ENERGY PROBE INTERROGATORY #1

Reference:
A-03-01 p.3

Interrogatory:
Preamble:
Hydro One's plan will address critical safety and environmental risks in its system. It will improve reliability performance by 13% to return to the top quartile performance that Hydro One's transmission customers are expecting

Please provide a listing of all the Exhibits and page numbers that contain evidence on HOTX System Reliability

Response:
Below please find a list of references to the evidence where Hydro One mentions transmission system reliability.

EXHIBIT A
Exhibit A, Tab 3, Schedule 1, Page 35 of 50
Exhibit A-3-1, Attachment 1, Page 10, 19-20
Exhibit A-6-6, Attachment 1, Page 5, 9
Exhibit A-6-6, Attachment 2, Page 3, 6, 7, 12
Exhibit A-7-2, Attachment 3, Page 5-15

EXHIBIT B
Exhibit B-1-1, TSP Section 1.1, Page 46
Exhibit B-1-1, TSP Section 1.2, Attachment 3, page 41
Exhibit B-1-1, TSP Section 1.2, Attachment 4, pages 53-57
Exhibit B-1-1, TSP Section 1.2, Attachment 11, page 30
Exhibit B-1-1, Section 1.3, Attachment 1, page 46, 131, 135, 141
Exhibit B-1-1, TSP Section 1.4, Attachment 13, Page 52
Exhibit B-1-1, TSP Section 1.5, Page 5 of 55
Exhibit B-1-1, TSP Section 1.5, Page 24 to 37
Exhibit B-1-1, TSP Section 1.5, Attachment 1, Page 9-12
Exhibit B, TSP Section 2.2, Page 4 of 117

Witness: Bruno Jesus

Exhibit B-1-1, TSP Section 3.3, Page 1 of 20
Exhibit B-1-1, TSP Section 3.3, Page 4 of 20
Exhibit B, TSP Section 2.2, pages 1-117
Exhibit B-1-1, TSP Section 3.2, Page 25 of 28
Exhibit B-1-1, TSP Section 3.3, Page 1 of 20

EXHIBIT D

Exhibit D, Tab 2, Schedule 1, pages 5-8, 10

EXHIBIT F

Exhibit F-4-1, Attachment 4, Page 1 of 1

ENERGY PROBE INTERROGATORY #2

Reference:
A-03-01 p.26 and 27 Tables 5 and 6, p.47 and 48 Tables 14 and 15

Interrogatory:
Preamble:
Approximately 3.8% of the average increase to transmission rates in 2020 resulting from the Application is driven by a reduction to Hydro One's load forecast relative the forecast currently underpinning rates, which is driven by factors that are beyond Hydro One's control as explained in Section 6.3 of this Exhibit.

a) Please provide a summary table that shows for 2011-2018, the forecast and actual load.

b) Please provide a quantitative discussion of the main drivers for historic reductions in load.

c) For 2019-2024 please discuss in quantitative terms the basis for the 3.8% forecast load reduction and reasons for changes in Ontario demand.

d) With regard to the Load Forecast Model, please provide details of latest sectoral forecast and graphical presentation(s), plus showing errors/trends, plus a discussion on statistical error associated with the model.

e) Discuss if there are structural changes or other factors resulting in forecast error.

<u>Response:</u>

a) Please see Table 1 below for the requested information.

Table 1
<u>Ontario Load for the Years 2011-2018</u>
(12-Month Average Peak in MW)

Year	Load
2011	20,547
2012	20,348
2013	20,360
2014	20,554
2015	20,203
2016	20,274
2017	19,696
2018	19,657

b) Over the period 2011 to 2018, inclusive, the total reduction in load is 890 MW. The main drivers for this historic reduction in load are: conservation and demand management (“CDM”), embedded generation, and economy. The reduction by each of these factors is as follows (based on the information contained in Table 2 below):

- CDM: -961 MW = - (1,924 MW – 963 MW)
- Embedded Generation (EG): -276 MW = - (578 MW – 302 MW)
- Economy: 347 MW = -890 MW – (-961 MW – 276 MW)

Table 2

History and Forecast of Ontario Load and Factors Affecting It
(12-Month Average Peak)

Year	Gross Load (1)	CDM (2)	Embedded Generation (3)	Net Load (4)
2011	21,812	963	302	20,547
2018	22,159	1,924	578	19,657

Notes.
(1) Gross load is defined as net load plus the load impact of CDM and Embedded Generation and are also presented in Exhibit E-03-01, Table 3 on Page 20, for 2018.
(2) Excludes Intustrial Conservation Initiative (ICI). Source: Exhibit E-03-01, Table 2 on Page 8.
(3) Figures are as used in load forecast and are also presented in Exhibit E-03-01, Table 3, on Page 20, for the years 2018.
(4) Load after deducting the CDM and Embedded Generation. Source: Exhibit E-03-01, Page 47.

c) The forecast period in this Application is 2019-2022 (rather than 2019-2024). The 3.8% reflects decrease in the 2019 load forecast in the present Application compared to the approved load forecast in EB-2016-0160 for the year 2018. The decrease is largely due to extension of ICI eligibility to a greater number of customers and reduction in the threshold for participation in ICI in 2017, as detailed in Exhibit E, Tab 3, Schedule 1, page 21.

In reference to Table 3 of Exhibit E, Tab 3, Schedule 1, the main drivers for reduction in load forecast are as follow.

From 2018 to 2019, the total reduction in load is 62 MW. The reduction is due to the following factors:

- CDM: -328 MW = - (2,252 MW – 1,924 MW)
- Embedded Generation (EG): -24 MW = -(602 MW – 578 MW)
- Economy: 291 MW = -62 MW – (-328 MW – 24 MW). 291 MW can also be derived as the difference between the load forecast prior to CDM and EG in the same Table (i.e., 22,450 MW – 22,159 MW = 291 MW).

From 2019 to 2020, the total reduction in load is 9 MW. The reduction is due to the following factors:

- CDM: -301 MW = - (2,552 MW – 2,252 MW)
- Embedded Generation (EG): -101 MW = -(703 MW – 602 MW)
- Economy: 391 MW = -9 MW – (-301 MW – 101 MW). 391 MW can also be derived as the difference between the load forecast prior to CDM and EG in the same Table (i.e., 22,842 MW – 22,450 MW = 391 MW).

From 2020 to 2021, the total reduction in load is 135 MW. The reduction is due to the following factors:

- CDM: -102 MW = - (2,654 MW – 2,552 MW)
- Embedded Generation (EG): -3 MW = -(706 MW – 703 MW)
- Economy: -30 MW = -135 MW – (-102 MW – 3 MW). -30 MW can also be derived as the difference between the load forecast prior to CDM and EG in the same Table (i.e., 22,812 MW – 22,842 MW = -30 MW).

From 2021 to 2022, the total reduction in load is 147 MW. The reduction is due to the following factors:

- CDM: -121 MW = - (2,775 MW – 2,654 MW)
- Embedded Generation (EG): -13 MW = -(719 MW – 706 MW)
- Economy: -13 MW = -147 MW – (-121 MW – 13 MW). -13 MW can also be derived as the difference between the load forecast prior to CDM and EG in the same Table (i.e., 22,799 MW – 22,812 MW = -13 MW).

d) Please see below for the requested information.

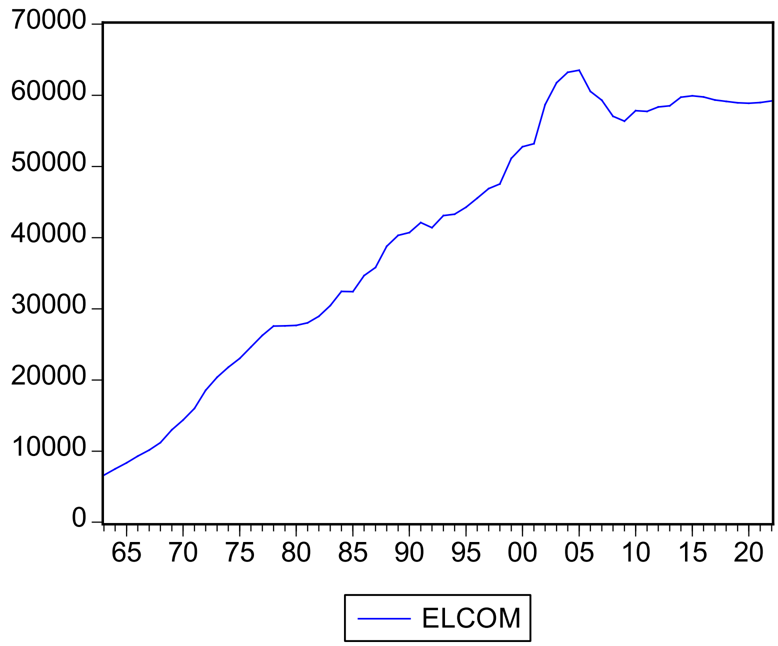
Table 3

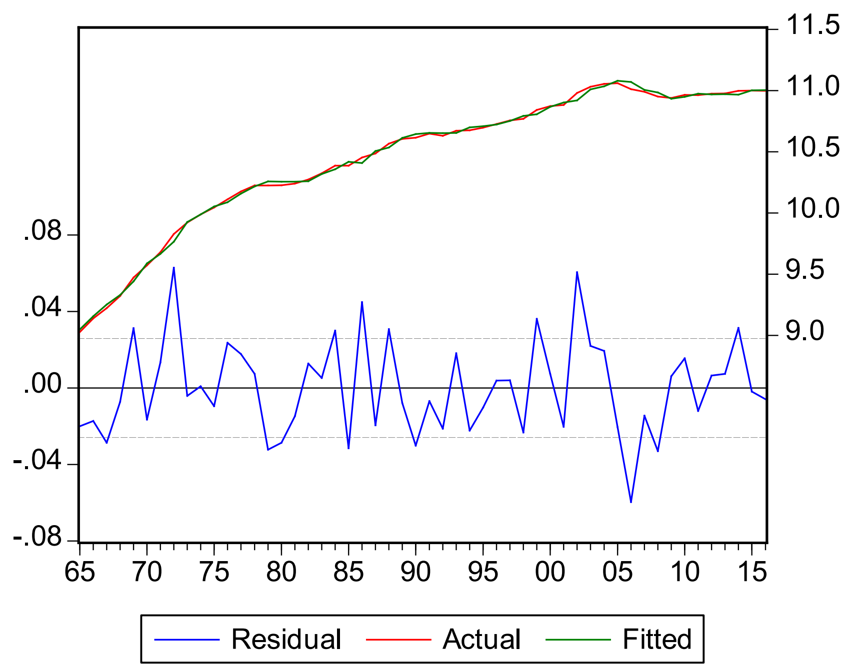
Latest Forecast by Sector

(GWh)

