment strategy and planning
  - Meter procurement
  - Meter asset management
  - Meter and deployment vendor management
  - Internal field force management

AMI Operations Centre (AOC)

- **04** AMI Operations Lead
  - AMI solution portfolio owners
    - Metering and Communications
    - Head End System (HES)
    - MDMS
    - Exception handling
    - Data Management

Third-party Vendors **05**

- Network Deployment Contractor
- Meter Deployment contractor

Procurement

1. Meter orders are submitted by procurement (in partnership with the Deployment Operations center (DOC) to the meter vendor
2. Meters are delivered to warehouses (provided by the install vendor), where the DOC performs meter acceptance testing
3. Upon the shipment being accepted, the order is processed into MDMS and the HES by the DOC

Installation

4. The DOC determines installation routes and provides batches of work orders to the deployment contractor
5. Appointment scheduling is managed by the installation vendor in partnership with the DOC
6. Meter technicians receive work assignment and process each completed installation

Commissioning

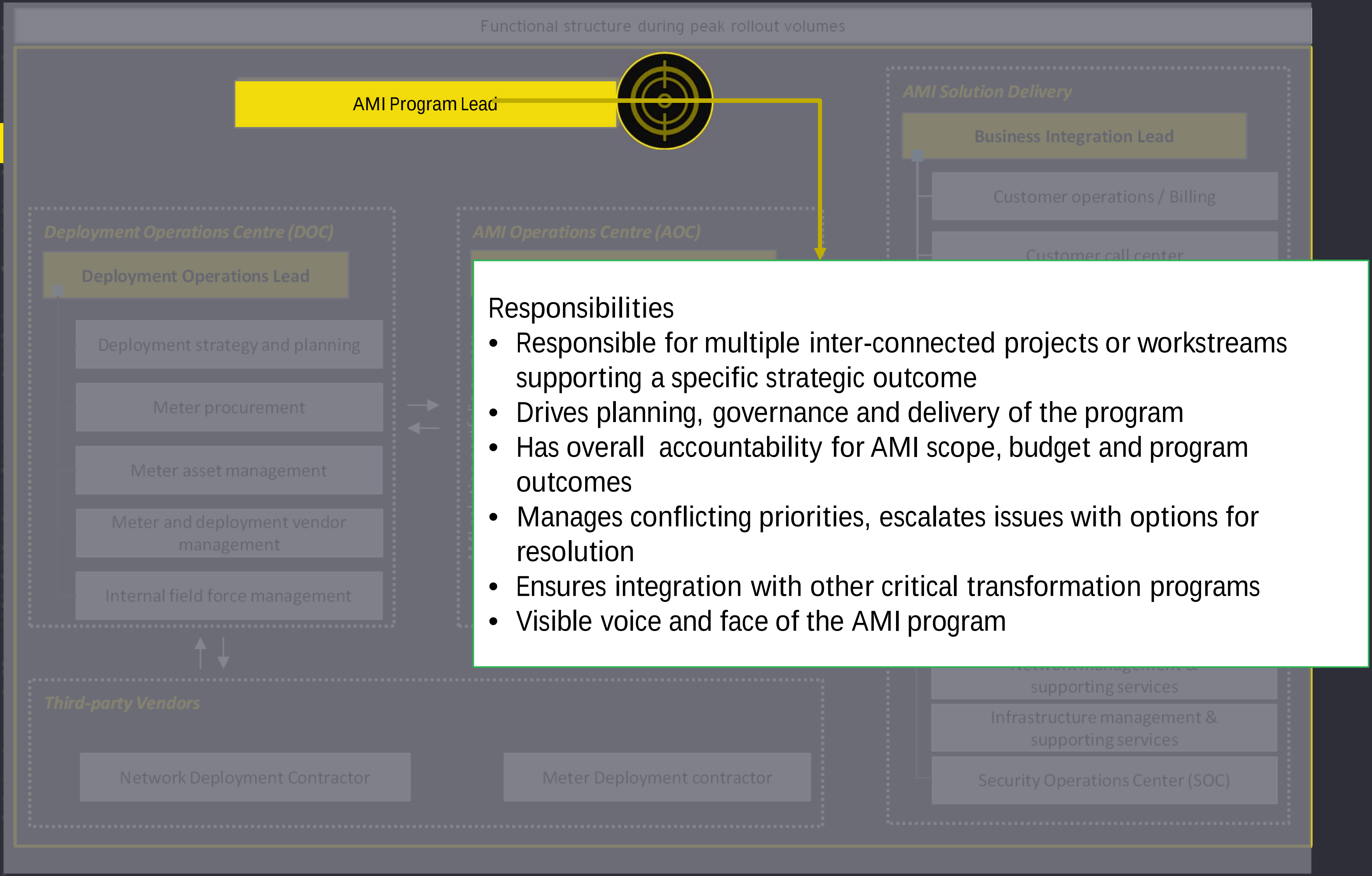
7. These meters enter a *QA Ready* status, and photos of the installation are reviewed by the AOC
8. If this review stage is passed, the meters enter a *QA Accepted* status, and a nightly batch process moves them over into the CIS and the MDMS
9. The meters undergo two validation tests once within the MDMS: (1) Successful first read, (2) 80% read quality over 5 day period. If successful, they now enter an *Installed* status

Operations

10. The AMI Operations center (AOC) undertakes reporting and data analysis to identify and resolve exceptions
11. The SOC and IT Support Services functions have dedicated smart program resources to handle specific AMI-related activity
12. Customer complaints are handled by the customer call center. Smart-related issues are handled on an ad-hoc basis via calls and emails to the AOC

*Revenue protection role will come across from the business

Typical AMI Program Organization Model – Program Management



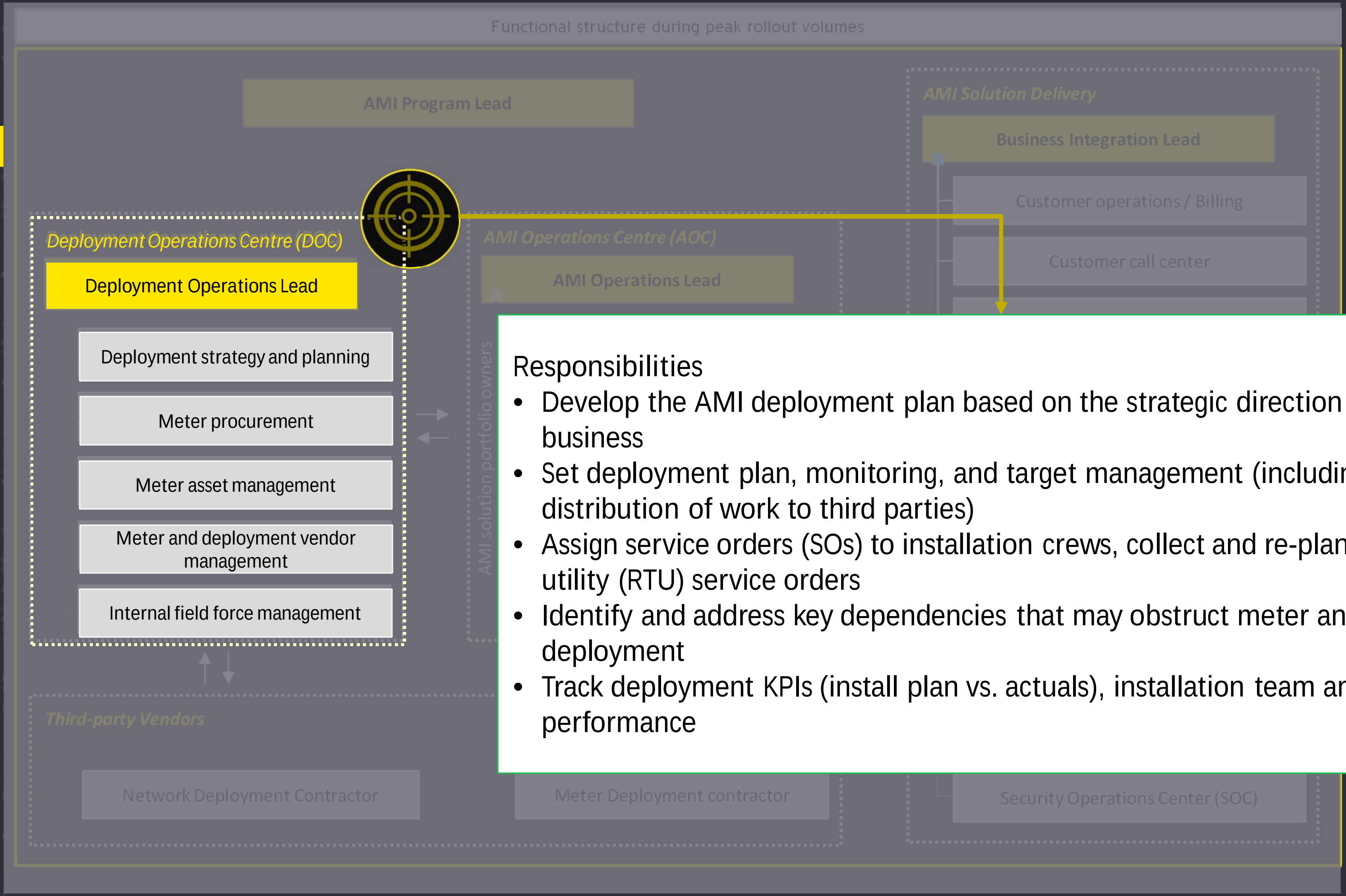
Responsibilities

- Responsible for multiple inter-connected projects or workstreams supporting a specific strategic outcome
- Drives planning, governance and delivery of the program
- Has overall accountability for AMI scope, budget and program outcomes
- Manages conflicting priorities, escalates issues with options for resolution
- Ensures integration with other critical transformation programs
- Visible voice and face of the AMI program

The AMI Project Management function is accountable for managing all aspects of the program.

AMI programs are a multi-year journey, impacting multiple stakeholders. A project management function is a critical success factor to coordinate across multiple workstreams and stakeholders.

Typical AMI Program Organization Model – Deployment Operations



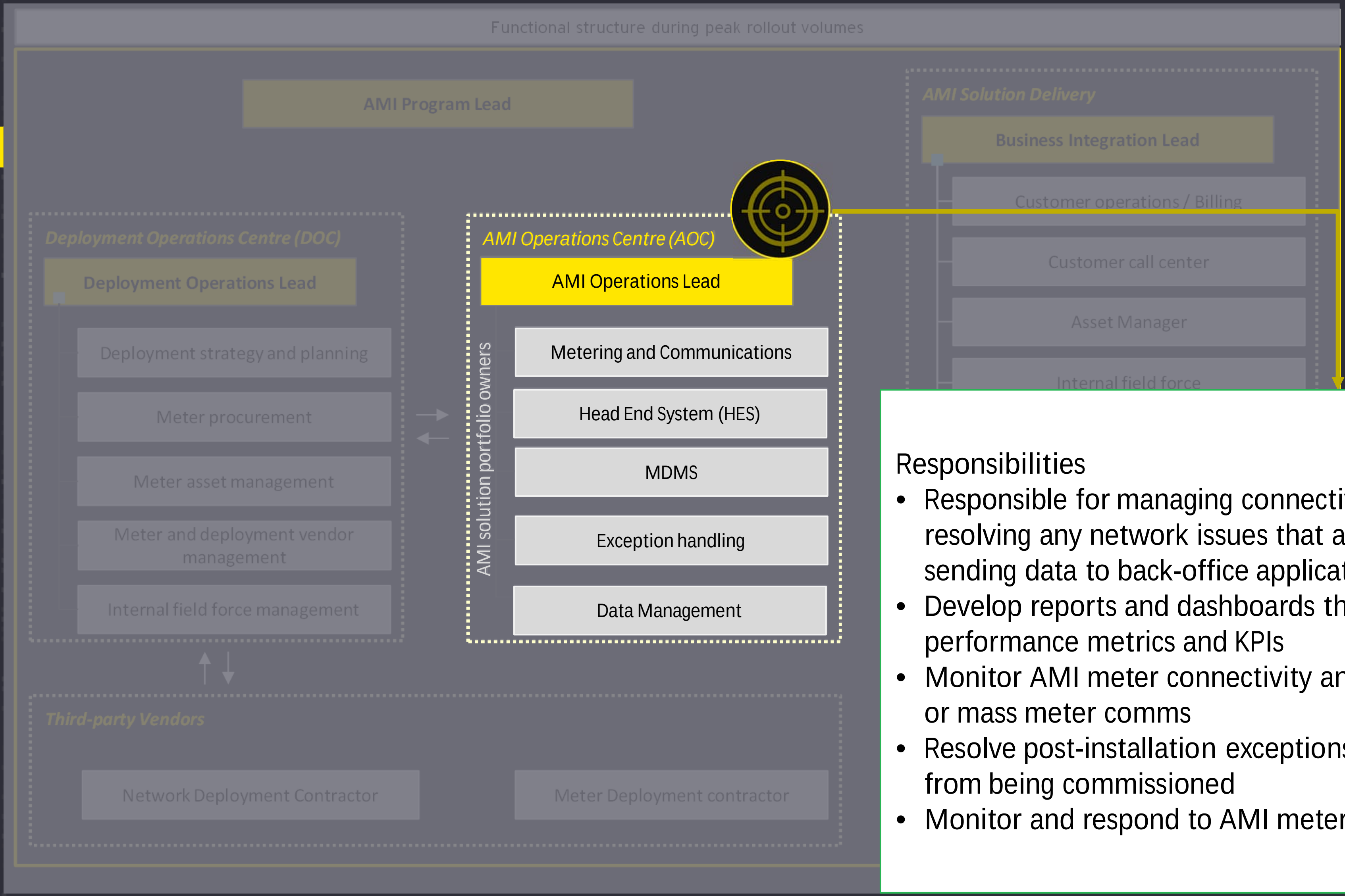
Responsibilities

- Develop the AMI deployment plan based on the strategic direction of the business
- Set deployment plan, monitoring, and target management (including distribution of work to third parties)
- Assign service orders (SOs) to installation crews, collect and re-plan return to utility (RTU) service orders
- Identify and address key dependencies that may obstruct meter and network deployment
- Track deployment KPIs (install plan vs. actuals), installation team and vendor performance

The Deployment Operations Center is accountable for the install of meters and comms per the Deployment Plan.

Meter and network deployments account for a significant portion of the total costs of an AMI program. A carefully evaluated deployment plan is a must-have to avoid cost overruns as well as to mitigate any customer issues.

Typical AMI Program Organization Model – AMI Operations



Responsibilities

- Responsible for managing connectivity of the AMI system and resolving any network issues that are preventing AMI meters from sending data to back-office applications
- Develop reports and dashboards that support with monitoring performance metrics and KPIs
- Monitor AMI meter connectivity and respond to issues with individual or mass meter comms
- Resolve post-installation exceptions that are preventing AMI meters from being commissioned
- Monitor and respond to AMI meter events and alarms

The AOC is accountable for revenue assurance, meter incident support.

Monitoring of installed meters to validate communications, alerts and other designed capabilities, as well as ability to generate accurate bills requires coordination across multiple systems and stakeholders. Lack of end to end ownership will result in incomplete root cause analysis and issues not being resolved in a timely manner.

Typical AMI Program Organization Model – Business Integration

Functional structure during peak rollout volumes

AMI Program Lead

Deployment Operations Centre (DOC)

AMI Operations Centre (AOC)

AMI Solution Delivery

Business Integration Lead

- Customer operations / Billing
- Customer call center
- Asset Manager/Network Operator
- Metering
- Customer Communications
- Change management

System Integration Lead

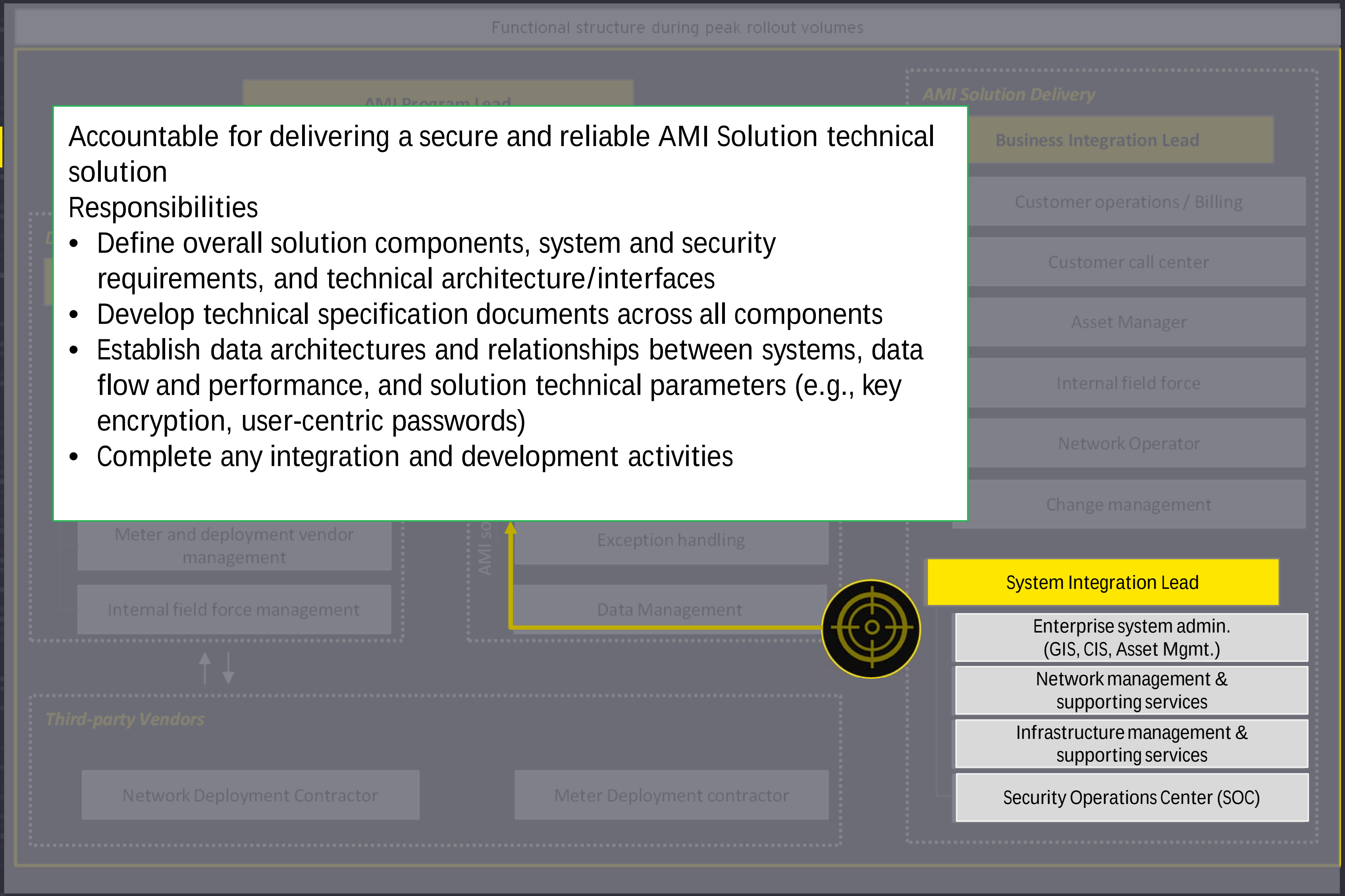
- Enterprise system admin. (GIS, CIS, Asset Mgmt.)
- Network management & supporting services
- Infrastructure management & supporting services
- Security Operations Center (SOC)

Accountability: Plan and design people, process updates, test the AMI 2.0 solution and release to Sustainment Operations

Responsibilities

- Define Deployment Strategy
- Assess impact of AMI on the business (baseline where the business is today, risks or changes that need to happen as a result of AMI)
- Develop business processes to enable AMI 2.0
- Assess change impacts and develop training
- Developing a plan and manage the transition of AMI into the business (develop new resourcing model, backfilling/filling roles in the org. structure)
- Execute organizational change management
- Manage customers through a structured communications program
- Provide implementation/business integration support services on an as needed basis

Typical AMI Program Organization Model – System Integration



Accountable for delivering a secure and reliable AMI Solution technical solution

Responsibilities

- Define overall solution components, system and security requirements, and technical architecture/interfaces
- Develop technical specification documents across all components
- Establish data architectures and relationships between systems, data flow and performance, and solution technical parameters (e.g., key encryption, user-centric passwords)
- Complete any integration and development activities

AMI 2.0 Program Structure Case Studies

The following sub-section shares case studies from utilities across the globe with respect to organizational constructs deployed to implement their smart meter programs.

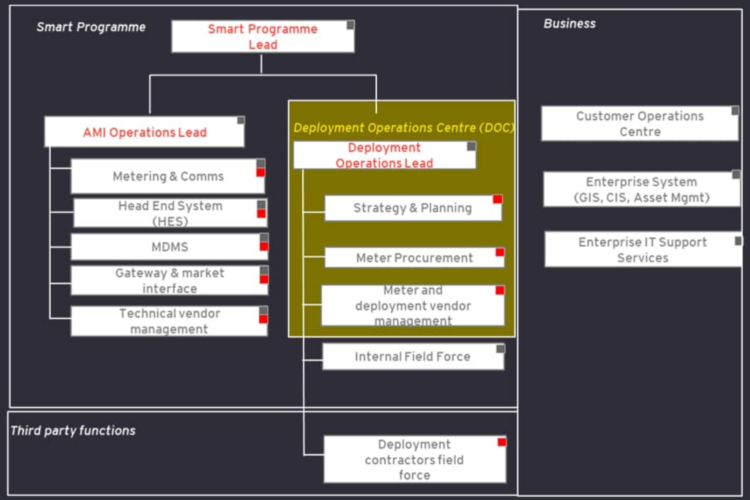
Case Study 1

- Utility-1 deployed 700,000 smart meters over a span of 8 years. The utility established its AMI, Deployment and Vendor Management capabilities within the smart meter deployment programme. AMI and Deployment resources were centralised within two Operations Centres (AOC and DOC) which sat on the same floor and interacted closely. Vendor Management capabilities were split across the Deployment and AMI teams.

Key takeaways:

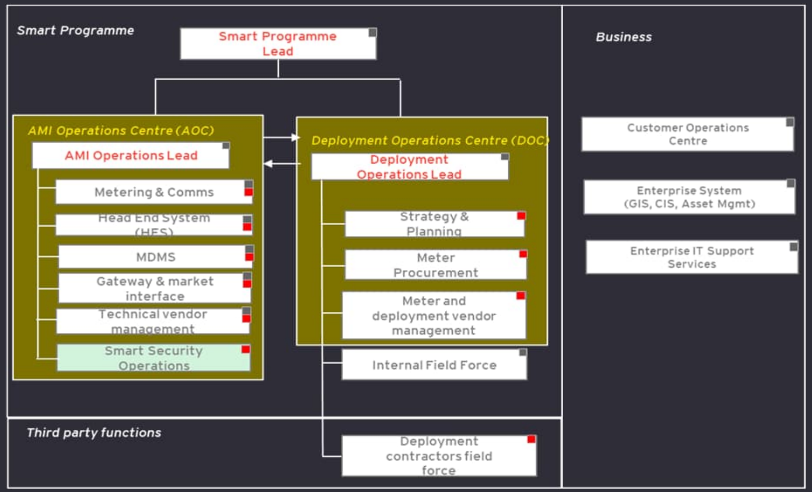
✓ Ensure close coordination between Deployment & AMI teams.
✓ Establish Security Operations Centre within the programme.
✓ Flex team resourcing as requirements change.
✓ Develop and maintain an operational reporting dashboard.

Early rollout



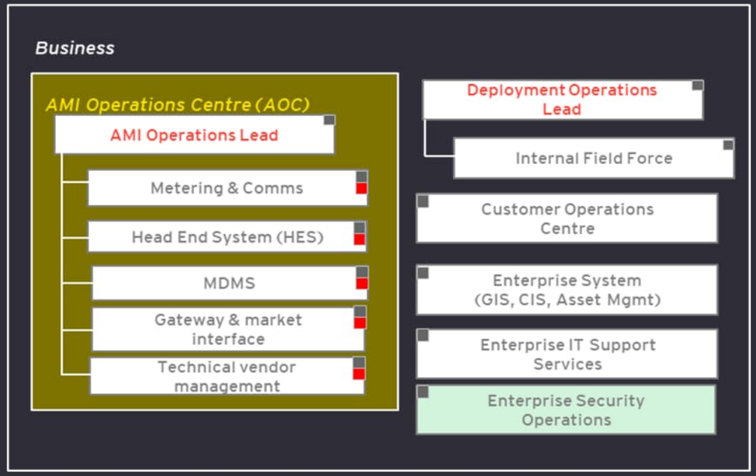
- During the early roll-out phase, the utility heavily outsourced its deployment operations early on due to a lack of internal capability. The deployment strategy and planning, meter procurement, management for the utility's field force and vendor management of the deployment contractors was managed by the third-party.
- AMI teams were not centralised into an operations centre, which resulted in a lack of coordination and difficulty in identifying the source of issues. As a result, these AMI teams were brought together into an operations centre situated on the same floor as the Deployment Operations Centre (DOC) during the mass roll-out.
- There was no Security Operations capability until a major breach incident occurred around two years into deployment.

Peak rollout volumes



- The AMI Operations Centre (AOC) was formed with the Leads for each technology to represent their respective teams. The AOC Lead would coordinate an investigation of any major issues across the entire team. It was evenly split between internal and external resources.
- The AOC coordinated closely with the DOC and field force during mass rollout after issues began to arise from a lack of communication (majorly due to the inability to accurately anticipate and mitigate installation issues).
- A generalist Vendor Management function sat within the DOC, focused on meter procurement, hardware faults and managing the relationship with the deployment contractors. A technical Vendor Management function sat within the AOC, with specialised resources focused on each technology vendor
- A team of IT security (Security Operations) were brought into the AOC to identify and mitigate security issues following the major breach.

Programme Completion



- As the smart programme neared completion, most non-AMI functions were absorbed into the wider business.
- The AOC remains as a standalone function in the same organisational structure as during the rollout. Resourcing for each technology area varied based on requirements.
- Security Operations were moved out of the AOC into the wider business, called the Enterprise Security Operations.
- The DOC was disbanded and capabilities were dispersed into the wider business, while all vendor management capabilities were absorbed into the AOC.

Legend
Internal teams
External teams
Mixed teams

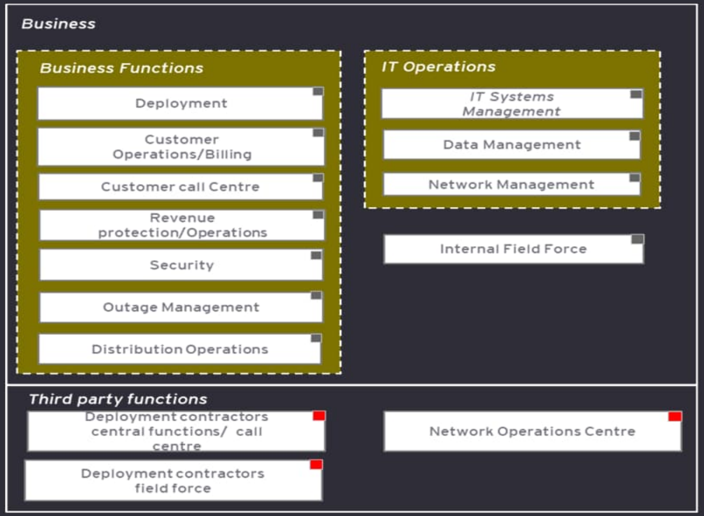
Case Study 2

- Utility-2 deployed 1.6 million electric smart meters over a span of 9 years. Majority of the meter deployment was performed by the deployment contractors. Most business functions were resourced internally, with some external support from the network operator and systems integrator. The utility formed an Insight and Control Centre as the hub of its smart meter deployment programme, performing the activities of both a DOC and SMOC and acting as an integration layer across the various business functions, using data insights to inform decision making. Its role expanded over time as various issues were experienced.

Key takeaways:

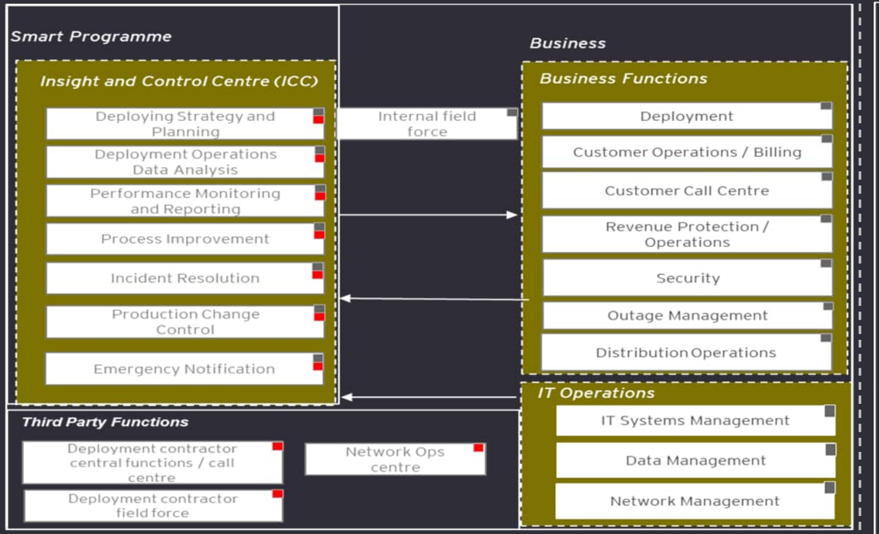
- ✓ Maintain a close working relationship with AMI / Comms vendors.
- ✓ Place data insights at the centre of decision making.
- ✓ Adopt an agile approach to allow capabilities to flex over time.
- ✓ Build ownership for outcomes into the organisational structure.
- ✓ Anticipate and plan for a large volume of exceptions.

Early rollout



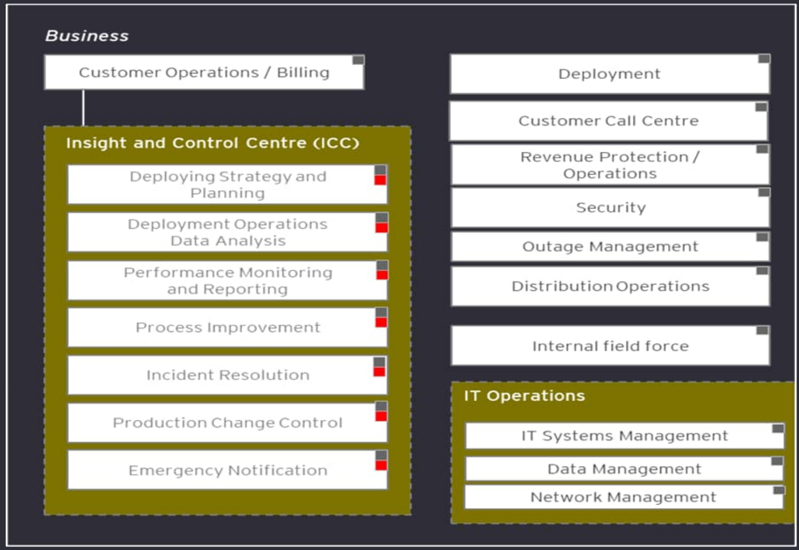
- During the smart meter kick-off, there was no central team sitting within a smart programme to coordinate across business units
- This dispersed model came under strain after an influx of major exceptions and operational issues during early deployment where there was an inability to identify the root cause. Thereafter the Insight and Control Centre (ICC) was set up.
- The leads for each of the business functions would attend meetings hosted by the ICC with a focus on resolving cross-functional issues. However, these meetings were often unproductive during the early rollout due to poorly defined ownership of outcomes and a lack of data to drive accountability
- Vendor management was the responsibility of the Deployment team, but the ICC would support this activity through delivering data insights to challenge their performance.

Peak rollout volumes



- The ICC was fully scaled during the peak roll out. It was successful due to its ability to analyse data to identify the most critical issues and drive rapid resolution.
- As more data became available, cross-functional issue resolution became more productive, and the ICC was able to drive accountability for outcomes and issue resolution.
- The AMI network vendor, deployed dedicated resources to the utility to perform data extracts and assist with network issue resolution
- Commissioning of installed meters was initially the responsibility of the Customer Operations team, but this became a ICC function after a large number of meters were unable to attain a billing read.

Programme Completion



- Due to the sustained volume of exceptions, ICC capabilities were not dispersed into the business, but were maintained within a scaled down ICC.
- The Network Operations Centre was moved out of the utility premises.