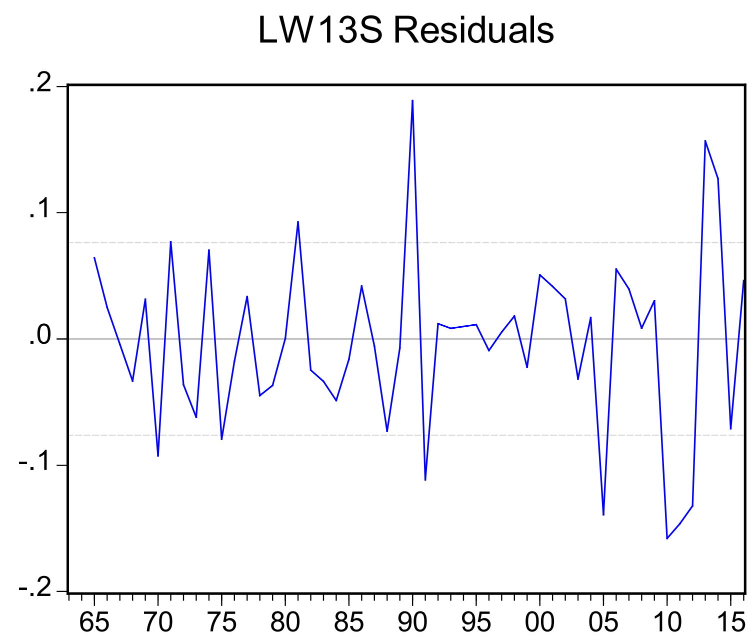
Year	Commercial	Industrial	Agriculture	Residential	Transportation
2019	58,943	42,970	2,513	43,227	526
2020	58,875	42,413	2,626	42,219	538
2021	58,970	41,733	2,548	42,021	548
2022	59,208	41,177	2,628	41,674	556

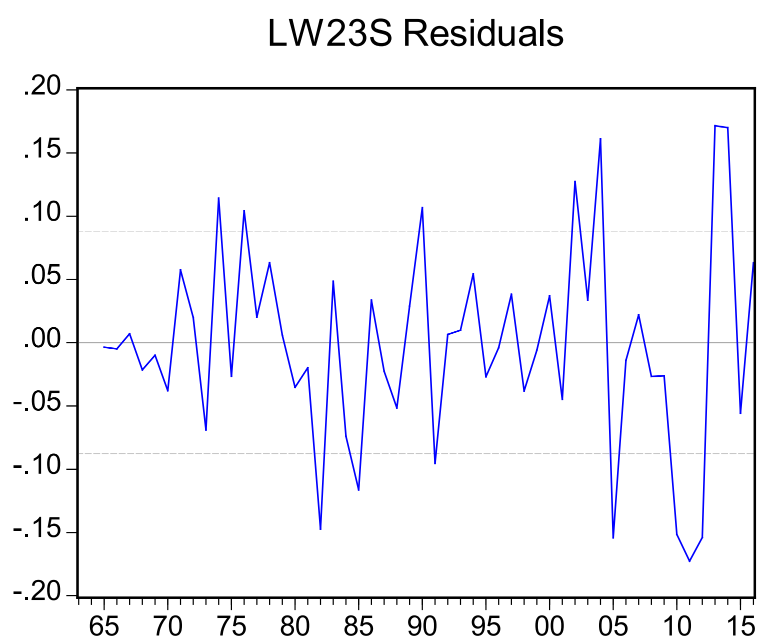
1 **i. Commercial Model**



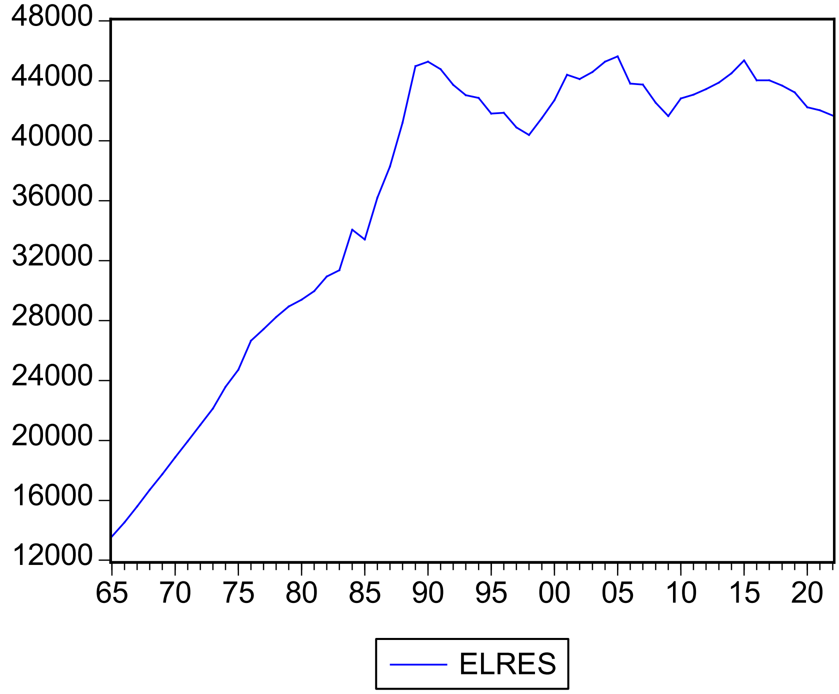


ii. **Industrial Model**

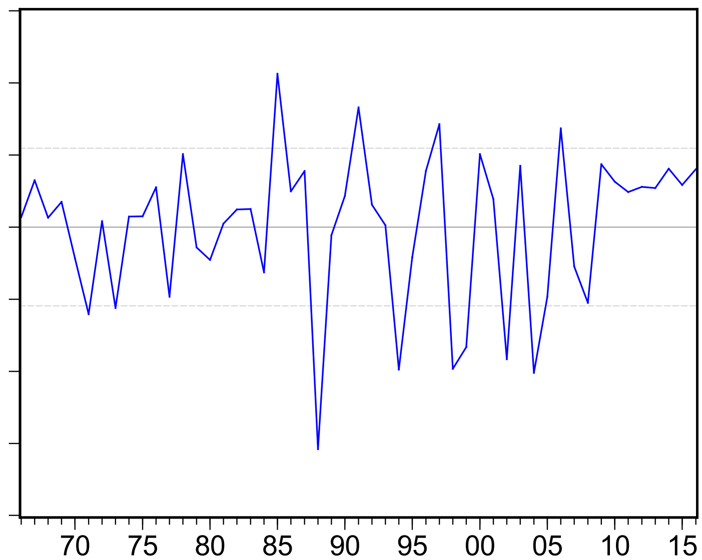




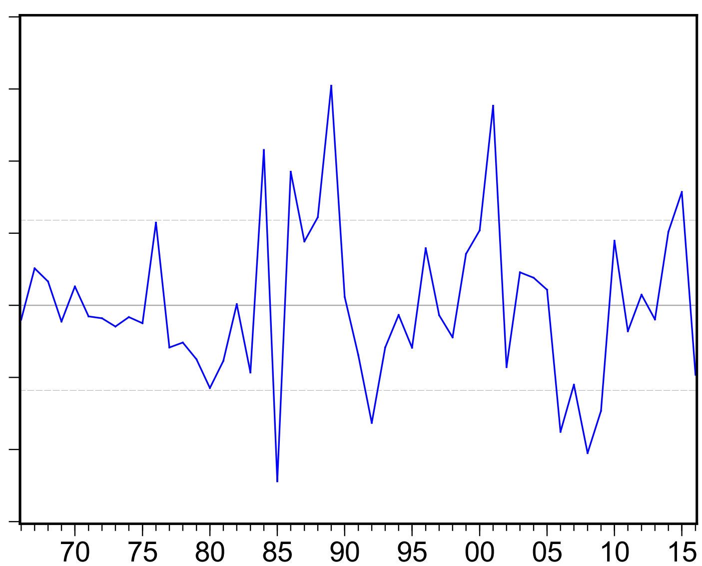
1 **iii. Residential Model**



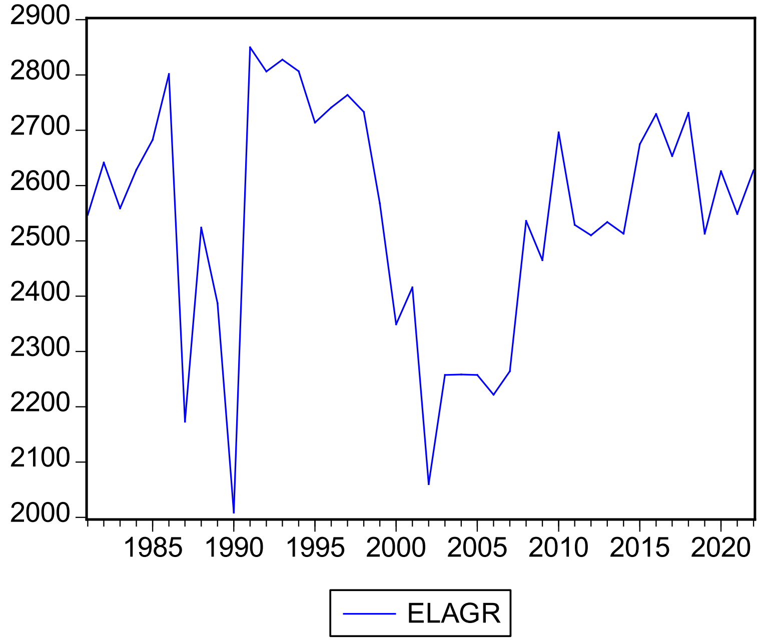
LELSAT Residuals

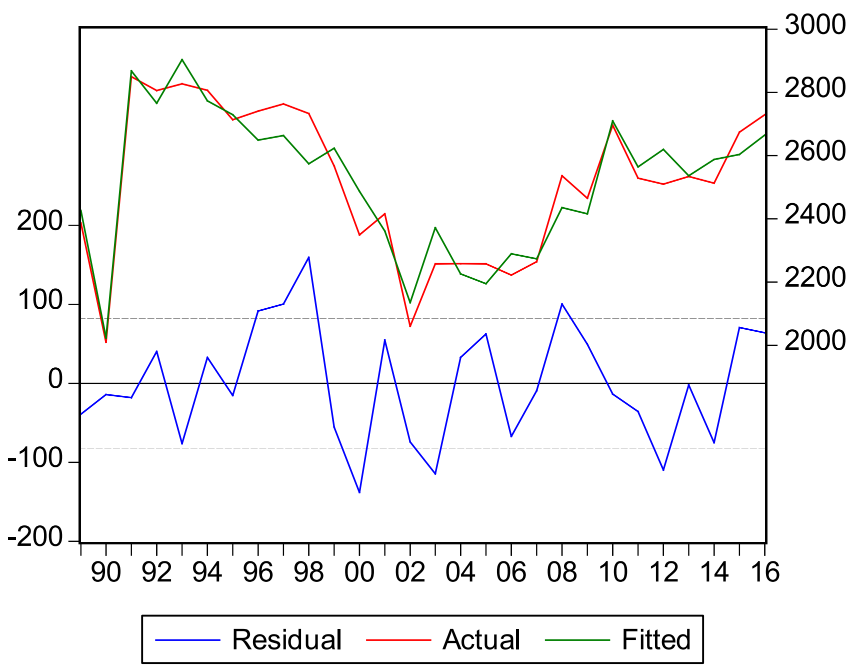


LELUSE Residuals

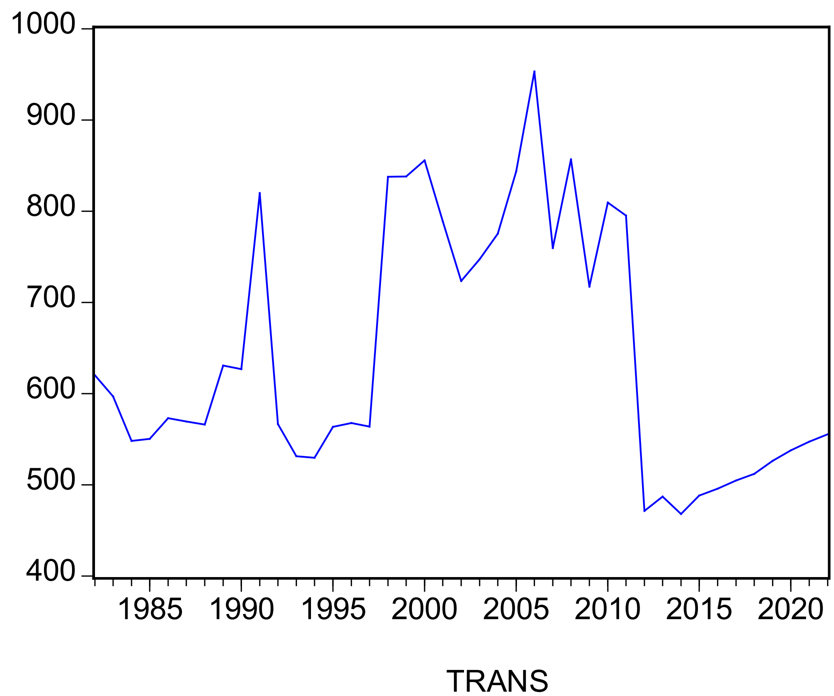


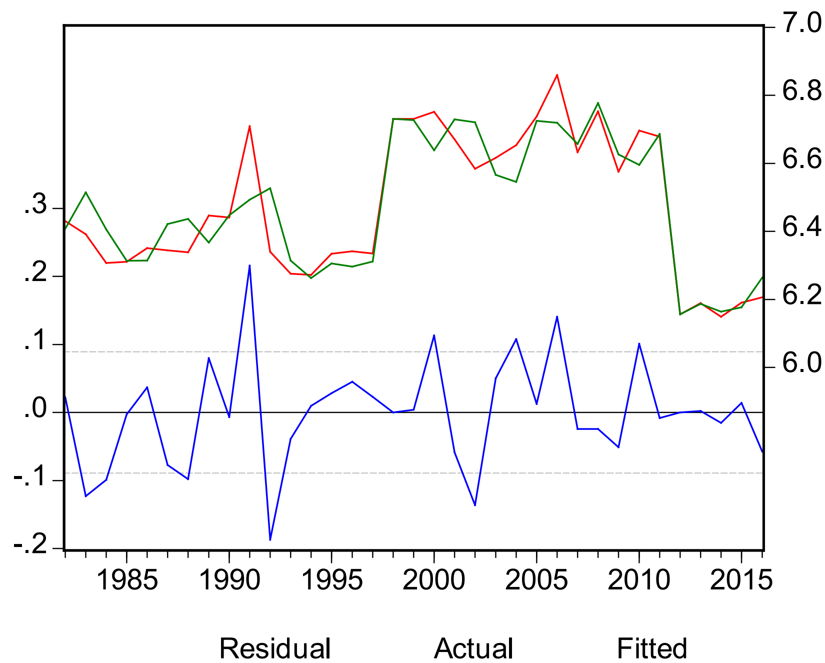
iv. Agricultural Model





1 **v. Transportation Model**





For each model, various statistics are provided in Exhibit E, Tab 3, Schedule 1 Appendix B, along with a discussion of results pointing to a good fit and reasonable residual variance. Moreover, the forecast trend in all models is consistent with the corresponding historical trend. For a discussion of residual errors, please see response to part (e) below.

e) For each model, the forecast error has not increased in relation to structural changes or other factors. Some structural changes were present and addressed using dummy variables, including trend and binary variables, as discussed in Exhibit E, Tab 3, Schedule 1 Appendix A. An exception to this is the residual for the share of each fuel sources in total energy relative to that for coal in the industrial sector. The closure of coal-fired stations in Ontario in recent years significantly impacted these relative shares. A dummy variable was used to capture step-wise closures of coal-fired stations. The model residual during the closure process experienced an increased range of variations and the increase persisted after the closure process was completed. To address this problem, the weighted SUR estimation method (which corrects for such heteroscedastic errors) was used to estimate the model parameters.

ENERGYPROBE INTERROGATORY #3

Reference:
A-03-01 p.16, A-03-01-01, A-07-01-01

Interrogatory:
Preamble:
Energy Probe has read the high level Corporate Objectives. We wish to understand why improving System Reliability is not the major priority for the 2019-2024 Investment Plan.

We have also reviewed the Evolved TX Scorecard.

a) Why is Hydro One still a worse performer for Reliability (T-SAIDI, T-SAIFI, T-MAIFI) than many of its peers, when weather and other external codes are taken into account?

b) Given the clear Customer Preferences summarized in References 2 and 3 above, please explain why System Reliability is not the number one Corporate priority after Safety.

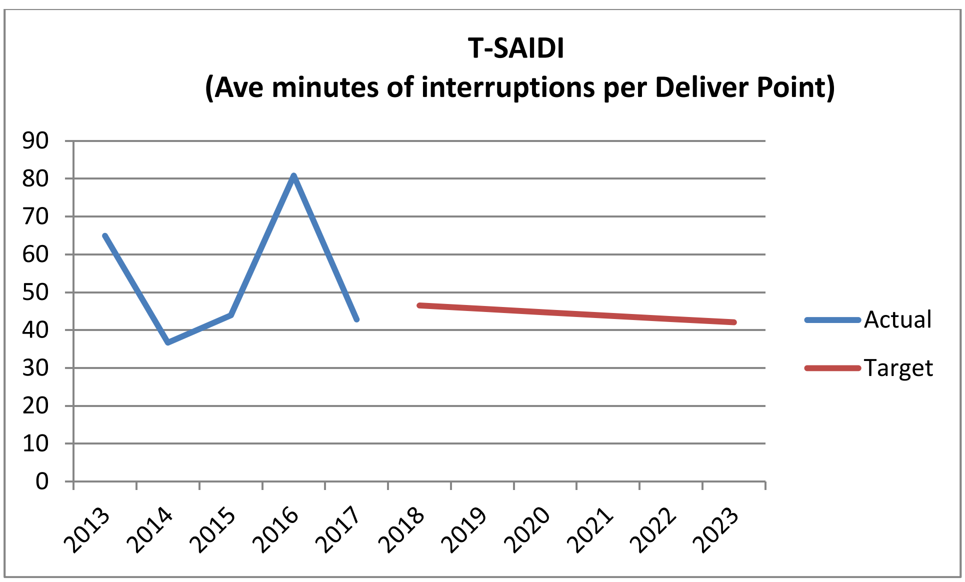
c) Please provide graphical representations of the historic and forecast T-SAIDI , T-SAIFI, T-MAIFI data shown in the Evolved Transmission Scorecard

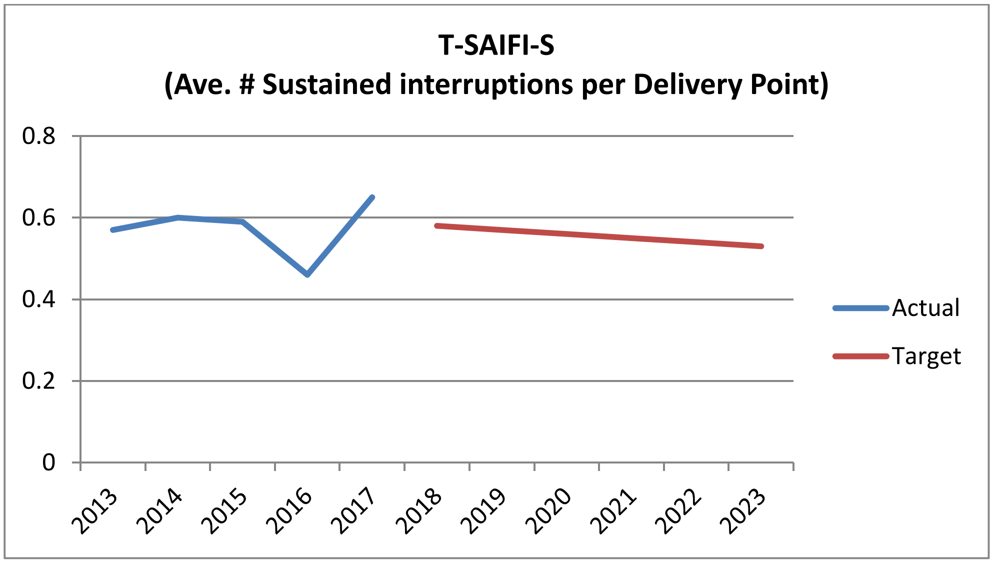
Response:
a) Hydro One's overall performance of T-SAIDI and T-SAIFI, including momentary and sustained interruptions has been mainly in the 2nd quartile as comparing to other Canadian transmission utilities for the past 10 years. The reasons for this are driven by the following: Hydro One's service territory and system is generally much larger compared to other Canadian utilities and has the most number of customer delivery points. A utility with a smaller system and fewer delivery points, the reliability performance would be expected to perform better. This is one reason that Hydro One's overall T-SAIDI and T-SAIFI performance is mainly in the 2nd quartile.

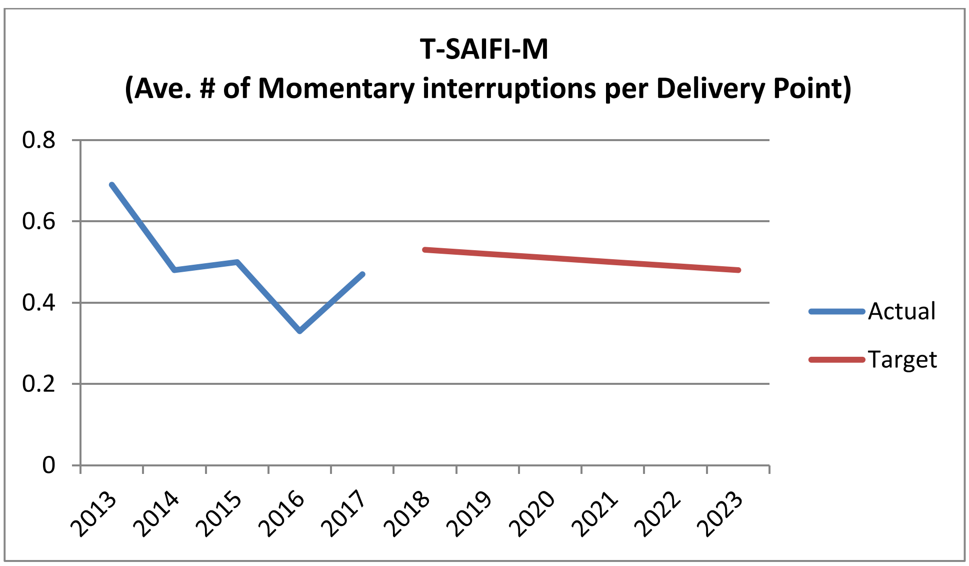
Historical design of the system to manage costs has resulted in about 40% of the delivery to be supplied from a radial transmission system; these delivery points contribute about 80% of the reliability events.

b) Reliability is the second priority as ranked by customers through the customer engagement process detailed in Exhibit B, Tab 1, Schedule 1, Section 1.3 and one of the top priorities for Hydro One. Hydro One's strategic priorities are not ranked. System Reliability is a strategic priority for Hydro One in alignment to customer preferences as indicated in Exhibit A Tab 3 Schedule 1 page 14.

c) The charts below are based on the actual and targeted performance for all delivery points, including both single-circuit and multi-circuit supplied delivery points.