Legend
Internal teams
External teams
Mixed teams

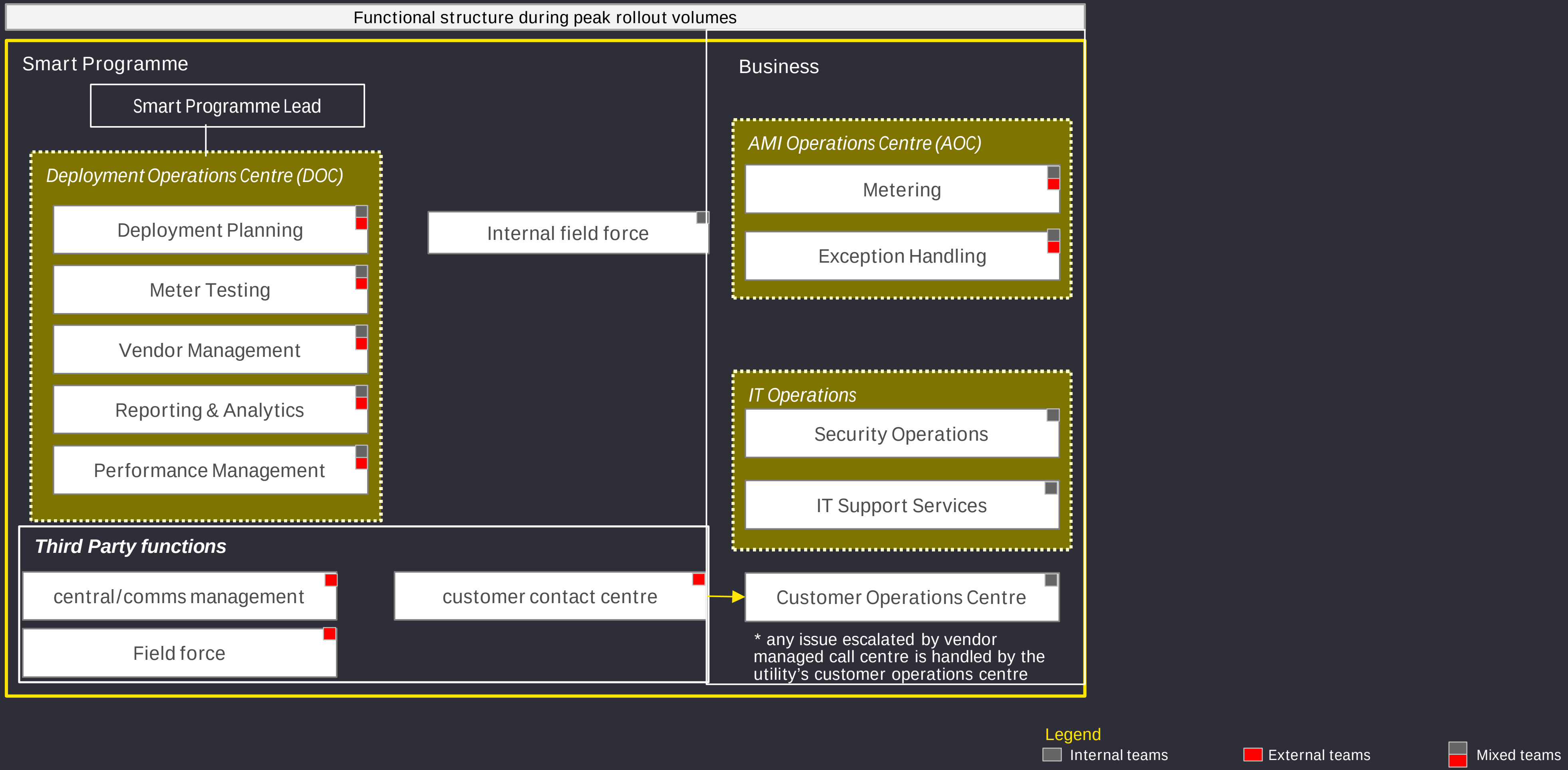
Case Study 3

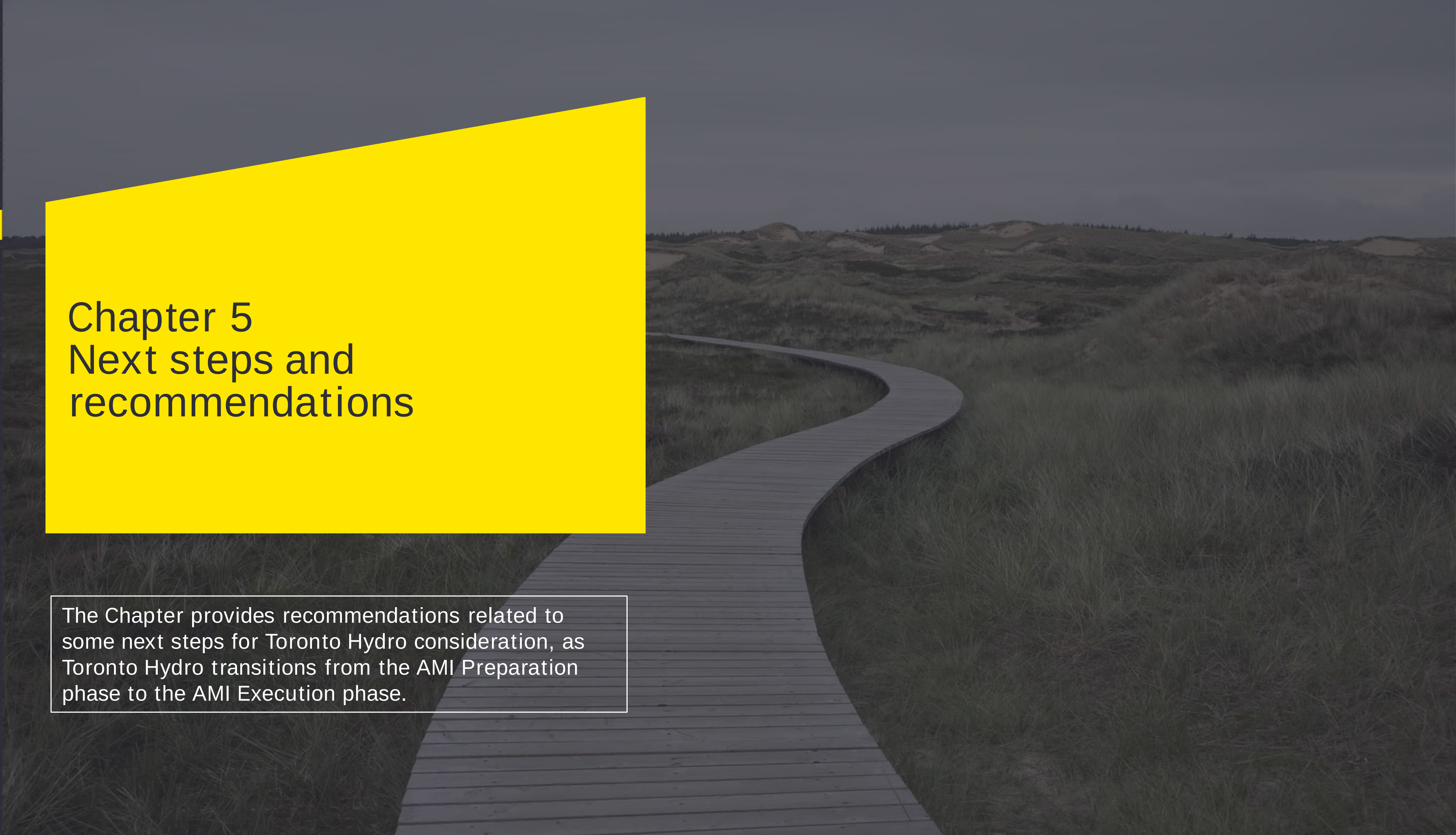
- Utility-3 is currently on its journey of deploying 1.1million electric smart meters for its customers. The AMI 2.0 deployment kicked off in 2016 is expected to see completion by the end of 2022. The utility already implemented AMI1.0 in its network operations. The utility has adopted a lean operating model, whereby most activity is coordinated by the Deployment Operations Centre (DOC), and operations are heavily outsourced to the deployment vendor. The AMI Operations Centre (AOC) has been established from the existing AMI (1.0) Operations Centre within the wider business. Almost all meter deployment activity has been outsourced to the vendor with the remainder undertaken by the internal field force within the utility.

Key takeaways:

✓ Monitor less metrics – but make sure they are the right one.

✓ Ensure there is shared ownership for operationalising meters.





Chapter 5
Next steps and recommendations

The Chapter provides recommendations related to some next steps for Toronto Hydro consideration, as Toronto Hydro transitions from the AMI Preparation phase to the AMI Execution phase.

AMI 2.0 Roadmap

STAGE: INITIATE

STAGE: PREPARE

STAGE: EXECUTE

1 High-level AMI Execution Plan
- Major activities
- Timelines
- Dependencies
- Accountabilities

2 Use Case prioritization
- Align on “next” use cases
- Determine what is needed to enable “next” use cases

3 Secure Meter Vendor
- Release RFP
- Complete evaluation
- Secure contract

4 Establish Deployment Strategy & Plan
- Develop Strategy
- Define scenarios
- Align on plan

Meter vendor selection will drive refinement to the deployment plan – incumbent vs new

5 Detailed AMI Execution Plan
- Major activities
- Timelines
- Dependencies
- Resources

Deployment Plan: timelines for install

Use cases: people/process/technology changes required

6 Secure Install Vendor
- Develop requirements
- Execute procurement

Deployment Plan will establish requirements

7 Establish Project Operating Model
- Define project organization
- Define resource requirements

Use Cases will impact Operating model: change required

Meter vendor will impact Operating model: change required to upgrade network

8 Secure resources
- Identify skills
- Develop resource plan
- Secure resources

9 Complete Solution Design
- Complete approach for solution design
- Execute Solution Design

Use cases/AMI 2.0 capabilities proposed to be delivered

AMI 2.0 brings your strategies to life

- Grid modernization roadmap
- Customer experience roadmap

AMI 2.0 Roadmap: recommended early start activities

#01

AMI 2.0 Project Roadmap

Establish an overall execution plan for AMI 2.0 that will enable Toronto Hydro to orchestrate the right activities and resources at the right time across the organization as well as externally. Such a plan should address a variety of elements including:

- Major program activities required to initiate execution
- Procurement of 3rd party vendors for deployment (D on Deployment Strategy)
- High-level change impacts as a result of AMI 2.0 to(people /process /technology (dependency on capabilities to be delivered by AMI 2.0 "Now")
- Program execution structure required to execute AMI 2.0
- Identify roles and resources required

#02

Use Case Prioritization

Validate and align on AMI 2.0 use cases across Toronto Hydro stakeholders.

- Align on capabilities and functionality to be delivered "now", "Next" and "Beyond"
- Assess implications across people, process, technology and data to identify any gaps
- Develop a roadmap for capabilities to be delivered over time

#03

Deployment Strategy and Plan

Establish a Deployment Strategy and Plan based on a structured approach, considering various options and risk profiles for each option.

- Define overarching guiding principles
- Align on the Customer Communications strategy
- Define revenue protection strategy
- Identify deployment constraints
- Identify and evaluate potential deployment scenarios and associated risk profiles to arrive at the best-fit Deployment Plan
- Finalize Deployment Strategy and Plan

Value to Toronto Hydro »

#01

- ✓ A well-articulated plan will provide a clear and common understanding of major activities, dependencies and timelines.
- ✓ Will enable resource fulfilment as well as execution to well-understood timelines.
- ✓ Visibility to major activities will allow for any course-correction of proposed activities and clear communications across all internal and external stakeholders

#02

- ✓ Alignment on AMI 2.0 use cases to enable Toronto Hydro Grid Modernization and Customer strategies
- ✓ A roadmap of use cases and capabilities that will support an actionable plan for Toronto Hydro

#03

- ✓ A carefully-developed deployment strategy will provide Toronto Hydro with confidence in your execution approach.
- ✓ It will allow Toronto Hydro to provide clear requirements to 3rd party vendors through any formal procurement actions (such as peak install volumes).

Appendix

Toronto Hydro smart meters overview

Source: information provided by Toronto Hydro

CLASS	# OF METERS
1-PHASE	561643
3-PHASE	37041
3-PHASE DELTA	6803
NETWORK	78970
TOTAL	684,457

CLASS	TX or SC	FORM_NBR	# OF METERS
1-PHASE	SC	1S	606
1-PHASE	SC	2S	556671
1-PHASE	TX	3S	4366
3-PHASE	SC	12S	26
3-PHASE	SC	16S	33443
3-PHASE	TX	N/A	83
3-PHASE	TX	35S	1223
3-PHASE	TX	36S	1553
3-PHASE	TX	9S	713
3-PHASE DELTA	SC	12S	6803
NETWORK	SC	12S	78970

MODEL	# OF METERS
A3_ILN	3914
A3RL	33260
A3TL	1134
R1S	434297
R2S	109999
R2S600	6803
R2SD	73381
RU	302
RUD	21367

Tentative Meter Deployment Timeline

Source: information provided by Toronto Hydro

CLASS	2023	2024	2025	2026	2027	2028
1-PHASE	84841	114362	142664	98903	92379	28494
3-PHASE	83	0	3856	5733	24713	2656
3-PHASE DELTA	0	0	0	0	0	6803
NETWORK	0	0	12084	53843	8165	4878
TOTAL	84924	114362	158604	158479	125257	42831

Toronto Hydro AMI 2.0 Use Cases Prioritization activity output

Page 12 of this report provides a summary of the approach used to prioritize Toronto Hydro use cases. The attached file is the output from that use case prioritization session.

EY - TH AMI 2.0 Use Cases Prioritization & Discussion 8.11.2022.pdf

MURAL Session Link:
https://app.mural.co/t/eystarter4106/m/eystarter4106/1660053179853/0e5008f5bc11044d5ae952895449cac7bb320f65?sender=u4c81af43644093e85a438865

AMI 2.0 Case Studies: Summary of the capabilities deployed by Utilities globally

Page 20 of this report provides a summary of some use cases deployed by utilities globally. The Table below provides a definition of the use cases listed on Page 20.

#	Services	Description
1.	High Bill Alert to Customers	Notification to customers once bills/consumption exceeds set thresholds
2.	Outage Alert to Customers	Notification to customers of planned and unplanned outages
3.	Net Energy Metering (Renewable Energy)	Energy produced from the solar PV installation will be consumed first, and any excess will be exported to utility at prevailing displaced cost.
4.	Outage Integration with ADMS	Ability to manage outages detected (received) from smart meters, respond accordingly to restore power
5.	Outage Visualization	Visualization of outage information on a dashboard
6.	Technical Losses and Non-Technical Losses	Analysis and analytics to reduce Technical Losses and Non-technical Losses
7.	Demand Response – Customer	Enable DR offering to commercial OPC customers (allow utility to control buildings and enact voluntary DR)
8.	Demand Response – Operations	Enable DR capability to address immediate operational emergencies to stabilize grid operations
9.	Volt/ Var Optimization	Increase Grid Efficiency through Regulation of voltage to optimum levels and adjust power factor to reduce distribution losses
10.	Power Quality	The degree to which the voltage, frequency, and waveform of a power supply system conform to established specifications
11.	Peer-to-peer (P2P) Trading	P2P trading platform to allow prosumers to trade energy with each other

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Building a better
working world

Toronto Hydro Corporation
14 Carlton Street #6
Toronto, Ontario
MB5 1K5, Canada

14 March 2024

Re: Toronto 2025-2029 General Rate Application

To whom it may concern,

This covering letter is provided in respect of the EY documents, described below, which are being disclosed in respect of the above-noted rate application hearing (the "Hearing"):

1. **AMI 2.0 Strategy_EY 2022 November.pptx**
2. **AMI.20 Program Outline_EY 2023 October.pdf**

For clarity, Ernst & Young LLP (EY) prepared these Reports solely for the information and use of Toronto Hydro-Electric System Limited ("Toronto Hydro" or "Client") pursuant to an agreement solely between EY and Client. EY did not perform its services on behalf of or to serve the needs of any other person or entity. The Reports are subject to many limitations and should not be relied upon by any third party. A third-party gaining access to these Reports (i) does not acquire any rights as a result of such access, (ii) acknowledges that EY does not assume any duties or obligations as a result of such access and, (iii) should not further distribute the Reports.

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EY reserves the right (but will not be obligated) to revise these Reports in light of any relevant information that comes to our attention after the date of issuance.

Yours faithfully,

Ernst & Young LLP

per Sonika Sood, Partner
Email: sonika.sood@ey.com

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-65

References: Exhibit 2B, Section E6.1

<u>Preamble:</u>

With respect to Area Conversions:

QUESTION (A):

a. [p.18] Please provide a revised version of Table 8, broken down by specific box construction asset, and includes 2017 ACA information, as well as 2029 ACA information based on the proposed investments included in the DSP. Please provide in Excel format.

RESPONSE (A):

Please see Appendix A to this response, '2B-SEC-65_App A ACA Information.xlsx', for a revised version of Table 8. Note that ACA information is only available for wood poles on box construction feeders and no other asset classes.

QUESTION (B):

b. [p.22] Toronto Hydro states that for its rear-lot conversion program it has "applied an average cost of $0.058 million per customer in developing the segment cost forecasts for the 2025-2029 rate period. This is a significant increase over the previous cost per customer estimated in the 2020-2024 DSP due to externally-driven escalations of labour, material, and other (e.g. vehicle) costs over recent years having a particularly high impact on the costs to plan and execute this complex conversion work." Please provide a table that shows, by category (e.g. labour, material, other), the per customer cost:

   i. forecast as part of the 2020-2024 DSP,
   ii. actual cost during the 2020-2024 period, and
   iii. forecast costs for the 2025-2029 rate period.

RESPONSE (B):

Please see Table 1 below. Toronto Hydro can only provide the breakdown based on actual costs incurred 2020-2023. The utility does not forecast costs at the level of labour, materials etc. and therefore is unable to provide the data for parts i. and iii.

Table 1: Breakdown of Actual Cost per Customer Converted

Cost/Customer	Labour	Materials	Other
i. 2020-2024 DSP Forecast	-	-	-
ii. 2020-2023 Actual	$43,007	$4,552	$4,909
iii. 2025-2029 Forecast	-	-	-

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-66

Reference: **Exhibit 2B, Section E6.2**

With respect to Underground System Renewal – Horseshoe:

QUESTION (A):

a) Please update Figures 1-3, 6-8, 13-16, and 22-24 with 2023 information.

RESPONSE (A):

Please see figures below.

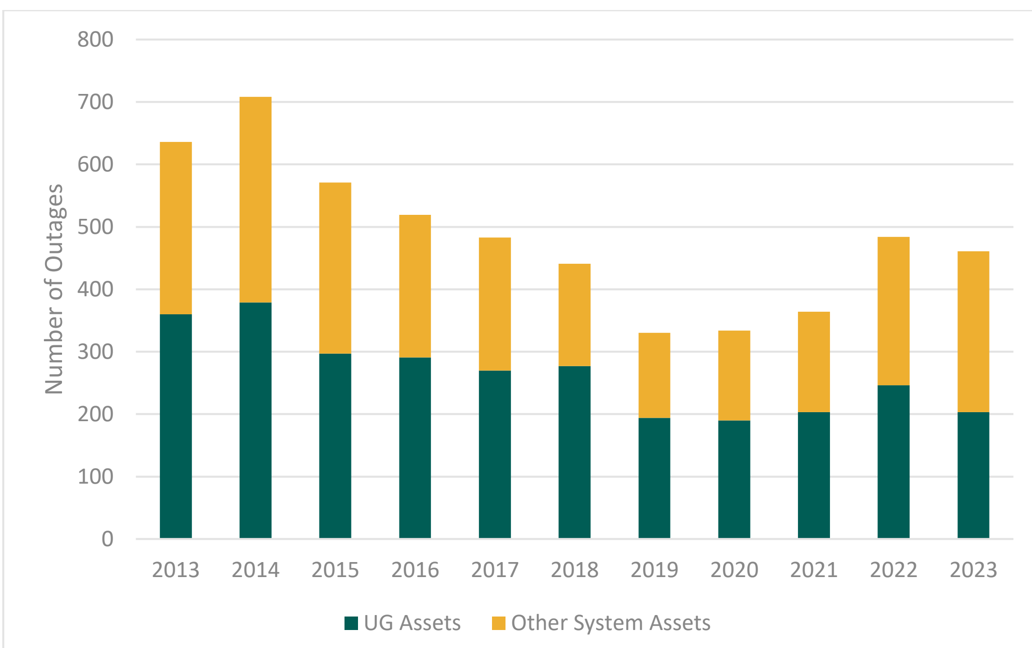


Figure 1: Ten-year Trend of Underground System Contribution to Overall System Outages

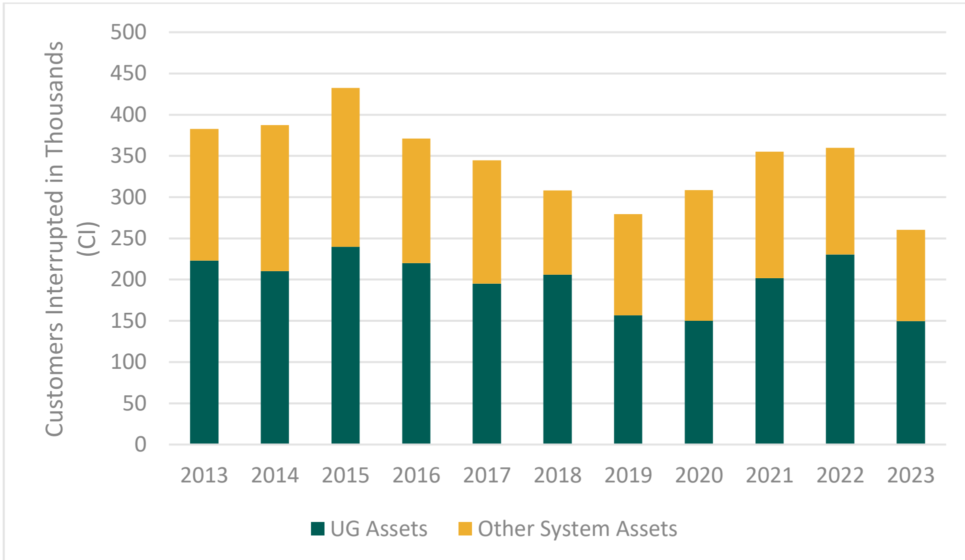


Figure 2: Ten-year Trend of Underground System Contribution to Overall System Customers Interrupted ("CI")

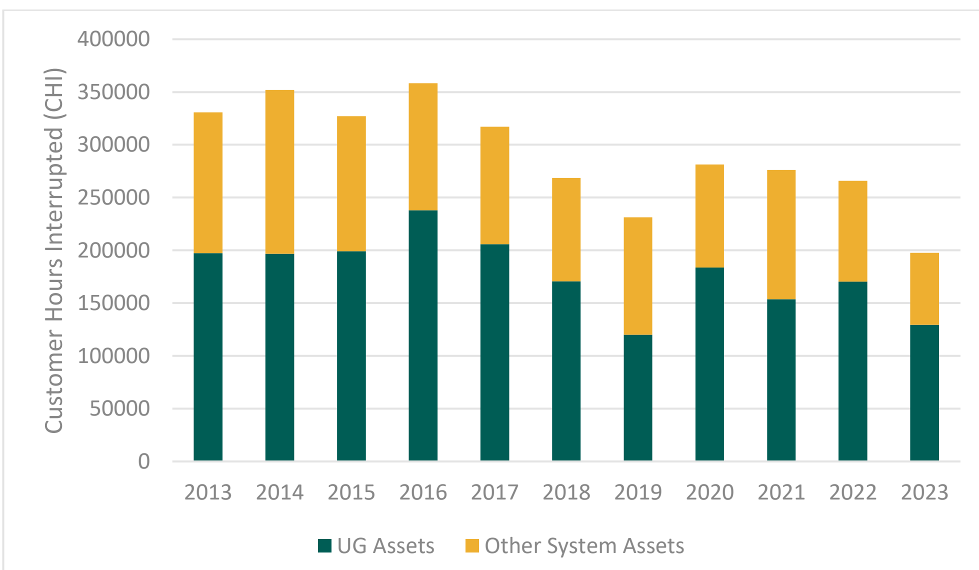


Figure 3: Ten-year Trend of Underground System Contribution to Overall System Customer Hours Interrupted (CHI)

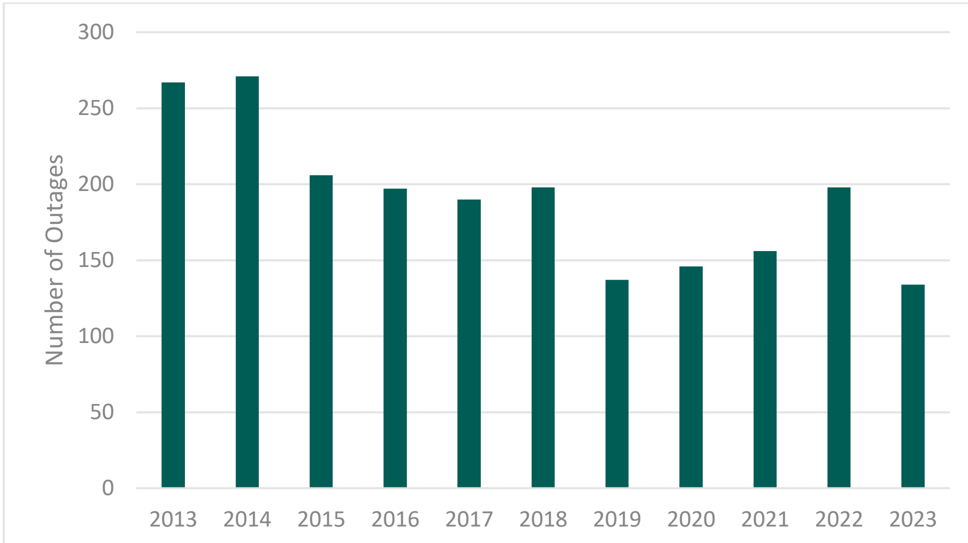


Figure 6: Ten-Year Trend of Outages due to Underground Cable Failure

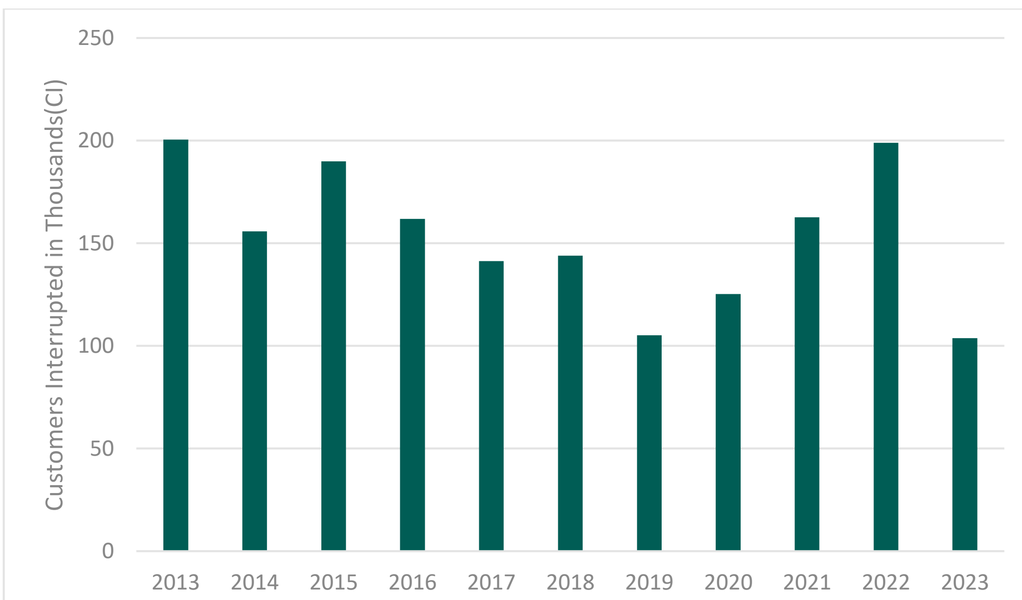


Figure 7: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Cable Failures

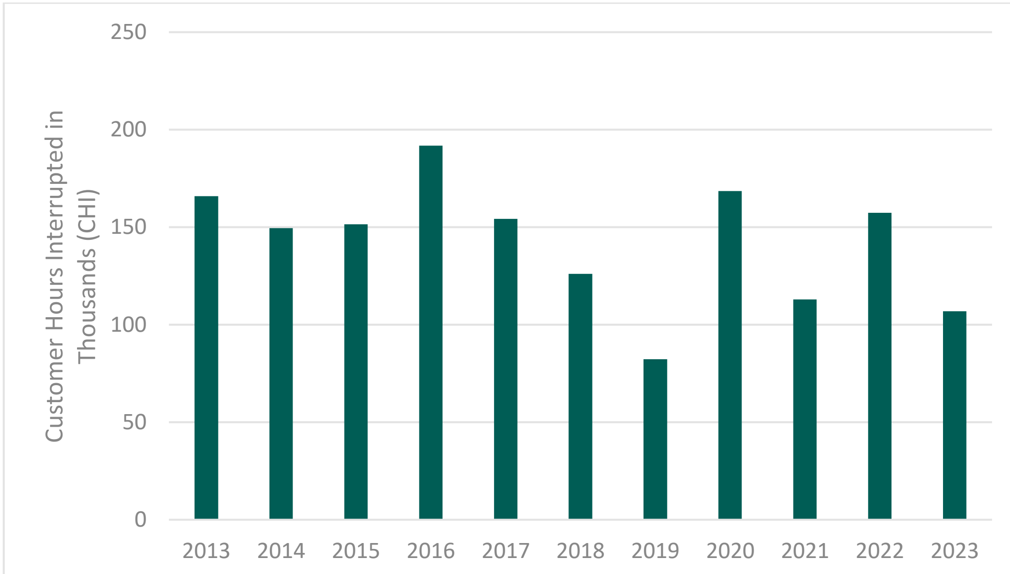


Figure 8: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Cable Failures

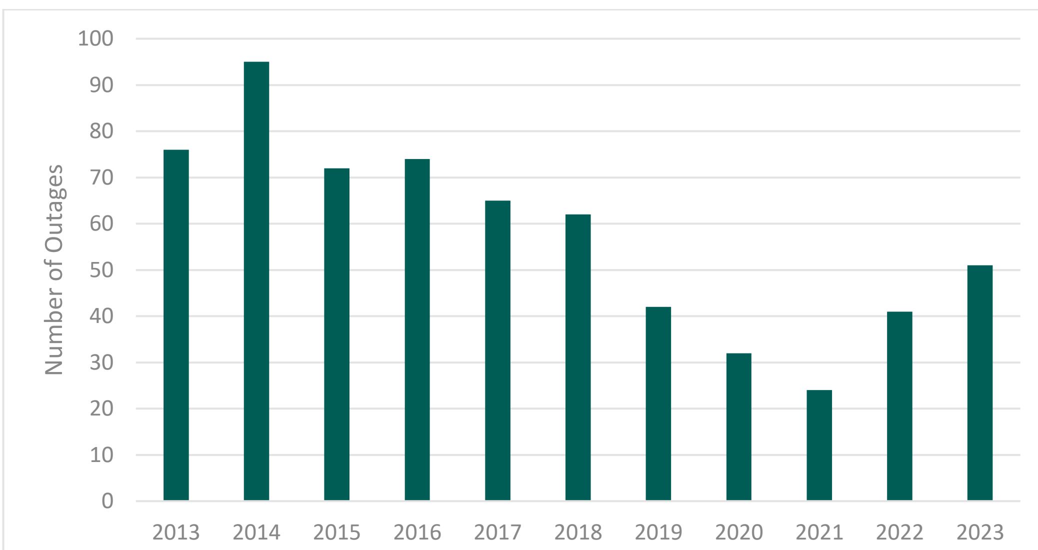


Figure 13: Ten-Year trend of Outages Due to Underground Transformer Failures

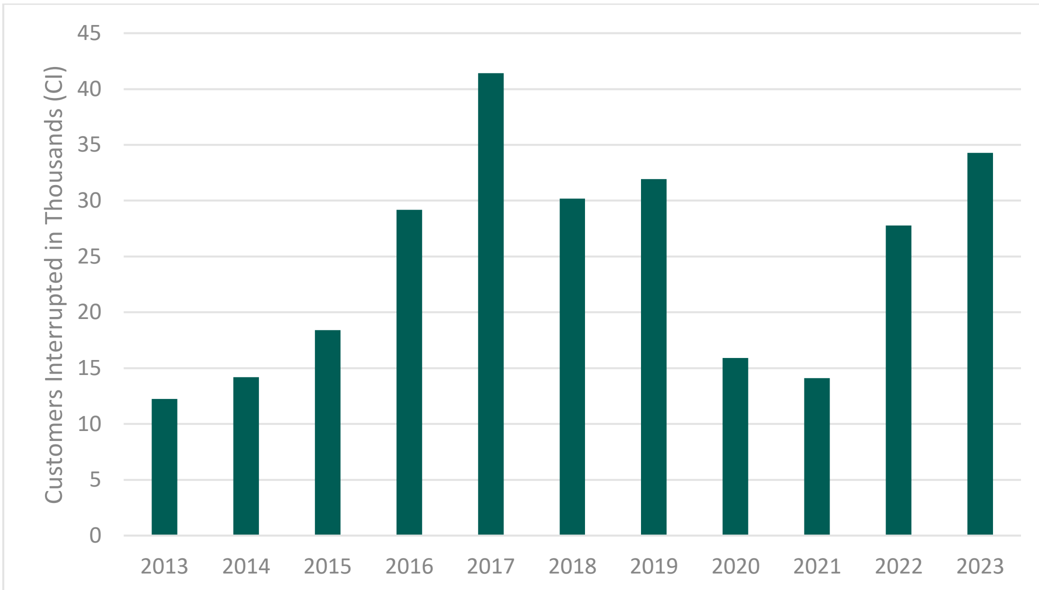


Figure 14: Ten-Year Trend of Total Customers Interrupted (CI) Due to Underground Transformer Failures

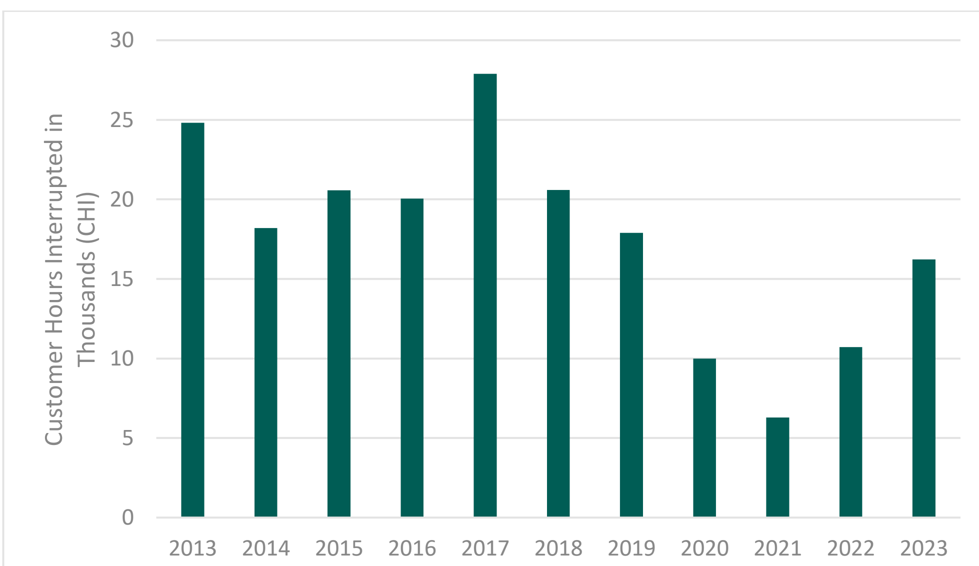


Figure 15: Ten-Year Trend of Customer Hours Interrupted (CHI) Due to Underground Transformer Failures

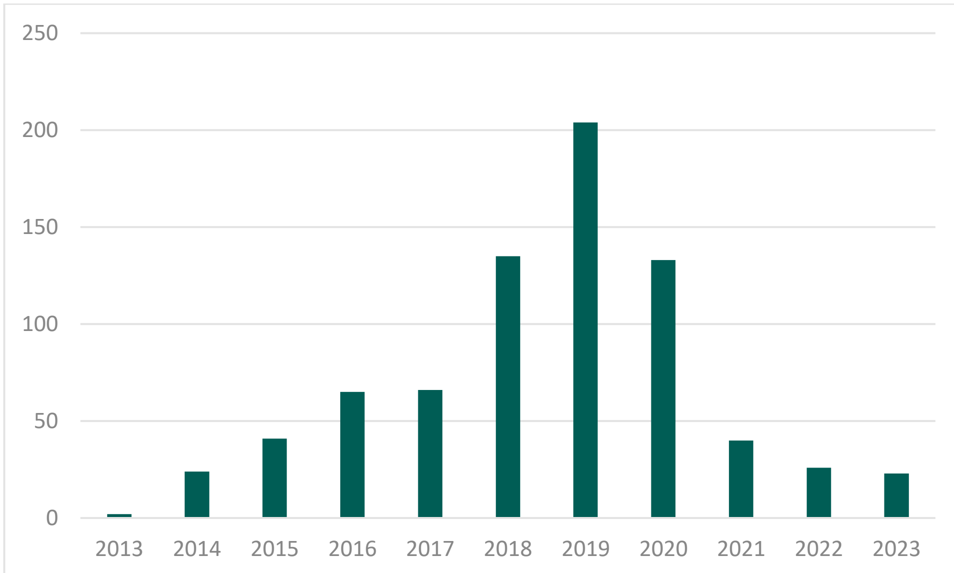


Figure 16: Number of Externally-Reported Oil Spills on Underground Transformers in Underground Horseshoe System

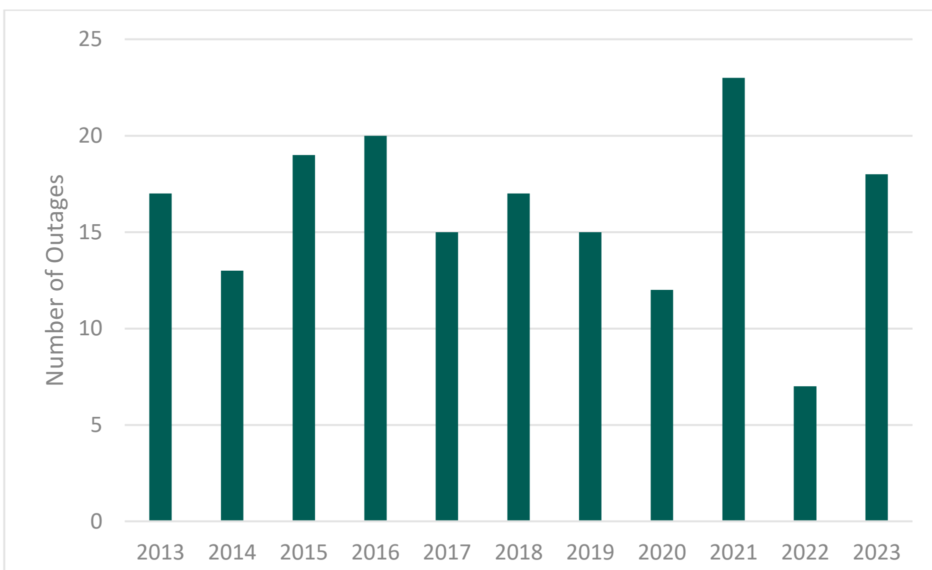
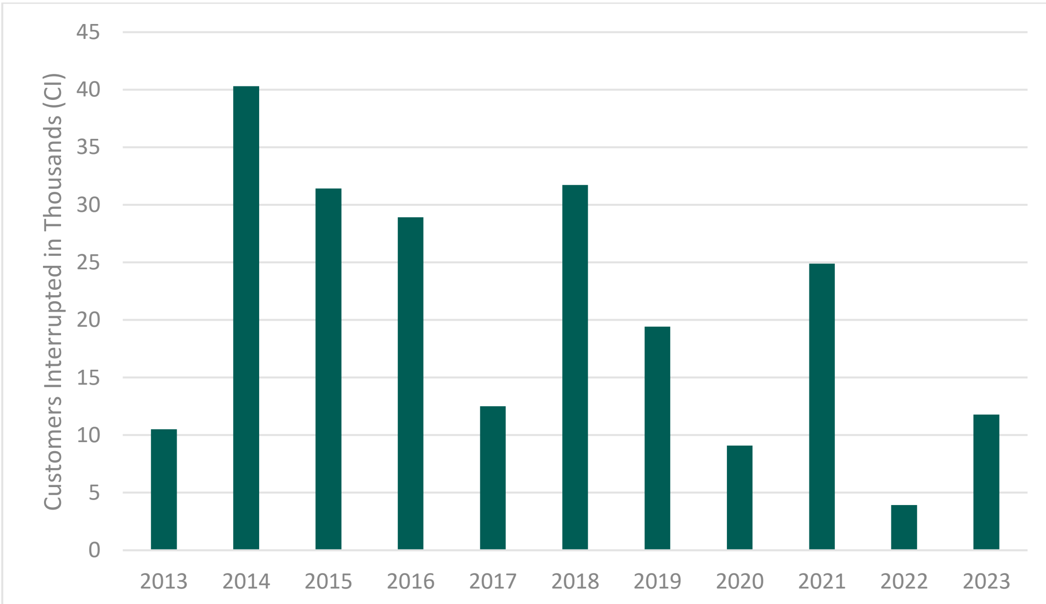
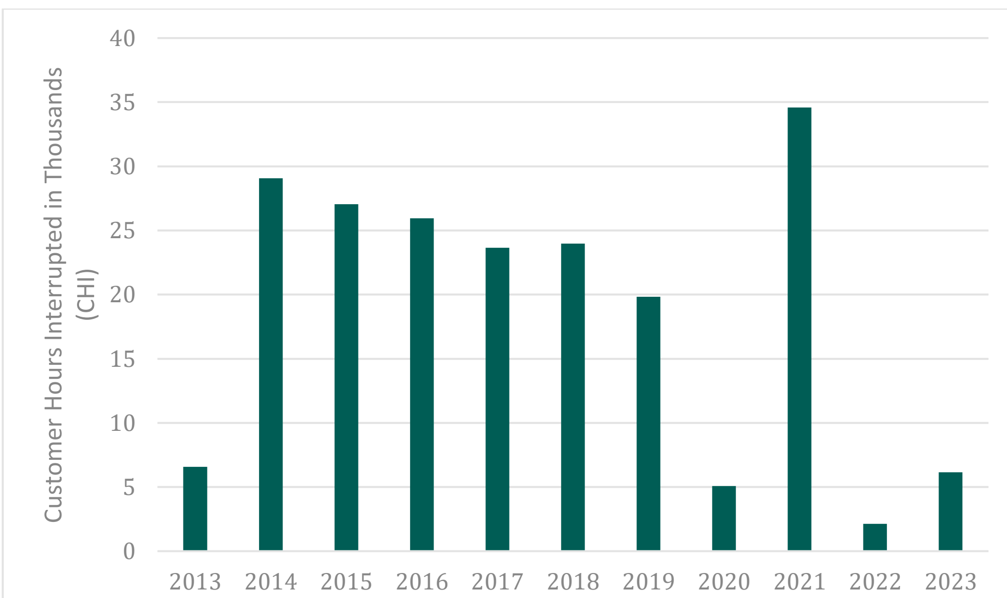


Figure 22: Ten-Year Trend of Outages due to Underground Switch Failures



1 **Figure 23: Ten-Year Trend of Total CI due to Underground Switch Failures**



2 **Figure 24: Ten-Year Trend of Total CHI due to Underground Switch Failure**

QUESTION (B):

b) [p.22, 28] Please provide a revised version of each of Table 5 and 6 that includes 2017 ACA information, as well as 2029 ACA information based on the proposed investments included in the DSP. Please provide the response also in Excel format.