T-SAIFI-S
(Ave. # Sustained interruptions per Delivery Point)
0.8
0.6
0.4
0.2
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Actual
Target


T-SAIFI-M
(Ave. # of Momentary interruptions per Delivery Point)
0.8
0.6
0.4
0.2
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Actual
Target

ENERGY PROBE INTERROGATORY #4

Reference:

A-04-01-01 p.18,19 and 37

Interrogatory:

Preamble:

However, it is likely that this output growth term will be very close to zero in the CIR period (see Table 8). The flat or declining nature of peak demands, due to conservation and demand management (CDM) plans and energy efficiency technology gains, makes it very likely that the maximum peak demand will be flat. Further, the total kilometres (KM) of transmission lines are projected by Hydro One to remain very close to current levels. Thus, the output growth rate will be essentially zero for each year of the CIR period.

a) Did Hydro One Provide a Peak demand forecast for the CIR period to PSE? If so please provide a copy.

b) Why does PSE use the assumption that peak demand growth (MW) will be flat given the negative load forecast (MWh), or will the System Load Factor change with load?

c) If the growth factor is negative what will be the impact on the CIR Formula and Revenue Requirement in 2021 and 2022?

d) Please provide a sensitivity analysis that shows this based on Hydro One Transmission peak demand data.

Response:

a) Yes.

Forecast of Transmission Annual Peak and Kilowat Hours Transmitted		
Year	Annual Peak (MW)	Annual Kilowatt Hours Transmitted
2017.00	22,178	135,104,305,239
2018.00	21,982	134,166,584,139
2019.00	21,763	132,844,060,731
2020.00	21,482	131,937,328,494
2021.00	21,439	130,803,164,625
2022.00	21,367	129,967,320,536
2023.00	21,291	129,104,753,912
Note. All figures are weather-normal.		

b) The output quantity index is comprised of the maximum peak demand and the total kilometres of transmission line. The definition of the maximum peak demand is the highest peak demand value for the transmission system that has occurred from 2004. Please see pages 24 and 25 of the PSE report for the definition of the maximum peak demand variable. Given the definition of the variable, the maximum peak variable will not decline during the forecasted period.

c) The growth factor will not be negative but is projected to be essentially zero.

d) Please see the response to part c.

ENERGYPROBE INTERROGATORY #5

Reference:
A-03-01 p.39, TSP-01-05 p.5

Interrogatory:

a) Please provide the weightings for each of the 4 Major Categories in the Evolved Scorecard.

b) Please explain/support the forecasts for System Reliability in the Evolved T Scorecard.

c) Please provide graphical representation of the 10 year historic and forecast Reliability measures (T-SAIDI, T-SAIFI and T-MAIFI).

d) Please provide in chart form the cause codes related to 2018 system reliability. Compare to the 5 year averages 2014-2017 and discuss reasons why/if 2018 is different

e) Please provide any internal reports related to the worsening of Reliability measures in 2018, including system availability and unsupplied load.

f) Please provide a list of where the delivery point "trouble spots" are located, the number of distributors (including Hydro One) and number of customers affected.

g) Please point to the evidence that describes and discusses the remedial actions Hydro One Transmission is taking to address the issues and provide a short synopsis.

h) Are the forecast 2019-2024 Reliability values targets and if so, what turns on achieving these? If not, explain why not.

Response:

a) There are no weightings for the 4 major categories in the Evolved Scorecard.

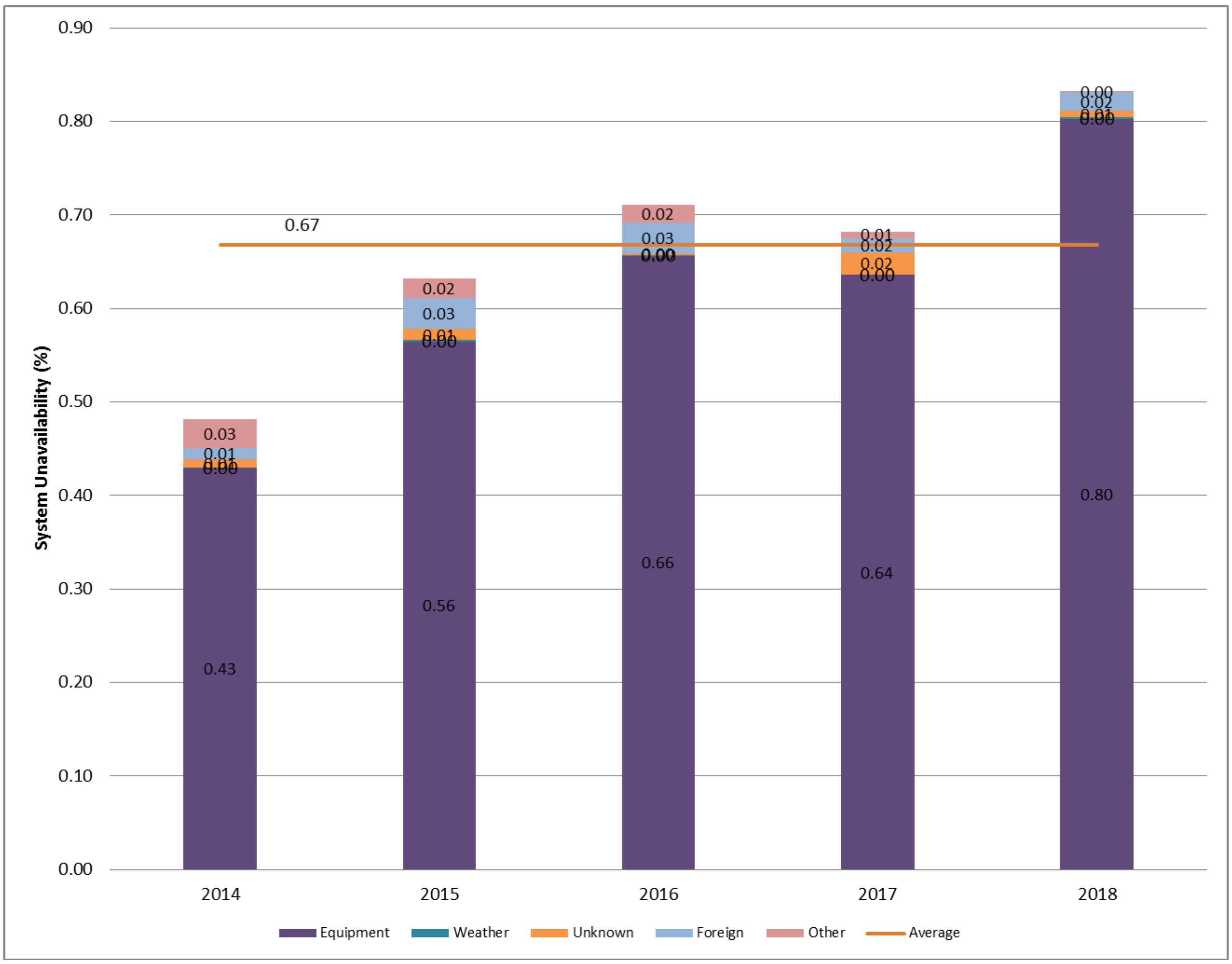
b) The forecasts for the System Reliability are established using the 2009-2018 ten-year 40th percentile for 2019, with a 2% improvement year-over-year beginning in 2020.

c) Refer to response to I-02-EnergyProbe-3-c.

d) Please refer to Exhibit B-1-1, TSP Section 1.5 Pages 29 to 32.

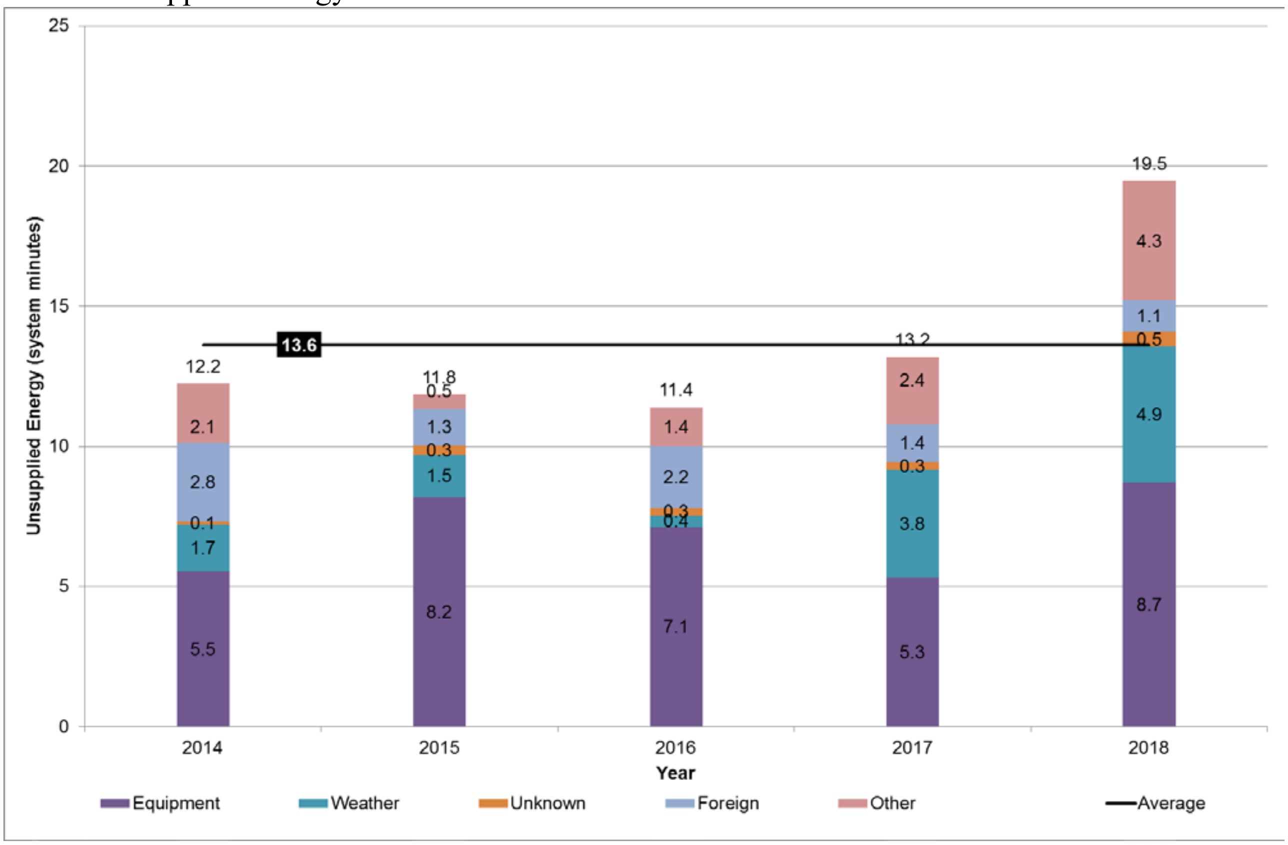
B-1-1 TSP 1.5 Page 29 Figure 6: TSAIFI-S
B-1-1 TSP 1.5 Page 30 Figure 7: TSAIFI-M
B-1-1 TSP 1.5 Page 32 Figure 6: TSAIDI

System Unavailability:



Witness: Bruno Jesus

Unsupplied Energy:



For the discussion of why or if 2018 is different, please refer to to OEB-147 c) & OEB-148 a)

e) Please refer to Exhibit B, Tab 1, Schedule 1, Section 1.5 pages 27 to 36 for a discussion of 2018 reliability performance, including unsupplied energy and system unavailability. Hydro One reviews operations reliability performance monthly. System reliability performance, including system unavailability and unsupplied energy and other performance measures are reviewed with follow-up actions. The December 2018 monthly "Operations Reliability Performance" reports is included as Attachment 1.

f) Chronic delivery point outliers are delivery points that have been identified as outliers for 4 consecutive years based on Customer Delivery Point Performance Standards and have been used to identify the "delivery point trouble spots" referenced in the question. Most of these delivery points are supplied by long single circuits. All 2017 chronic outliers are grouped below by Transmission Zones. Also provided is the number of LDC and transmission end-user customers connected to the delivery point.

TRANSMISSION ZONE	2017 Chronic Outliers	# of LDC Customers	# of Tx End-User Customers
NE 115	MOOSONEE DS	1	0
	SUDBURY SMELTER CTS	0	1
	HOLLOWAY HOLT #2 CTS	0	1
	ONAKAWANA CTS	0	1
	RENISON CTS	0	1
	HOLLOWAY HOLT #3 CTS	0	1
NW 115	CAT LAKE MTS	1	0
	CROW RIVER DS	1	0
	MUSSELWHITE CTS	0	1
	JELLICOE #3 DS	1	0
	RED LAKE TS B	1	0
	LONGLAC TS Z	1	0
	SLATE FALLS DS	1	0
West 115	TILLSONBURG TS B	2	0
	TILLSONBURG TS Y	2	0
	STRATHROY TS B	1	0
	STRATHROY TS Q	1	0

g)

Hydro One undertakes transmission reliability assessment and improvement activities including:

- System Renewal – these planned investments are listed at TSP Section 3.2 and are required to maintain and/or improve safe, secure and reliable operation of the transmission system.

- Outliers Delivery Points - Assessment of outlier delivery points (ODP) is undertaken for delivery points experiencing performance that is below the standard that has been approved by the OEB. In 2017 there were 84 ODP. Assessments have been undertaken for each of them to identify the causes, and review of planned system renewal investments to identify if additional remedial actions that could be taken (such as fault locator installation or animal abatement investments)

- Worse performing circuits - Assessment of worse performing transmission circuits is conducted to assess the causes of reliability issues and review planned system renewal investments to consider if additional remedial actions such as fault locator or line sectionalizing are required.

h) The forecast 2019-2024 Reliability values are targets. The business plan has been set to achieve the Performance Measures noted in TSP section 1.5 and Strategic Priorities and Objectives noted in TSP 2.1.2.

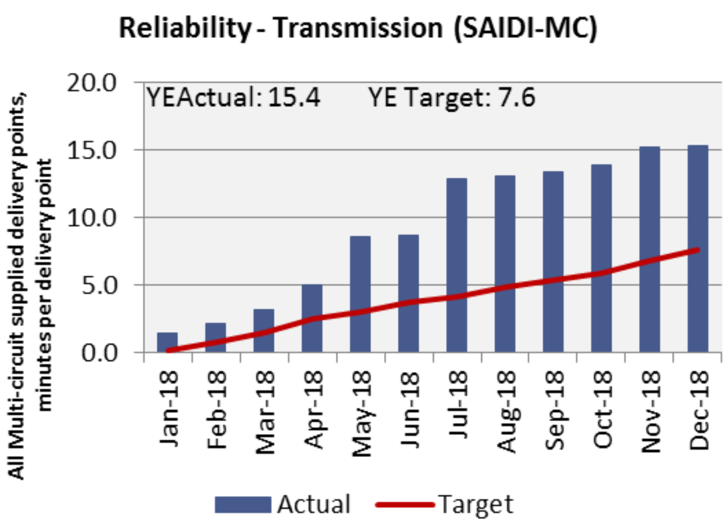
Operations Reliability Performance

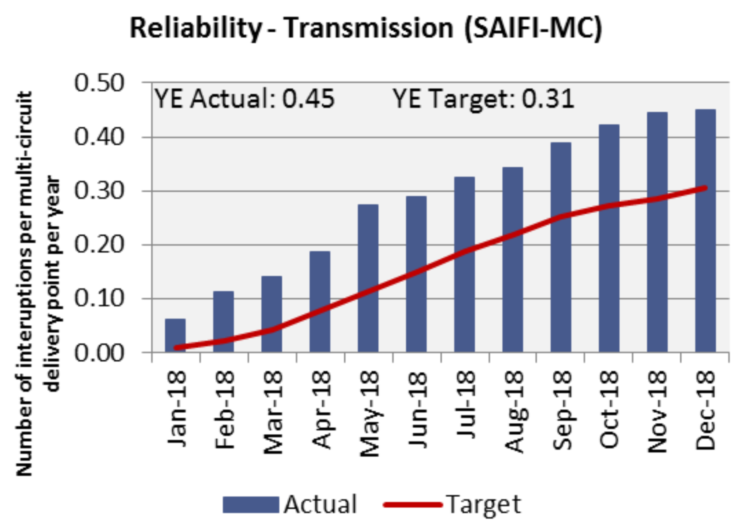
December 2018

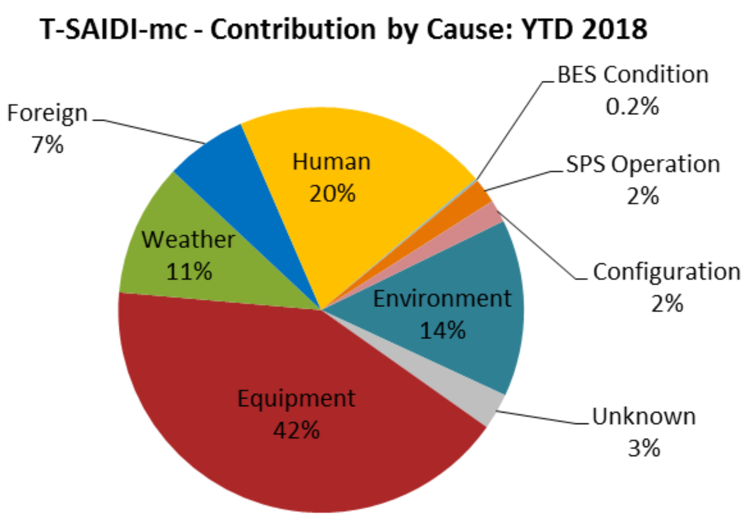
hydro One

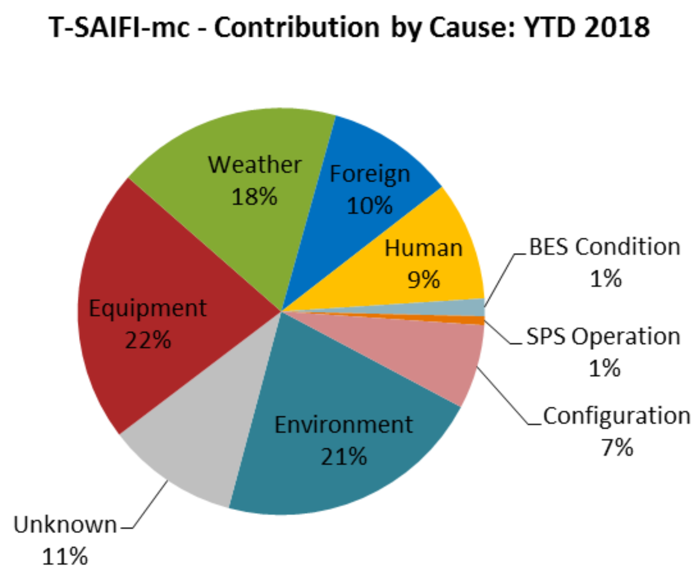
YTD - Transmission Reliability Multi-Circuit Performance & Causes

There were 3 delivery point interruptions occurred with a total load interruption duration of 60 minutes. December YTD Transmission reliability performance, both interruption duration and frequency are worse than targets.









Operations Scorecard – Transmission Reliability

Monthly Summary

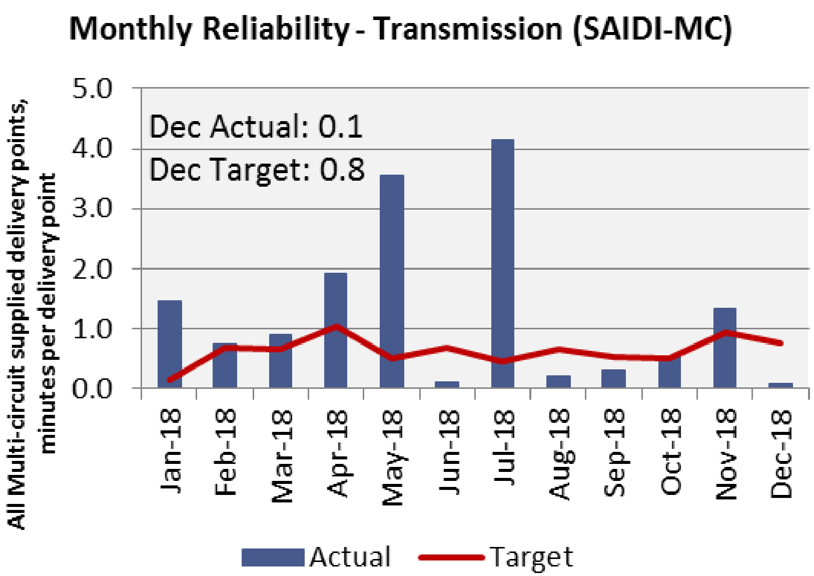
There were no significant events in December. Three delivery point interruptions occurred with total load interruption duration of 60 minutes. December YTD Transmission reliability performance, both interruption duration and frequency are worse than targets.