RESPONSE (B):

Please see Tables 5 and 6 below and Appendix A to this response with 2017 data included. Unlike the information provided in the original tables in Exhibit 2B, Section E6.2, the 2017 data does not distinguish between Horseshoe and Downtown assets and therefore these tables include system-wide ACA demographics for all years. Toronto Hydro does not model Assets Past Useful Life based on its investment plan. For a comprehensive discussion of expected changes in asset demographics over the 2025-2029 period, please see Toronto Hydro's response to 2B-SEC-44.

Table 5: Asset Condition Assessment for Underground Transformers System-Wide in 2017, 2022, and 2029 without Investment

Condition	UG TX – Padmounted			UG TX – Submersible			UG TX – Vault			Total 2017	Total 2022	Total 2029
	2017	2022	2029	2017	2022	2029	2017	2022	2029			
HI1 – New or Good Condition	5547	5142	4451	7816	8120	7330	6807	6799	5220	20170	20061	17001
HI2 – Minor Deterioration	656	1085	542	588	699	642	4315	3869	1668	5559	5653	2852
HI3 – Moderate Deterioration	283	527	887	271	162	635	450	571	3595	1004	1260	5117
HI4 – Material Deterioration	113	233	595	172	133	240	214	247	587	499	613	1422
HI5 – End-of-Serviceable Life	18	24	536	55	47	314	45	11	427	118	82	1277
Grand Total	**6617**	**7011**	**7011**	**8902**	**9161**	**9161**	**11831**	**11497**	**11497**	**27350**	**27669**	**27669**

Table 6: Asset Condition Assessment for System-Wide Underground Padmounted Switches (Air and SF_6 Type) in 2017, 2022, and 2029 without Investment

Condition	UG Switch Padmounted Air			UG Switch Padmounted SF6			Total 2017	Total 2022	Total 2029
	2017	2022	2029	2017	2022	2029			
HI1 – New or Good Condition	404	359	350	402	663	663	**806**	**1022**	**1013**
HI2 – Minor Deterioration	20	4	11	0	0	0	**20**	**4**	**11**
HI3 – Moderate Deterioration	73	64	2	2	0	0	**75**	**64**	**2**
HI4 – Material Deterioration	30	24	13	0	1	0	**30**	**25**	**13**
HI5 – End-of-Serviceable Life	45	29	104	6	16	17	**51**	**45**	**121**
Grand Total	**572**	**480**	**480**	**410**	**680**	**680**	**982**	**1160**	**1160**

QUESTION (C):

c) [p.29-31] Please provide a breakdown of annual costs included in Table 7 based on the asset categories included in Tables 8 and 9.

RESPONSE (C):

In the process of preparing this interrogatory response, Toronto Hydro identified an error with the numbers reported for transformers for 2020 and 2021. Toronto Hydro also identified that the volumes of cable shown for the 2020-2024 period were incorrectly entered as conductor-kms instead of circuit-kms. An updated Table 8 with the corrected actuals, as well as 2023 actuals and an updated 2024 forecast, has been provided below:

Updated Table 8:

Asset Class		Actuals				Bridge	Total
		2020	2021	2022	2023	2024	
Total Cable	*cct-km*	45	33	51	33	22	184
Transformers	*Units*	260	251	281	321	886	1,999
Switches	*Units*	55	20	52	14	3	144

Annual Asset Cost based on Asset Counts in Updated Table 8 ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge
Total Cable	7.82	5.95	12.9	10.9	5.45
Transformers	6.69	10.0	7.60	12.1	32.3
Switches	7.49	2.94	6.45	2.02	2.72

Annual Asset Cost based on Forecasted Asset Volumes in Table 9 ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Total Cable	7.65	18.8	22.5	21.7	21.2
Transformers	32.1	14.6	14.7	19.6	21.8
Switches	1.97	3.7	4.8	4.6	5.1

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-67

Reference: Exhibit 2B, Section E6.3

<u>Preamble:</u>

With respect to Underground System Renewal – Downtown:

QUESTION (A):

a) Please update Figures 9, 18, and 19 with 2023 information.

RESPONSE (A):

Please see Figures 1, 2, and 3 below (original figure numbers noted in captions).

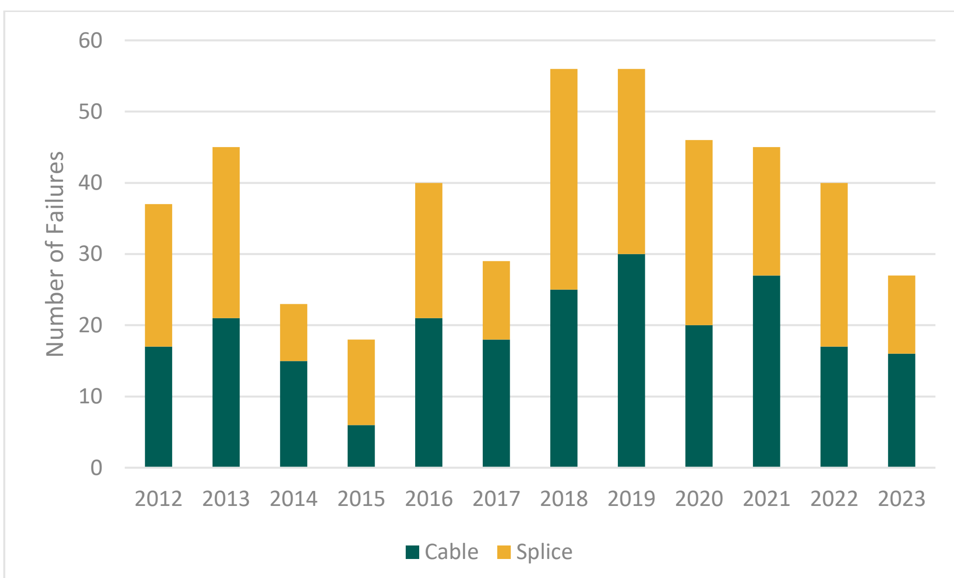


Figure 1: Number of PILC Cable/Splice Failures per Year (Figure 9)

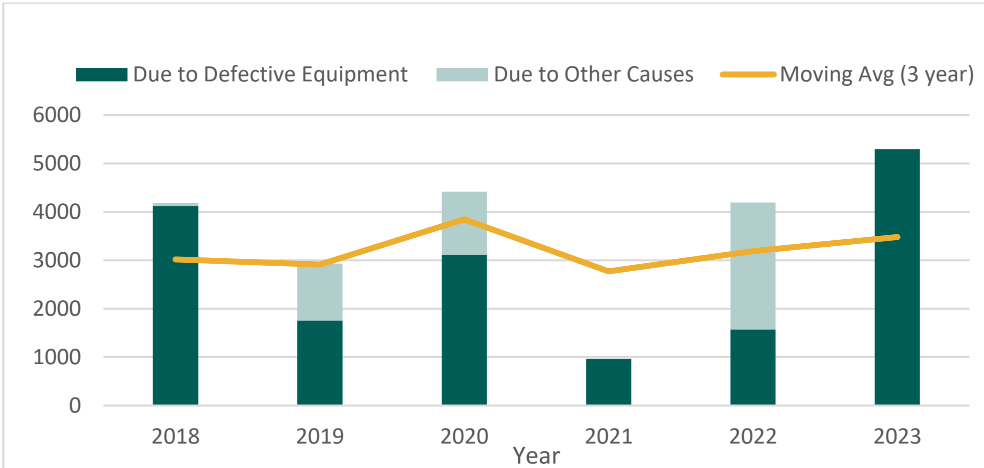


Figure 2: Customers Interrupted — URD System (Figure 18)

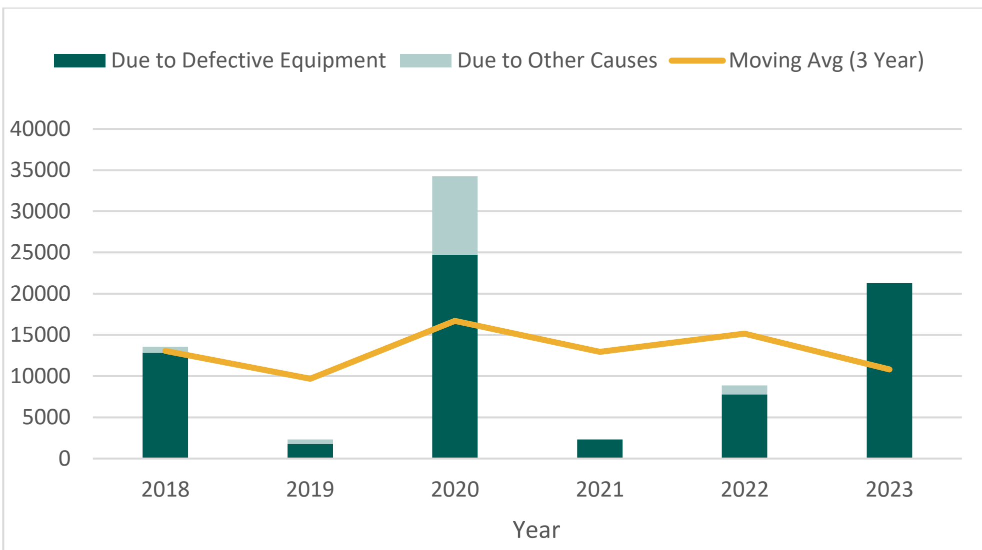


Figure 3: Customer Hours Interrupted — URD System (Figure 19)

QUESTION (B):

b) Please provide a version of the information included in Figures 12, 26, 30, 33 and 35 in tabular format, that also includes 2017 ACA information, as well as the 2029 ACA information based on the proposed investments included in the DSP. Please provide in Excel format.

RESPONSE (B):

Please see Appendix A to this response, '2B-SEC-67_App A ACA Information.xlxs' for the information in Figures 12, 26, 30, 33, and 35 in tabular format and for 2029 ACA projections with investment for URD switches (Figure 30), URD transformers (Figure 33), and Underground Switchgear (Figure 35). For 2029 ACA projections with investment for cable chambers and URD Vaults and for the context and underlying assumptions regarding all projected health demographics in 2029 with investment, please refer to Toronto Hydro's response to interrogatory 2B-SEC-44.

QUESTION (C):

c) [p.36-37] Please provide a breakdown of annual costs included in Table 6 based on the asset categories included in Table 7.

RESPONSE (C):

Please see Table 1 below.

Table 1: Updated Underground Cable Renewal Costs Broken Down by Asset Category ($ Millions)

	Actual				Bridge	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Underground Cable Renewal	3.1	5.2	10.2	11.3	9.7	8.6	10.8	11.7	13.4	16.5
PILC Cable	3.1	4.4	9.2	11.2	9.5	7.8	9.7	10.5	12	14.7
AILC Cable	0.0	0.8	1.0	0.1	0.2	0.8	1.0	1.1	1.3	1.6
Fiber Optic Cable	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2

QUESTION (D):

d) [p.39-40] Please provide a breakdown of annual costs included in Table 8 based on the asset categories included in Table 9.

RESPONSE (D):

Please see Table 2 below.

1 **Table 2: Updated Cable Chamber Renewal Costs Broken Down by Asset Category ($ Millions)**

	Actual				Bridge	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Cable Chamber Renewal	4.0	2.9	9.4	15.8	4.6	10.4	13.6	19.1	26.3	27.1
Cable Chamber	2.3	0.9	6.2	1.0	1.7	1.7	2.3	5.3	8.9	9.2
Cable Chamber Roof	0.5	0.2	0.4	0.5	0.3	1.3	2.6	3	3.2	3.3
Cable Chamber Abandonment	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2
Cable Chamber Lid	1.2	1.8	2.8	14.3	2.6	7.3	8.5	10.7	14	14.4

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-68

Reference: Exhibit 2B, Section E6.4

Preamble:

With respect to Network System Renewal:

QUESTION (A):

a) [p.7, 9] Please provide a version of the information included in Figures 3 and 6 in tabular format, that also includes 2017 ACA information, as well as the 2029 ACA information based on the proposed investments included in the DSP. Please provide in Excel format.

RESPONSE (A):

Please see Appendix 2B-SEC-68_App A ACA Data for the information in Figures 3 and 6 in tabular format with 2017 ACA information. For 2029 ACA information please refer to Toronto Hydro's response to interrogatory 2B-SEC-44.

QUESTION (B):

b) [p.18-19] Please expand Table 9 to include the forecast units replaced in each year between 2025 and 2029.

RESPONSE (B):

Please see Table 1 below.

Table 1: Network Units Replaced – 2020-2029 Actual/Bridge/Forecast

	Actuals				Bridge	Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Units	20	30	32	40	35	17	17	30	32	34

QUESTION (C):

c) [p.22] Please provide a similar table as Table 12 that shows both the number of actual/forecast units replaced as part of the Network Vault Renewal segment between 2020 and 2024, as well as the forecast number of units to be replaced in EB-2018-0165.

RESPONSE (C):

Please see Table 2 below.

Table 2: Network Vault Renewal 2020-2024 Plan (EB-2018-0165) and Actuals/Bridge

		2020	2021	2022	2023	2024
2020-2024 Actual/Bridge	Vault Rebuild	9	3	4	7	6
	Roof Rebuild	0	0	3	5	1
	Vault Decommissioning	0	1	0	0	1
	Total	9	4	7	12	8
Plan Per EB-2018-0165	Total	7	7	7	7	5

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-69

Reference: Exhibit 2B, Section E6.5

Preamble:

With respect to Overhead System Renewal:

QUESTION (A):

a) Please update Figures 3,4, 7, 8, 13, 14, 21, 22, 26 and 27 with 2023 information.

RESPONSE (A):

Please see the updated figures below.

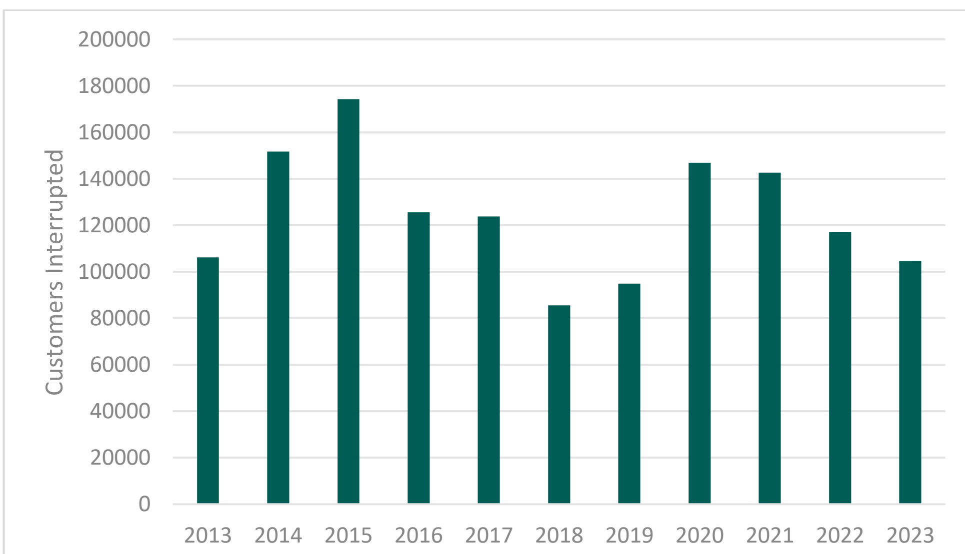


Figure 1: Updated Figure 3 Customers Interrupted ("CI") on the Overhead System (2013-2023)

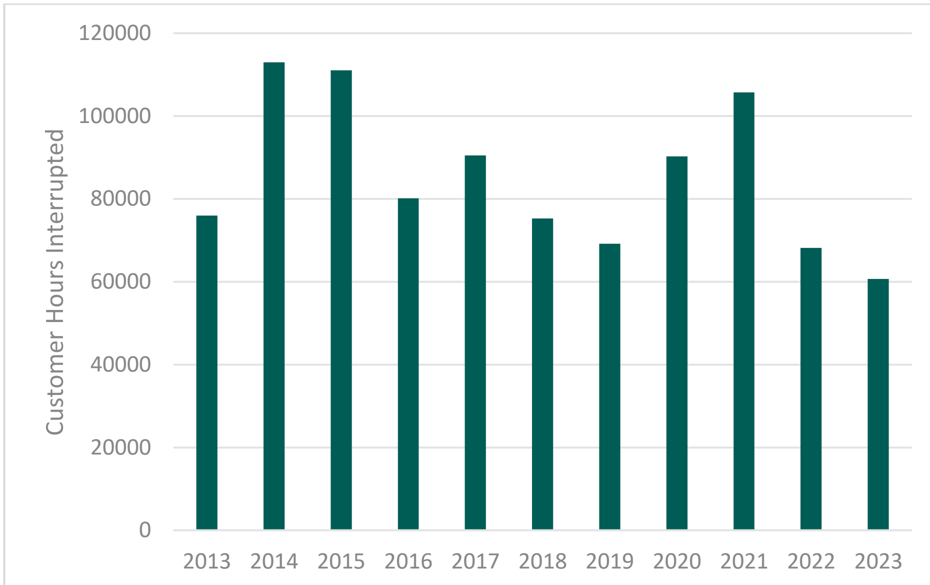


Figure 2: Updated Figure 4 Customer Hours Interrupted ("CHI") on the Overhead System (2013-2023)

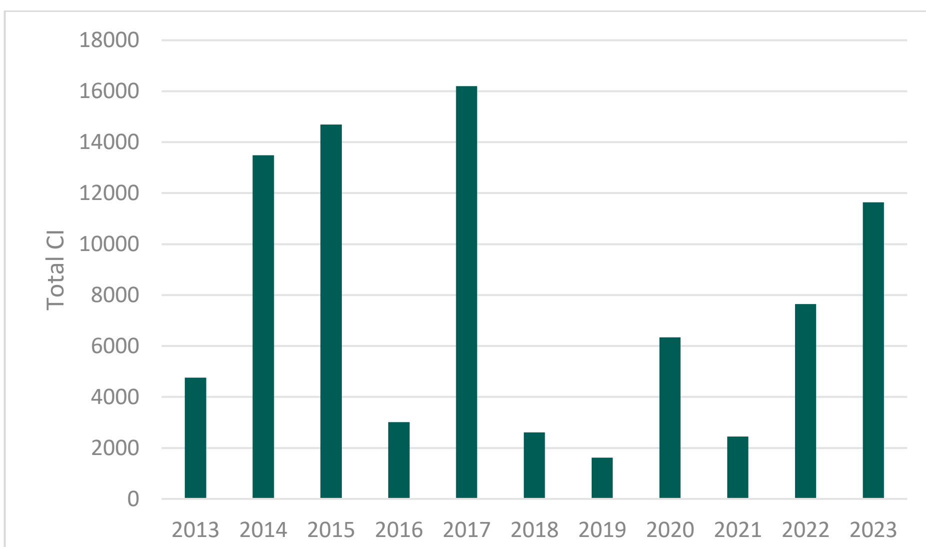


Figure 3: Updated Figure 7 Customers Interrupted ("CI") for Pole-top Transformers[1]

[1] Added 2013-2017 results for Figure 7 and Figure 8 in response to interrogatory 2B-Staff-222 (b).

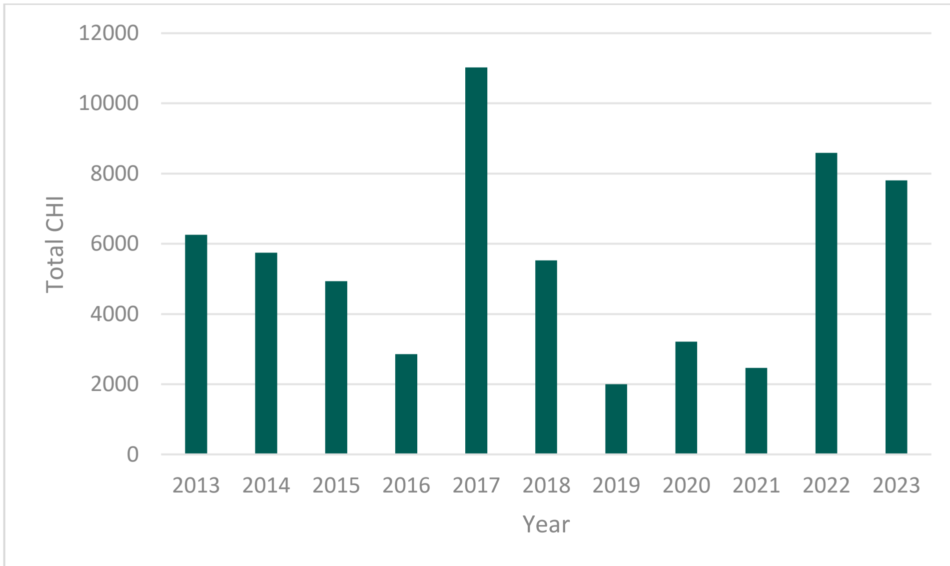


Figure 4: Updated Figure 8 Customer Hours Interrupted ("CHI") for Pole-top Transformers

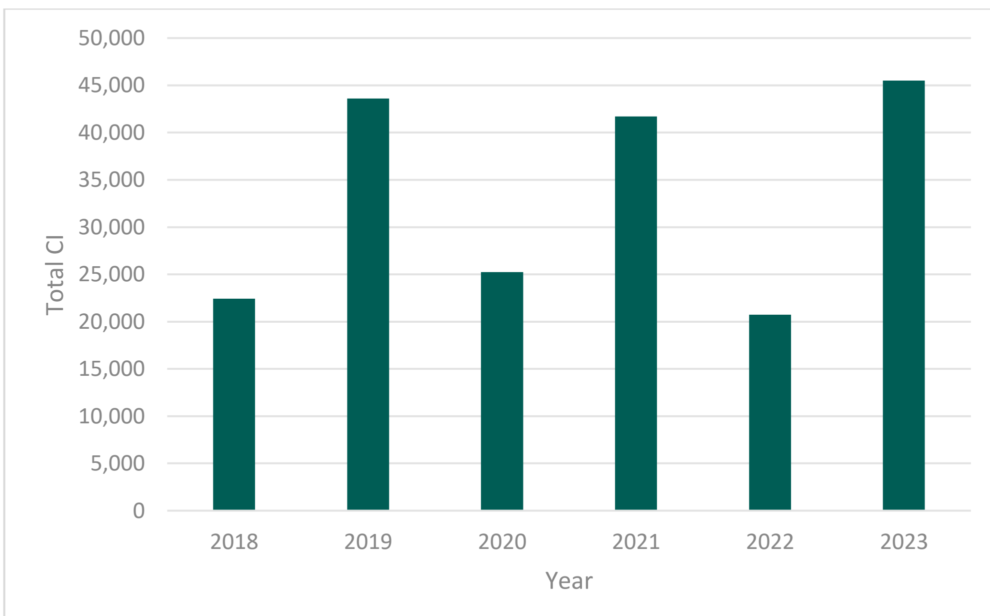
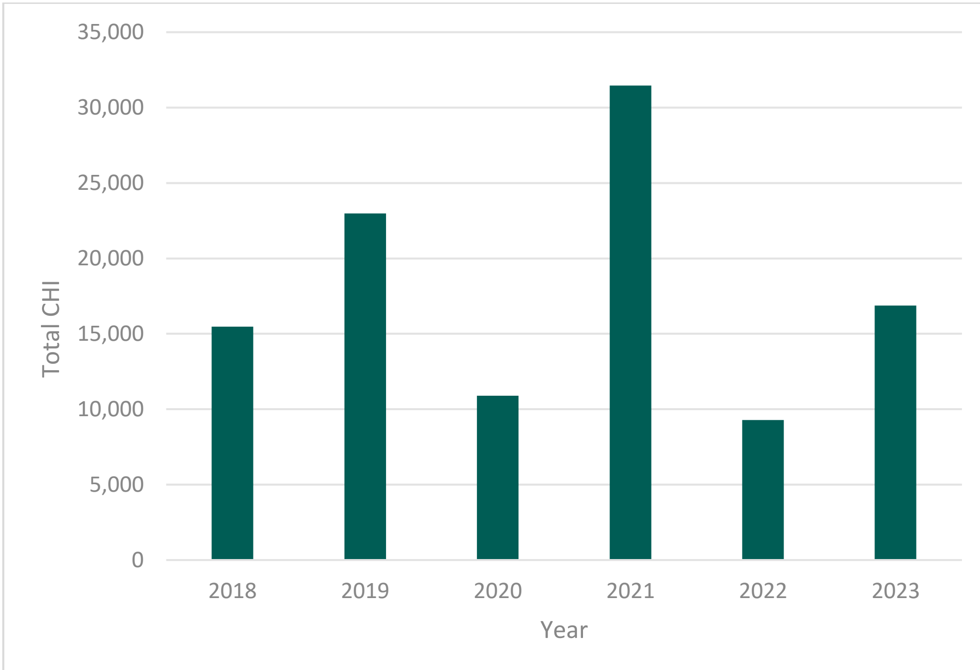
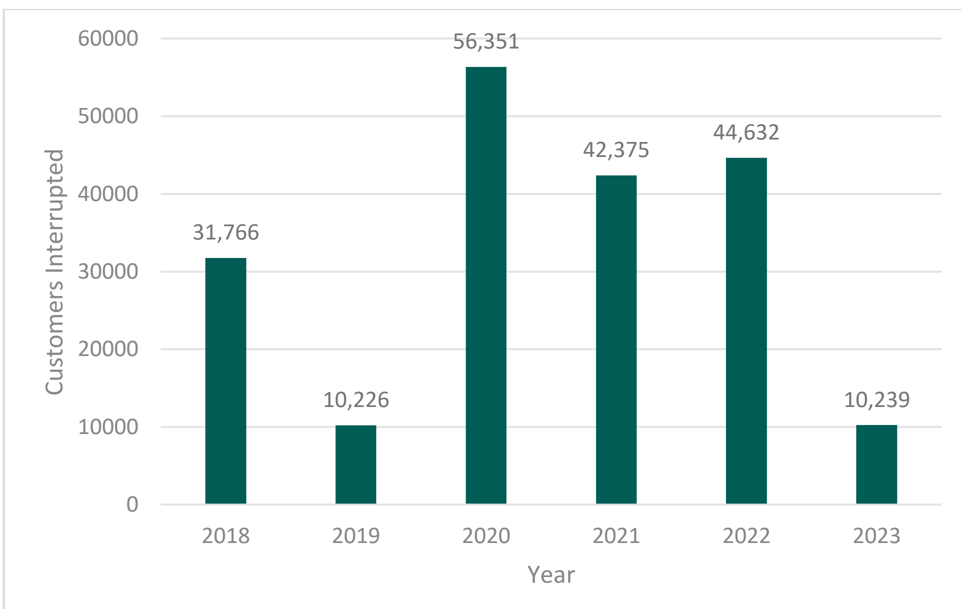


Figure 5: Updated Figure 13 Customers Interrupted ("CI") for Poles and Pole Accessories



1 **Figure 6: Updated Figure 14 Customer Hours Interrupted ("CHI") for Poles and Pole Accessories**

2



3 **Figure 7: Updated Figure 21 Customers Interrupted ("CI") for Overhead Switches**

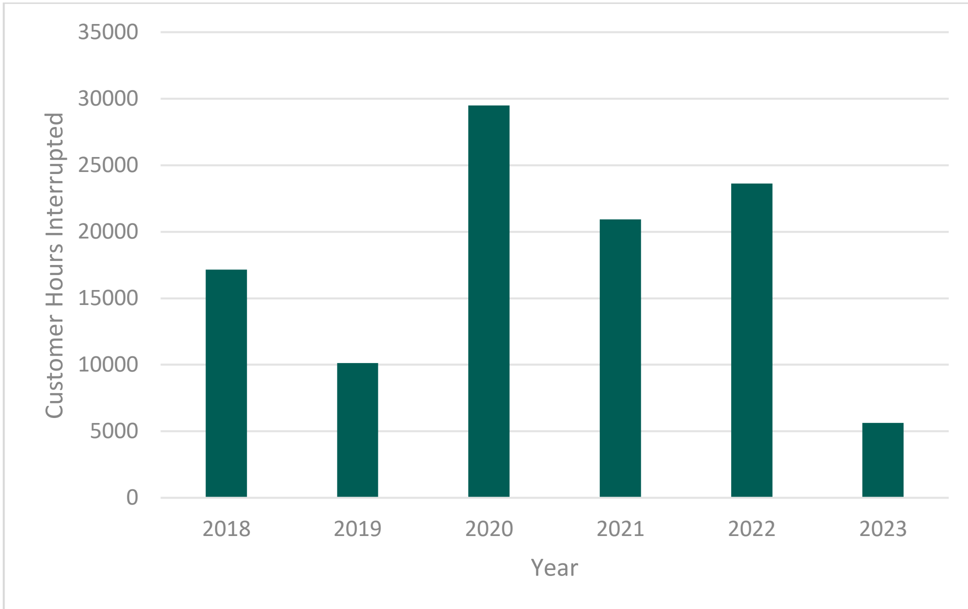


Figure 8: Updated Figure 22 Customer Hours Interrupted ("CHI") for Overhead Switches

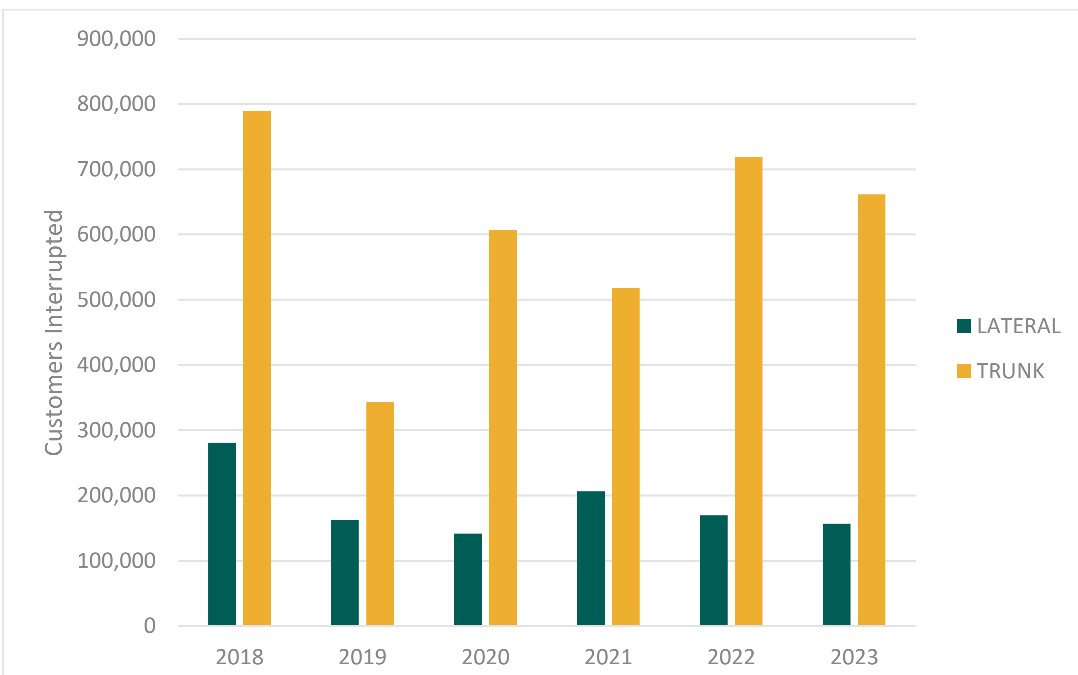


Figure 9: Updated Figure 26 Total Customers Interrupted (CI) – Trunk Versus Lateral

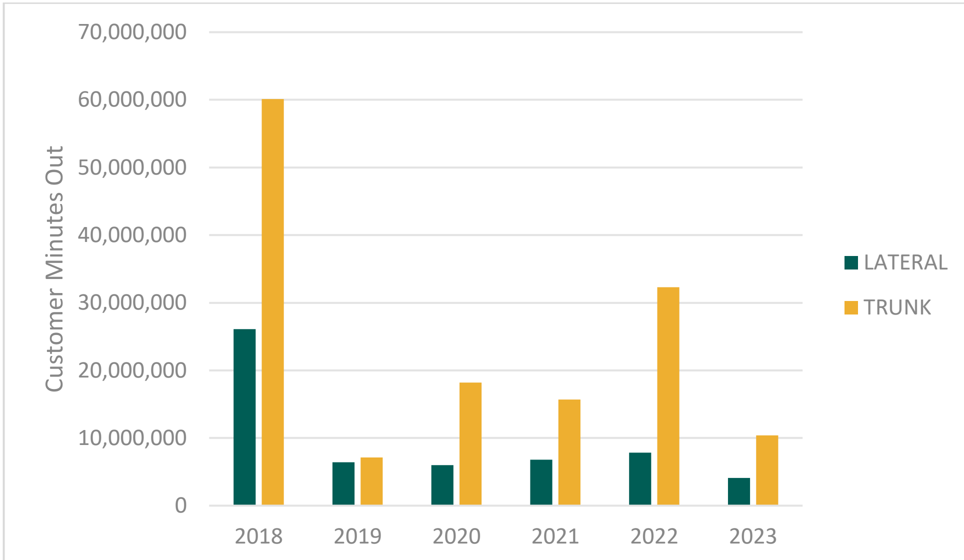


Figure 10: Updated Figure 27 Total Customer Minutes Out – Trunk Versus Lateral

QUESTION (B):

b) [p.9] Please provide a revised version of Table 4 that includes 2017 ACA information, as well as 2029 ACA information based on the proposed investments included in the DSP. Please provide in Excel format.