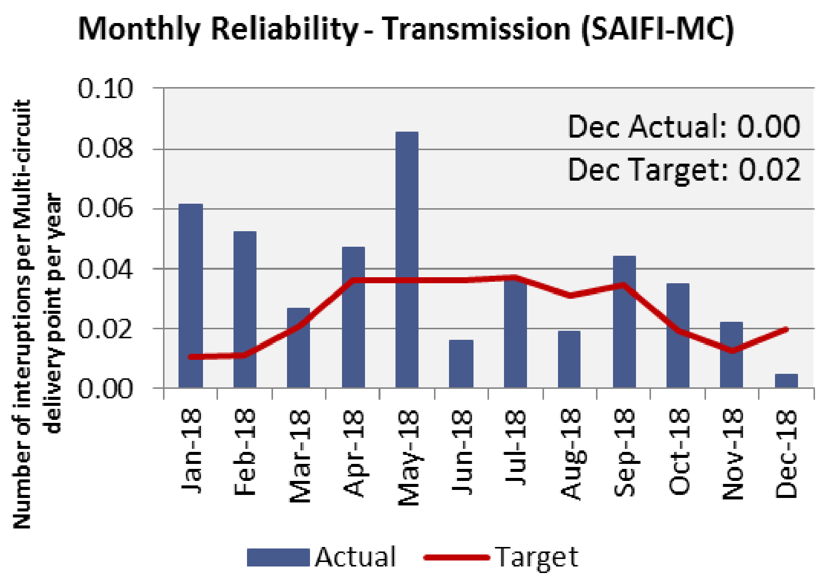
Significant Events:

- There were no Significant Events in December

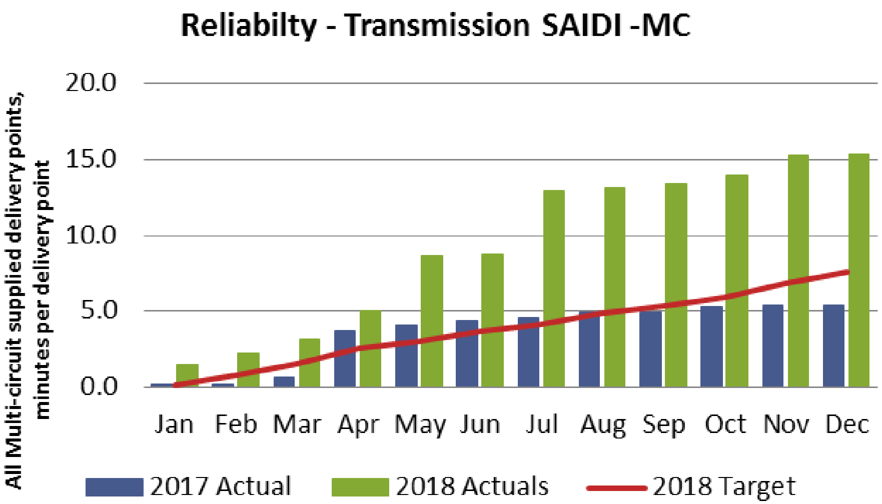
Coincident Events:

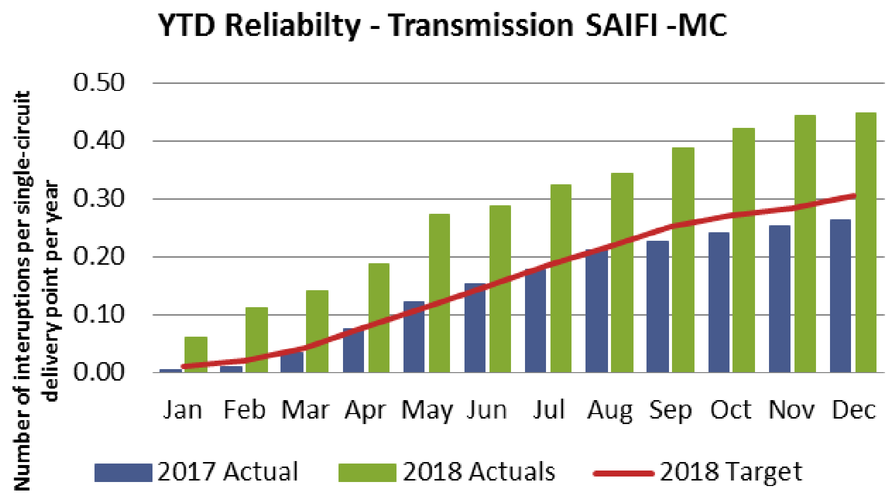
- There were no Coincident Events in December

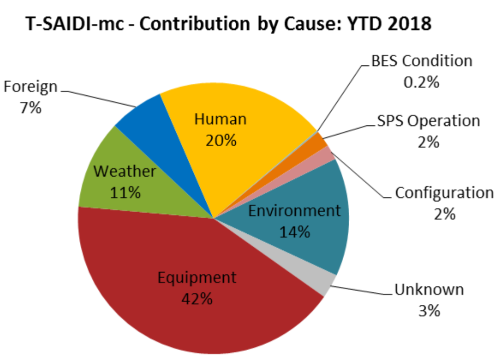


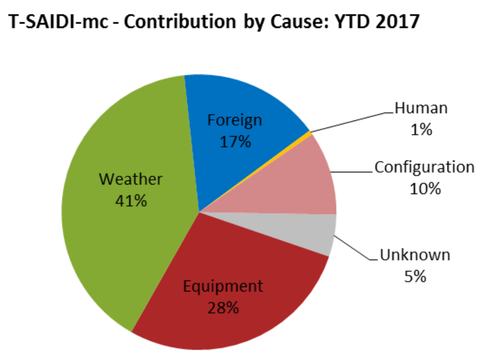


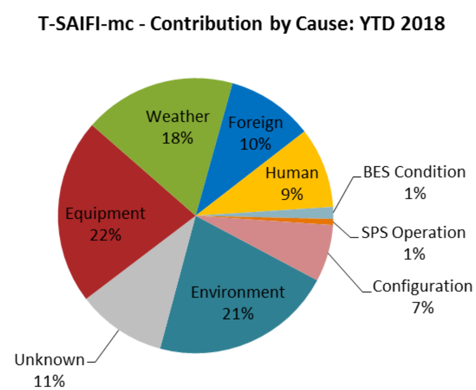
Transmission Reliability 2017 VS. 2018

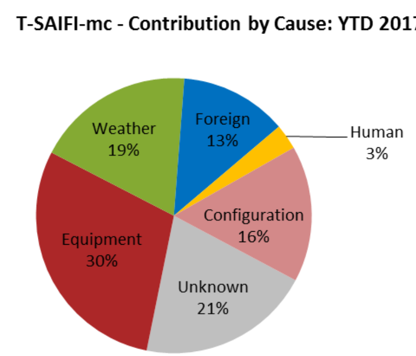




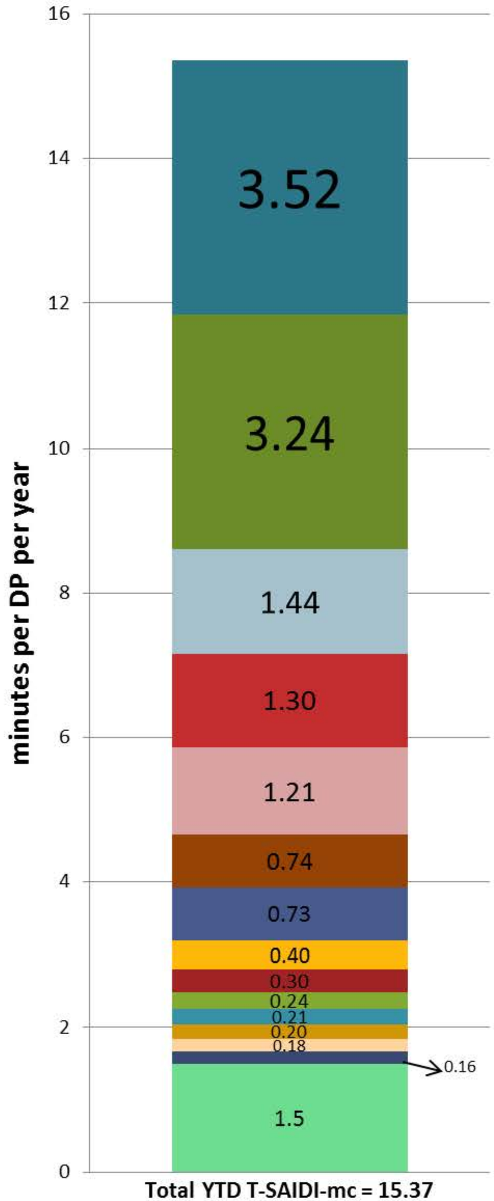








December YTD T-SAIDI-MC Significant Events Contribution



T-SAIDI-mc Significant Event Contribution - December YTD

- July 27/28: Finch TS T2 transformer failure and protection issues resulted in 6 DP interruptions for a total of 2,234 minutes.
- May 4: Severe windstorm in Southern Ontario and protection setting issues resulted in 31 DP interruptions for a total of 2,059 minutes.
- Jan 8: 115 kV Circuits H1L and H3L (Hearn SS - Leaside TS) tripped due to contamination at Gerrard TS. This resulted in 32 DP interruption for a total of 916 minutes.
- April 14: 115 kV Circuit Q11S (Beck TS - Glendale TS) was tripped due to downed poles during freezing rain. This is resulted in 11 DP interruptions for a total of 828 minutes.
- Nov 14: T31H was removed from service due to broken conductor while 230kV circuit T22C was on planned outage. Five delivery points were interrupted for a total duration of 764 minutes.
- Mar 22: 115 kV Circuit K1W (Manby TS - Wiltshire TS) tripped due to animal contact. Companion Circuit K3W was also tripped due to relay malfunction. This resulted in 8 DP interruptions with a total of 469 minutes.
- Feb 10: 115 kV Circuit H1L (Hearn TS - Leaside TS) tripped due to contamination at Gerrard TS. 29 DPs were interrupted for a total of 462 minutes.
- April 24: Stratford TS T2 (230/27.6 kV) transformer tripped due to a raccoon contact. With 230 kV Circuit B22D (Bruce TS - Detweiler TS) planned outage, 6 DP was interrupted with a total duration of 253 minutes.
- July 16: 500 kV Circuit P502X tripped in the Northeast triggering SPS operation and interrupted 2 DPs at Timmins for 193 minutes.
- Oct 19: Mylar balloon caused differential on Mohawk T2 while companion T1 on planned outage interrupting 2 DP's for a total of 153 minutes.
- May 2: Cherrywood TS T7 and T8 (230/44 kV) transformers tripped due to protection misoperation caused by a wiring issue. 2 DPs were interrupted for a total duration of 132 minutes.
- July 16: Wingham TS 44 kV Y bus was tripped for 128 minutes due to a failed bushing on 44 kV BY breaker,
- Oct 20: Customer inadvertently sent transfer trip signal to V41H circuit while companion circuit V42H was on planned outage interrupting 8 DP's for a total of 115 minutes
- Sept 19: 230 kV circuit C21J (Chatham TS - Keith TS) out of service for planned work, its companion circuit C22J was automatically removed from service impacted 6 DPs for 104 minutes.
- All other events contributed to 1.50 T-SAIDI-mc minutes.

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Operations Scorecard – Transmission Reliability

Year-to-Date Summary

Significant Events Summary:

Date	Event Description	T-SAIDI-mc minutes	Coincident Event?
14-Nov	Nov 14: 230kV circuit T31H (Clarington TS - Havelock TS) removed from service due to broken conductor while 230kV circuit T22C (Clarington TS - Chat Falls TS) was on planned outage. Havelock TS Y bus interrupted when T2Y breaker initiated breaker fail during T31H line protection operation. Otonabee TS (44 kV) BY busses and (27.6kV) JQ busses as well as Havelock TS (44kV) Y bus interrupted. Five delivery points were interrupted for a total duration of 764 minutes.	1.21	Yes
20-Oct	230 kV Circuit V41H (Claireville TS x Hurontario TS) was automatically removed from service without receipt of primary protection annunciation. A directly connected transmission customer had been testing one of their terminal breaker for circuit V41H when of their staff inadvertently applied a transfer trip send signal to circuit V41H, which initiated a trip and lockout of all terminals of the circuit. There was an ongoing scheduled outage to the companion circuit V42H (Claireville TS x Hurontario TS) as the time of the event.	0.18	Yes
19-Oct	Mohawk TS T2 transformer (115/13.8 kV) was automatically removed from service by differential protection due to a a Mylar balloon that had made contact with T2 secondary surge arrestors. At the time of the event there was already an ongoing outage on the Mohawk T1 transformer.	0.24	Yes
21-Sep	A major storm event with multiple tornadoes occurred in the Ottawa area interrupting large areas of the electrical grid in the region. OGCC confirmed that an E/F-2 tornado, with wind speeds up to 220km/h, touched down at the Merivale TS yard. Multiple major 230 kV and 115 kV circuits tripped in this event, including : 230 kV circuits: M30A and M31A (Merivale TS - Hawthorne TS), M32S (Merivale TS - South March SS), E34M (Merivale TS – Almonte TS), 115 kV circuits: W3B (Barrett Chute TS – Stewartville TS), C7BM (Chats Falls TS - Merivale TS - Barrett Chute TS), S7M (Merivale TS - South March SS), M4G and M5G (radial from Merivale TS), V12M and F10MV (radial from Merivale TS), A8M and A3RM (Merivale TS - Hawthorne TS), L2M and M1R (radial from Merivale TS). Pembroke TS was the only station impacted by CP during this event. 115 kV Circuits X6 and X2Y (both radial from Chenaux TS) load was lost due to the refurbishment outage at the time of the event. This event resulted in 40 multi-circuit supplied DP interruptions with a total duration of 48,634 minutes.	76.70	Yes
19-Sep	With the 230 kV Circuit C21J (Chatham TS – Keith TS) out of service for planned work, the companion Circuit C22J was automatically removed from service, resulting in load interruptions in the Windsor area. There was no active weather in the area at the time of the trip and the cause is being investigated. The total duration of the interruptions was 104 minutes at 6 DPs.	0.16	Yes
27-Jul/28-Jul	Finch TS (230/27.6 kV) T2 transformer failed and followed by T1 tripping. This interrupted the Finch TS 27.6 kV B and Y buses delivery points. Due to protection issues at Finch TS, Finch JQ (27.6 KV) yard was deenergized and multiple 230 kV circuits were removed from service. This interrupted two more delivery points at Finch TS, Markham MTS#1, and IBM Markham CTS. In total there were 6 delivery points interrupted for 2,234 minutes.	3.52	No
16-Jul	Wingham TS (44 kV) Y bus was tripped due to a failed bushing on 44 kV BY breaker. The impact to the T-SAIDI-mc was 0.2016 minutes per delivery point.	0.20	No
16-Jul	Two Delivery Points (DPs) at Timmins TS (28 kV Q/Z busses) were interrupted from the widespread impactive northern outages stemming from the loss of the 500 kV CircuitP502X (Porcupine TS- Hanmer TS), which was removed from service during bad weather. Special Protection Systems removed a number of other circuits & generators in the area to provide load and generation stability. The Timmins TS DPs that were interrupted contributed 0.3039 minutes/dp to the T-SAIDI-mc reliability numbers.	0.30	No
4-May	A severe windstorm hit Ontario on May 4, resulting in multiple outages across the province and numerous multi connected delivery points were interrupted for a total of 241 minutes. During this storm Armitage TS and Thornton TS were impacted by incorrect protection settings and large interruptions resulted. See separate entries for these events as the resultant DPIS were not directly from the weather event. P&C confirmed incorrect protection settings. The Brantford Z (28 kV) bus was interrupted due to a defective Voltage Transformer. Brantford TS (230/28 kV) T4 transformer tripped on differential protection coincident with Z Bus (28kV) tripping. Staff found the Z Bus VT Blue phase failed. Impact of this event to T-SAIDI-mc was 0.20 minutes. Dual Circuittripping of 230 kV circuits T38B and T39B circuits (Trafalgar TS – Burlington TS) on line protections and did not auto reclose as was blocked by Breaker Duty Cycle. Load was interrupted in Halton and Mississauga at 3 stations: Transformer Stations at Halton TS, Meadowvale TS, Trafalgar DESN, and Tremaine TS. 8 DPs were interrupted in total combining for an impact of 0.17 minutes/dp. The last event to the May 4th T-SAIDI-mc, and that event was the Lincoln Heights TS (13 kV) B1/B2 busses momentary outage. Woodroffe (115/13 kV) T4 transformer was removed from service twice on May 4 on differential protection operation. Field staff found the cause of the fault to be a string that got caught on the primary side of the T4 transformer and burned away. 115kV CircuitF10MV was removed reclosed successfully as designed. Lincoln Heights TS 14 kV B1 and B2 busses were interrupted twice each due to a long term outage to the T2B2 14kV breaker. The impact of this event to T-SAIDI-mc was 0 minutes as it was momentary in nature.	3.24	No
	The largest load interruption event on May 4 during severe windstorms, was a coincident planned interruption event which occurred east of Toronto when the Thornton TS (230/44 kV) T4 transformer was removed from service by protection operation during an outage to the Thornton T3 and the supply CircuitT26C. Delivery point interruptions resulted at the following stations: Thornton TS, Gerdau Whitby CTS, Atlantic Packaging CTS, Oshawa G.M TS and Whitby TS. There were reports of a large fire outside of Thornton TS with several downed poles on multiple feeders. P&C tech services have confirmed that the Thornton TS T4 'B' differential protections required an update for close in feeder faults, this was caused by incorrect protections settings. This event had an impact of 2.1 minutes/dp.		Yes
	The second most impactive event during the windstorms on May 4 was the Armitage TS event that contributed a total of 0.76 minutes/dp to the T-SAIDI-mc. The Armitage T1 and T2 (230/44 kV) transformers both tripped during a feeder fault in the station. The NEOA analysis concluded that the T1 and T2 'A' protections misoperated for a feeder fault. Pending settings updates were in PCMIS for these relays, but they had not been applied to the relays yet. Field have been asked them to apply the Pending settings. 6 Delivery Points at Armitage TS and Brown Hill were interrupted in this event. P&C confirmed that there were incorrect protection settings in the Armitage transformer protections. This event had an impact of 0.76 minutes/dp.		No
2-May	Cherrywood TS (230/44 kV) T7 and T8 transformers were removed from service from a protection misoperation. A wiring issue was found: DC grounds were found incorrectly applied tying together trip circuits for T7 and T8 transformers. As a result Veridian customer load was interrupted.	0.21	No
24-Apr	During a scheduled outage to Stratford TS T1 and 230kV CircuitB22D (Bruce TS - Detweiler TS), Stratford TS T2 was removed from service from what Stations staff discovered a raccoon carcass near the T2 revenue metering unit. 115 kV CircuitL7S (radial from Seaforth TS) was supplied from B23D at the time due to the B22D outage, interrupting Hydro One and LDC load. Field staff found multiple faults along CircuitL7S. On April 17th, L7S repairs were completed. 7 DPIs were interrupted at Stratford TS, Wingham TS, Festival MTS, and Seaforth TS for a total duration of 253 minutes.	0.40	Yes
14-Apr	OGCC anticipated a large weather impact event due to the ongoing and prospective impact of the freezing rain that took place in the southern portion of the province, it was upgraded to Stage 2 Flashover conditions from Stage 1. The impact area was localized in the Toronto to Niagara corridor but as the weather system moved towards South Western Ontario the impact was expected to be more widespread. In the Niagara area, 115kV CircuitQ11S (Beck TS - Glendale TS) was removed from service by protection LDC load. Hydro One lines staff discovered a faulted section of Q11S with downed poles. The Bunting load loss occurred as the companion transformer T3 was out of service for planned work. The affected LDC's were eventually able to transfer their load internally to alternate supplies. Bunting TS T3 transformer was recalled from an outage and was placed in service. On April 16th new poles were installed and the affected section of Q11S was returned to service. The total station outage at Bunting was 828 minutes in duration.	1.30	Yes
22-Mar	115 kV circuits K1W and K3W (Manby TS - Wiltshire TS) both auto-reclosed from line protections after the Wiltshire TS T2 and T7 (115/14 kV) transformers were automatically removed from service by differential protections. This resulted in the loss of LDC load at Fairbank TS and Wiltshire TS, in the GTA. Field investigation confirmed that animal contact was the initial cause for the Wiltshire TS T2 outage and that the Wiltshire TS T7 tripped from a bad pallet in the T7A3A4 (14 kV) breaker. The event resulted in interruptions to 8 delivery points and a total interruption duration of 469 minutes.	0.74	No
10-Feb	115 kV Circuit H1L (Hearn TS - Leaside TS) auto-reclosed initiated by line protection, the previous day after multiple auto-recloses on the 115 kV Circuit H3L (Hearn x Leaside) had locked out. This resulted in Toronto Hydro-Electric System Limited load interruptions. Field crews indicated that flashovers at Gerrard TS due to the contamination buildup on the insulators were the cause of the outages. Delivery Point interruptions were observed at Basin TS, Gerrard TS, and Carlaw TS. This event resulted in 29 interruptions to 11 delivery points with a total interruption duration of 462 minutes.	0.73	No
8-Jan	The Leaside TS 230 kV J bus was tripped by JL3 breaker failure protection operation after multiple auto-recloses on the H3L circuit. This was followed by lock out of both the 115 kV circuits, H1L (Hearn TS - Leaside TS) and H3L (Hearn TS - Leaside TS), resulting in interruptions of Toronto Hydro-Electric System Limited load. Field crews indicated that flashovers at Gerrard TS due to the contamination buildup on the insulators were the cause of the outages. Delivery Point interruptions were observed at Basin TS, Gerrard TS, and Carlaw TS. This event resulted in 32 interruptions to 11 delivery points with a total interruption duration of 916 minutes.	1.44	No