RESPONSE (B):

Please see the revised version of the requested table below including 2017 ACA information.

Table 1: Condition Data for Wood Pole

Asset Condition Index	2017	2022	2029 (Without Investment)
HI1 – New or Good Condition	63,526	68,193	60,253
HI2 – Minor Deterioration	7,354	7,536	8,310
HI3 – Moderate Deterioration	29,779	21,015	5,544
HI4 – Material Deterioration	5,687	8,918	24,404
HI5 – End-of-serviceable Life	722	504	7,655

For a comprehensive discussion of expected changes in asset demographics over the 2029 period, please see Toronto Hydro's response to 2B-SEC-44.

QUESTION (C):

c) [p.25-26] Please provide a version of the information included in each of Figures 24 and 25 in tabular format, that also includes 2017 ACA information, as well as the 2029 ACA information based on the proposed investments included in the DSP. Please provide in Excel format. e. [p.34] Please provide a breakdown of annual costs included in Table 7 based on the asset class included in Table 8.

RESPONSE (C):

Please see the tables below of based on Figures 24 and 25 including 2017 ACA information.

Table 2: Condition Data for Overhead Gang Operated Load Break Switches

Asset Condition Index	2017	2022	2029 (Without Investment)
HI1 – New or Good Condition	854	659	517
HI2 – Minor Deterioration	27	98	106
HI3 – Moderate Deterioration	76	88	111
HI4 – Material Deterioration	3	10	91
HI5 – End-of-serviceable Life	9	13	43

Table 3: Condition Data for Overhead SCADA-Mate Switches

Asset Condition Index	2017	2022	2029 (Without Investment)
HI1 – New or Good Condition	1,084	1,078	724
HI2 – Minor Deterioration	1	9	65
HI3 – Moderate Deterioration	26	66	69
HI4 – Material Deterioration	0	4	149
HI5 – End-of-serviceable Life	8	13	163

For a comprehensive discussion of expected changes in asset demographics over the 2029 period, please see Toronto Hydro's response to 2B-SEC-44.

QUESTION (D):

d) [p.37] Please provide a similar table as Table 9 that shows the volume of assets replaced each year as part of the Overhead Infrastructure Resilience segment.

RESPONSE (D):

Please see Table 4 below.

Table 4: Volume of Assets Replaced as part of the Overhead Infrastructure Resiliency

Asset Class	2025	2026	2027	2028	2029	Total
Poles	0	164	346	356	368	1235
Transformers	0	44	93	96	99	333
Overhead Switches	0	22	47	49	50	169
Conductors* (km)	0	27	58	59	61	205

*Primary conductor only

QUESTION (E):

e) [p.34] Please provide a breakdown of annual costs included in Table 7 based on the asset class included in Table 8.

RESPONSE (E):

In the process of preparing this interrogatory response, Toronto Hydro identified administrative errors with the numbers reported for overhead switches in 2020 and conductors in 2021 in Table 5 of Exhibit 2B, Section E6.5, as well as the pacing of transformer replacements entered into Table 6 for the years 2025-2029. Note that the total number of transformer replacements over the period is unchanged.

Please see the updated tables below:

Table 5: Updated 2020-2024 Overhead Asset Replacement Volumes

Asset Class	Actual				Bridge	Total
	2020	**2021**	**2022**	**2023**	**2024**	
Poles	1,418	1,263	1,137	1,892	2,093	7,803
Transformers	401	584	579	558	1,377	3,499
OH Switches	194	290	71	105	97	757
Conductors* (km)	53	106	76	38.8	48.6	323

*Primary cables only

Table 6: Updated 2025-2029 Volumes (Forecast): Overhead System Renewal

Asset Class	Forecast					Total
	2025	**2026**	**2027**	**2028**	**2029**	
Poles	2,113	1,556	1,556	1,556	1,556	8,337
Transformers	924	984	988	985	966	4,847
OH Switches	123	91	91	104	102	511
Conductors* (km)	66	49	49	45	44	253

*Primary cables only

Please see Table 7 below for the breakdown of annual costs by asset class.

Table 7: Annual Cost Breakdown by Asset Class ($ Millions)

Asset Class	Actual				Bridge	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Poles	12.5	8.8	9.7	13.8	18.4	21.1	15.9	16.3	16.8	17.3
Pole Top Transformers	7.7	10.6	10.5	11.2	33.6	20.9	22.8	23.4	24.1	24.3
Overhead Switches	0.9	2.0	1.2	1.2	1.6	1.1	0.8	0.9	1.0	1.0
Primary Conductor (km)	2.1	3.5	2.7	2.2	3.3	2.9	2.2	2.2	2.1	2.1

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-70

Reference: Exhibit 2B, Section E6.6

With respect to Station Renewal:

QUESTION (A):

a) Please provide a version of the information included in each of Figures 3, 8, 14, and 16, in tabular format, that also includes 2017 ACA information, as well as the 2029 ACA information based on the proposed investments included in the DSP. Please provide in Excel format.

RESPONSE (A):

Please see Tables 1-4 for the data underpinning Figures 3, 8, 14, and 16. This information is also provided as an Excel spreadsheet in Appendix A to this response. Please refer to Toronto Hydro's response to interrogatory 2B-SEC-44 Table 2 for a summary of the 2029 health demographic projections for stations assets.

Table 1: TS Switchgear Breakers Condition from Figure 3 including 2017 ACA

	2017	2022	2029 w/o Investment
HI1	633	688	631
HI2	78	46	58
HI3	302	255	101
HI4	7	12	200
HI5	49	28	39

Table 2: TS Outdoor Breakers Condition Figure 8 including 2017 ACA

	2017	2022	2029 w/o Investment
HI1	44	72	52
HI2	8	8	12
HI3	21	7	4
HI4	13	5	16
HI5	3	0	8

Table 3: MS Air Mag Circuit Breakers Condition from Figure 14 including 2017 ACA

	2017	2022	2029 w/o Investment
HI1	97	13	4
HI2	70	27	10
HI3	141	251	22
HI4	20	1	202
HI5	39	13	8

Table 4: MS Power Transformer Condition from Figure 16 including 2017 ACA

	2017	2022	2029 w/o Investment
HI1	83	86	61
HI2	77	64	5
HI3	61	12	45
HI4	13	8	6
HI5	8	0	7

QUESTION (B):

b) Please explain why Toronto Hydro does not track the condition of RTUs, and battery and ancillary systems.

RESPONSE (B):

Toronto Hydro conducts routine maintenance and inspection of station RTU’s and battery and ancillary systems as part of the station maintenance program (refer to Exhibit4 Tab 2 Schedule 3 - Preventative and Predictive Station Maintenance). In its development of the CBRM approach, Toronto Hydro concluded that extending the methodology to encompass communication devices, batteries and ancillary systems was not appropriate as these assets have inherent self-monitoring capabilities which are monitored by Toronto Hydro through its SCADA system.

QUESTION (C):

c) Please provide a revised version of each of Tables 15, 16, and 17 that shows 2017 information, as well as 2029 information based on the proposed investments included in the DSP. Please provide in Excel format.

RESPONSE (C):

Toronto Hydro is unable to provide relay information from the 2020-2024 rate application as the utility started to proactively replace these assets in 2022 (with the exception of Pilot Wire relays). Table 15 has been updated below to include the impact of the investments.

Table 15: Relay Type, Quantity, and Useful Life (Revised)

Relay Type	No. of Assets	Obsolete / Past UL 2024	Obsolete / Past UL 2029 (w/ Program)	Obsolete / Past UL 2029 (w/o Program)	% Obsolete / Past UL 2024	% Obsolete / Past UL 2029 (w/ Program)	% Obsolete / Past UL 2029 (w/o Program)
TS Relay	1063	419	307	407	39%	29%	38%
MS Relay	724	365	85	215	50%	12%	30%
Pilot Wire Relay	71	14	0	14	20%	0%	20%
Transfer Trip Relay	33	7	0	7	21%	0%	21%
Total	**1891**	**805**	**392**	**643**	**43%**	**21%**	**34%**

Please see below table for battery and chargers. Toronto Hydro is unable to provide 2019 information as the utility began tracking battery and charger demographics separately in 2020, as their useful life differ. Toronto Hydro notes that Table 16 (in Exhibit 2B, Section E6.6) also includes AC panels, which the utility began tracking in 2023.

Table 16: Battery and Ancillary Systems Demographics (Revised)

Asset Type	No. of Assets	Useful Life	Assets Past UL (2024)	Assets Past UL w/o Investments (2029)	Assets Past UL w/ Investments (2029)
Battery	148	10	18	69	14
Charger	148	20	11	20	16
Station Service Transformers	44	45	3	3	0
AC Panels	21	-	5	5	0
Air Compressors[1]	14	15	0	0	0
Total	**361**		**37**	**97**	**30**
Percentage			**10%**	**27%**	**8%**

Please see below Table 17 showing 2029 information in the last column. Toronto Hydro is unable to provide 2019 information from the last filing since the Utility began to track Battery and Charger Demographics separately in 2020 (after last filing).

Table 17: Battery and Charger Systems Demographics (Revised)

Asset Type	Assets Past UL (2024)	Assets Past UL w/o Investments (2029)	Assets Past UL w/ Investments (2029)
MS Battery	11%	43%	11%
TS Battery	19%	62%	0%
MS Charger	9%	16%	13%
TS Charger Systems	0	4%	0%

Tables 15, 16 and 17 have also been provided as an Excel spreadsheet in Appendix A to this response.

[1] No work is planned for in 2025-2029 as no air compressor is beyond useful life. During 2020-2024 one Air Compressor was replaced reactively and the other station was sold to a third party.

QUESTION (D):

d) [p.45] For each year between 2020 and 2024, please provide the number of TS switchgear units replaced.

RESPONSE (D):

Please refer to Toronto Hydro's response to interrogatory 2B-AMPCO-61.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-71

Reference: Exhibit 2B, Section E6.7

Preamble:

With respect to Reactive and Corrective Capital:

QUESTION (A):

a. [p.13] Please expand Table 7 to include 2020 to 2024 information.

RESPONSE (A):

Please refer to Toronto Hydro's response to Interrogatory 2B-AMPCO-62 part (f).

QUESTION (B):

b. [p.18] Please provide a table that shows, for each year between 2020 and 2029, for each asset type shown in Figure 11, the number of assets replaced/planned to be replaced, under the worst preforming feeder segment.

RESPONSE (B):

Please see Toronto Hydro's response to interrogatory 2B-AMPCO-62 part (k). Due to the reactive nature of this work in addressing deficiencies and trends as they emerge, Toronto Hydro is unable to forecast asset replacements in future years.

QUESTION (C):

c. [p.25] Please provide a table that shows, for each year between 2020 and 2029, for each asset type, the number of assets replaced/planned to be replaced, under the Reactive Capital segment.

RESPONSE (C):

Please see Table 1 below. Toronto Hydro notes that it does not plan asset replacements under Reactive Capital due to the unpredictable nature of asset failures. However, in Table 1 below Toronto Hydro has provided a forecast of the approximate number of assets to be replaced in 2024 and the average annual replacements over 2025-2029 based on historical trends and condition information. Actual volumes will fluctuate year-to-year, similar to what has occurred over 2020-2023.

Table 1: Actual and Forecast Asset Replacements under Reactive Capital

Asset Type	Actual				Forecast	
	2020	2021	2022	2023	2024	2025-2029 Avg
Transformers	1,287	651	483	469	~591	540
Poles	287	309	336	466	~378	394
Overhead Switches	565	451	447	389	~436	425
Switchgear	66	55	28	50	~46	45

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-72

Reference: Exhibit 2B, Section E7.2, p.14-16

QUESTION:

With respect to Toronto Hydro's Flexibility Service Program, please explain why an option was not considered to significantly increase the procurement target to further avoid and/or defer capital expenditures.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 1B-Staff-88 (a) and (b).

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-73

Reference: EB-2018-0165, Exhibit 2B, Section E7.4, Page 41

Please provide a revised version of Table 29 and 30 that show the actual cost effectiveness test results for local demand response at the Cecil TS and Basin TS. Please provide all underlying assumptions and calculations.

RESPONSE:

In Toronto Hydro's 2020-2024 CIR Application (EB-2018-0165), the LDR program proposed to target a total of 10 MW at Cecil TS and Basin TS. Both of these stations were evaluated for inclusion in the LDR program, but were ultimately not selected (in favor of Manby TS and Horner TS). Cecil TS was not selected due to loading changes between 2018 and 2020. In 2018 Toronto Hydro forecasted that Cecil TS would reach about 85% of its capacity by 2024; however, this outlook changed to about 78% when re-evaluated in 2020. As a result, Cecil TS was no longer suitable for LDR. Basin TS was excluded for different reasons. A switchgear replacement at Carlaw TS (adjacent to Basin TS) enabled permanent load relief in this area, which alleviated issues at Basin TS during this rate period. Furthermore, Hydro One has a replacement plan for the transformers at Basin TS in the 2025-29 period and as part of the replacement intends to upsize the transformers adding new capacity to the station.

With Basin and Cecil no longer suitable for LDR, and with more acute capacity constraints emerging in the Manby and Horner TS area, Toronto Hydro adjusted its program to target 10 MW of demand response at these stations. The goal of the program was to avoid the need for incremental load transfers from Manby TS and Horner TS to surrounding stations. The assumed and actual results of the Benefit Cost Analysis (BCA) for LDR in the current rate period, using the methodology appended to 1B-Staff-49, are summarized in Tables 1 and 2 below.

Table 1: Assumed Benefit-Cost Analysis for Manby/Horner TS Program

	Avoided Capital
Parameters	**$4.00 Millions** in load transfer capital investment avoided over the life of the assets beginning in 2021 (48 years) at an operational cost of **$2.40 Millions**
Costs	NPV of the operational costs of the non-wires solution (2025-2029): **$1.99 Millions**
Benefits	NPV of revenue requirement associated with capital investment avoided in 2025 over the 48-year EUL: **$3.67 Millions** *Less (-)* NPV Costs: **$1.99 Millions** *Equals (=)* **$1.68 Millions** NPV Benefits
Total	**Total Assumed NPV Benefits = $1.68 Millions**

The Manby/Horner TS LDR work was launched in 2022, along with the pursuit of the Benefit-Stacking Pilot as part of IESO's Grid Innovation Fund, which layered the exploration of bulk-system value on top of the planned LDR program (see Exhibit 2B Section E7.2 for details). Toronto Hydro contracted and dispatched 4 MW of demand response in summer 2023, and has thus far contracted 6 MW of demand response for summer 2024 dispatch. Table 2 outlines the actual benefits based on the most up-to-date information.

Table 2: Actual Benefit-Cost Analysis for Manby/Horner TS Program as of February 29, 2024

	Avoided Capital
Parameters	**$4.00 Millions** in load transfer capital investment avoided over the life of the assets, beginning in 2023 (48 years) at an operational cost of **$1.20 Millions**
Costs	NPV of the operational costs of the non-wires solution (2025-2029): **$0.93 Millions**
Benefits	NPV of revenue requirement associated with capital investment avoided in 2025 over the 48-year EUL: **$3.29 Millions** *Less (-)* NPV Costs: **$0.93 Millions** *Equals (=)* **$2.36 Millions** NPV Benefits
Total	**Total Actual NPV Benefits =** **$2.36 Millions**

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-74

Reference: Exhibit 2B, Section E7.4, Page 33

Please provide a revised version of Table 19 that shows the Downsview TS expenditures on an in-service additions basis.

RESPONSE:

Following Toronto Hydro's update filed on January 29, 2024 Table 19 [Section 2B, Section E7.4, at page 33] referenced above is now Table 16 [Section 2B, Section E7.4 at page 28]. Please see the table below with Downsview TS expenditures on an in-service additions basis.

Table 1: 2025-2034 Downsview TS Expenditure on an In-service Additions Basis ($ Millions)

	Forecast – Planning and Preparation					Forecast – Construction & Energization				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Downsview TS	--	--	6.5	--	8.4	--	--	--	--	147.8

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-75

Reference: Exhibit 2B, Section E7.4, Page 55

Toronto Hydro has provided estimated station expansion investment costs based on the Low Efficiency Scenario included in the Future Energy Scenarios Report. Please provide similar estimates, in the same format, based on all the scenarios included in that report.

RESPONSE:

Toronto Hydro notes that the referenced Flexibility Considerations section (at page 55) was updated on January 29, 2024 (see Exhibit 2B, Section E7.4.8, pages 45-47). The table below provides the estimated stations expansion investments needed under the other Future Energy Scenarios.

Table 1: Estimated Stations Expansion Investment Needed under Future Energy Scenarios

CIR Period	NZ40-Low (Jan 29, 2024)	CT	CT-Low	NZ40	SP	ST
2025-2029	95	73	89	76	88	80
2030-2034	192	23	104	40	61	40
2035-2039	527	40	219	97	91	105

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-76

References: Exhibit 2B, Section E8.1

Please provide a copy of the internal business case for the EDC Relocation program.

RESPONSE:

The options analysis presented in subsection E8.1.4 of Exhibit 2B, Section E8.1 represents Toronto Hydro's internal business case analysis for the EDC relocation program.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-77

References: Exhibit 2B, Section E8.3

With respect to Fleet and Equipment Services:

QUESTION (A):

a) [p.10] Please provide a more detailed explanation of the change in fleet utilization methodology and how both the old and current metric are calculated.

RESPONSE (A):

Please refer to Toronto Hydro's response to 2B-Staff-266(b).

QUESTION (B):

b) [p.10] Please update Figure 4 to provide 2023 year-end actuals and provide the underlying data used in the calculation of the revised table. Please provide in Excel format.

RESPONSE (B):

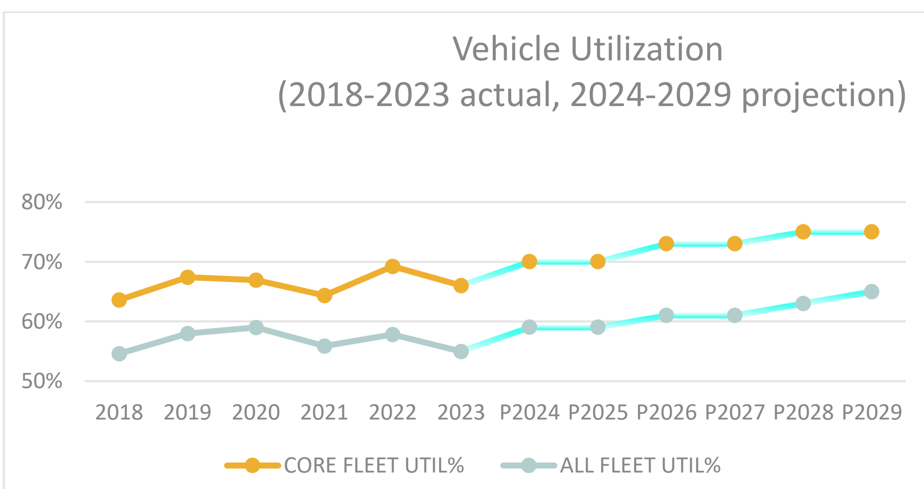


Figure 4: "Days Used" Vehicle Utilization Metric (Updated)

Please refer to the appendix of this interrogatory response for the underlying data in Excel format.

QUESTION (C):

c) [p.12] Please expand Table 5 to include 2020 to 2024 information.

RESPONSE (C):

Table 5: 2020-2024

Description	2020		2021		2022		2023		2024	
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost
Heavy Duty	8	5.1	10	1.1	5	8.8	8	2.3	26	6.3
Light Duty	20	1.3	22	1.1	52	5.5	24	1.2	15	1.6
Equipment	0	0.1	1	0.1	10	1.1	3	0.4	3	0.7
Total	**28**	**6.5**	**33**	**2.3**	**67**	**15.4**	**35**	**3.9**	**44**	**8.6**

Toronto Hydro has discovered summation errors in the annual columns and the total cost allocation between the Light Duty and Equipment categories of the original Table 5 submitted as part of Exhibit 2B, Section E8.3, which have been corrected in the table below. There is no change to the aggregate program cost of $43.7 million for 2025-2029.

Table 6: 2025-2029

Description	2025		2026		2027		2028		2029		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Heavy Duty	10	6.2	13	6.4	23	7.2	11	5.4	12	3.8	**29**
Light Duty	17	2	26	3.3	10	0.9	12	1.8	40	4.6	**12.6**
Equipment	2	0.4	1	0.2	1	0.2	1	0.2	10	1.1	**2.1**
Total	**29**	**8.6**	**40**	**9.9**	**34**	**8.3**	**24**	**7.4**	**62**	**9.5**	**43.7**

QUESTION (D):

d) [p.12] What is the total size of Toronto Hydro's fleet by type (heavy, light, equipment).

RESPONSE (D):

There are currently 149 heavy duty vehicles, 210 light duty vehicles, and 69 equipment units in Toronto Hydro's fleet.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 2B-SEC-78

Reference: Exhibit 2B, Section E

For all material capital projects undertaken or forecast to be undertaken between 2020 to 2024, please provide a table that includes the following: i) project name, ii) Toronto Hydro program (and segment), iii) original budget costs (or cost budgeted in EB-2018-0165 application), iv) actual or revised forecast cost, v) original forecast in-service year, vi) actual or revised forecast year in-service year, and vii) explanation for any project where the variance between (iii) and (iv) is +/- 10%.

RESPONSE:

Please see Appendix A to this response which shows the actual and budgeted costs between 2020 to 2024 for material capital projects undertaken.

2B-SEC-78: Appendix A

Question		HONI Contributions	Copeland Phase 2	ERP	Control Room Operations Reinforcement	CIS Upgrade
i)	Project name	CCRA Horner TS	Copeland Transformer Station - Phase 2[1]	Enterprise Resource Planning	Control Room Operations Reinforcement	CIS Upgrade
ii)	Toronto Hydro program (and segment)	Stations Expansion	Stations Expansion	IT/OT Systems	Control Room Operations Reinforcement	IT/OT Systems
iii)	Original budget costs (or cost forecast in EB-2018-0165 application) ($ Millions)	34.4	78.5	46.3	40.2	38.5
iv)	Actual or revised forecast cost ($ Millions)	27.9	79.5	24.4	40.1	38.0
v)	Original forecast in-service year	2023	2022 - 2025	2020 - 2024	2022	2022
vi)	Actual or revised forecast year in-service year	2022	2022 - 2024	2020 - 2025	2021-2024	2022-2024
vii)	Explanation for any project where the variance between (iii) and (iv) is +/- 10%	At the time of the 2020-2024 rate application (EB-2018-0165), the project estimate in the forecast was provided by Hydro One as a Class C estimate. This estimate was produced prior to the completion of a CCRA, and to the detailed scope of work.	Variance within +/-10%	Toronto Hydro's prudent decision to delay the SAP S4Hanna initiative to the 2025–2029 rate period was a key factor that contributed to the variance. SAP announced in February 2020 that the SAP ECC Support will be extended until 2027. Based on this announcement, Toronto Hydro made the decision to delay the SAP S4Hanna initiative to the 2025–2029 rate period. (See Exhibit 2B, Section E4, P.10, and Exhibit 2B, Section E8.4, p. 21.) Given the access to reliable support for the existing solution, Toronto Hydro focused its efforts in the 2020–2024 rate period on SAP ECC improvements and enhancements. These initiatives included applying the latest release from the vendor and ensuring the backend infrastructure is effectively maintained and supported as per Toronto Hydro's IT standards. In addition, Toronto Hydro also implemented various SAP enhancements, such as SAP Business Planning and Consolidation Enhancements, SAP Warehouse Management Solution, SAP Payroll Enhancements, and 400+ SAP small enhancements.	Variance within +/-10%	Variance within +/-10%

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-12

Reference: Exhibit 2B, Section A3.4

QUESTION (A):

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

RESPONSE (A):

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. This study did analyze various climate parameters including, but not limited to, snowfall, extreme rainfall, freezing rain, high temperature and high winds. In 2022, this study was updated. Please refer to Exhibit 2B, Section D2, Appendix A.

QUESTION (B):

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

RESPONSE (B):

Cumulative rainfall in this section is presented as an indicator of trend. An increase in heavy rainfall days and freezing rain may be a correlated with the upward trend of cumulative rainfall.

QUESTION (C):

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

RESPONSE (C):

Toronto Hydro does not take into account other weather phenomena. The steps Toronto Hydro has taken relative to the study of climate change is the completion of a Climate Change Vulnerability Assessment, see Section 2B, D2, Appendix A.

QUESTION (D):

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

RESPONSE (D):

Toronto Hydro only has outage data dating back to 2002. Table 1 below shows the number of sustained interruptions (excluding MEDs).

Table 1: Number of Outages due to Adverse Weather, Lightning and Tree Contacts from 2002-2022

Year	Adverse weather	Lightning	Tree contacts
2002	294	88	105
2003	324	79	148
2004	77	64	92
2005	170	48	127
2006	129	90	166
2007	130	45	116
2008	111	90	114
2009	88	67	91
2010	79	25	119
2011	115	64	113
2012	120	50	61
2013	177	16	112
2014	82	12	112
2015	89	7	57
2016	58	7	69
2017	41	14	67
2018	129	4	81
2019	57	3	48
2020	49	2	70
2021	79	22	104
2022	80	5	120

QUESTION (E):

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

RESPONSE (E):

Toronto Hydro only has MED data dating back to 2002 – see Table 2.

Table 2: Number of MEDs from 2002-2022

Year	Number of MED's
2002	0
2003	3
2004	0
2005	3
2006	2
2007	2
2008	0
2009	4
2010	1
2011	0
2012	2
2013	8
2014	3
2015	1
2016	0
2017	1
2018	5
2019	0
2020	1
2021	0
2022	1

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-13

Reference: Exhibit 2B, Section E5.4

QUESTION (A):

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

RESPONSE (A):

Please see Tables 1 and 2 below.

Table 1: New Meter Installation for Residential and GS<50, Suite Meters

New Meter Installation	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential and GS < 50, Suite Meters	18,922	14,242	11,667	13,270	106,370	159,946	175,514	181,285	70,354	1,177

Table 2: Meter Reverification/Resealing for Residential, GS<50, Suite Meters

Reverified/ Resealed	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential and GS < 50, Suite Meters	16,162	6,745	16,095	9,207	11,066	9,782	12,195	13,816	14,994	12,023

QUESTION (B):

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

RESPONSE (B):

As noted in Exhibit 2B, Section E5.4,[1] Toronto Hydro's historical smart meter deployment strategy was in support of provincial policy objectives concerning the rollout of smart meters and time-of-use billing in Ontario. Building on the strategy approved in the 2020 Rate Application,[2] Toronto Hydro intends to replace meters surpassing their expected lifespan over a five-year period. Mass deployment of meters over a period greater than five years results in future risks to billing and customer experience, while delaying the benefits of AMI 2.0 that can only be realized once a majority of next generation meters have been installed, as shown in Toronto Hydro's response to interrogatory 2B-Staff-194. Toronto Hydro will assess the timing and pace of future metering programs closer to the implementation of those programs based on the risk of failure, ability to reseal, and benefits of any replacement meters at that time.

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[1] At page 9, lines 9-10.

[2] EB-2018-0165, Exhibit 2B, Section E5.4; see especially lines 16-27 at page 16.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-14

Reference: Exhibit 2B, Section E5.3

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

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

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

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

QUESTION (A) :

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

RESPONSE (A):

The Station Buses referenced for Esplanade, Horner, Manby QZ, and Windsor are the same in both tables, with the exception of Basin. Basin is not included in the planned Bus Station Relief for the 2025-2029 period, as indicated in Section E5.3.3.4 Table 5 in the Load Demand narrative (updated January 29, 2024).

Table 1: Station Buses

<table>
<tr><th>Station</th><th>EB-2018-0165
Proposed</th><th>EB-2018-0165
Completed</th><th>EB-2023-0195
Proposed</th></tr>
<tr><td>Basin</td><td>A5-6BN</td><td>N/A – no longer required</td><td>N/A – no longer required per Jan 29, 2024 update</td></tr>
<tr><td>Esplanade</td><td>A1-2X</td><td rowspan="2">Yes, including incremental transfers for Windsor buses A5-6WR, A13-14WR, A17-18WR</td><td rowspan="2">Scheduled for relief as part of Copeland TS – Phase 2</td></tr>
<tr><td>Windsor</td><td>Bus supplying feeders in area bounded by Bathurst St, Adelaide St W, Yonge St, and 7 Railway Corridor</td></tr>
<tr><td>Horner</td><td>B&Y</td><td>In Progress</td><td>B&Y (Continuation)</td></tr>
<tr><td>Manby</td><td>Q&Z; V&F</td><td>No – Deferred</td><td>Q&Z</td></tr>
</table>

QUESTION (B):

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

RESPONSE (B):

There is approximately $9.8 million in load transfers initiated during the 2020-2024 period which are expected to be completed in 2025-2029. Additionally, load transfers not initially planned but completed during the 2020-2024 rate period due to changing needs of the system, are provided in the table below. As a result, load transfers originally planned for Manby QZ in the 2020-2024 period were reprioritized and deferred to 2025-2029, which is forecasted to amount to $8.4 million.

Table 2: Load Transfers Completed in 2020-2024

Station	Buses	Completed Year
Windsor	A5-6WR, A13-14WR, A17-18WR	2021
Terauley	A1-2A, A3-4A	2021, 2024
George & Duke	A1-2GD	2021
Dufferin	A5-6DN	2022
Leaside	Q1&Q2	2022

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-15

Reference: Exhibit 2B, Section E6.1

Preamble:

Table 11: Planned Rear Lot Projects for 2025-2029

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

QUESTION (A):

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

RESPONSE (A):

Please see Table 1 below.

Table 1: Number of Non-Momentary Rear Lot Outages (Excluding MEDs) 2020-2023

	2020	2021	2022	2023
# of Outages	18	20	26	23

QUESTION (B):

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

RESPONSE (B):

Please see Table 2 below.

Table 2: Number of Non-Momentary Rear Lot Outages (Excluding MEDs) 2012-2019

	2012	2013	2014	2015	2016	2017	2018	2019
# of Outages	27	35	30	22	18	25	35	15

QUESTION (C):

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

RESPONSE (C):

Please see Table 3 below. All Rear Lot projects entail conversion to an underground front lot system. Note that some of the customer counts in the table have been updated based on more recent detail design data.

1 **Table 3: Budgeted Capital Costs for Planned Rear Lot Projects**[1]

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2022)	Number of Outages Greater than 5 Hours (2012-2022)	Project Cost $
Thorncrest Phase 12*	139	2025	1	0	$7,511,700
Markland Woods*	285	2025-2026	17	8	$20,635,271
Martin Grove Garden*	307	2025-2027	7	2	$16,590,590
Willowridge	201	2027-2028	11	3	$14,447,838
Mount Olive	61	2027-2028	2	2	$4,288,653
Kingsview	156	2028-2029	11	2	$11,295,096
Eringate Centennial-West Deane*	133	2025-2027	18	2	$7,187,454
Richview Park	263	2028-2029	1	0	$19,042,373

* Projects with cost incurred in both the 2020-2024 and 2025-2029 periods.

[1] Please note that the sum of these project budgets will not equal the proposed 2025-2029 costs for the Rear Lot segment due to project costs incurred in 2020-2024 and the inclusion of approximately $24 million to begin the conversion of five new rear lot areas towards the end of the rate period, which Toronto Hydro will determine using reliability metrics closer to the time of project planning.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-16

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

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

RESPONSE:

Please see Appendices A-D to this response for the annual audit reports.

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-VECC-16
Appendix A
FILED: March 11, 2024
(27 Pages)

REPORT OF THE ANNUAL AUDIT
AND DECLARATION OF COMPLIANCE
UNDER ONTARIO REGULATION 22/04

SUBMITTED TO THE ELECTRICAL SAFETY AUTHORITY

SUBMITTED BY

Hani Taki, P.Eng.
Director, Standards & Technical Studies
Toronto Hydro-Electric System
500 Commissioners Street
Toronto, ON M4M 3N7

July 14, 2020

Report Due Date: July 31, 2020

Contents

1.0 SUMMARY - 2019/2020 AUDIT AND DECLARATION OF COMPLIANCE

This report is submitted to the Electrical Safety Authority by Toronto Hydro-Electric System Limited (‘Toronto Hydro’), as required under Ontario Regulation 22/04, “Electrical Distribution Safety” issued under the Electricity Act, 1998 (the ‘Regulation’).

This report covers the period from May 1, 2019 through April 30, 2020.

This report contains the report of the Auditor, and if applicable an Action Plan to further improve compliance with Ontario Regulation 22/04, and the Declaration of Compliance.

For this reporting period, Toronto Hydro hired Acumen Engineered Solutions International Inc. (AESI) to perform the audits.

Les Stoch, an ESA approved auditor, performed the audit on behalf of AESI. The audit covered sections 4, 5, 6, 7, and 8 of Ontario Regulation 22/04. Les Stoch also performed an audit in support of the Declaration of Compliance.

2.0 2019/2020 AUDIT RESULTS AND ACTION PLANS

The 2019/2020 Audit was performed by Les Stoch on May 5, 6, 12, and 13, 2020 to verify the extent of Toronto Hydro's compliance with Ontario Regulation 22/04. There were no opportunities for improvement and no non-compliances found during this year's Ontario Regulation 22/04 audit. A copy of the audit report is included in Appendix A.

Even though no opportunities for improvement and non-compliances were found during this year's Ontario Regulation 22/04 audit, Toronto Hydro is still very committed to continuous improvement.

3.0 DECLARATION OF COMPLIANCE

Toronto Hydro employed an external auditor (AESI) to assess the Company's compliance to Sections 3, 9, 10, 11 and 12 of the Regulation.

The Declaration is included here.

Toronto Hydro-Electric System Ltd.

Annual Declaration of Compliance

Year 2019/20

Period May 1, 2019 to April 30, 2020.

This Declaration of Compliance is submitted by Toronto Hydro-Electric System Ltd. (THESL) in accordance with Ontario Regulation 22/04, Section 14.

I Hani Taki, P. Eng., of Toronto Hydro-Electric System Ltd. state that, to the best of my knowledge and belief and having made reasonable inquiries, Toronto Hydro-Electric System Ltd. has complied with the following sections of Ontario Regulation 22/04:

1) Section 3 – Change of ownership;
2) Section 9 – Deviations from required standards;
3) Section 10 – Proximity to distribution lines;
4) Section 11 – Disconnection of unused lines;
5) Section 12 – Reporting of serious electrical incidents.

Ont. Reg. 22/04 Section10 (4) states that “The distributor shall provide reasonable information with respect to the location of its underground distribution lines and associated plant within a reasonable time.” Furthermore, Section 2.6 of the ESA Guideline for Excavation in the Vicinity of Utility Lines states that “Except in cases of an emergency, or when the response for the *locate* request has been agreed with the *Excavator,* the *utility* shall make every reasonable effort to respond to notification requests and provide *locates* within 4 working days of receiving the notification, and 5 working days during peak times.” THESL confirms its commitment to achieving these levels of performance. In the 2018/2019 declaration, THESL stated its intention to hire a third locates service provider to help improve locates performance. In 2019, a third locates service provider was brought on board, resulting in improved performance in this reporting period as compared with the 2018/2019 reporting period (while volumes remained relatively steady). THESL’s average monthly 5-day completion time during this reporting period was 90.3%. THESL will continue to monitor performance of its locates service.

Toronto Hydro-Electric System Ltd. has used a methodology of review and validation of processes by an independent external auditor, appointed by Toronto Hydro-Electric System Ltd. to assess and verify compliance. Documentation to support this review and validation process is available to the ESA, upon request.

……………………………….
Signature

Hani Taki, P. Eng.
Director, Standards & Technical Studies

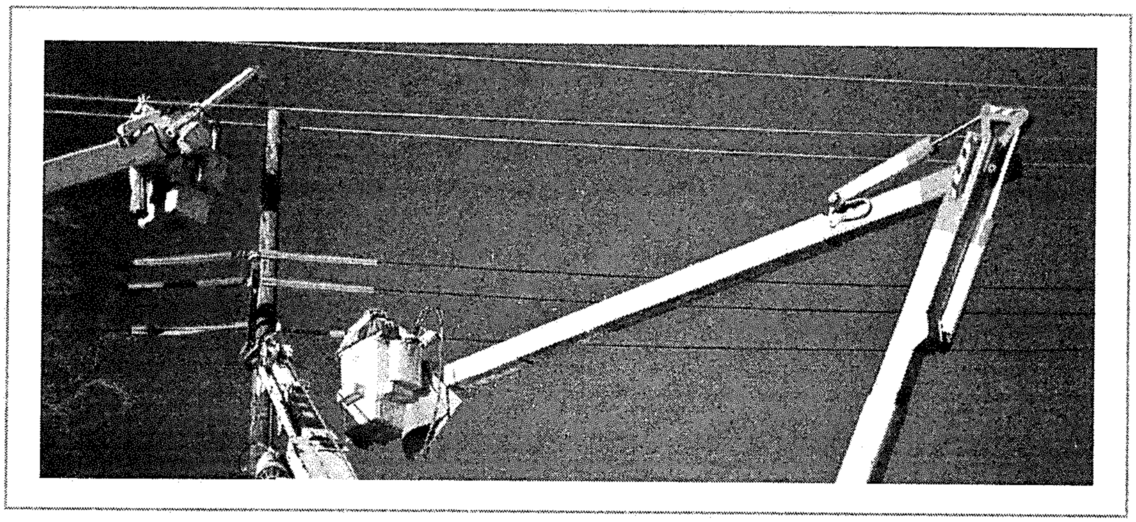
June 29, 2020
……………………………….
Date

4.0 APPENDIX A – REPORT OF THE AUDITOR

The enclosed report was provided by the external auditor (Sections 4 to 8 of Ontario Regulation 22/04)

REMOTE AUDIT REPORT

Ontario Regulation 22/04 Sections 4 to 8



Client
Toronto Hydro Electric System

4ate
May 27, 2020

Prepared by
L. Stoch and Associates

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Remote Audit Report
May 1, 2019 to April 30, 2020
Ontario Regulation 22/04
Sections 4 to 8

Toronto Hydro Electric System,
500 Commissioners Street,
Toronto, ON M4M 3N7

Prepared by: Leslie Stoch **Date:** May 28/20

L. Stoch, P.Eng.

Reviewed by: ____________________ **Date:** __________

Toronto Hydro-Electric System Limited

Ontario Regulation 22/04 Compliance

Period May 1, 2019, to April 30, 2020

I, Hani Taki, of Toronto Hydro-Electric System Limited state that to the best of my knowledge and belief and having made reasonable inquiries, Toronto Hydro-Electric System Limited has complied with the following Sections of Ontario Regulation 22/04.

1. Section 4 Safety standards
2. Section 5 When safety standards met
3. Section 6 Approval of electrical equipment
4. Section 7 Approval of plans, drawings, and specifications for installation work
5. Section 8 Inspection and approval of construction

Toronto Hydro-Electric System Limited has used an internal methodology of review and validation of processes to assess and verify compliance.

Hani Taki, P.Eng.
Director, Standards & Technical Studies
Engineering

May 25, 2020

Description and Scope of Remote Audit

An Ontario Regulation 22/04 remote audit of Toronto Hydro Electric System was carried out on May 5, 6, 12 and 13, 2020 by Les Stoch of L. Stoch and Associates. The audit closing meeting was held on May 27, 2020.The purpose of the audit was to assess the distributor's extent of compliance with respect to OR 22/04, Sections 4 to 8 to measure whether the distributor has appropriate processes in place to comply with the safety standards set out in the regulation and whether the organization correctly follows its processes. The time period audited was May 1, 2019 to April 30, 2020.

The Toronto Hydro Electric System distributes electricity in the City of Toronto, serving approximately 778,000 residential, commercial and industrial customers. Ownership is by the City of Toronto. The scope of this audit involved processes concerning 144 municipal substations, 27.6 kV volts to 4160 volts, overhead and underground primary and secondary lines. The distributor also contracts out work to qualified consulting engineers and contractors, and such work was included within the scope of the audit. The distributor maintains a staff of approximately 1360 persons. The LDC owns 36 transformer stations that are not within the scope of the audit.

The remote audit plan, shown in the attached audit checklist/report covers the distributor's policies and procedures concerning OR 22/04. Standard auditing methods and procedures were used including interviews with personnel, examining documents and records for a relevant sample of work activities.

Although the emphasis of this audit was directed toward noncompliances and aspects that should be considered for improvement, nothing in this report should be construed as criticism of neither the distributor's staff nor the services provided.

Auditor Qualifications and Experience

Les Stoch is a professional electrical engineer, qualified quality management system auditor and consultant. Since 1993, he provides electrical engineering services under a PEO Certificate of Authorization, and quality management consulting services for organizations working toward ISO 9001 registration. He is a member of Professional Engineers Ontario, the American Society for Quality, the International Association of Electrical Inspectors and the Ontario Electrical League.

His electrical industry experience includes 21 years with Electrical Inspection, Ontario Hydro in electrical engineering and management positions. He is a past member of the Ontario Provincial Advisory Committee, developing recommendations on Ontario's electrical code. Through Dalhousie University, he provides professional development and training seminars on the electrical code and code-related subjects across Canada.

Auditor Independence

L. Stoch and Associates declares itself to be independent from the Toronto Hydro Electric System and the work to be audited, and free of any potential threats to the auditor's independence including self-interest, self-review, advocacy, familiarity and intimidation.

Executive Overview

A remote audit of the Toronto Hydro Electric System was performed on May 5, 6, 12 and 13, 2020 to verify the organization's extent of compliance with OR 22/04, to identify any gaps and to evaluate the effectiveness of procedures in place for compliance purposes.

The audit covered the organization's existing processes and new ones developed in response to the regulation. The distributor's processes are in good compliance with the regulation.

The Toronto Hydro Electric System is an effective organization, concerned about public safety, and protecting the public from any harm that might result from its operations. The professionalism and dedication of its employees was clearly evident throughout the audit.

Noncompliances

No noncompliances were found:

Opportunities for Improvement

No opportunities for improvement were noted:

General Observations

Several general observations are included:

1. The LDC employs services of a consulting engineers and a quality management system registrar for inspection of work by contractors and design-build contractors.

2. The LDC should revise the equipment re-use approval procedure in accordance with ESA Bulletin DB-01-19 if from time to time reusable equipment is stored on a construction site or on a truck rather that returned to stores.

3. Bell Mobility installs Wireless Antennae on the LDC's pole lines. A Wireless Permit Application form is used as a work instruction. The form does not identify the designer or the reviewer of the work instruction. The form also indicates that Bell Mobility (not confirmed by a person) is in compliance with OR 22/04 and Toronto Hydro Standard SKE-221. Work instructions need to be signed.

4. Substation design may be carried out by the LDC or by a consulting engineer. No design or contraction was done in 2019; work was limited to minor improvements.

Management Response to ESA

The Electrical Safety Authority will ask the distributor to submit a copy of this audit report. Management will be asked to prepare a response to the audit findings, which should include actions on any identified issues with a timetable to address each issue. An action plan should be submitted to ESA along with the audit report.

ESA will respond directly on receiving the distributor's report. An audit review meeting with ESA may take place. The audit findings listed in the report will be reviewed, and any items that require action will be addressed along with the distributor's action plan and any timelines.

If any actions are required, the distributor will be asked to submit a progress report to ESA to provide information on progress in addressing any issues identified in the audit and action plan.

Opening Meeting

No opening meeting was held.

Closing Meeting

A remote closing meeting was held May 27, 2020

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment **up to 750 volts not part of distribution** to ensure proper operation and safety (ancillary equipment) (Maintenance and inspection schedules, logs, checklists)	Inspection and PM low voltage ancillary equipment: • Municipal street lighting maintained by LDC's contractor, recorded in Work Activity Log (WAL) and inspected by ESA under Roadway Lighting permit. Reactive work signed off by contractor and LDC's Contract Administrator (red folder). Planned work is signed by contactor and Contract Administrator (green folder). • Substation lighting, heating, ventilation and batteries checked during monthly inspections • Battery and charger maintenance twice annually Inspection and PM records available		X		
4(4)	A maintenance and inspection program for **overhead primary and secondary distribution** lines to ensure proper operation and safety • Maintenance schedule • Maintenance records • Asset management	Inspection and PM overhead systems: • LDC's inspection and maintenance programs are planned and documented • Line patrols by contractor, – 3-year cycle; deficiencies recorded electronically, summarized and deficiencies corrected under reactive work program • Annual IR inspection by contractor – over 4160 V • Twice annual insulator washing by contractor • Pole testing by contractor – 10-year cycle (11,198 poles tested in 2019) • Fault indicators installed • Tree trimming by contractor – 3 to 5-years • Porcelain insulation replacements with capital work • PCB testing and elimination program • SCADA switch maintenance by contractor – 4-year cycle Inspection and PM records available		X		

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
4(5)	A maintenance, inspection and testing program for **underground primary and secondary distribution** lines to ensure proper operation and safety • Maintenance schedule • Asset management • Maintenance records	Inspection and PM underground systems: • Padmount transformers inspected, results collected electronically and IR inspection by contractor - 3-year cycle (in 2019 inspections 2300 padmount transformers, 960 switches and 3448 submersible transformers) • Submersible transformers inspected by contractor – 3-year cycle • Padmount switchgear – annual visual and IR inspection; dry ice cleaning by contractor as required • Fault indicators installed • Voltage upgrades and underground rebuilds • Vaults checked annually; cleaning as necessary • Cable chamber inspections and IR scan by contractor – 10-year cycle • PCB testing and elimination program • Network systems (electrical and civil) checked annually by contractor and LDC Inspection and PM records available		X		
4(6)	A maintenance, inspection and testing program for **distribution stations** to ensure proper operation and safety • Maintenance schedule • Asset management • Maintenance records	Inspection and PM substations: • Monthly substation inspections and two seasonal, more detailed inspections annually by contractor • IR inspection twice annually • Stations shut down for maintenance by LDC 3-year cycle; relays, switches and circuit-breakers tested during shutdowns (31 maintained in 2019) • Vegetation control by contractor • PCB testing and elimination program • Annual oil sampling and gas analysis by contractor • Network breakers checked – 3-year cycle Inspection and PM records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
6	Distribution equipment approved when approved by **certification or field inspection;** or approved under **Rule of Distributor** • Documented outline of equipment approval process including identification of competent persons, review of test reports • List of approved major equipment up-to-date and reference to standards • Major equipment specifications approved by a competent person or P.Eng. • Approval records • Non-major equipment – Good Utility Practice	The major and non-major equipment approval procedures are documented and flow-charted. New equipment proposals are assessed by the Standards Department. Technical Specifications display P.Eng. signatures and seals, and reference equipment standards as applicable. The approved equipment list is maintained in electronic format.		X		
6(1)(a)	**Specifying** equipment approved by **certification or field evaluation**	Equipment may be approved when certified or approved by field approval.		X		
6(1(a)	**Checking** that supplied ancillary equipment ordered is approved by **certification or field evaluation**.	Warehouse personnel check for inventory codes to confirm approval.		X		
6(1)(b)	**Major distribution equipment** approval under **Rule of the Distributor**: • Documented approval process • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P.Eng., competent person and no undue hazard; or • Supporting record of approvals • Certified tests reviewed by a competent person	Major equipment proposals are reviewed by the Quality and Standards Engineers. Certified test data is reviewed to ensure that a recognized national or international standard is met. Technical Specifications reference equipment specifications, signed and sealed by a P.Eng. Observations – Reviewed: • South Wire 600 V Neutral Supported and Field Lashed XLPE cable – certified to CSA Standard C22.2 No. 129 and certified test report • ABB 4160 V Padmount Transformers, 4160 V, 13.8 kV and 27.6 kV – 120/240 V- certified test report		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	**Re-Use of Major Equipment** • Documented process identifies competent person • Used major equipment approved by competent person or a P.Eng. and no undue hazard • Competent person records no undue hazard • Testing or repair – competent person records no undue hazard • Must fail safely • Otherwise approve as new	The procedure for approving equipment for re-use is documented. Transformers, network protectors and load-break switches may be re-used. Returned equipment is tagged, recorded in an Equipment Re-Use Consent form and dispositioned by a Quality and Standards Engineers. Transformers are sent to the manufacturer for testing, repair or refurbishment before return to inventory. Manufacturers' testing and repair records are provided in detail. Transformers may also be tested ibn-house. Observations – the LDC should revise the equipment re-use approval procedure in accordance with ESA Bulletin DB-01-19 if from time to time equipment is stored at construction sites or on trucks rather than returned to stores.		X		
6(1)(b)	**Non-major Equipment** approval under **Rule of the Distributor** (no undue hazards**)**: • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards. • GUP may include successful use in comparable systems • Supporting documentation • Composite cross-arms	The non-major equipment approval procedure is documented in a manual and flow-charted. Non-major equipment is approved by Quality and Standards Engineers when recognized standards are met or under Good Utility Practice after a 2-year observation period. Observations- reviewed approval records: • Ilsco Copper Ground Clamp – certified by CSA • PLP Oval Eye Nut – type test report displayed P.Eng. seal • Channel Bulk Tap Box – installed for 2-year field trial		X		
6(1)(b)	Equipment is **specified** to meet **Rule of Distributor** standards (Purchase orders, reference to standard by model numbers, engineering specifications, technical data)	Tender documents and requests for proposals for major equipment reference the LDC's Technical Specifications and for non-major equipment, manufacturer's part numbers and stock codes. Purchase orders show Technical Specifications, stock codes, manufacturer's part numbers, equipment descriptions and ratings.		X		

	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	Supplied equipment **meets Rule of Distributor** requirements • Inspection procedure • Dealing with vendor noncompliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. Bar code scanning checks receipts against purchase orders and enters equipment into inventory. Packing slips are stamped and initialed.		X		
6(2)	**Inspection and testing** of equipment supplied based on **Rule of Distributor** requirements (Inspection and testing records)	The distributor has not developed any unique equipment standards and relies on existing industry standards.	X			
6(2)	**Determining inspection and testing methods** for equipment supplied to distributor (Records of analysis, conclusions, manufacturers declaration, witness testing, third party or distributor testing)	The distributor has not developed any unique inspection or testing methods.	X			
6(1)(a) 6(2)	Dealing with **vendor noncompliance** (Field evaluation, rejection, communications)	Nonconforming shipments are quarantined and tagged, vendors are contacted and equipment is returned if necessary.		X		
7	Work Instructions and Plans: • Prepared by a P.Eng.; and/or • Based on standard design drawings and specifications or Sect. 75 OESC • Reviewed and approved by a P.Eng. or ESA • Subdivision developers • External consultants • Temporary power plans • Deviation of approval	Standard design drawings are certified by Standards Engineers. The standards manual displays a certificate of approval and P.Eng. seals for all standards. Personnel access the standards in a Construction Standard E Book. Deviations are made as sketches that may become standards. Sketches display P.Eng. seals. Construction changes are classified as major or minor. Major changes are reviewed with engineering. Deviations from the LDC's overhead and underground standards are approved by a P.Eng. Deviations from the CSA construction standards are reported to ESA in a Certificate of Deviation Approval form signed by a P.Eng. Observations – construction by LDC - drawings reviewed: • Brimley Rd. & Scagway Ave., Scarborough - 27.6 kV overhead and underground commercial/industrial rebuild, construction by THES, signed off by Design Supervisor		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

	Audit Plan	Audit Results	NA	C	NI	NC
		• 1792 Birchmount Ave., Scarborough - 150 kVA, 27.6 kV- 600/347, padmount transformer, signed off by Design and Construction Supervisors • 56 Boywood Lane, Toronto – 27.6 kV underground residential rebuild. Certificate of Deviation by civil engineer for replacement of padmount transformer pad. • Mercer St. – New Temporary 13.8 kV Underground Supply Service for 1500 kVA, 13.8 kV-600/347 V Padmount transformer. Civil and electrical design by LDC signed off by designer and reviewed by Design Supervisor. • College & Beverly St. – 120/208 V Secondary Buss Relocations signed off in Customer Service Order. Design work may also be done by the LDC's design-build contractors using the LDC's design standards. Drawings are reviewed by the LDC's design supervisors and Contract Administrator and display P.Eng. seals. The LDC's contract inspector completes a close out checklist to ensure that all design details have been fulfilled All LDC's design processes are followed. Observations – by design-build contractor reviewed: • Project X14597 Isabella St. Network Transformer Underground Vault Rebuild, civil and electrical re-design by same firm. Drawings display P.Eng. seal. Project Supervisor and design –build P.Eng. sign off on drawings. • Scarborough Golf Club, 27.6 kV and 4160 V Overhead Project and Underground Rebuild. Drawings display contract P.Eng. seal. Drawings reviewed by the LDC's Design Supervisor.				

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
		Substation design may be carried out either by the LDC or a consulting engineer. No substation design or construction was carried out in 2019; substation design was limited to improvements. Observations – reviewed: • Renforth MS - RTU Replacements - changes to the existing circuit diagrams. Drawings showed certificates of approval. Final certificate of inspection on green folder signed off by Technologist and Supervisor. • Brimley Shaddock Station – battery chargers designed by engineering firm and installed by contractor – drawings showed certificates of approval. Certificate of inspection signed off by contractor and LDC supervisor.				
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy construction	Approved drawings are provided except for like-for-like, emergency and legacy construction		X		
7	Ensure third party attachments are: • Authorized; and • No adverse affect on distribution system safety • Engineering plans certified by LDC or third party P.Eng. (no gaps in certification) • Certified third party standards – evidence of certification • Third party generation • Bell Canada plans	Third party attachers are Bell, Rogers, Cogeco, Telus, Enbridge, Mahoney, BIA, U of T, and Toronto Police. On submitting an application, the third party surveys the subject lines and submits construction drawings. The LDC reviews the third party's plans and provides any required make ready work. The LDC tracks third party construction through an electronic tracking system. Third parties are permitted 6 months to complete work and 90 days to vacate mid-span structures. Observations – reviewed plans: • Bell, Bayview-Heathcott Ave. – drawing showed certificate of approval and P.Eng. seal.		X		

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
		• Bell Wireless Antenna, Florence Ave. and Circuit-breaker – the Wireless Permit Application form is not a work instruction for the following reasons.. The form does not the signatures of the designer and the reviewer. The form specifies that Bell Mobility (not a person) is in compliance with OR 22/04 and THES standard SKE-221.				
7	Up-to-date copies of internal specifications and identified standards available to approving P.Eng. – examples: • Electrical Safety Code • CSA Std. O/H Systems • CSA Std. U/G Systems • National Electrical Safety Code • Equipment Standards	Engineering staff has access to all necessary codes and standards including equipment standards.		X		
7	Ensure P.Eng. memberships valid and current	P.Eng. memberships are subsidized maintained current.		X		
7	Identify competencies of identified <u>competent persons</u> and ensure they have the required competencies (training records, position descriptions, resumes)	Sample of qualifications of identified competent staff reviewed and confirmed. The LDC requires College certificate or OACETT membership and previous design experience. Qualifications are listed electronically. CVP training and refresher training is provided every 3 years.		X		
7(1)(a)	Installations based on plans by a P.Eng.: • Reviewed and approved by a P.Eng; or • Reviewed and Approved by ESA	Installations are based on plans reviewed and approved by a P.Eng. Plans by consultants and as-built contractors are reviewed by the LDC's P.Eng.		X		
7(1)(b)	Installations based on standard drawings and specifications assembled by a P. Eng., engineering technologist or competent person (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by engineering technicians and technologists. Plans may be produced by an external P.Eng. or design-build contractor.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications **reviewed and approved** by a P.Eng. or ESA (Signatures, stamps)	Plans, standard designs and specifications are reviewed and approved by a P.Eng. Externally produced plans are reviewed by the LDC.		X		
7(3) 7(5)	Plans, standard design drawings and specifications **certified** by a P.Eng. or ESA (Plans, drawings, specifications, certificates)	Standard design drawings are certified by a P.Eng. Drawings by consulting engineers and design-build contractors follow LDC standards and design procedures.		X		
7(6)	Ensure that standard design drawings, specifications and certificates are: • Recorded and tracked • As-built drawings show changes made in construction • Retained and available to ESA • Retained for minimum of one year after audit • Electronic storage	As-built drawings and Equipment Change Out Forms are scanned and indexed electronically by project number and a list of search names. Reactive work is scanned and indexed by request numbers and a list of other search names. Paper design drawings are destroyed after one year. The GIS is updated. Green work folders containing marked up and as-built drawings, material lists, certificates of inspection are stored in a warehouse.		X		
8(1)	Construction verification program: • Approved by ESA • When approved • Qualified persons list up-to-date • Any changes approved	The CVP is approved by ESA and qualified persons list maintained up-to-date.		X		
8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on: • Approved and certified plans before construction; or • Standard design drawings and specifications • Approved equipment • Safety standards met • Noncompliances noted in record of inspection	Planned work records are assembled in green construction folders. As-built plans are stamped and signed off by construction crew leaders, construction supervisors and engineering. Partial certificates of inspection are signed off on construction drawings and green construction folders. Deviations from standards are documented in an operating procedure. Final certificates of inspection and as-built drawings are signed off by the Crew Leader and Construction Supervisor		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Noncompliance

<table>
<tr><th></th><th>Audit Plan</th><th>Audit Results</th><th>NA</th><th>C</th><th>NI</th><th>NC</th></tr>
<tr><td></td><td></td><td>Observations – reviewed:
• 56 Boywood Lane, Toronto – residential underground rebuild, underground civil construction by contractor, daily inspection reports by the LDC's contract inspector. Contractor and contract inspector sign off on green folder certificate of inspection. One technical deviation – duct moved to avoid obstacle.
• 1792 Birchmount Rd., Scarborough – 27.6 kV, 150 kVA, 600/347 V transformer. Separate civil and electrical drawings. Civil construction by contractor – certificate of inspection on green folder signed off by contractor and the LDC's contract inspector.
• 27.6 kV Bellamy MS Cable Replacement– civil construction, install poles and SCADA switch installed by contractors. Civil signed off by contractor and civil inspector. Electrical signed off by contractor and Supervisor. Red folder created for replacement of faulty cable; RCF sheet signed off.
• Ellesmere Ave., Toronto – two customer specific transformers replaced and voltage converted, 4160 V to 27.6 kV and replaced by 150 kVA padmount transformer by contractor. Crew Leader signed off on electrical drawings and green folder. Supervisor signed off on green folder. Civil contract inspector signed off on civil construction.
• Thorncrest Voltage Conversion, 4160 V to 27.6 kV – overhead by LDC and underground by contractor. New poles by contractor and framed by the LDC. Partial certificates of inspection on construction drawings signed by Crew Leader. Green construction folder signed by Construction Supervisor.
• 120/208 V Overhead Secondary Line Relocation by LDC. Partial certificate of inspection signed by Crew Leader. Final Inspection certificate and as constructed drawing signed by Supervisor.</td><td></td><td></td><td></td><td></td></tr>
</table>

	Audit Plan	Audit Results	NA	C	NI	NC
		• Mercer St. 13.8 kV Temporary Service, 1500 kVA-600 /347 V Transformer. Green civil construction folder signed by Design Supervisor and Contract Administrator. Contract civil inspector sighed own folder. As constructed drawings signed by contractor foreman and Design Supervisor.				
8(1)	Ensure construction inspected and approved before use: • When implemented? • Monitored to cover all construction	Reactive work by LDC personnel and contractors is filed in red work folders, inspected and signed off in Corrective Maintenance Work Orders off by Crew Leaders. Records are maintained in red folders. Final certificates of inspection are signed off on the red folders by LDC and contractor Supervisors. Grid Response reports may be signed off by LDC personnel or contractors.		X		
8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person • Metering • Cutoff and reconnection • Customer service • NC's rectified • No undue hazard statement (how?) • Inspection record and certificate	Metering activities are recorded and signed off in paper Field Orders and Service Orders. Trouble reports are recorded in electronic SRR report forms. Collection activity records are recorded by contractors in yellow Field Orders for service disconnections and white Field Orders for reconnections. A "no undue hazards" statement is signed. Street disconnection reported in work orders by Operations personnel.		X		
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P.Eng.; or • Qualified person identified in inspection verification program; or • ESA	Inspections are normally carried out by qualified staff identified in the CVP. Supply services are signed off by lines personnel, partial and final certificates, as-built stamp on plans and back of green project folder. Certificates of inspection for substation work are signed off on engineering drawings and on the green folders.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Noncompliances rectified Stamped, signed or initialed	Records of inspection provide all required information on what was inspected, identify the inspector and include: • Marked up and as-built drawings • As constructed stamps • Final and partial certificates on plans and project folders • Field Orders • Work Orders and Service Orders • System Response Reports • Street Lighting Work Activity Logs (WAL)		X		
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature or initials • Like-for-like and legacy construction no undue hazards	Certificates of inspection provide all necessary information on what was inspected and identify the inspector. Certificates include: • Certificates of inspection on drawings and project folders • As constructed stamps • Work Orders and Service Orders • Field Orders • System Response Reports • Street Lighting Work Activity Logs (WAL)		X		
8(7)	Certificates and records of inspection available to ESA and: • Who maintains records and certificates • Covers all applicable construction • Signed and dated	Certificates and records of inspection are available in engineering project files or other departments as applicable.		X		
	Competent and qualified persons trained on CV program and process for updating • All identified in CVP	Competent and qualified personnel receive initial CVP training and refresher training every 3 years. Sample of qualifications of competent and qualified staff reviewed and confirmed. Reviewed 2019 CVP training records.		X		
	Third party contractors trained and listed in the CVP	Contractors receive initial CVP training during orientation and refresher CVP training at 3-year intervals by IHSA.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

	Audit Plan	Audit Results	NA	C	NI	NC
	Sampling program developed	Sampling inspections not done except for re-inspections of contractors' work.		X		
	Process for resolving noncompliances and design changes	Noncompliances and field proposals for design changes are managed in accordance with the LDC's operating procedure.		X		
	Third party construction by contractors • Approved plan followed	Civil and electrical construction may be carried out by the LDC's design-build contractors. Contractors' work is inspected and signed off by the LDC's contract inspectors who also provide close out project reports. Contractors and contract inspectors sign off on as-built plans. Partial certificates of inspection by contractors. Project folders signed off by crew leader, construction supervisor and Contract Administrator. Contract inspector signs off in a separate inspection folder. Observations – design-build construction reviewed: • Scarborough Golf Club, 27.6 kV and 4160 V Overhead Project and Underground Rebuild. Contractor Superintendent and Contract Administrator sign off on certificate of inspection and as-built drawings. Contractor Foreman signs off on partial certificates of inspection on plans. Contract Foremen and Contract Supervisor signs off on civil and electrical green folders. • Isabella St. 13.8 kV Network transformer Underground Vault Rebuild. Design-build contractor did both civil and electrical construction. LDC's contract inspector signed off certificates of inspection for civil and electrical work. The inspector submitted daily and final inspection reports. The contract inspector signs off on the green inspection folder. Contractor Supervisor, contract inspector and Contract Administrator sign off on the green electrical and civil folders.		X		

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
	Third party attachment – communications and community antenna systems: • Meets safety requirements • Noncompliances and variations resolved • Inspection by P.Eng. or person qualified	The LDC's inspectors inspect and sign off on third party attachments by means of stamped certificates of inspection on the construction drawings..		X		
	Public safety promotion Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials Safety communications Interest and input from the Board	The distributor promotes public safety in the following ways: • Emergency preparedness planning • Electrical safety information on distributor's web-site including electrical safety videos, information on Ontario One Call, power outages, kids safety, downed power lines, emergency preparedness • ISO45001 and ISO 14001 • Participation with safety professionals – AEUSP, BCRSP, CEA, and CRSP • Dig safe promotion • Radio electrical safety messages • Among Canada's Safest Employers • Billing inserts – electrical safety for home owners • Communications with City council • Electrical safety messages in community newspapers • Electrical safety presentations at community events • Use of social media to provide electrical safety tips and safety alerts including road safety in vicinity of Hydro crews, emergency preparedness, kids safety, weather alerts and safety videos, • Electrical safety messages in public transit and THES vehicles Records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-VECC-16
Appendix B
FILED: March 11, 2024
(28 Pages)

REPORT OF THE ANNUAL AUDIT

AND DECLARATION OF COMPLIANCE

UNDER ONTARIO REGULATION 22/04

SUBMITTED TO THE ELECTRICAL SAFETY AUTHORITY

SUBMITTED BY

Hani Taki, P.Eng.
Director, Standards & Energy Solutions
Toronto Hydro-Electric System
500 Commissioners Street
Toronto, ON M4M 3N7

July 26, 2021

Report Due Date: July 31, 2021

Contents

1.0 SUMMARY - 2020/2021 AUDIT AND DECLARATION OF COMPLIANCE

This report is submitted to the Electrical Safety Authority by Toronto Hydro-Electric System Limited ('Toronto Hydro'), as required under Ontario Regulation 22/04, "Electrical Distribution Safety" issued under the Electricity Act, 1998 (the 'Regulation').

This report covers the period from May 1, 2020 through April 30, 2021.

This report contains the report of the Auditor, and if applicable, an Action Plan to further improve compliance with Ontario Regulation 22/04 and the Declaration of Compliance.

Toronto Hydro hired Acumen Engineered Solutions International Inc. (AESI) to perform the audits for this reporting period.

Les Stoch, an ESA-approved Auditor, performed the audit on behalf of AESI. The audit covered sections 4, 5, 6, 7, and 8 of Ontario Regulation 22/04. Les Stoch also performed an audit in support of the Declaration of Compliance.

2.0 2020/2021 AUDIT RESULTS AND ACTION PLANS

The 2020/2021 Audit was performed by Les Stoch on May 4, 5, 11, and 12, 2021, to verify the extent of Toronto Hydro's compliance with Ontario Regulation 22/04. There were no opportunities for improvement and no non-compliances found during this year's Ontario Regulation 22/04 audit. A copy of the audit report is included in Appendix A.

Even though no opportunities for improvement and non-compliances were found during this year's Ontario Regulation 22/04 audit, Toronto Hydro is still committed to continuous improvement.

3.0 DECLARATION OF COMPLIANCE

Toronto Hydro employed an external auditor (AESI) to assess the Company's compliance to Sections 3, 9, 10, 11, and 12 of the Regulation.

The Declaration is included here.

Toronto Hydro-Electric System Ltd.

Annual Declaration of Compliance

Year 2020/21

Period May 1, 2020 to April 30, 2021

This Declaration of Compliance is submitted by Toronto Hydro-Electric System Limited (THESL) in accordance with Ontario Regulation 22/04, Section 14.

I, Hani Taki, P. Eng., of THESL state that, to the best of my knowledge and belief and having made reasonable inquiries, THESL has complied with the following sections of Ontario Regulation 22/04:

1) Section 3 – Change of ownership;
2) Section 9 – Deviations from required standards;
3) Section 10 – Proximity to distribution lines;
4) Section 11 – Disconnection of unused lines;
5) Section 12 – Reporting of serious electrical incidents.

In Q4 of 2020, it came to Toronto Hydro's attention that 19 primary lines exist in the electrical distribution system in a disconnected but not grounded state as defined by ESA's Guideline for Disconnecting Unused Lines dated October 5, 2005. Toronto Hydro is in process of correcting these deficiencies by grounding or removing the unused lines as applicable. Work has been scheduled with an expected completion by August 2021. All locations are in areas inaccessible to the public (e.g. submersible vaults) and therefore the risk to the public remains low. Toronto Hydro remains committed to public safety and compliance with Ontario Regulation 22/04.

Performance records for 2020/21 show that over 90% requests for locates were completed within 5 days during the audit period.

THESL has used a methodology of review and validation of processes by an independent external auditor, appointed by THESL to assess and verify compliance. Documentation to support this review and validation process is available to the ESA, upon request.

Hani Taki, P. Eng.
Director, Standards & Energy Solutions

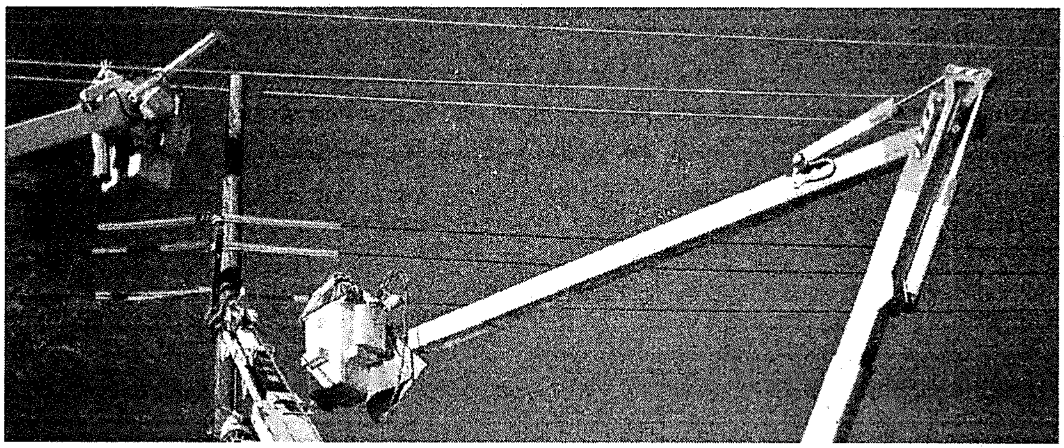
June 30, 2021

4.0 APPENDIX A – REPORT OF THE AUDITOR

The enclosed report was provided by the External Auditor (Sections 4 to 8 of Ontario Regulation 22/04)

REMOTE AUDIT REPORT

Ontario Regulation 22/04 Sections 4 to 8



Client
Toronto Hydro Electric System
date
May 18, 2021

Prepared by
L. Stoch and Associates

AESI

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Remote Audit Report
May 1, 2020 to April 30, 2021
Ontario Regulation 22/04
Sections 4 to 8

Toronto Hydro Electric System,
500 Commissioners Street,
Toronto, ON M4M 3N7

Prepared by: Leslie Stoch **Date:** May 18/21

L. Stoch, P.Eng.

Reviewed by: ______ **Date:** June 1, 2021

Description and Scope of Remote Audit

An Ontario Regulation 22/04 remote audit of Toronto Hydro Electric System was carried out on May 4, 5, 11 and 12, 2021 by Les Stoch of L. Stoch and Associates. The audit closing meeting was held on May 18, 2021.The purpose of the audit was to assess the distributor's extent of compliance with respect to OR 22/04, Sections 4 to 8 to measure whether the distributor has appropriate processes in place to comply with the safety standards set out in the regulation and whether the organization correctly follows its processes. The time period audited was May 1, 2020 to April 30, 2021.

The Toronto Hydro Electric System distributes electricity in the City of Toronto, serving approximately 78,230 residential, commercial and industrial customers. Ownership is by the City of Toronto. The scope of this audit involved processes concerning 143 municipal substations, 27.6 kV volts to 4160 volts, overhead and underground primary and secondary systems. The distributor also contracts out work to qualified consulting engineers and contractors, and such work was included within the scope of the audit. The distributor maintains a staff of approximately 1270 persons. The LDC owns 36 transformer stations that are not within the scope of the audit.

The remote audit plan, shown in the attached audit checklist/report covers the distributor's policies and procedures concerning OR 22/04. Standard auditing methods and procedures were used including interviews with personnel, examining documents and records for a relevant sample of work activities.

Although the emphasis of this audit was directed toward noncompliances and aspects that should be considered for improvement, nothing in this report should be construed as criticism of neither the distributor's staff nor the services provided.

Auditor Qualifications and Experience

Les Stoch is a professional electrical engineer, qualified quality management system auditor and consultant. Since 1993, he provides electrical engineering services under a PEO Certificate of Authorization, and quality management consulting services for organizations working toward ISO 9001 registration. He is a member of Professional Engineers Ontario, the American Society for Quality, the International Association of Electrical Inspectors and the Ontario Electrical League.

His electrical industry experience includes 21 years with Electrical Inspection, Ontario Hydro in electrical engineering and management positions. He is a past member of the Ontario Provincial Advisory Committee, developing recommendations on Ontario's electrical code. Through Dalhousie University, he has provided professional development and training seminars on the electrical code and code-related subjects across Canada.

Auditor Independence

L. Stoch and Associates declares itself to be independent from the Toronto Hydro Electric System and the work to be audited, and free of any potential threats to the auditor's independence including self-interest, self-review, advocacy, familiarity and intimidation.

Executive Overview

A remote audit of the Toronto Hydro Electric System was performed on May 4, 5, 11 and 12, 2020 to verify the organization's extent of compliance with OR 22/04, to identify any gaps and to evaluate the effectiveness of procedures in place for compliance purposes.

The audit covered the organization's existing processes and new ones developed in response to the regulation. The distributor's processes are in good compliance with the regulation.

The Toronto Hydro Electric System is an effective organization, concerned about public safety, and protecting the public from any harm that might result from its operations. The professionalism and dedication of its employees was clearly evident throughout the audit.

Noncompliances

No noncompliances were found:

Opportunities for Improvement

No opportunities for improvement were noted:

General Observations

Several general observations are included:

1. The LDC has converted the collection and storage of many work records to digital format.

2. The LDC employs services of a consulting engineers and a quality management system registrar for inspection of work by contractors and design-build contractors.

3. The previous audit noted that work instructions for cellphone antennae attachments to overhead pole lines did not clearly identify the designers. This oversight was corrected by the third parties, either providing a construction drawing sealed by a P.Eng. or by identifying the designer of the work instruction.

4. The LDC is in process of converting construction drawing files to digital format..

Management Response to ESA

The Electrical Safety Authority will ask the distributor to submit a copy of this audit report. Management will be asked to prepare a response to the audit findings, which may include actions on any identified issues with a timetable to address each issue. An action plan may be requested by ESA along with the audit report.

ESA will respond directly on receiving the distributor's report. An audit review meeting with ESA may take place. The audit findings listed in the report may be reviewed, and any items that require action will be addressed along with the distributor's action plan and any timelines.

If any actions are required, the distributor will be asked to submit a progress report to ESA to provide information on progress in addressing any issues identified in the audit and action plan.

Opening Meeting

See attachment.

Remote Closing Meeting

See attachment

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment **up to 750 volts not part of distribution** to ensure proper operation and safety (ancillary equipment) (Maintenance and inspection schedules, logs, checklists)	Inspection and PM low voltage ancillary equipment: • Municipal street lighting maintained by LDC's contractor, recorded by contractor in Work Activity Log and inspected by ESA under CSS permit. Red folder signed off by contractor and LDC's Contract Administrator. Planned work is signed by contactor and Supervisor, Maintenance and Construction on green folder. Random checks by the LDC's contract inspector signed off in a Daily Activity Report. ESA inspection application taken out for new installations. • Substation lighting, heating, ventilation and batteries checked during monthly inspections • Battery and charger maintenance twice annually Inspection and PM records available		X		
4(4)	A maintenance and inspection program for **overhead primary and secondary distribution** lines to ensure proper operation and safety • Maintenance schedule • Maintenance records • Asset management	Inspection and PM overhead systems: • System patrols by contractor, – 3-year cycle, deficiencies recorded in work orders – digital records • Annual IR inspection by contractor all, primary lines • Twice annual insulator washing by contractor • Pole testing by contractor – 10-year cycle (14,200 poles tested and approximately 200 replaced in 2020) • Fault indicators installed • Tree trimming by contractor – 1 to 5-years as necessary • Porcelain insulation replacements • PCB testing and elimination program • SCADA and manual switch maintenance by contractor – 4-year cycle Inspection and PM records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

	Audit Plan	Audit Results	NA	C	NI	NC
4(5)	A maintenance, inspection and testing program for **underground primary and secondary distribution** lines to ensure proper operation and safety • Maintenance schedule • Asset management • Maintenance records	Inspection and PM underground systems: • Padmount and submersible transformers inspected by contractor including IR inspections - 3-year cycle • Digital inspection records ; deficiencies corrected in work orders • Switchgear - annual visual and ultrasound inspection by contractor and dry ice cleaning as required • Fault indicators installed • Voltage upgrades and underground rebuilds • Vaults checked annually; cleaning as necessary • Cable chamber inspections and IR scan by contractor – 10-year cycle • PCB testing and elimination program • Network systems checked by contractor and LDC – 1 to 5 years • Manholes and cable chambers checked every 10 years Inspection and PM records available		X		
4(6)	A maintenance, inspection and testing program for **distribution stations** to ensure proper operation and safety • Maintenance schedule • Asset management • Maintenance records	Inspection and PM substations: • Monthly substation inspections by contractor; deficiencies recorded in work orders • Digital inspection records • IR inspection twice annually • Stations shut down for maintenance by LDC 4-year cycle; relays, switches and circuit-breakers tested (34 stations maintained in 2020) • Vegetation control by contractor • PCB testing and elimination program • Annual oil sampling and gas analysis by contractor • Network inspections by LDC twice annually • Apartment building vaults, transformers up to 2 mVA checked – 3-year cycle Inspection and PM records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
6	Distribution equipment approved when approved by **certification or field inspection;** or approved under **Rule of Distributor** • Documented outline of equipment approval process including identification of competent persons, review of test reports • List of approved major equipment up-to-date and reference to standards • Major equipment specifications approved by a competent person or P.Eng. • Approval records • Non-major equipment – Good Utility Practice	The LDC's equipment approval procedures are documented and flow-charted, approved by the Director of Standards and Technical Studies. Flow-charts are approved by a P.Eng. New proposals are assessed by the Standards Department. Equipment Technical Specifications display P.Eng. signatures and seals, and reference equipment standards as applicable. An approved equipment list is maintained in digital format.		X		
6(1)(a)	**Specifying** equipment approved by **certification or field evaluation**	Certified or field approved low voltage equipment is approved.		X		
6(1(a)	**Checking** that supplied ancillary equipment ordered is approved by **certification or field evaluation**.	Warehouse personnel check for inventory codes to confirm approval.		X		
6(1)(b)	**Major distribution equipment** approval under **Rule of the Distributor**: • Documented approval process • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P.Eng., competent person and no undue hazard; or • Supporting record of approvals • Certified tests reviewed by a competent person	Quality and Standards Engineers assess new requests for major equipment prior to approval. Certified type test data is reviewed to ensure that a recognized standard is met. Technical Specifications reference equipment standards and specifications, signed and sealed by a P.Eng. Observations – Reviewed: • CES 2400 V - 120/240 V, 50 kVA Submersible Transformer. Certified type test report verified and Technical Specification approved by P.Eng.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	**Re-Use of Major Equipment** • Documented process identifies competent person • Used major equipment approved by competent person or a P.Eng. and no undue hazard • Competent person records no undue hazard • Testing or repair – competent person records no undue hazard • Must fail safely • Otherwise approve as new	The procedure for approving equipment for re-use is documented. Transformers, network protectors, load-break switches and switchgear may be re-used. Operations personnel complete an Equipment Change Record and tag returned equipment. Equipment is sent out for testing or repairs before approval, recorded in an Equipment Re-Use Consent form and approved by Quality and Standards Engineers. Equipment may also be tested in-house or returned to service without return to inventory after assessment by competent persons.		X		
6(1)(b)	**Non-major Equipment** approval under **Rule of the Distributor** (no undue hazards)**:** • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards. • GUP may include successful use in comparable systems • Supporting documentation • Composite cross-arms	The non-major equipment approval procedure is documented and flow-charted. Equipment is approved by Quality and Standards Engineers when recognized standards are met or under Good Utility Practice after a 2-year observation period. Observation – reviewed: • Cicame Energy Aluminum Tinned Termination Lug. Record signed by professional engineer showed that standards ANSI C119-4-2003 and CSA C57-98 had been met. • No new types of equipment were under review a 2-year within the audit period.		X		
6(1)(b)	Equipment is **specified** to meet **Rule of Distributor** standards (Purchase orders, reference to standard by model numbers, engineering specifications, technical data)	Tender documents reference in the LDC's Technical Specifications, stock codes and manufacturer's part numbers. Purchase orders show Technical Specifications, stock codes, manufacturer's part numbers, equipment descriptions and ratings.		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	Supplied equipment **meets Rule of Distributor** requirements • Inspection procedure • Dealing with vendor noncompliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. Bar code scanning checks receipts against purchase orders and enters equipment into inventory. Packing slips are stamped and initialed.		X		
6(2)	**Inspection and testing** of equipment supplied based on **Rule of Distributor** requirements (Inspection and testing records)	The distributor has not developed any unique equipment standards and relies on existing industry standards.	X			
6(2)	**Determining inspection and testing methods** for equipment supplied to distributor (Records of analysis, conclusions, manufacturers declaration, witness testing, third party or distributor testing)	The distributor has not developed any unique inspection or testing methods.	X			
6(1)(a) 6(2)	Dealing with **vendor noncompliance** (Field evaluation, rejection, communications)	Nonconforming shipments are quarantined and tagged, vendors are contacted and equipment is returned by the Buyer if necessary.		X		
7	Work Instructions and Plans: • Prepared by a P.Eng.; and/or • Based on standard design drawings and specifications or Sect. 75 OESC • Reviewed and approved by a P.Eng. or ESA • Subdivision developers • External consultants • Temporary power plans • Deviation of approval	Standard design drawings are certified and sealed by Standards Engineers and the standards manual is certified by the Director of Standards and Technical Studies. Departures from standards are made as sealed sketches that may become standards, provided when specific standards are unavailable. Construction changes are classified as major or minor. Major changes are reviewed with Engineering. Observations – reviewed drawings by the LDC: • Project X18290 Danforth Ave. Ph. B, Overhead and Underground Conversion 4160 V to 13.8 kV, drawings identify the Designer and Design Supervisor. Sealed sketch and Certificate of Deviation provided for reduced clearances around padmount transformer. Job Instruction Sheet provides direction to contractor.		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
		• Project E14140 Maisonette 27.6 kV Underground Subdivision Rebuild Ph. 1 – electrical and civil drawings identify the Designer and Design Supervisor. Transformers, primary and secondary cables and street lighting replaced. Deviations from standards shown in sealed sketches. • New 13.8 kV Underground Service to Customer Substation Office Tower 65 King St. Customer drawings reviewed by LDC. Design work may also be done by the LDC's design-build contractors using the LDC's design standards. Drawings are reviewed by the LDC's Design Supervisors and Contract Administrator and display P.Eng. seals. The LDC's contract inspector completes a close out checklist to ensure that all design details have been fulfilled All LDC's design processes are followed. Observations – design by design-build contractor reviewed: • E17114 Orton Park Merkley Square, 27.6 kV Overhead rebuild showed certificate of inspection and P.Eng. seal, reviewed by the LDC's Contract Administrator. One deviation from drawing - overhead transformer removed, approved by Contract Administrator. Partial certificates of inspection by contractor and final certificate by LDC's contract inspector. • E15485 Comrie Terrace Underground primary and secondary rebuild. Drawings showed certificate of approval and P.Eng. seal. Partial certificates of inspection by contractor and final certificate by LDC's contract inspector. Green contractor folder signed by contractor and inspection folder by contract inspector.				

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
		Substation design may be carried out either by the LDC or by an external engineer. No substation design or construction was carried out in 2020; design limited to equipment replacements. Observations – reviewed: • 27.6 kV Windsor MS - Battery Replacements by external P.Eng.– Work Instruction showed certificate off Approval and P.Eng. seal; installation by contractor. Commissioning by THES personnel. • 4160 V Pharmacy MS - Switchgear replacement by LDC. Work Instruction showed certificate of approval and P.Eng. seal. Relay Settings Specification showed certificate of approval and technician's signature. Drawing showed certificate of approval and P.Eng. seal. • 27.6 kV Pharmacy MS - 5 mVA Transformer Replacement and replacement ground grid design by LDC. Work Instruction showed certificate of approval and P.Eng. seal. Transformer purchased per previously approved specification installed by contractor.				
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy construction	Approved drawings are provided except for like-for-like, emergency and legacy construction		X		
7	Ensure third party attachments are: • Authorized; and • No adverse affect on distribution system safety • Engineering plans certified by LDC or third party P.Eng. (no gaps in certification) • Certified third party standards –	Third party attachers are Bell, Rogers, Cogeco, Beanfield and Zayo On submitting an application, the third party surveys the subject lines and submits construction drawings. The LDC reviews the third party's drawings and provides any required make ready work. The LDC tracks third party construction using an electronic spread sheet.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance 7

	Audit Plan	Audit Results	NA	C	NI	NC
	evidence of certification • Third party generation • Bell Canada plans	Observations – reviewed construction drawings: • Rogers, Avenue Road – drawings show certificate of approval and P.Eng. seal • Cogeco, Kenneth Drive – drawings show certificate of approval and P. Eng. seal. • Bell, 148 Falstaff Ave. cellphone antenna - Wireless Permit Application showed installation instructions supported by construction drawing sealed and certificate of approval by P.Eng. • Rogers, Bunton Road cellphone antenna – Wireless Permit Application identifies competent person who did the design. • The previous audit noted that work instructions for cellphone antennae attachments by third parties neglected to identify the designers of work instructions. This was corrected by identifying the designer or providing a sealed and certified construction drawing.				
7	Up-to-date copies of internal specifications and identified standards available to approving P.Eng. – examples: • Electrical Safety Code • CSA Std. O/H Systems • CSA Std. U/G Systems • National Electrical Safety Code • Equipment Standards	Engineering staff has access to all necessary codes and standards including equipment standards.		X		
7	Ensure P.Eng. memberships valid and current	P.Eng. memberships are subsidized maintained current.		X		
7	Identify competencies of identified <u>competent persons</u> and ensure they have the required competencies (training records, position descriptions, resumes)	Sample of qualifications of identified competent personnel reviewed and confirmed. Qualifications are listed electronically. The LDC requires that engineering personnel be qualified as engineering technologists or technicians.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
7(1)(a)	Installations based on plans by a P.Eng.: • Reviewed and approved by a P.Eng; or • Reviewed and Approved by ESA	Installations are based on construction drawings reviewed and approved by a P.Eng. Drawings by consultants and as-built contractors are reviewed by the LDC's P.Eng.		X		
7(1)(b)	Installations based on standard drawings and specifications assembled by a P. Eng., engineering technologist or competent person (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by engineering technicians and technologists. Drawings may be produced by an external P.Eng. or design-build contractor.		X		
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications **reviewed and approved** by a P.Eng. or ESA (Signatures, stamps)	Construction drawings, standard designs and specifications are reviewed and approved by a P.Eng. Externally produced plans are reviewed by the LDC.		X		
7(3) 7(5)	Plans, standard design drawings and specifications **certified** by a P.Eng. or ESA (Plans, drawings, specifications, certificates)	Standard design drawings are certified by a P.Eng. Drawings by consulting engineers and design-build contractors follow LDC standards and design procedures.		X		
7(6)	Ensure that standard design drawings, specifications and certificates are: • Recorded and tracked • As-built drawings show changes made in construction • Retained and available to ESA • Retained for minimum of one year after audit • Electronic storage	Planned work records are stored in green folders (presently being scanned), indexed by year, Project #, project scope, drawing number and address. Digital records are stored in SAP and the GIS, indexed by location, Date, drawing # and drawing type. Reactive work records are stored in red folders and digital format indexed by Work Request #.		X		
8(1)	Construction verification program: • Approved by ESA • When approved • Qualified persons list up-to-date • Any changes approved	The CVP is approved by ESA and qualified persons list maintained up-to-date. CVP training is provided and refresher training is done on-line every 3 years.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on: • Approved and certified plans before construction; or • Standard design drawings and specifications • Approved equipment • Safety standards met • Noncompliances noted in record of inspection	Operations personnel are fully aware of the LDC's CVP requirements. Construction is inspected; certificates of inspection and as-built drawings are signed off by Crew Leaders and Construction Supervisors. Partial certificates of inspection are signed off on construction drawings and construction folders. Changes are categorizes as minor or major. Major changes are reviewed by Engineering. Partial certificates of inspection are stamped and signed on construction drawings. Observations – reviewed construction by LDC: • 27.6 kV Overhead and Underground Scagway Ave. Rebuild Ph. 1 by LDC. Partial certificates of inspection signed and dated on drawings by Crew Leader and Construction Supervisor. Green construction folder signed off by Crew Leader, Construction Supervisor and Design Supervisor. • 27.6 kV Overhead and Underground Rebuild to bypass underground cable fault. Pole and anchor installations by contractor. Electrical work by the LDC. Contractor's work inspected and signed off by the LDC's contract inspector (records unavailable). Work still underway .		X		
8(1)	Ensure construction inspected and approved before use: • When implemented? • Monitored to cover all construction	Reactive work may be initiated by an electronic SRR or request for maintenance by LDC or contractors and filed in red work folders. Work is completed and signed off in Corrective Maintenance Work Orders crew members. Records are maintained in red folders. Final certificates of inspection are signed off on the red folders by LDC and contractor Supervisors.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person • Metering • Cutoff and reconnection • Customer service • NC's rectified • No undue hazard statement (how?) • Inspection record and certificate	Trouble reports are recorded in System Response Report (SRR) forms signed off electronically by Operations personnel or contractors. Trouble reports may result in reactive work records. Collections records are recorded by contractors in yellow paper Field Orders for service disconnections and white Field Orders for reconnections. All metering work is recorded in Field Orders.		X		
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P.Eng.; or • Qualified person identified in inspection verification program; or • ESA	Inspections are normally carried out by qualified personnel identified in the CVP. Supply services are signed off by lines personnel, partial and final certificates, as-built stamp on drawings and back of green project folder. Certificates of inspection for substation work are signed off on engineering drawings and on the green construction folders.		X		
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Noncompliances rectified Stamped, signed or initialed	Records of inspection provide all required information on what was inspected, identify the inspector and include: • Marked up and as-built drawings • As constructed stamps • Final and partial certificates on plans and project folders • Field Orders • Work Orders and Service Orders • System Response Reports • Work Activity Logs (WAL)		X		
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature or initials	Certificates of inspection provide all necessary information on what was inspected and identify the inspector. Certificates include: • Certificates of inspection on drawings and project folders • As constructed stamps		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
	• Like-for-like and legacy construction no undue hazards	• Work Orders and Service Orders • Field Orders • System Response Reports • Work Activity Logs (WAL)				
8(7)	Certificates and records of inspection available to ESA and: • Who maintains records and certificates • Covers all applicable construction • Signed and dated	Certificates and records of inspection are available in engineering project files or other departments as applicable.		X		
	Competent and qualified persons trained on CV program and process for updating • All identified in CVP	Powerline Technicians are required to attain Red Seal status during their apprenticeship programs. Competent and qualified personnel receive initial CVP training and refresher training on-line every 3 years. Sample of qualifications of competent and qualified staff reviewed and confirmed.		X		
	Third party contractors trained and listed in the CVP	Contractors receive initial CVP training during orientation and refresher CVP training at 3-year intervals by IHSA.		X		
	Sampling program developed	Sampling inspections not done.		X		
	Process for resolving noncompliances and design changes	Noncompliances and field proposals for design changes are managed in accordance with the LDC's operating procedure.		X		
	Third party construction by contractors • Approved plan followed	Civil and electrical construction may be carried out by the LDC's design-build contractors. Contractors' work is inspected and signed off by the LDC's contract inspectors. Contractors and contract inspectors sign off on as-built plans. Partial certificates of inspection by contractors. Project folders signed off by crew leader, construction supervisor and Contract Administrator. Contract inspector signs off in a separate inspection folder.		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Noncompliance

Remote OR 22/04 Audit Checklist

	Audit Plan	Audit Results	NA	C	NI	NC
		Observations – design-build construction reviewed: • 27.6 kV Windsor MS Battery Replacement design by contractor. Certificate of inspection on drawing signed off by contractor and LDC's Construction Supervisor. • 4160 V Pharmacy MS Switchgear Replacement design by contractor. Certificate of inspection on drawing showed certificate of inspection signed by Construction Supervisor and Technician. • 27.6 kV Pharmacy MS 5 mVA Transformer and ground grid replacement by contractor. Construction drawing signed by Contractor Supervisor.				
	Third party attachment – communications and community antenna systems: • Meets safety requirements • Noncompliances and variations resolved • Inspection by P.Eng. or person qualified	Third parties provide a stamped certificate of inspection on the Occupancy Permit. The LDC's inspectors do follow up inspection and sign off on third party attachments on certificates of inspection on the construction drawings.		X		
	Public safety promotion Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials Safety communications Interest and input from the Board	The distributor promotes public safety in the following ways: • Emergency preparedness planning with the City • Certification to Standards – ISO 14001 Environment OHSAS 18001 and ISO 45001 Health and Safety • Electrical safety information on distributor's web-site • Public safety messages by social media including public electrical safety, Dig Safe, Emergency preparedness, Powerline safety, Electrical fires, Electrical safety reporting, ESA safety tips and Children's safety • Development of electrical safety information for children accessible on line • Radio, television and newspaper safety messages • Monthly mail outs to customers including electrical safety messages Records available		X		

All sessions in Eastern Daylight Time (Toronto, GMT-04:00)
Session detail for 'Ontario Regulation 22/04 - Kick off meeting':

Caution: This is a preliminary report. It provides immediate access to session data before the final repoı

	Participant Name	Email	Date	Invited	Registered	Company	Title	Phone Nun
1	Afshin Dary	adaryaei@	########	No				
2	Scott Wilgc	swilgosh@	########	Yes				
3	Mahnoush	mhamzehk	########	No				
4	Leslie Stocl	lstochanda	########	Yes				
5	Rob McKec	rmckeown	########	Yes				
6	Ben Pantin	bpantin@t	########	Yes				
7	Luzmilla YC	lyousif@to	########	Yes				
8	Daniel Sma	dsmart@tc	########	Yes				
9	Akiff Maret	amaredia@	########	Yes				
10	Luzmilla YC	lyousif@to	########	Yes				
11	Martijn Hu	mhuigens@	########	Yes				
12	Umar Rehn	urehman@	########	Yes				
13	Michael M	mmarchan	########	Yes				
14	Liam Ross	lross@toro	########	No				
15	Mike McDc	mmcdonal	########	Yes	N/A			
16	Edmond W	ewong1@t	########	Yes	N/A			
17	Pat Allen	pallen@tor	########	Yes	N/A			
18	Ammar Abı	aabughazal	########	Yes	N/A			
19	Bryan Desc	bdesouza@	########	Yes	N/A			
20	Shaun Pina	spinard@t	########	Yes	N/A			
21	Matthew F	mfisher1@	########	Yes	N/A			
22	Russell BAI	rbaker@to	########	Yes	N/A			
23	Leila Karim	lkarimi@to	########	Yes	N/A			
24	Rajesh Yat	ryata@tor	########	Yes	N/A			
25	Thomas Pa	tpalleschi@	########	No	N/A			
26	Darar Abdi	DAbdissa@	########	No	N/A			
27	Sakaran M	smanivann	########	Yes	N/A			
28	Richard He	rheighway	########	Yes	N/A			
29	Darren Far	dfarrugia@	########	Yes	N/A			
30	Roger Ersil	rersil@torc	########	Yes	N/A			
31	Duncan Ke	dkerr@tor	########	Yes	N/A			
32	Andrew Ml	ametrick@	########	Yes	N/A			
33	Joe Bembri	jbembridge	########	Yes	N/A			
34	Daniel Tan	dtan@toro	########	Yes	N/A			
35	Phil Genow	pgenoway	########	Yes	N/A			
36	Darren Far	dfarrugia@	########	Yes	N/A			
37	Hani Taki	htaki@torc	########	Yes	N/A			
38	Victor Volo	vvolokitin@	########	Yes	N/A			
39	James Wei	jwei@toro	########	Yes	N/A			
40	Mike Sulit	msulit@to	########	Yes	N/A			
41	Chris Hend	chenderso	########	Yes	N/A			
42	Daniel Pizz	DPizzardi@	########	No	N/A			
43	Magda Sul	msulzycki@	########	Yes	N/A			
44	Hasdeep Bl	hbhatia@t	########	Yes	N/A			
45	Claudio Bel	cbellisario@	########	Yes	N/A			
46	Christina Ll	clima@tor	########	Yes	N/A			
47	T.J. Wahid	twahid@to	########	Yes	N/A			
48	Jeremy Pas	jpasma1@	########	Yes	N/A			
49	Michele D'l	mdmello@	########	Yes	N/A			
50	Spyros Nik	snikolaidis	########	Yes	N/A			
51	Claudio Bel	cbellisario@	########	Yes	N/A			
52	John Piroli	jpiroli@tor	########	Yes	N/A			
53	Sunny Pate	SPatel@To	########	No	N/A			
54	Darryl Seal	dseal@tor	########	Yes	N/A			
55	Keith Hunt	khunter@t	########	Yes	N/A			

All sessions in Eastern Daylight Time (Toronto, GMT-04:00)
Session detail for 'Ontario Regulation 22/04 - Closing Meeting':

Participant	Name	Email	Date	Invited	Company
1	Afshin Daryaei	adaryaei@TorontoHydro.com	5/18/2021	No	
2	Matthew Fisher	mfisher1@torontohydro.com	5/18/2021	Yes	
3	Akiff Maredia	amaredia@torontohydro.com	5/18/2021	Yes	
4	James Wei	jwei@torontohydro.com	5/18/2021	Yes	
5	Martijn Huigens	mhuigens@torontohydro.com	5/18/2021	Yes	
6	Pat Allen	pallen@torontohydro.com	5/18/2021	Yes	
7	Safal Bhattarai	sbhattarai@torontohydro.com	5/18/2021	Yes	
8	Shaun Pinard	spinard@torontohydro.com	5/18/2021	Yes	
9	Hani Taki	htaki@torontohydro.com	5/18/2021	Yes	
10	Umar Rehman	urehman@torontohydro.com	5/18/2021	Yes	
11	Rob McKeown	rmckeown@torontohydro.com	5/18/2021	Yes	
12	Mike McDonald	mmcdonald@torontohydro.com	5/18/2021	Yes	
13	Rajesh Yata	ryata@torontohydro.com	5/18/2021	Yes	
14	Christina LIMA	clima@torontohydro.com	5/18/2021	Yes	
15	Leslie Stoch	lstochandassoc@bellnet.ca	5/18/2021	Yes	
16	Leila Karimi	lkarimi@torontohydro.com	5/18/2021	Yes	
17	Ben Pantin	bpantin@torontohydro.com	5/18/2021	Yes	
18	Russell BAKER	rbaker@torontohydro.com	5/18/2021	Yes	
19	Darren Farrugia	dfarrugia@torontohydro.com	5/18/2021	Yes	
20	Leila Karimi	lkarimi@torontohydro.com	5/18/2021	Yes	
21	Victor Volokitin	vvolokitin@torontohydro.com	5/18/2021	Yes	
22	Scott Wilgosh	swilgosh@torontohydro.com	5/18/2021	Yes	
23	Dave Martins	dmartins@torontohydro.com	5/18/2021	Yes	
24	Phil Genoway	pgenoway@torontohydro.com	5/18/2021	Yes	
25	Daniel Smart	dsmart@torontohydro.com	5/18/2021	Yes	
26	Michele D'Mello	mdmello@torontohydro.com	5/18/2021	Yes	
27	Andrew METRICK	ametrick@torontohydro.com	5/18/2021	Yes	
28	Hasdeep Bhatia	hbhatia@torontohydro.com	5/18/2021	Yes	
29	Spyros Nikolaidis	snikolaidis@torontohydro.com	5/18/2021	Yes	
30	Daniel Tan	dtan@torontohydro.com	5/18/2021	Yes	
31	Sammy Elias	selias@torontohydro.com	5/18/2021	Yes	
32	Steve Strugar	sstrugar@torontohydro.com	5/18/2021	Yes	
33	Magda Sulzycki	msulzycki@torontohydro.com	5/18/2021	Yes	
34	Luzmilla YOUSIF	lyousif@torontohydro.com	5/18/2021	Yes	
35	Luzmilla YOUSIF	lyousif@torontohydro.com	5/18/2021	Yes	
36	Steve Strugar	sstrugar@torontohydro.com	5/18/2021	Yes	
37	Emily Majdi	emajdi@torontohydro.com	5/18/2021	Yes	
38	Sushma Narisetty	snariset@torontohydro.com	5/18/2021	Yes	
39	Ammar Abughazaleh	aabughazaleh@torontohydro.com	5/18/2021	Yes	
40	Edmond Wong	ewong1@torontohydro.com	5/18/2021	Yes	
41	Richard Heighway	rheighway@torontohydro.com	5/18/2021	Yes	
42	Chris Henderson	chenderson@torontohydro.com	5/18/2021	Yes	

43	Jeremy Pasma	jpasma1@torontohydro.com	5/18/2021	Yes
44	Bryan Desouza	bdesouza@torontohydro.com	5/18/2021	Yes
45	Jeremy Pasma	jpasma1@torontohydro.com	5/18/2021	Yes
46	Gerry Zervos	gzervos@torontohydro.com	5/18/2021	Yes

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-VECC-16
Appendix C
FILED: March 11, 2024
(32 Pages)

REPORT OF THE ANNUAL AUDIT
AND DECLARATION OF COMPLIANCE
UNDER ONTARIO REGULATION 22/04

SUBMITTED TO THE ELECTRICAL SAFETY AUTHORITY

SUBMITTED BY

Sushma Narisetty, P.Eng.
Director, Standards & Procurement
Toronto Hydro-Electric System
500 Commissioners Street
Toronto, ON M4M 3N7

July 28, 2022

Report Due Date: July 31, 2022

Contents

The information in these materials is based on information currently available to Toronto Hydro Corporation and its affiliates (together hereinafter referred to as "Toronto Hydro"), including information provided by an independent external auditor to verify Toronto Hydro's compliance with Ontario Regulation 22/04. Toronto Hydro (including its directors, officers, employees, agents and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein. Certain information included in these materials constitutes "forward-looking information" within the meaning of applicable securities laws in Canada ("ForwardLooking Information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities, and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "can", "could", "will" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forwardlooking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: risks associated with the execution of the Corporation's capital and maintenance programs necessary to maintain the performance of our distribution assets and make required infrastructure improvements; risks associated with electricity industry regulatory developments and other governmental policy changes, including in respect of conditions created by COVID-19; risks associated with the timing and results of regulatory decisions regarding the Corporation's revenue requirements, cost recovery and rates; risk that the Corporation is not able to arrange sufficient and cost-effective debt financing to fund capital expenditures and other obligations; risk of downgrades to the Corporation's credit rating; the impact of COVID-19 on the Corporation's operating results and financial position in the future; and the ultimate duration and level of impact of COVID-19 on the economy and the Corporation's business.

1.0 SUMMARY - 2021/2022 AUDIT AND DECLARATION OF COMPLIANCE

This report is submitted to the Electrical Safety Authority by Toronto Hydro-Electric System Limited ('Toronto Hydro'), as required under Ontario Regulation 22/04, "Electrical Distribution Safety" was issued under the Electricity Act, 1998 (the 'Regulation').

This report covers May 1, 2021, through April 30, 2022.

This report contains the auditors' report and, if applicable, an action plan to further improve compliance with Ontario Regulation 22/04 and the Declaration of Compliance.

Toronto Hydro hired Acumen Engineered Solutions International Inc. (AESI) to perform the audits for this reporting period.

Ted Olechna, P.Eng. and Daljit Cheema, P.Eng., as ESA-approved Auditors, performed the audit on behalf of AESI. The audit covered sections 4, 5, 6, 7, and 8 of Ontario Regulation 22/04. Daljit Cheema, P.Eng. also performed audit interviews in support of the Declaration of Compliance.

2.0 2021/2022 AUDIT RESULTS AND ACTION PLANS

The 2021/2022 Audit was performed by Ted Olechna, P.Eng. and Daljit Cheema, P.Eng., on May 11, 12, 17, 18, and 20, 2022, to verify the extent of Toronto Hydro's compliance with Ontario Regulation 22/04. No opportunities for improvement and no non-compliances were found during this year's Ontario Regulation 22/04 audit. A copy of the audit report is included in Appendix A.

Even though no opportunities for improvement and non-compliances were found during this year's Ontario Regulation 22/04 audit, Toronto Hydro is still committed to continuous improvement.

3.0 DECLARATION OF COMPLIANCE

Toronto Hydro employed an external auditor (AESI) to assess the Company's compliance with Sections 3, 9, 10, 11, and 12 of the Regulation.

The Declaration is included in this report.

Toronto Hydro-Electric System Limited

Annual Declaration of Compliance

Year 2021/22

Period May 1, 2021 to April 30, 2022

This Declaration of Compliance is submitted by Toronto Hydro-Electric System Limited ("THESL") in accordance with Ontario Regulation 22/04, section 14.

I, Sushma Narisetty of THESL, state that, to the best of my knowledge and belief and having made reasonable inquiries, THESL has complied with the following sections of Ontario Regulation 22/04:

1) Section 3 – Change of ownership;

2) Section 9 – Deviations from required standards;

3) Section 10 – Proximity to distribution lines;

4) Section 11 – Disconnection of unused lines;

5) Section 12 – Reporting of serious electrical incidents.

In last year's declaration, THESL identified 19 primary lines that exist in the distribution system in a disconnected but not grounded state as defined by the Electrical Safety Authority's ("ESA") Guideline for Disconnecting Unused Lines dated October 5, 2005. THESL confirms that it corrected these deficiencies by December 2021 by grounding or removing the unused lines. Where any other unused primary lines in a disconnected but not grounded state are newly identified, Toronto Hydro continues to correct these deficiencies in a timely manner. Such locations are typically in areas inaccessible to the public and therefore any risk to the public remains low. Toronto Hydro remains committed to public safety and compliance with Ontario Regulation 22/04.

Performance records for 2021/22 show that 88% of requests for locates were completed within 5 days during the audit period. The slight decrease from the previous reporting period can be attributed to the industry-wide shortage of locator resources. The recent passage of legislative amendments under Bill 93 (Getting Ontario Connected Act, 2022) is expected to further affect the availability of locators and locate performance. Furthermore, Toronto Hydro is working with the Locate Alliance Consortium to implement the provincial strategy and increase the quantity of locators.

THESL has used a methodology of review and validation of processes by an independent external auditor, appointed by THESL to assess and verify compliance. Documentation to support this review and validation process is available to the ESA, upon request.

Sushma Narisetty

Digitally signed by Sushma Narisetty
DN: cn=Sushma Narisetty, email=snariset@torontohydro.com
Date: 2022.07.27 22:20:24 -04'00'

Sushma Narisetty, P. Eng., M. Eng., MBA

Director, Standards & Procurement

4.0 APPENDIX A – REPORT OF THE AUDITOR

The enclosed report was provided by the External Auditor (Sections 4 to 8 of Ontario Regulation 22/04)

AESI AUDIT REPORT

Ontario Regulation 22/04 Sections 4 to 8

Client

Toronto Hydro-Electric System Ltd.

Date

June 28, 2022

AESI

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PRIVATE AND CONFIDENTIAL

TABLE OF CONTENTS

APPENDIX LISTING

1. Audit Scope & Summary

This audit report was prepared for Toronto Hydro Electric-Hydro Ltd. (THESL), which distributes electricity in the City of Toronto, serving approximately 787,000 residential, commercial, and industrial customers.

The scope of this audit involved processes for one hundred and forty-three 143 municipal substations, 4,16kV to 27.6kV overhead and underground primary and secondary lines. THESL may contract out a portion of its work to qualified contractors; such work was included within the scope of the audit. THESL employs 1169 regular staff.

THESL also owns one hundred and thirty-six (36) transformer stations. The audit of these transformer stations is out of the scope of Ontario Regulation 22/04 (Regulation).

Ted Olechna has a Lead QMS Auditor Certificate (ISO 9001:2015). Ted is registered with the Professional Engineers of Ontario and has over 35 years of experience working in various capacities at Ontario Hydro/Hydro One in Ontario, as well as a Director at the Electrical Safety Authority (ESA). This audit report is prepared by Ted Olechna under the supervision of Daljit Cheema, P. Eng.

The auditor, Daljit Cheema, has a Lead QMS Auditor Certificate (ISO 9001:2008). Daljit is registered with the Professional Engineers of Ontario and has over 30 years of experience working in various capacities at local electrical distribution companies in the Greater Toronto Area. He is an approved auditor by ESA to conduct this audit to the requirements of the Regulation for THESL.

As the COVID-19 pandemic situation continues to evolve, ESA recommended that this year auditors and the distributors discuss the possibility of performing the audits remotely. ESA will accept and recommends remote audits under the circumstances. The recommendation may continue to be applied to each audit year or updated at a future time.

Sushma Narisetty, P. Eng., Director, Standards & Procurement has agreed to a remote audit. Therefore, site visits and walk-throughs of stores and outside equipment storage facilities were not conducted. Audit meetings were conducted via WEBEX. Records, plans, and standard design drawings were made available by screen sharing and emails.

The audit was conducted on May 11th, 12th, & 17th, 18^{th,} and 20^{th,} 2022, including the period required for documentation review. Additional time was required for audit preparation and to prepare this report.

The audit covered the period from May 1, 2021, to April 30, 2022.

The scope of the audit covered the following processes and departments:

- Management Infrastructure/Oversight
- Review of the responses to the issues from previous audits (if applicable)
- Maintenance
- Purchasing
- Engineering/Design
- Field Construction and Inspection
- Health and Safety

- THESL's Construction Verification Program (CVP)

The audit was conducted in accordance with the requirements of Sections 4 – 8 of the Regulation. The audit confirmed the control environment according to the ESA's Auditing Guidelines.

The auditor declares himself to be independent of THESL, the work to be audited and free of any potential threat to the auditors' independence, including self-interest, self-review, advocacy, familiarity, and intimidation.

The processes documented within the Construction Verification Program and associated procedures were followed, personnel interviewed, and records reviewed to confirm the implementation of the program.

Although the emphasis of this audit was directed towards non-compliances and aspects that should be considered for improvements, nothing in this report should be construed as criticism of either THESL's staff, or it services provided.

1.1.Opportunity for Improvements or Non-Compliances

No issues were identified in the audit covered from May 1, 2021, to April 30, 2022.

1.2.Observations

- Preventive Maintenance and inspection programs for equipment up to 750V not part of the distribution system, overhead/underground primary & secondary distribution lines, and substations equipment comply with Appendix 'C' of OEB's Distribution System Code. Excellent Asset Management Programs. P.O. reviewed for inspection programs (infrared inspections, tree trimming, vegetation control, and oil testing for gas analysis). W.O. issued for required corrective actions were signed off by competent persons with "no undue hazard" statement.

- All work programs and inspection data are scanned or electronically inputted into a central database for access. All work records reviewed acknowledged that no undue hazards were present.

- THESL Inspected 2232 locations where 3 phase, 3 wire solidly grounded WYE system (Delta) were suspected. 744 required corrective action, with 458 locations corrected. Leaving 286 to be corrected from this audit period. In total, there are 8080 Delta services identified, with 5530 inspections completed. Plans are continuing to verify/correct the remaining +/- 2500, by the end of 2024.

1.3. Management Response to ESA

ESA will request a copy of this audit report. Management will be asked to prepare a response to the audit findings, including actions or any opportunities for improvement, with a timetable to address each issue. An action plan should be submitted to ESA along with the audit report.

ESA will respond directly to THESL on receiving the report. An audit review meeting with ESA may take place. The audit findings may be reviewed, and any items that may require action addressed along with the THESL's action plan and timelines. If actions are required, THESL may be asked to submit a progress report to ESA

1.4.Auditor Opinion

It is the opinion of this auditor that THESL is in compliance with the requirements of Sections 4, 5, 6, 7, and 8 of the Regulation.

Sushma Narisetty
Digitally signed by Sushma Narisetty
DN: cn=Sushma Narisetty, email=snariset@torontohydro.com
Date: 2022.07.27 22:20:11 -04'00'

Ted Olechna

Client
Sushma Narisetty, P.Eng.
Director, Standards and Procurement
Toronto Hydro-Electric System Ltd.
500 Commissioners Street
Toronto, ON M4M-3N7

Prepared By
Ted Olechna, P.Eng.
AESI Acumen Engineered Solutions Int'l Inc.
5575 North Service Road, Ste 410
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Daljit S. Cheema

Approved by
Daljit Cheema, P.Eng.
AESI Acumen Engineered Solutions Int'l Inc.
5575 North Service Road, Ste 410
Burlington, ON L7L-6M1

Appendix 1

AUDIT RESULTS AND CHECKLIST

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment ***up to 750 volts not part of distribution*** to ensure proper operation and safety (ancillary equipment). (Maintenance and inspection schedules, logs, checklists)	Inspection and PM low voltage ancillary equipment: • Municipal street lighting maintained by THESL contractor and THESL staff, recorded by the contractor in Work Activity Log, and inspected by ESA under CSS permit. • Red Construction Folder (RCF) signed off by contractor and THESL Contract Administrator. Planned work is signed by the contactor and Supervisor. • Maintenance and Construction in Green Construction Folder (GCF). Random checks by THESL contract administrator are signed off in a Daily Activity Report. ESA inspection application is taken out for new installations as needed. • Substation lighting, heating, ventilation, and batteries are checked during monthly inspections. • Battery and charger maintenance every six months. Inspection and PM records available for review		X		
4(4)	A maintenance and inspection program for ***overhead primary and secondary distribution*** lines to ensure proper operation and safety • Maintenance schedule • Maintenance records • Asset management program	Inspection and PM overhead systems: • System patrols by contractor – annually on 3-year cycle, deficiencies recorded in work orders – digital records • Primary lines Infra-Red inspections by a contractor - annually • Insulator washing by the contractor - every 6 months • Pole testing by contractor tested 14,287 poles during audit period – annually on a 10-year cycle • Fault indicators installation • Tree trimming by contractor – 1 to 5-years as required		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Porcelain insulation replacements – ongoing and as required • PCB testing and elimination program - ongoing • SCADA and manual load break switch maintenance– annually on a 4-year cycle Inspection and PM records available for review				
4(5)	A maintenance, inspection and testing program for ***underground primary and secondary distribution lines to ensure*** proper operation and safety • Maintenance schedule • Asset management program • Maintenance records	Inspection and PM underground systems: • Padmount and submersible transformers inspection and Infra-Red scanning by contractor – annually on a 3-year cycle • Digital inspection records; deficiencies corrected in work orders • Switchgear - annual visual and ultrasound inspection by contractor and dry ice cleaning as required • Fault indicators installation • Voltage upgrades and underground rebuilds • Submersible Vault Inspection – annually on a 3-year cycle • Cable chamber inspections and IR scan by contractor – annually on a 10-year cycle • PCB testing and elimination program • Network systems checked by contractor and THESL – 1 to 5 years (Once a year – electrical Inspection and Once a year Civil inspection) • Contact Voltage Mobile Surveying – annually where specified or as reported Inspection and PM records available for review Contact voltage mobile surveying procedure reviewed		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
4(6)	A maintenance, inspection, and testing program ***for distribution stations*** to ensure proper operation and safety • Maintenance schedule • Asset management program • Maintenance records	Inspection and PM substations: • Digital inspection records, deficiencies recorded in work orders • Substation inspections (meeting Regulation requirements) by contractor - monthly • Infra-Red inspection – every six months • Complete stations shutdown maintenance by THESL - annually on a 4-year cycle relays ○ 34 stations were maintained in the audit period • Vegetation control by the contractor – as required • PCB testing and elimination program • Annual oil sampling and gas analysis by the contractor • Network inspections by THESL – every six months • Apartment building vaults, transformers up to 2 MVA checked – annually on a 3-year cycle Inspection and PM records available for review.		X		
6	Distribution equipment approved when approved by ***certification or field inspection or approved under Rule of Distributor*** • Documented outline of equipment approval process including identification of competent persons, review of test reports • List of approved major equipment up-to-date and reference to standards	THESL's equipment approval procedures are documented, flow-charted, and approved by the Director of Standards and Technical Studies. New proposals are assessed by the Standards Department. Equipment Technical Specifications display P.Eng. signatures and seals and reference equipment standards as applicable.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• Major equipment specifications approved by a competent person or P. Eng. • Approval records • Non-major equipment – Good Utility Practice • Receiving inspection • Pre-regulation equipment - GUP	An approved equipment list is maintained in digital format.				
6(1)(a)	***Specifying*** equipment approved by ***certification or field evaluation***	Low voltage equipment is approved by a Certification Body or Field Evaluation Agency		X		
6(1(a)	***Checking*** that supplied ancillary equipment ordered is approved by ***certification or field evaluation.***	Warehouse personnel check for inventory codes to confirm approval.		X		
6(1)(b)	Major distribution equipment approval under Rule of the Distributor: • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P. Eng., competent person, and no undue hazard; or • Documented approval process • Supporting documentation of approvals • Certified tests reviewed by a competent person • Composite poles & wood poles	Quality and Standards Engineers assess new requests for major equipment prior to approval. Certified type test data is reviewed to ensure that a recognized standard is met. Technical Specifications reference equipment standards and specifications, signed and sealed by a P.Eng. Observations – Reviewed: • CES – 50 KVA transformer type test report		X		
6(1)(b)	Re-Use of Major Equipment	The procedure for approving equipment for re-use is documented.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC

	• Documented process identifies competent person
	• Used major equipment approved by competent person or a P. Eng. and no undue hazard.
	• Competent person records no undue hazard
	• Testing or repair – competent person records no undue hazard
	• Must fail safely
		Transformers, network protectors, load-break switches, and switchgear may be re-used.
		Operations personnel complete an Equipment Change Record and tag returned equipment. Equipment is sent out for testing or repairs before approval, recorded in an Equipment Re-Use Consent form and approved by Quality and Standards Engineers. Equipment may also be tested in-house or returned to service without return to inventory after assessment by competent persons.
		
		Observation – reviewed the following W.O:
		• WO – RK4036 CAM Tran Co. Ltd
		  ○ 8kV 100KVA transformer quote and analysis
		  ○ Test report
		  ○ Equipment Reuse consent Form
		  ○ Equipment Return Tag
		• WO – 97-48-056 Network protector
		  ○ Internal
		  ○ Equipment Re-Use Consent Form				

6(1)(b)	Non-major Equipment approval under Rule of the Distributor (no undue hazards**):** • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards	The non-major equipment approval procedure is documented and flow-charted. Equipment is approved by Quality and Standards Engineers when recognized standards are met or under Good Utility Practice after a 2-year observation period. STAMP process Observation – reviewed the following: • Ilsco – part GPL3905BU ○ Grounding clamp		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• GUP may include successful use by a different LDC	○ Approved by certification body • SDA-2551 – Wildlife guards kit 25kV SCADA Mate switch ○ Approved ○ P.Eng report				
6(1)(b)	Equipment is specified to meet Rule of Distributor standards • Tendering • Purchasing alliances • Purchasing approved equipment (Purchase orders, reference to standard by model numbers, engineering specifications, technical data)	Purchase orders show THESL's Technical Specifications, stock codes, manufacturer's part numbers, equipment descriptions and ratings.		X		
6(1)(b)	Supplied equipment meets Rule of Distributor requirements • Inspection procedure • Dealing with vendor non-compliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. Bar code scanning checks receipts against purchase orders and enters equipment into inventory. Packing slips are stamped and initialed.		X		
6(2)	Inspection and testing of equipment supplied based on Rule of Distributor requirements (Inspection and testing records)	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. Bar code scanning checks receipts against purchase orders and enters equipment into inventory. Packing slips are stamped and initialed.		X		
6(2)	Determining inspection and testing methods for equipment supplied to distributor	The distributor has not developed any unique inspection or testing methods	X			

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	(Records of analysis, conclusions, manufacturers declaration, witness testing, third party or distributor testing)					
6(1)(a) 6(2)	Dealing with vendor noncompliance (Field evaluation, rejection, communications)	Nonconforming shipments are quarantined and tagged, vendors are contacted, and equipment is returned by the Buyer if necessary.		X		
7	Plans and work : • Prepared by a P. Eng. • Based on standard design drawings and specifications or Sect. 75 OESC • Reviewed and approved by a • P. Eng. or ESA • Plans by subdivision developers • Plans by external consultants • Temporary power design standard • Deviation from approved standards	THESL's standard design drawings and Standards manual are certified and sealed by Standards Engineers, P.Eng. approved by the Director of Standards and Technical Studies THESL is also a member of USF. USF standard design drawings are certified by a group of professional engineers. Deviations from standards are prepared as a sketch and approved by a P. Eng. This sketch may become a standard, until a specified standard is available. Construction changes are classified as major or minor. Major changes are reviewed with Engineering, and minor changes are discussed in the field. Assembly of work instructions, standard design drawings, and specifications are prepared by a competent person. Plans are prepared by a P. Eng. Approved standard design drawing displays a certificate of approval and seal of P.Eng. Reviewed reactive work, record keeping, and signing off process Reviewed the GCF process Reviewed Construction standards - Ebook Observation - Reviewed the following projects:		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Project P-200209 – McCowan Rd. - changeout of THESL's transformer on customer property. • Project P-210351 – Windsor Station to Copeland TS. tie – Replace and install new cables. Certificate of deviation prepared by P.Eng.- 3 neutral cables in one duct. • Project P-190056 – Holmes Ave. New 3 phase underground service with overhead rebuild. • Project – C-220031 – Cadmus Rd. Residential service upgrade to 400A. overhead to underground conversion • Project P-0211384 - Brimley Seminole MS power transformer replacement All the plans were prepared by P. Eng., display P. Eng. seal and certificate of approval				
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy construction	Approved drawings are provided except for like-for-like, emergency and legacy construction		X		
7	Ensure third party attachments are: • Authorized; and • No adverse effect on distribution system safety • Engineering plans certified by THESL or third-party P. Eng. (no gaps in certification)	Third-party will apply for the permit. Third party will survey the subject lines. Based on line survey third party's P. Eng. will prepare plans and a list of make ready work. THESL makes standards relating to project available to third party for purpose of designing. THESL will review the plans (including pole loading engineering analysis) and required make ready work to ensure there are no conflicts. If approved, THESL will allow the third party to install their asset. THESL tracks third party construction using an electronic spread sheet.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• Certified third party standards – evidence of certification • Third party generation • Bell Canada standards	Third party attachers are Bell, Rogers, Cogeco, Metro Connect, Beanfield and Zayo. Observations: • P-2022-00138 – Beanfield, fiber on Poles, Lawrence Ave East • D2022-00125 Zayo, Underground conduit, Bay Street • P2020-00832 – Zayo, Fiber on poles, Islington Ave, All plans for above projects were prepared by P. Eng. and display certificate of approval and P.Eng. seal All projects designed by third party attachers have been constructed and will be reviewed in section 8. • W2021-00103 – Rogers, small cell installed on pole, Layton Blvd The work instruction was prepared by a competent person				
7	Up-to-date copies of internal specifications and identified standards available to approving P. Eng. – examples: • Ontario Electrical Safety Code, 28 edition, 2021 • CSA Std. O/H Systems, No. 1 - 20 • CSA Std. U/G Systems, No. 7 - 20 • CSA/CSA – 22.3 No. 61931:08 • National Electrical Safety Code C2 -2017	Engineering and design staff have access to all necessary codes and standards including equipment standards.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• Equipment Standards					
7	Ensure P. Eng. memberships valid and current	Engineers are registered with PEO. Memberships are maintained in electronic database. Cost of membership subsidized.		X		
7	Identify competencies of identified competent persons and ensure they have the required competencies (training records, position descriptions, resumes)	Reviewed electronic record database of personnel, and status of training completion. Reviewed employee credential policy. THESL runs the Powerline Technician Program. It is a 5 ½ year program. E-learning is the preferred format, and staff are tracked when complete. Staff notified of upcoming training requirements. Regulation refresher training every 3 years for staff. Electronic records kept on contractors, mandatory safety training and refresher every 3 years, (CVP) Training material reviewed Records of apprentice evaluation reviewed Reviewed THESL's policies and procedures on training.		X		
7(1)(a)	Installations based on plans: • Reviewed and approved by a P. Eng.; or • Reviewed and approved by ESA (Sample of plans)	Installations are reviewed and approved by THESL's Engineers		X		
7(1)(b)	Installations based on standard drawings and specifications assembled by a P. Eng., engineering technologist or competent person (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by engineering technicians and technologists. Drawings are also produced by an external engineers or design-build contractor, based on THESL's standard specifications.		X		
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications reviewed and approved by a P. Eng. or ESA	Plans, standard designs and specifications are reviewed and approved by a P.Eng.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	(Signatures, stamps)					
7(3) 7(5)	Plans, standard design drawings and specifications certified by a P. Eng. or ESA (Plans, drawings, specifications, certificates)	Standard design drawings are certified by a P.Eng.		X		
7(6)	Ensure that standard design drawings, specifications and certificates are: • Recorded and tracked • As-built drawings show changes made in construction • Retained and available to ESA • Retained for minimum of one year after audit • Electronic storage	Planned work records are stored in GCF (presently being scanned from paper) • GCF are indexed by year, Project #, project scope, drawing number and address for ease of locating. • Records are stored in SAP and the GIS, indexed by location, Date, drawing # and drawing type. Reactive work records are stored in RCF • Accessed in digital format and signed electronically. • All changes are recorded electronically and reviewed. • Indexed by location, Date, drawing # and drawing type.		X		
8(1)	Construction verification program: • Approved by ESA • When approved • Qualified persons list up to date • Any changes approved	CVP revision 6 submitted to ESA Qualified persons list maintained up-to-date in database. CVP training is provided and refresher training for internal staff and contractors every 3 years. CVP for external contractors provided by IHSA Reviewed the training matrix for THESL staff and contractors		X		
8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on:	Operations personnel are fully aware of THESL's CVP requirements. Construction is inspected before use. Partial, final inspections and certificates are signed off on construction drawings and construction folders by competent person, or contractor. Certificates of inspection		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• Approved and certified plans before construction; or • Standard design drawings and specifications • Approved equipment • Safety standards met • Non-compliances noted in record of inspection • Collections Department	and as-built drawings are signed off by Crew Leaders and Construction Supervisors. Changes are categorizing as minor or major. Major changes are reviewed by Engineering. Observations: • Milner ave – new service 27.6/16 kV - U/G duct • Northdale Road - New residential service – 400A • William Kitchen Road - New commercial, underground, 600/347 V, 400A service Partial, final record of inspections, and certificates signed by competent person, available for review				
8(1)	Ensure construction inspected and approved before use: • When implemented? • Monitored to cover all construction	Construction is inspected and approved before use.		X		
8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person • Metering • Cutoff and reconnection • Customer Service • NC's rectified • No undue hazard statements • Inspection record and certificate	Trouble reports are recorded in System Response Report (SRR) forms signed off electronically by Operations personnel or contractors. Trouble reports may result in reactive work records. Collections records are recorded by contractors in yellow paper Field Orders for service disconnections and white Field Orders for reconnections. All metering work is recorded in Field Orders. Observation: • # 3414090274 – No meter pulses, Russel St.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		Site left with no undue hazard				
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P. Eng.; or • Qualified person identified in inspection verification program; or • ESA	Inspections are normally carried out by qualified personnel identified in the CVP.		X		
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Non-compliances rectified • Stamped, signed, or initialed • Inspection verification program followed	Records of inspection include: • Marked up and as-built plans • Record of inspection • Approved equipment used • Inspection date • Installation identified • Non-compliances were not noted • Stamped, signed, or initialed by the inspector competent person • Inspection verification program followed.		X		
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature, or initials • Like-for-like and legacy construction no undue hazards	Certificate of inspection provide all necessary information on what was inspected, identify the inspector, date of inspection, stamp and initial of the inspector		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
8(7)	Certificates and records of inspection available to ESA and: • Records and certificates of inspection • Covers all applicable construction • Signed and dated • Progressive inspections and sampling process certificates • Records of inspection for underground work	Certificates and records of inspection are available in engineering project files or other departments as applicable and are available to ESA		X		
	Competent and qualified persons trained on CVP and process for updating	Competent and qualified personnel receive CVP refresher training on-line every 3 years.		X		
	Third party contractors trained and listed in the CVP	Contractors receive initial CVP training during orientation and refresher CVP training at 3-year intervals by IHSA.		X		
	Sampling program developed	Sampling inspections not done.	X			
	Process for resolving non-compliances and design changes	Non-compliances and field proposals for design changes are managed in accordance with THESL's operating procedure.		X		
	Third party construction by contractors • Construction and maintenance on electrical distribution system • Records of inspection and certificates • Approved plan followed	Civil and electrical construction may be carried out by THESL's design-build contractors. Contractors' work is inspected and signed off by THESL's contract inspectors. Contractors and contract inspectors sign off on as-built plans. Partial certificates by contractors. Project folders signed off by crew leader, construction supervisor and Contract Administrator. Observations: • Project P-210036 – Inverness MS, battery and charger replacement • Project P-218000 – Runnymede – Load Relief phase 3		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Project P-210101 – Lakeshore & Fleet, underground cable renewal • Project P-200007 – Warden Ave & Lupin Dr. - Replace numerous PCB Transformers and associated equipment. Certificates of approval signed by THESL's P.Eng and certificates signed by THESL's approved contractor				
	Third party attachment – communications and community antenna systems: • Meets safety requirements • Non-compliances and variations resolved • Inspection by P. Eng. or person qualified in CVP • Certificate and record of inspection • Other joint users	Third parties provide a stamped certificate of inspection on the Occupancy Permit. Reviewed the following projects. • P2022-00138 – Beanfield, fiber on Poles, Lawrence Ave East • D2022-00125 Zayo, Underground conduit, Bay Street • P2020-00832 – Zayo, Fiber on poles, Islington Ave, Plans for the above third party attachers installations were prepared by P.Eng. Plans displayed certificate and P.Eng. seal. THESL's inspectors follow up on completed installations to inspect and sign off on certificates on the construction drawings.		X		
	Public safety promotion Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials	THESL Promotes Public Safety in the following way: • Electrical Safety Tips on THESL's website (Emergency Preparedness Guide in eight different languages). • Emergency Preparedness Plan with the City, IESO, Hospitals, Enbridge, and communication companies.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	Safety communications Interest and input from the Board	• Emergency Preparedness week from May 2 to May 8. • Emergency Resources. • Business Continuity Plan. • Emergency Preparedness for business (Prepare your business). • Electrical Safety Tips (Safety at home, outdoor safety, and Powerline safety). • Contact voltage Safety tips (avoid touching any outdoor electrical structures, including bus shelters and walk around handwells). • Crew safety. • Plan outages related to construction works map. • Life Support Notification and Special Needs Program • Road Safety (tips for drivers & pedestrians and cyclist information). • Dig safety - contact Ontario One Call. • Track THESL vehicles incidents via GPS on vehicles (speeding, braking, seatbelt issues). Vehicles speeding and incidents are reviewed every month. These incidents are reduced substantially. • Inter active map to locate a streetlight and report an issue online. • Use of social media to promote safety (Facebook, twitter, and Instagram). • Crisis management with oil, gas, OPG, transmission and distribution.				

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Reports on THESL's Health and Safety presented to the Board of Directors quarterly. • Four (4) Lost Time Injuries during the audit period. • Canadian Occupational Safety 5-Star Energy and Resource Company Award. • Certifications to Standards – ISO 14001 Environment Management System & ISO 45001 Occupational Health and Safety. • CEA's Centre of Excellence awards for two (2) separate projects: ➢ On-street charging network pilot project, ➢ Bulwer Station Battery Energy Storage System, • Global pandemic communication – keep employees safe. • Contractors' safety and training records uploaded in training matrix. • THESL's employees safety and training records uploaded in training matrix. • Work with the City on Café' TO, to ensure safety of the public and avoid any encroachment of THESL asset. Records available				

Appendix 2

Opening and Closing Meetings Attendees List

Opening Meeting

Opening Meeting held on May 11, 2022, with the following team members present:

Afshin Daryaei	Andrew Otal	Sunny Patel
Isabelle Caron	Anupam Dave	Vinesh Bharat
Rajesh Yata	Bonnie Lam	Ashley Collier
Shaun Pinard	Dan Smart	Jeremy Pasma
Edmond Wong	Daniel Tan	Steve Strugar
Darren Farrugia	Elyas Syed	Gabriel Grauer Michael
Duncan Kerr	Emma Halilovic	Andrew Kha
Maria Kuruvilla	Gaurav Uppal	Phill Genoway
Pat Allen	Paul Lopes	Roger Ersil
Patrick McDonnell	Riad Khan	Russell Baker
Hasdeep Bhatia	Dave Martins	Thomas Marshall
Leila Karimi	Joe Bembridge	Sushma Narisetty
Matrijn Huigens	Long Zhuang	T. J. Wahid
Michael Marchant	Michele D'Mello	Zane Hussain
Mike McDonald	Spyros Nikolaidis	Jay Gorecki
Ted Olechna (AESI)	Daljit Cheema (AESI)	

Closing Meeting

Closing Meeting held on May 20, 2022, with the following team members present:

Afshin Daryaei	Andrew Otal	Sunny Patel
Darer Abdissa	Anupam Dave	Sammy Elias
Rajesh Yata	Bonnie Lam	Ashley Collier
Shaun Pinard	Dan Smart	Seeuma Tepuksorn
Edmond Wong	Daniel Tan	Steve Strugar
Darren Farrugia	Elyas Syed	Gabriel Grauer Michael
Duncan Kerr	Emma Halilovic	Andrew Kha
Maria Kuruvilla	Gaurav Uppal	Phill Genoway
Pat Allen	Paul Lopes	Roger Ersil
Patrick McDonnell	Riad Khan	Bryan De Souza
Fatima Al emara	Dave Martins	Thomas Marshall
James Murchison	Joe Bembridge	Sushma Narisetty
Matrijn Huigens	Long Zhuang	Binendra Shakya
Michael Marchant	Michele D'Mello	Zane Hussain
Mike McDonald	Spyros Nikolaidis	Jay Gorecki
Ted Olechna (AESI)	Daljit Cheema (AESI)	Ryan Doung

Appendix 3

THESL List of Designate Personnel Knowledgeable in Regulation Procedures & Audit Evidence

Section 4 (Maintenance/Inspections of electrical equipment <750V, Overhead & Underground Distribution Lines and Distribution Substations:

Afshin Daryaei, Darren Farrugia, Ricky Khullar, Sakaran Manivannan, Isabella Caron, Binendra Shakya, Michele D'Mello, Imtiaz Ahmed, Ted Olechna, Daljit Cheema

Section 6 (Approval of Electrical Equipment):

Afshin Daryaei, Andrew Kha, Rajesh Yata, Gaurav Uppal, Joe Bembridge, Mike McDonald, Emma Halilovic, Zane Hussain, Ted Olechna, Daljit Cheema

Sections 7 (Approval of Plans, Standard Designs Drawings, and Specifications, Third-Party Attachment for Installation Work):

Afshin Daryaei, Sunny Patel, T. J. Wahid, Akif Maredia, Bryce Dmello, Patrick McDonnell, Emma Halilovic, Zane Hussain, Leila Karimi, Mike Sulit, Gerry Zervos, Ted Olechna, Daljit Cheema,

Section 8 (Inspections, Approval of Constructions, Employee Qualification/Certification, Training & Public Safety Promotions):

Afshin Daryaei, Rich Heigh, Keith Hunter, Maria Kuruvilla, Anupam Dave, Bryce Dmello, Dikshya Gautam, Roger Ersil, Riad Khan, Bonnie Lam, Patrick McDonnell, Jeremey Pasma, Mark Atkinson/James Murchison, Awais Kadam, Ammar Abughazaleh, Luke Susnik, Vinesh Bharat, Ted Olechna, Daljit Cheema

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-VECC-16
Appendix D
FILED: March 11, 2024
(39 Pages)

REPORT OF THE ANNUAL AUDIT AND DECLARATION OF COMPLIANCE UNDER ONTARIO REGULATION 22/04

SUBMITTED TO THE ELECTRICAL SAFETY AUTHORITY

SUBMITTED BY

Sushma Narisetty, P.Eng.
Director, Standards
Toronto Hydro-Electric System
500 Commissioners Street
Toronto, ON M4M 3N7

July 12, 2023

Report Due Date: July 31, 2023

Contents

The information in these materials is based on information currently available to Toronto Hydro Corporation and its affiliates (together hereinafter referred to as "Toronto Hydro"), including information provided by an independent external auditor to verify Toronto Hydro's compliance with Ontario Regulation 22/04. Toronto Hydro (including its directors, officers, employees, agents and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein. Certain information included in these materials constitutes "forward-looking information" within the meaning of applicable securities laws in Canada ("Forward-Looking Information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities, and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "can", "could", "will" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: risks associated with the execution of the Corporation's capital and maintenance programs necessary to maintain the performance of our distribution assets and make required infrastructure improvements; risks associated with electricity industry regulatory developments and other governmental policy changes, including with respect to conditions created by COVID-19; risks associated with the timing and results of regulatory decisions regarding the Corporation's revenue requirements, cost recovery and rates; risk that the Corporation is not able to arrange sufficient and cost-effective debt financing to fund capital expenditures and other obligations; risk of downgrades to the Corporation's credit rating; the impact of COVID-19 on the Corporation's operating results and financial position in the future; and the ultimate duration and level of impact of COVID-19 on the economy and the Corporation's business.

1.0 SUMMARY – 2022/2023 AUDIT AND DECLARATION OF COMPLIANCE

This report is submitted to the Electrical Safety Authority by Toronto Hydro-Electric System Limited ('Toronto Hydro'), as required under Ontario Regulation 22/04, "Electrical Distribution Safety" under the *Electricity Act, 1998* (the 'Regulation').

This report covers May 1, 2022 through April 30, 2023.

This report contains the auditors' report and, if applicable, an action plan to further improve compliance with Ontario Regulation 22/04 and the Declaration of Compliance.

Toronto Hydro hired Acumen Engineered Solutions International Inc. (AESI) to perform the audits for this reporting period.

Ted Olechna, P.Eng., as an ESA-approved Auditor, performed the audit on behalf of AESI. The audit covered sections 4, 5, 6, 7 and 8 of Ontario Regulation 22/04. Ted Olechna, P.Eng., also performed an audit in support of the Declaration of Compliance.

2.0 2022/2023 AUDIT RESULTS AND ACTION PLANS

The 2022/2023 Audit was performed by Ted Olechna, P.Eng., on May 15, 16, 17, 18, 29 and 31, 2023, to verify the extent of Toronto Hydro's compliance with Ontario Regulation 22/04. No opportunities for improvement and no non-compliances were found during this year's Ontario Regulation 22/04 audit. A copy of the audit report is included in Appendix A.

Even though no opportunities for improvement and non-compliances were found during this year's Ontario Regulation 22/04 audit, Toronto Hydro is still committed to continuous improvement.

3.0 DECLARATION OF COMPLIANCE

Toronto Hydro employed an external auditor (AESI) to assess the Company's compliance with Sections 3, 9, 10, 11 and 12 of the Regulation.

The Declaration is included in this report.

Toronto Hydro-Electric System Limited

Annual Declaration of Compliance

Year 2022/2023

Period May 1, 2022 to April 30, 2023.

This Declaration of Compliance is submitted by Toronto Hydro-Electric System Limited ("THESL") in accordance with Ontario Regulation 22/04, section 14.

I, Sushma Narisetty of THESL, state that, to the best of my knowledge and belief and having made reasonable inquiries, THESL has complied with the following sections of Ontario Regulation 22/04:

1) Section 3 – Change of ownership;
2) Section 9 – Deviations from required standards;
3) Section 10 – Proximity to distribution lines;
4) Section 11 – Disconnection of unused lines;
5) Section 12 – Reporting of serious electrical incidents.

THESL identified and corrected 152 primary lines that exist in the distribution system in a disconnected but not grounded state as defined by the Electrical Safety Authority's ("ESA") Guideline for Disconnecting Unused Lines dated October 5, 2005. THESL confirms that it corrected these deficiencies by December 2022 by grounding or removing the unused lines. Where any other unused primary lines in a disconnected but not grounded state are newly identified, Toronto Hydro continues to correct these deficiencies in a timely manner. Such locations are typically in areas inaccessible to the public and therefore any risk to the public remains low. Toronto Hydro remains committed to public safety and compliance with Ontario Regulation 22/04.

Performance records for 2022/2023 show that 84 per cent of requests for locates were completed within five days during the audit period of May 2022 to April 2023. The recent passage of legislative amendments under Bill 93 (*Getting Ontario Connected Act, 2022*) has affected the availability of locators and locate performance. Toronto Hydro has worked with the Locate Alliance Consortium to implement the provincial strategy and increased its quantity of locators. Monthly locates performance has since improved to above 90 per cent in April 2023.

THESL has used a methodology of review and validation of processes by an independent external auditor, appointed by THESL to assess and verify compliance. Documentation to support this review and validation process is available to the ESA, upon request.

Sushma Narisetty

Digitally signed by Sushma Narisetty
DN: cn=Sushma Narisetty, email=snariset@torontohydro.com
Date: 2023.07.11 16:18:42 -04'00'

Sushma Narisetty, P. Eng., M. Eng., MBA
Director, Standards
July 12, 2023

4.0 APPENDIX A – REPORT OF THE AUDITOR

The enclosed report was provided by the External Auditor (Sections 4 to 8 of Ontario Regulation 22/04).

ACUMEN

Acumen Audit Report

Ontario Regulation 22/04 Sections 4 to 8

Prepared For:

Toronto Hydro-Electric System Ltd.

AESI Acumen Engineered Solutions International Inc.

5575 North Service Road, Suite 401
Burlington, Ontario, L7L 6M1
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ACUMEN

Audit Report

Ontario Regulation 22/04 Sections 4 to 8

Toronto Hydro-Electric System Ltd.

Prepared By: Ted Olechna, P. Eng. Date: 2023-06-23

Table of Contents

1. Audit Scope & Summary

This audit report was prepared for Toronto Hydro-Electric System Ltd. (THESL), which distributes electricity in the City of Toronto, serving approximately 790,000 residential, commercial, and industrial customers.

The scope of this audit involved processes concerning one hundred and thirty-one (131) municipal substations, 4.16kV to 27.6kV overhead and underground primary and secondary lines. THESL contracts out a portion of its work to qualified contractors; such work was included within the scope of the audit. THESL employs 1245 regular staff.

There are 36 active transformer stations in Toronto, and THESL owns five (5) transformer stations, the other thirty-one (31) are owned and operated by Hydro One. The audit of these 36 transformer stations is not in the scope of O.Reg 22/04 (Regulation).

The auditor, Ted Olechna, has a Lead QMS Auditor Certificate (ISO 9001:2015). Ted is registered with the Professional Engineers of Ontario and has over 35 years of experience working in various capacities at Ontario Hydro/Hydro One in Ontario, as well as a Director at ESA. He is an approved auditor by the Electrical Safety Authority (ESA) to conduct this audit to Ontario Regulation 22/04 (Regulation) requirements for THESL.

ESA has identified that this year audits could be performed in-person or remotely. Sushma Narisetty, P. Eng., (Director, Standards) has agreed to a hybrid model. Therefore, walk-through of stores and equipment storage facilities was conducted. Audit meetings were conducted in person and via WebEx. Records, plans, and standard design drawings were made available at the meetings, by screen sharing and emails.

The audit was conducted on May 15th, 16th, 17th, 18th, 29^{th,} and 31st, 2023, including the period required for documentation review. Additional time was required for audit preparation and to prepare this report.

The audit covered the period from May 1st, 2022, to April 30th, 2023.

The scope of the audit covered the following processes and departments:

- Management Infrastructure/Oversight
- Review of the responses to the issues from previous audits (if applicable)
- Maintenance
- Purchasing
- Engineering/Design
- Field Construction and Inspection

- Health and Safety
- THESL's Construction Verification Program (CVP)

The audit was conducted in accordance with the requirements of Sections 4–8 of the Regulation. The audit conformed the control environment according to the ESA's Auditing Guidelines.

The auditor declares himself to be independent of THESL, the work to be audited and free of any potential threat to the auditors' independence including self-interest, self-review, advocacy, familiarity, and intimidation.

The processes documented within the Construction Verification Program and associated procedures were followed, personnel interviewed, and records reviewed to confirm the implementation of the program.

Although the emphasis of this audit was directed towards non-compliances and aspects that should be considered for improvements, nothing in this report should be construed as criticism of either THESL's staff or it services provided.

1.1 Opening Meeting

The opening meeting was held on May 15, 2023.

1.2 Closing Meeting

The closing meeting was held on May 31, 2023.

1.3 Participants

Individuals who have participated in the opening and closing meetings and other audit sections:

Rowena Chan	Elizabeth Chelmecki	Sean Fletcher
Sushma Narisetty	Ferdinand Strang	Maria Kuruvilla
Awais Kadam	Fiona Noshirwani	Mike Sulit
Andrew Sandrasagra	Gabriel Michael	Pat Allen

Anupam Dave	Hardik Gadani	Patrick McDonnell
Aaron Wilhelm	Hasdeep Bhatia	Phil Genoway
Andrew Kha	James Murchison	Pranav Kalra
Andrew Otal	James Wei	Rajesh Yata
Bass Khadori	Ian Fernandez	Rich Heighway
Binendra Shakya	Jen Grado	Richard Lowns
Brandon Dale	Jeremy Pasma	Rob Beaverstock
Bryan De Souza	Joe Bembridge	Roger Ersil
Claudio Bellisario	Keith Hunter	Roshan Reginold
Dan Smart	Kitty Leung	Ryan Duong
Daniel McNeil	Leila Karimi	Sean Fletcher
Daniel Tan	Martijn Huigens	Seeuma Tepuksorn
Darren Farrugia	Michele D'Mello	Sergio Higuera
Dave Martins	Michael Merchant	Stephen Sheehy
Diana Tonus	Mike McDonald	Steve Strugar
Duncan Kerr	Numaya Iqbal	Sunny Patel
Edmond Wong	Sakaran Manivannan	T.J Wahid
		Zane Hussain

1.4 Observations

- Preventive Maintenance and inspection programs for equipment up to 750V not part of the distribution system, overhead/underground primary & secondary distribution lines, and municipal substations conducted as per Appendix 'C' of Ontario Energy Board's Distribution System Code. Excellent Asset Management Programs. P.O. are issued to execute some inspection programs by contractors (e.g. tree trimming, vegetation control, oil testing for gas analysis and IR scans)

- PCB testing is ongoing to identify and remove PCB liquid equipment
  - Despite global supply chain challenges and their impact on the supply of transformers, THESL continues to make headway in removing PCB filled equipment

- THESL has a documented equipment re-use program.

- Refresher CVP training for engineering, managers, and line staff is done every 3 years, and starting in 2024 it will be every 2 years.

- All work programs and inspection data are scanned or electronically inputted into a central database for access.
    - GCF – planned work
    - RCF – Reactive work
    - All work records reviewed acknowledged that no undue hazards were present.

- 3 phase, 3 wire solidly grounded WYE system (Delta)
    - THESL inspected 1715 locations where 3 phase, 3 wire solidly grounded WYE system (Delta) were suspected.
    - 616 locations were corrected which included locations identified from prior year.
    - In total, there are 8080 Delta services identified, with 7245 inspections completed. Plans are continuing to verify the remaining +/- 835, by the end of 2025.
    - The original plan was to complete the inspection and necessary corrective work by 2024. A request was sent to and accepted by the ESA in July 2022 to revise the proposed completion date to 2025.

- One-Call is back on track to respond to Locates requests within the prescribed timelines.

- Third-party attachers (communication) are being managed and responded to in a timely manner.

- Planned work is delayed due to equipment availability. However, THESL's robust enterprise program management and procurement mitigated any risks to the system.

- THESL's public safety information to the public has a wide reach and covers seasonal as well as specific safety topics

- Review of CSA C22.3 No. 11 (Maintenance of electric and communication utility equipment and systems) is in the process of determining what if anything needs to be changed in relation to THESL's maintenance program.

1.5 Opportunities for Improvement & Non-compliances

No opportunities for improvement & non-compliances were recorded

1.6 Management Response to ESA

ESA will request a copy of this audit report. Management will be asked to prepare a response to the audit findings, including actions or any opportunities for improvement with a timetable to address each issue. Action plan should be submitted to ESA along with the audit report.

ESA will respond directly to THESL on receiving the report. An audit review meeting with ESA may take place. The audit findings may be reviewed, and any item that may require action, addressed along with THESL's action plan and timelines. If actions are required, THESL may be asked to submit a progress report to ESA.

1.7 Auditor Opinion

It is the opinion of this auditor that THESL is in compliance with the requirements of ONTARIO REGULATION 22/04 Section 4, 5, 6, 7, and 8.

Sushma Narisetty

Digitally signed by Sushma Narisetty
DN: cn=Sushma Narisetty, email=snariset@torontohydro.com
Date: 2023.07.11 16:18:54 -04'00'

Ted Olechna

Client

Sushma Narisetty, P. Eng.
Director, Standards
Toronto Hydro-Electric System Ltd.
500 Commissioners Street

Auditor

Ted Olechna, P. Eng.
AESI Acumen Engineered Solutions Int'l Inc
5575 North Service Road, Suite 401
Burlington, Ontario, L7L 6M1

Toronto, ON M4M 3N7

2. Appendix 1

Audit Results and Checklist

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment ***up to 750 volts not part of distribution*** to ensure proper operation and safety (ancillary equipment). (Maintenance and inspection schedules, logs, checklists)	Inspection and PM low voltage ancillary equipment: • Municipal street lighting maintained by THESL's contractor and THESL's staff, recorded by the contractor in Work Activity Log, and inspected by ESA under CSS permit as needed. • Red Construction Folder (RCF) signed off by contractor and THESL's Contract Administrator. Planned work is signed by the contractor and Supervisor. • Maintenance and Construction in Green Construction Folder (GCF). Random checks by THESL's contract administrator are signed off in a Daily Activity Report. ESA inspection application is taken out for new installations as needed. • Substation lighting, heating, ventilation, and batteries are checked during monthly inspections. • Battery and charger maintenance every six months. Inspection and PM records available for review		X		
4(4)	A maintenance and inspection program for ***overhead primary and secondary distribution*** lines to ensure proper operation and safety • Maintenance schedule • Maintenance records • Asset management program	Inspection and PM overhead systems: • System patrols by a contractor – annually on a 3-year cycle, deficiencies recorded in work orders – digital records • Primary lines Infra-Red inspections by a contractor - annually • Insulator washing by the contractor - every 6 months • Pole testing by contractor tested 12,157 poles during the audit period – annually on a 10-year cycle • Fault indicators installation ongoing • Tree trimming by a contractor – 1 to 5 years as required		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC

		• Porcelain insulation replacements – ongoing and as required
		• PCB testing and elimination program – by 2025
		  ○ Lack of replacement TX
		• SCADA and manual load break switch maintenance– annually on a 4-year cycle
		• 3-phase, 3-wire connected solidly to WYE at customers' service entrances (Delta).
		  ○ 1715 were Inspected during the audit period.
		  ○ Remaining 835 to be completed by 2025
		
		Inspection, PM records, and maintenance summary spreadsheet available for review				

4(5)	A maintenance, inspection, and testing program for ***underground primary and secondary distribution lines to ensure*** proper operation and safety
	
	• Maintenance Schedule
	• Asset management program
	• Maintenance records
		Inspection and PM underground systems:
		
		• Padmount and submersible transformers inspection and Infra-Red scanning by a contractor – annually on a 3-year cycle
		• Digital inspection records; deficiencies corrected in work orders
		• Switchgear - annual visual and ultrasound inspection by a contractor and dry ice cleaning as required
		• Fault indicators installation
		• Voltage upgrades and underground rebuilds
		• Submersible Vault Inspection – annually on a 3-year cycle
		• Cable chamber inspections and IR scan by a contractor – annually on a 10-year cycle
		• PCB testing and elimination program
		  ○ ~2500 Tx to be completed by 2025
		  ○ Shortage of replacement transformers
				X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Network systems checked by contractor and THESL – 1 to 5 years (Once a year – electrical Inspection and Once a year Civil inspection) • Contact voltage mobile surveying procedure reviewed Inspection, PM records, and maintenance summary spreadsheet available for review				
4(6)	A maintenance, inspection, and testing program ***for distribution stations*** to ensure proper operation and safety • Maintenance schedule • Asset management program • Maintenance records	Inspection and PM substations: • Digital inspection records, deficiencies recorded in work orders • Substation inspections (meeting Regulation requirements) by a contractor - monthly • Infra-Red inspection – every six months • Complete stations shutdown maintenance by THESL - annually on a 4-year cycle relays • Cable chambers infra-red every 10 years • Vegetation control by the contractor – as required • PCB testing and elimination program to be completed by 2025 • Annual oil sampling and gas analysis by the contractor • Network inspections by THESL – every six months • Apartment building vaults, transformers up to 2 MVA checked – annually on a 3-year cycle Inspection, PM records, and maintenance summary spreadsheet available for review		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
6	Distribution equipment approved when approved by ***certification or field inspection or approved under Rule of Distributor*** • Documented outline of equipment approval process including identification of competent persons, review of test reports • List of approved major equipment up-to-date and reference to standards • Major equipment specifications approved by a competent person or P. Eng. • Approval records • Non-major equipment – Good Utility Practice • Receiving inspection • Pre-regulation equipment - GUP	THESL's equipment approval procedures are documented, flow-charted, reviewed by Product Change Committee (PCC), and approved by the Director of Standards. Observation: • product change process map • PCC (Product Change Committee) New proposals are assessed by the Standards Department. Equipment Technical Specifications display P.Eng. signatures and seals and reference equipment standards as applicable. Approximate 11,000 parts in stock An approved equipment list is maintained in digital format. Observation: Stock numbers match the equipment in the stock room		X		
6(1)(a)	***Specifying*** equipment approved by ***certification or field evaluation***	Low-voltage equipment is approved by a Certification Body or Field Evaluation Agency		X		
6(1(a)	***Checking*** that supplied ancillary equipment ordered is approved by ***certification or field evaluation.***	Warehouse personnel check for inventory codes to confirm approval.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
6(1)(b)	Major distribution equipment approval under Rule of the Distributor: • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P. Eng., competent person, and no undue hazard; or • Documented approval process • Supporting documentation of approvals • Certified tests reviewed by a competent person • Composite poles & wood poles	Quality and Standards Engineers assess new requests for major equipment prior to approval. Certified type test data is reviewed to ensure that a recognized standard is met. Technical Specifications reference equipment standards and specifications, signed and sealed by a P.Eng. Observations – Reviewed: Poles with new Preservative Hitachi transformers • Test report from manufacturers • Part number assigned and stocked		X		
6(1)(b)	Re-Use of Major Equipment • Documented process identifies the competent person • Used major equipment approved by a competent person or a P. Eng. and no undue hazard. • Competent person records no undue hazard • Testing or repair – competent person records no undue hazard • Must fail safely	The procedure for approving equipment for re-use is documented. Transformers, network protectors, load-break switches, and switchgear may be re-used. No Poles or Minor equipment re-used Operations personnel complete an Equipment Change Record and tag returned equipment. Equipment is sent out for testing or repairs before approval, recorded in an Equipment Re-Use Consent form, and approved by Quality and Standards Engineers. TX may be reused in the field, by a competent person. If returned to stock, shall go through re-use program 120 Pole mounted TX were reused		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		Observation – reviewed the following W.O: • WO – WR1095 CAM Tran Co. Ltd ○ 27kV 50KVA transformer quote and analysis ○ Test report ○ Equipment Reuse Consent Form ○ Equipment Return Tag • PO – 4500058506 2015 switch refurbished ○ External Company				
6(1)(b)	Non-major Equipment approval under the Rule of the Distributor (no undue hazards**):** • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards • GUP may include successful use by a different LDC	The non-major equipment approval procedure is documented and flow-charted. Equipment is approved by Quality and Standards Engineers when recognized standards are met or under Good Utility Practice after a 2-year observation period. STAMP process		X		
6(1)(b)	Equipment is specified to meet the Rule of Distributor standards • Tendering • Purchasing alliances • Purchasing approved equipment	Purchase orders show THESL's Technical Specifications, stock codes, manufacturer's part numbers, equipment descriptions and ratings.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	(Purchase orders, reference to standard by model numbers, engineering specifications, technical data)					
6(1)(b)	Supplied equipment meets the Rule of Distributor requirements • Inspection procedure • Dealing with vendor non-compliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. Bar code scanning checks receipts against purchase orders and enters equipment into inventory. Packing slips are stamped and initialed. Non-compliant equipment is returned to the vendor		X		
6(2)	Inspection and testing of equipment supplied based on the Rule of Distributor requirements (Inspection and testing records)	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. Bar code scanning checks receipts against purchase orders and enters equipment into inventory. Packing slips are stamped and initialed.		X		
6(2)	Determining inspection and testing methods for equipment supplied to the distributor (Records of analysis, conclusions, manufacturers declaration, witness testing, third party or distributor testing)	The distributor has not developed any unique inspection or testing methods	X			
6(1)(a) 6(2)	Dealing with vendor non-compliance (Field evaluation, rejection, communications)	Nonconforming shipments are quarantined and tagged, vendors are contacted, and equipment is returned by the Buyer if necessary.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
7	Approval of Plans, Drawings and Specifications for Installation Work Plans and work : • Prepared by a P. Eng. • Based on standard design drawings and specifications or Sect. 75 OESC • Reviewed and approved by a • P. Eng. or ESA • Plans by subdivision developers • Plans by external consultants • Temporary power design standard • Deviation from approved standards	THESL's standard design drawings and Standards manual are certified and sealed by Standards Engineers, P.Eng. approved by the Director of Standards THESL is a member of USF. USF standard design drawings are certified by a group of professional engineers. Deviations from standards are prepared as a sketch and approved by a P. Eng. This sketch may become a standard until a specified standard is available. Construction changes are classified as major or minor. Major changes are reviewed with Engineering, and minor changes are discussed in the field. Observation - • Std # 31-1600 deviation approval for cable entry window in existing cable chamber Assembly of work instructions, standard design drawings, and specifications are prepared by a competent person. Plans are prepared by a P. Eng. Approved standard design drawing displays a certificate of approval and seal of P.Eng.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		Reviewed the GCF process Reviewed Construction standards - Ebook Observation - Reviewed the following projects: • Watercliffe MS – Battery replacement • P-190049 – Dundas street west, 8kV to 27.6 kV, Entera , SNC Lavalin Auditor • P-190193 – Gerrard Street – Station-to-station cable replacement, Ainsworth • P-220040 – The Westway, 4kV O/H replacement, Valard. All the plans were prepared by P. Eng., display P. Eng. seal and certificate of approval Reviewed in Section 8,				
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy Construction	Approved drawings are provided except for like-for-like, emergency and legacy construction Observations: new standards developed • New Pole and preservative • Std # 03-2500 Overwater span		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Std # 03-2110 Minimum clearance for in-pole spans				
7	Ensure third-party attachments are Authorized • No adverse effect on distribution system safety • Engineering plans certified by THESL or third-party P. Eng. (no gaps in certification) • Certified third-party standards – evidence of certification • Third-party generation •	Third-party will apply for the permit. The third-party will survey the subject lines. Based on the line survey third parties' P. Eng. will prepare plans and a list of make-ready work. THESL makes standards relating to projects available to third parties for the purpose of designing. THESL will review the plans (including pole loading engineering analysis) and required make-ready work to ensure there are no conflicts. If approved, THESL will allow the third party to install their asset. THESL tracks third-party construction using an electronic spreadsheet. After completion, THESL goes out and inspects, Third-party attachers are Bell, Rogers, Cogeco, Metro Connect, Beanfield, Telus, and Zayo. Observations: • P-2022-00725 – Rogers - Bainhart Cres, Conditional granted and followed by Final granted • TP23-0401 Rogers, Decline, no equipment on switch pole • P2022-00027 – Bell, • D2023-00078 – Zayo, U/G Ducts • W2023-00080 – Rogers, Cell Modem on Pole All plans for the above projects were prepared by P. Eng. and display certificate of approval and P.Eng. seal		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		Reviewed in section 8. The work instruction was prepared by a competent person				
7	Up-to-date copies of internal specifications and identified standards available to approving P. Eng. – examples: • Ontario Electrical Safety Code, 28 edition, 2021 • CSA Std. O/H Systems, No. 1 - 20 • CSA Std. U/G Systems, No. 7 - 20 • CSA/CSA – 22.3 No. 61931:08 • National Electrical Safety Code C2 -2017 • Equipment Standards	Engineering and design staff have access to all necessary codes and standards including equipment standards. CSA C22.3 No. 11 • Review started on internal processes to determine what if any changes are needed.		X		
7	Ensure P. Eng. memberships are valid and current	Engineers are registered with PEO.		X		
7	Identify competencies of identified <u>competent persons</u> and ensure they have the required competencies (training records, position descriptions, resumes)	Reviewed electronic record database of personnel, and status of training completion. Reviewed employee credential policy. THESL runs the Powerline Technician Program. It is a 5 ½ year program. E-learning is the preferred format, and staff are tracked when complete. Staff notified of upcoming training requirements. Regulation refresher training every 3 years for staff. Electronic records kept on contractors, mandatory safety training and refresher every 3 years, (CVP) Records of apprentice evaluation reviewed		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		Reviewed THESL's policies and procedures on training.				
7(1)(a)	Installations based on plans: • Reviewed and approved by a P. Eng.; or • Reviewed and approved by ESA (Sample of plans)	Installations are reviewed and approved by THESL's Engineers		X		
7(1)(b)	Installations based on standard drawings and specifications assembled by a P. Eng., engineering technologist or competent person (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by engineering technicians and technologists. Drawings are also produced by an external engineer or design-build contractor, based on THESL's standard specifications.		X		
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications reviewed and approved by <u>a P. Eng. or ESA</u> (Signatures, stamps)	Plans, standard designs, and specifications are reviewed and approved by a P.Eng.		X		
7(3) 7(5)	Plans, standard design drawings, and specifications certified by a <u>P. Eng. or ESA</u> (Plans, drawings, specifications, certificates)	Standard design drawings are certified by a P.Eng.		X		
7(6)	Ensure that standard design drawings, specifications, and certificates are: • Recorded and tracked	Planned work records are stored in GCF (presently being scanned from paper) • GCFs are indexed by year, Project #, project scope, drawing number, and address for ease of locating.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• As-built drawings show changes made in construction • Retained and available to ESA • Retained for a minimum of one year after the audit • Electronic storage	• Records are stored in SAP and the GIS, indexed by location, Date, drawing #, and drawing type. Reactive work records are stored in RCF • Accessed in digital format and signed electronically. • All changes are recorded electronically and reviewed. • Indexed by location, Date, drawing # and drawing type.				
8(1)	Construction verification program: • Approved by ESA • When approved • Qualified persons list up to date • Any changes approved	CVP revision 7 submitted to ESA (January 2023) Currently, CVP refresher training for internal staff and contractors every 3 years, starting in 2024 it will be every 2 years. The qualified persons' list is maintained up-to-date in the database. CVP for external contractors provided by IHSA Reviewed the training matrix for THESL's staff and contractors		X		
8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on: • Approved and certified plans before construction; or • Standard design drawings and specifications • Approved equipment • Safety standards met • Non-compliances noted in the record of inspection • Collections Department	Operations personnel are fully aware of THESL's CVP requirements. Construction is inspected before use. Partial, final inspections and certificates are signed off on construction drawings and construction folders by a competent person, or contractor. Certificates of inspection and as-built drawings are signed off by Crew Leaders and Construction Supervisors. Changes are categorized as minor or major. Major changes are reviewed by Engineering.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		Observations: • Watercliffe MS – Battery replacement • P-190049 – Dundas street west, 8kV to 27.6 kV, Entera, SNC Lavalin Auditor • P-190193 – Gerrard street – Station to station cable replacement, Ainsworth • P-220040 – The Westway, 4kV O/H replacement, Valard. Partial, final record of inspections, and certificates signed by a competent person, available for review				
8(1)	Ensure construction is inspected and approved before use: • When implemented? • Monitored to cover all construction	Construction is inspected and approved before use.		X		

8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by a competent person
	
	• Metering
	• Cutoff and reconnection
	• Customer Service
	• NC's rectified
	• No undue hazard statements
	• Inspection record and certificate
		Trouble reports are recorded in System Response Report (SRR) forms signed off electronically by Operations personnel or contractors. Trouble reports may result in reactive work records. Collections records are recorded by contractors in yellow paper Field Orders for service disconnections and white Field Orders for reconnections. All metering work is recorded in Field Orders.
		• 3 levels of priority
		  ○ P1 -15 days
		  ○ P2 – 15-60 days
				X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		○ P3 – 60-180 days Reactive folder - RCF Observation: • 2199 Queen St East 120/240 meter • Canon-Jackson Dr. Bulk meter • 2787 Eglinton Ave E – Itron Meter • 630 Vesta Dr – TX rusted • M-220227 – Steeles and Pharmacy – cable fault Site left with no undue hazard statement				
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P. Eng.; or • Qualified person identified in inspection verification program; or • ESA	Inspections are carried out by qualified personnel identified in the CVP.		X		
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Non-compliances rectified	Records of inspection include: • Marked-up and as-built plans • Record of inspection • Approved equipment used • Inspection date • Installation identified • Non-compliances were not noted		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	• Stamped, signed, or initialed • Inspection verification program followed	• Stamped, signed, or initialed by the inspector (competent person) • Inspection verification program followed.				
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature, or initials • Like-for-like and legacy construction no undue hazards	The certificate of inspection provides all necessary information on what was inspected, and identifies the inspector, date of inspection, stamp, and initial of the inspector. Shows partial certificate and final certificate		X		
8(7)	Certificates and records of inspection available to ESA and: • Records and certificates of inspection • Covers all applicable construction • Signed and dated • Progressive inspections and sampling process certificates • Records of inspection for underground work	Certificates and records of inspection are available in engineering project files or other departments as applicable and are available to ESA		X		
	Competent and qualified persons trained on CVP and process for updating	Competent and qualified personnel receive CVP refresher training online every 3 years.		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
	Third party contractors trained and listed in the CVP	Contractors receive initial CVP training during orientation and refresher CVP training at 3-year intervals by IHSA.		X		
	Sampling program developed	Sampling inspections not done.	X			
	Process for resolving non-compliances and design changes	Non-compliances and field proposals for design changes are managed in accordance with THESL's operating procedure.		X		
8(7)	Third-party construction by contractors • Construction and maintenance of electrical distribution system • Records of inspection and certificates • Approved plan followed	• Civil and electrical construction may be carried out by THESL's design-build contractors. • Contractors' work is inspected and signed off by THESL's contract inspectors. • Contractors and contract inspectors sign off on as-built plans. Partial certificates by contractors. • Project folders signed off by crew leader, construction supervisor and Contract Administrator. Observations: • Humber Bay MS, 27.6kV / 4.16kV replacement. • 541 Commissioners , 13.8kV/600V service upgrade Certificates of approval signed by THESL's P.Eng and certificates signed by THESL's approved contractor .No Undue hazard		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
8(7)	Third party attachment – communications and community antenna systems: • Meets safety requirements • Non-compliances and variations resolved • Inspection by P. Eng. or person qualified in CVP • Certificate and record of inspection • Other joint users	Third parties provide a stamped certificate of inspection on the Occupancy Permit. Observations: • P-2022-00725 – Rogers - Bainhart Cres, Conditional granted and followed by Final granted • P2022-00027 – Bell, • D2023-00078 – Zayo, U/G Ducts • W2023-00080 – Rogers, Cell Modem on Pole Plans for the above third-party attachers installations were prepared by P.Eng. Plans displayed certificate and P.Eng. seal. THESL's inspectors follow up on completed installations to inspect and sign off on certificates on the construction drawings.		X		
	Public safety promotion & Training Safety communications	THESL Promotes Public Safety in the following way: • Electrical Safety Tips on THESL's website (Emergency Preparedness Guide in ten different languages). • Emergency Preparedness Plan with the City, IESO, Hospitals, Enbridge, and communication companies. • Emergency Preparedness week from May 1 to May 7. • Emergency Resources. • Business Continuity Plan. • Emergency Preparedness for business (Prepare your business).		X		

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Electrical Safety Tips (Safety at home, outdoor safety, and Powerline safety). • Powerline safety campaign May 16 to May 22 • Contact voltage Safety tips (avoid touching any outdoor electrical structures, including bus shelters and walk around handwells, including Pet safety) • Crew safety. • Plan outages related to the construction work map. • Life Support Notification and Special Needs Program • Road Safety (tips for drivers & pedestrians and cyclist information). • Dig safety - contact Ontario One Call. ○ Issued a joint news release with Alectra, Elexicon Energy, Hydro One, and Hydro Ottawa • Interactive map to locate a streetlight and report an issue online. • Use of social media to promote safety (Facebook, Twitter, and Instagram). • Crisis management with oil, gas, OPG, transmission, and distribution. • CafeTO – worked with City –safety around electrical infrastructure • Electrical Vehicle – Charging safety. • Bright ideas publication • eCONNECT (email) Records available				

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
1	Public safety promotion & Training Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials Interest and input from the Board	• Reports on THESL's Health and Safety presented to the Board of Directors quarterly. • Two (2) Lost Time Injuries during the audit period. • Seven (7) recordable injuries • Certifications to Standards – ISO 14001 Environment Management System & ISO 45001 Occupational Health and Safety. • THESL tracks vehicle incidents via GPS on vehicles (speeding, braking, seatbelt issues). Vehicle speeding and incidents are reviewed every month. These incidents are reduced substantially. • Training • Contractors' safety and training records uploaded in the training matrix. • THESL's employees safety and training records are uploaded in the training matrix. • Each employee has a different training track depending on the job performed • Training records are assessed every 2 months and managers are notified if staff is not in compliance • ESA Reg training will be every 2 years starting 2024, as per 2023 CVP • Line staff in classroom training				

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
		• Admin staff e-learning Awards Best 50 Corporate Citizens in Canada (2022)- Corporate Knights • 9th overall • 1st among Electricity Transmission and Distribution in Canada 5-Star Energy and Resource Company (2022) • Canadian Occupational Safety				

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-17

References: **Exhibit 1B, Tab 3, Schedule 1, Page 8**
Exhibit 2B, Section C, Pages 5-6

Preamble:

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

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

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

1. Increased number of outages affecting a small number of customers.
2. Improved resolution of outage duration, down to the second.
3. Increased number of scheduled outages reported; and
4. Changes in outage structuring: currently, outages are structured manually, typically broken down by feeder. OUA will streamline this process by automatically generating outage reports based on restoration actions recorded in NMS.

QUESTION (A):

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

RESPONSE (A):

As described in the evidence referenced, implementation of OUA results in more accurate reporting of scheduled outages in the future, which introduces significant uncertainty with future forecasts. The other factors discussed in the preamble above are expected to have relatively minor impacts on SAIDI/SAIFI.

QUESTION (B):

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

RESPONSE (B):

The implementation of Oracle Utility Analytics solution will not interfere with an effective evaluation of programs. The additional unplanned outages reported through the platform impact a very small number of customers, which in turn has a marginal impact on overall system reliability metrics.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC -18

Reference: Exhibit 2B, Section C, Page. 15

QUESTION (A):

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

RESPONSE (A):

Please refer to Exhibit 1B, Tab 3, Schedule 1, pages 8-9 for an explanation of the rationale behind the PIM measures. Independent of the PIM measure, Toronto Hydro measures and monitors "all-in" reliability metrics (including scheduled outages) on an ongoing basis, and has an established process for managing the impacts of scheduled outages on customers.

Toronto Hydro agrees that customers are concerned about outages irrespective of their reason. However, Toronto Hydro disagrees with the implication that scheduled outages are equivalent to unplanned outages when it comes to the customer experience. Toronto Hydro offers the following high-level comparison of scheduled and unplanned outages for further consideration.

Aspect	Scheduled Outages	Unplanned Outages
Predictability	Planned in advance, scheduled time known	Occur without warning, unpredictable
Duration and Impact	Typically short, a few hours, and contained	Variable, can last from minutes to days, and can impact thousands of customers

Aspect	Scheduled Outages	Unplanned Outages
Communication	Toronto Hydro communicates schedule in advance	No advance notice
Impact on Customers	Predictable, can plan around outage	Disruptive, can cause inconvenience and losses
Mitigation Options	Customers can prepare, use backup power	Limited options, may not be able to mitigate
Frequency	Regular, scheduled based on capital and maintenance plan	Occasional, based on system reliability
Preventive Purpose	Preventive maintenance, system improvements	Reactionary response to failures

QUESTION (B):

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

RESPONSE (B):

Toronto Hydro routinely measures and monitors "all-in" SAIFI and SAIDI, "defective equipment" SAIFI and SAIDI, volume/impact of outages by specific cause codes and availability/accuracy of outage Estimated Time of Restoration. Large outages are reviewed on a weekly basis for lessons learned and improvement opportunities.

QUESTION (C):

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

RESPONSE (C):

Crews undertaking scheduled outages are expected to plan outages in a manner that minimizes customer impact (duration and scope) to the extent possible. Outage requests are submitted to the Control Centre with start and finish times. Controllers will review the request and create a switching order to enable work to be completed safely while minimizing the number of customers impacts.

Field Managers oversee the work and monitor progress to ensure that work is completed within the allotted time.

Additionally, in the planning phase, proactive engagement with customers is facilitated through community relations teams (as detailed in Exhibit 4, Tab 2, Schedule 18). Notices regarding power interruptions, along with advance information about the expected outage duration, are provided.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC-19

Reference: Exhibit 2B, Section E7

QUESTION (A):

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

RESPONSE (A):

Outcomes and measures impacted by the System Enhancements program are documented in Exhibit 2B, Section E7.1, Table 2. This table describes measures these investments will contribute to, such as reliability objectives (e.g. SAIFI, SAIDI), the reduction of impact due to Major Event Days ("MEDs"), maintaining Toronto Hydro's Total Recorded Injury Frequency ("TRIF") and safety objectives, and contributing to Toronto Hydro's financial objectives by reducing operational costs associated with patrolling feeders for fault finding purposes.

In addition to these outcomes and measures, the System Enhancements program contributes to metrics under Toronto Hydro's Performance Incentive Mechanism ("PIM"). The program contributes to the Grid Automation Readiness PIM by increasing the number of Horseshoe feeders with a minimum of 2.5 switches from 78 percent in 2022 to 90 percent by 2029. This prepares the system for achieving its distribution automation goals. To support the Outage Duration and Outage Frequency PIMs, investments in this program allow for the installation of SCADA switches, tie-points and reclosers on targeted feeders to improve outage response capabilities, reduce fault isolation times and reduce the number of customers impacted by an outage event on a feeder. Overall, this program will form the system configuration required for Toronto Hydro's self-healing grid in 2030 and beyond, contributing to long-term reliability benefits. Please refer to Exhibit 1B, Tab 3, Schedule 1 for more details on the Outage Duration, Outage Frequency, and Grid Automation Readiness PIMs.

QUESTION (B):

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

RESPONSE (B):

The System Enhancements program is a critical part of Toronto Hydro's Grid Modernization Strategy. Investments in this program are generally prioritized on the basis of need, including, for example, which parts of the system are experiencing poor reliability and would benefit most from additional flexibility. As discussed in Section E2, page 19, there are evolving systemic challenges such as climate change and electrification which Toronto Hydro expects will have the dual effect of (i) increasing reliability risk on the system due to greater system utilization and more frequent impacts from adverse weather, and (ii) increasing the average customer's sensitivity to outages due to an increased reliance on electricity as their primary source of energy. With these broader trends in mind, the utility concluded that the 2025-2029 investment period would demand a greater emphasis on modernizing the grid, leveraging technologies such as SCADA-operated switches and reclosers, distribution sensors, and advanced distribution management tools to not only continue to improve the customer's overall reliability experience within the rate period, but establish the foundation for full-scale grid automation in 2030 and beyond, ensuring the utility is prepared to deliver stable reliability performance as climate change and electrification pressures accelerate. Furthermore, as noted in Section D4.2, these and other Grid Modernization investments will provide crucial reinforcement to the utility's "least regrets" investment approach as it deals with uncertainty with respect to future rates of growth and electrification. System Enhancements will provide Toronto Hydro with the capability to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to optimize the capacity and performance of a more heavily utilized grid.

A 20 percent reduction in the System Enhancements program would not only undermine this long-term strategy, but would also delay the realization of customer benefits within the 2025-2029 rate period from the deployment of cost-effective solutions on the worst performing and most vulnerable parts of the grid (e.g. reclosers). If faced with a reduction of this magnitude, Toronto Hydro would be forced to reassess the viability of the various segments that constitute this program and defer a large portion of the plan.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 2B-VECC -20

Reference: Exhibit 2B, Section E8

QUESTION (A) :

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

RESPONSE (A):

As noted in Table 1 of Exhibit 2B, Section E8.1, the cost for the relocation project is $72.0 million.

There will be no land acquisition costs as the proposed EDC will be constructed in an existing Toronto Hydro facility.

The project will be completed over the 2025-2029 period. Design will begin in 2025, with tendering and procurement beginning in 2026. Construction will take place until the end of 2028, with site finishing, commissioning, and testing taking place in 2029. The proposed EDC would be fully functional in 2029.

A breakdown of the project budget is shown below:

Cost Category	Budget ($ millions)
Building Shell	0.4
Building Interiors	1.4
Mechanical	5.1

Electrical	15.0
Site Work	0.5
Ancillary (Demolition + Temporary Work)	0.4
IT	26.2
General Requirements, CM Fees	7.1
Soft Costs (Permitting, Consulting, Project Management etc.)	7.8
Inflation Escalation	8.1
Total	72.0

QUESTION (B):

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

RESPONSE (B):

There will be no proceeds of sale for EDC 1 since it is located in an existing building that continues to operate for other business purposes. Decommissioning EDC 1 is not possible until the proposed EDC is constructed and comprehensively tested and commissioned. Since the estimated timing for this phase is the second half of 2029, Toronto Hydro estimates that the decommissioning of EDC 1 will potentially take place in the 2030-2034 rate period. Toronto Hydro estimates that decommissioning costs will be immaterial, but is unable to estimate any future proceeds at this time.

QUESTION (C):

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

RESPONSE (C):

No. Please also refer to Toronto Hydro's response to 2B-Staff-259, subpart (b).