Operations Scorecard – Transmission Reliability

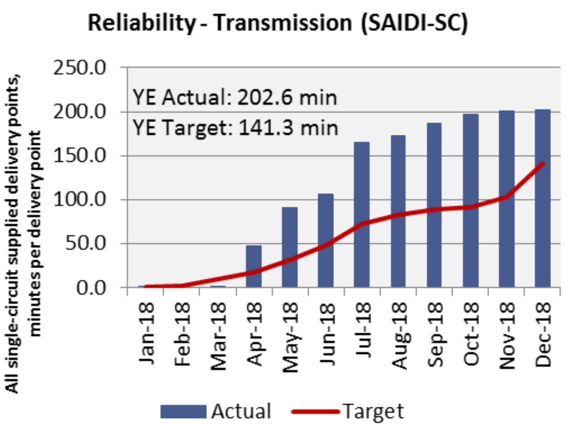
Year-to-Date Summary

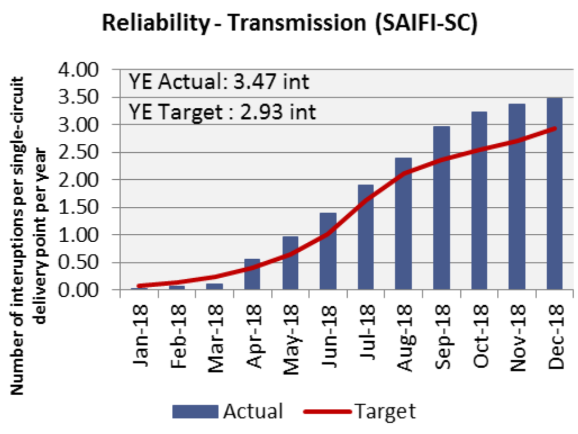
Coincident Events Summary:

Date	Event Description	T-SAIDI-mc minutes	Coincident Event?
19-Nov	Nov 19: 115 kV Circuits K2Z (Kingsville TS - Lauzon TS) tripped from what was suspected to be from weather. Two delivery points were interrupted at Kingsville TS, due to the K6Z supply to Kingsville TS being out of service for an outage.	0.00	Yes
12-Oct	Circuits B10 (Burlington TS x Birmingham TS), HL4 (Beach TS x NewtonTS) and K1G (Gage TS x Kenilworth TS) were removed from service by line protection and autoreclosed. Suspected caused was red phase of motorized switch 50HL4-17 switch moving beyond end stop while closing causing a phase imbalance. Q bus o/s at Birmingham TS at the time.	0.01	Yes
12-Oct	Water main break near Bayview and Dundas St. There was a 10X10ft chunk of concrete (road way) that would fall into the H3L circuit (Section Gerrard TS x Mill St. Jct). There was also an Enbridge gas main in close proximity. Circuit was offloaded as precaution. Basin T5 planned out of service at the time.	0.03	Yes
4-Oct	X2Y Chenaux line protection misoperation for faults on Pembroke M3 feeder while circuit X6 was on planned outage.	0.03	Yes
19-Sep	115 kV Circuit F12C (Freeport TS - Cedar TS) was automatically removed from service , when the Cedar TS T7 (115/13.8 kV) differential protection operated. However due to ongoing planned work at Burlington TS on circuit B5C and B6C (Burlington TS - Cedar TS), B5C load (LDC and Hydro One) was interrupted.	0.01	Yes
17-Sep	With the 230 kV Circuit C21J (Chatham TS – Keith TS) out of service for planned work, the companion Circuit C22J was automatically removed from service, resulting in load interruptions in the Windsor area. There was no active weather in the area at the time of the trip and the cause is being investigated.	0.01	Yes
7-Sep	230 kV Circuit X1P (Dobbin TS - Chenaux TS) was removed from service by protection as designed 115 kV Circuits X6/X2Y (radial form Chenaux TS) were also automatically removed from service by a Special Protection System (SPS) operation, interrupting load including Pembroke TS delivery points.	0.03	Yes
6-Sep	230 kV Circuit X1P (Dobbin TS - Chenaux TS) was removed from service by protection as designed 115 kV Circuits X6/X2Y (radial form Chenaux TS) were also automatically removed from service by a Special Protection System (SPS) operation, interrupting load including two Pembroke TS delivery points.	0.04	Yes
5-Sep	115 kV Circuit X6 (Chenaux TS - Pembroke TS) was removed from service by line protections and successfully automatically reclosed. The companion 115 kV Circuit X2Y (Chenaux TS - Pembroke TS) was on a planned outage at the time. Load was interrupted Pembroke TS as a result at two delivery points. Heavy rain was moving through the area at the time of the trip.	0.00	Yes
29-Aug	115 kV Circuit S7M (South March SS - Merivale TS) was removed from service as a result of lightning activity in the Ottawa area. This resulted in an interruption to Hydro One load including multi connected delivery points at Stewartville TS and Marchwood MTS. It also created an island as 115kV Circuit W6CS (Stewartville TS - South March SS) and area generation were separated from the Hydro One grid. W6CS was manually removed from service collapsing the island and interrupting load and generation. One DP at Marchwood MTS was interrupted and two DPs at Stewartville TS were interrupted.	0.04	Yes
6-Aug	115 kV Circuit X6 (Chenaux TS - Pembroke TS) was removed from service by line protections and successfully automatically reclosed. The companion 115 kV Circuit X2Y (Chenaux TS - Pembroke TS) was on a planned outage at the time. Load was interrupted Pembroke TS as a result at two delivery points. Adverse weather was moving through the area at the time of the trip.	0.00	Yes
5-Aug	115 kV Circuit D2L (Crystal Falls SS - Dymond TS) was removed from service during bad weather in the area. The Dymond (44 kV) BY breaker was open for a planned outage causing an interruption to one delivery point at Dymond TS.	0.00	Yes
30-Jul	230 kV Circuit N22W (Scott TS – Buchanan TS) was removed from service following Wonderland TS T5 differential protection trip. Due to the companion Circuit230 kV N21W (Scott TS – Buchanan TS) planned outage, LDC load was interrupted at Modeland TS (28 kV) J and Q busses.	0.02	Yes
27-Jul	230 KV Circuit B22D tripped during the companion 230 kV CircuitB23D outage between Zurich JCT and Detweiler TS. Load was lost at Festival MTS #1 and Stratford TS.	0.04	Yes
11-Jul	230 kV Circuit R21TH (Richview TS - Trafalgar TS) tripped during a planned outage to Tomken TS T3 (230/44 kV) transformer. Staff patrolling the line discovered a bonding conductor that broke off the companion R19TH tower and fell into the R21TH. .	0	Yes
2-Jul	230 kV Circuit T22C (Clarington TS - Chats Falls TS) was automatically removed from service during thunderstorm activity in the area. The companion Circuitsupply to Otonabee TS, 230 kV T31H (Havelock TS - Clarington TS) was on a planned outage .	0	Yes
12-Jul	Buchanan TS T4 (230/115 kV) autotransformer was removed from service following animal contact. 230kV supply Circuit W37 (radial from Buchanan TS) was removed along with the Talbot TS T4 (230/28kV) transformer. At the time the Talbot TS T3 (230/28kV) transformer was out of service for a planned outage.	0.06	Yes
11-Jun	Commerce Way TS T2 transformer was tripped due to animal contact. 115 kV Circuit K12 (Commerce Way TS - Karn TS) tripped and successfully reclosed as designed. Brant TS was being abnormally supplied by Circuit K12 at the time and Y bus was interrupted for 3 minutes.	0.05	Yes
15-May	230 kV Circuit B15C (radial from Cooksville TS) was momentarily interrupted by reports of thunderstorms in the area, during a B16C planned circuit outage. This interrupted delivery points at Ford Oakville CTS, Oakville TS and Lorne Park TS. Oakville and Alectra load was interrupted.	0	Yes
9-May	Kirkland Lake TS suffered a momentary station interruption, 115 kV (Ansonville TS - Kirkland Lake TS) A9K tripped, reclosed successfully during a Kirkland Lake T13 (115/44 kV) transformer outage. This resulted in an interruption to the T12 transformer (115/44 kV) and two Kirkland Lake TS DPs by configuration.	0	Yes
26-Apr	Finch TS T2 and Circuit P22R (Parkway TS - Richview TS) were removed from service from T2 protection operation. Due to an outage to the T1 transformer and Circuit C20R (Cherrywood TS - Richview TS) load at Finch TS was interrupted. due to protection operation on the T2 at Finch TS. Circuit P22R reclosed as designed. This caused an outage for	0.11	Yes
16-Apr	With Cedar T8 out of service, the companion transformer T7 was removed from service by differential protection interrupted LDC load in Guelph. EMD staff reported a squirrel contact on T7 as the cause.	0.01	Yes
14-Apr	During John TS T1 transformer planned outage, the companion transformer T3 was removed from service by protection operation, interrupting LDC load in the GTA.	0.06	Yes
13-Apr	230 kV Circuit H27H (Havelock TS -Hinchinbrook TS) was forced from service to remove arcing 230 kV breaker disconnect switch (AL27-27). This resulted in an interruption of LDC and Hydro One load, as the companion supply CircuitT31H to Havelock TS was out of service for planned work. After the arcing was extinguished and the switch inspected, CircuitH27H was returned to service and the Havelock TS load restored.	0.03	Yes
28-Mar	Chenaux TS T4/TR4 (230/115 kV) transformer and by configuration the 115 kV CircuitX6 (Chenaux TS - Pembroke TS) were removed from service by protection operation. The companion Chenaux T3/TR3 (230/115 kV) transformer was out of service at the time due to the planned outage to the T3/A4, so that the Chenaux T4 was supplying X6 and X2Y at the time when it gassed. Hydro One and LDC load at Pembroke TS and Cobden TS in Eastern Ontario was interrupted.	0.06	Yes

YTD - Transmission Reliability Performance: Single-Circuit, Overall & Momentary

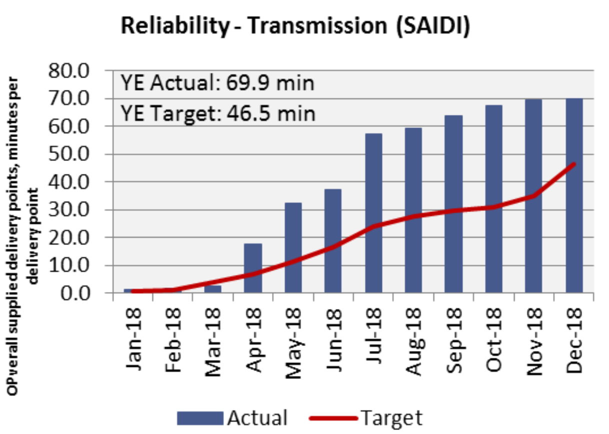
Single Circuit:

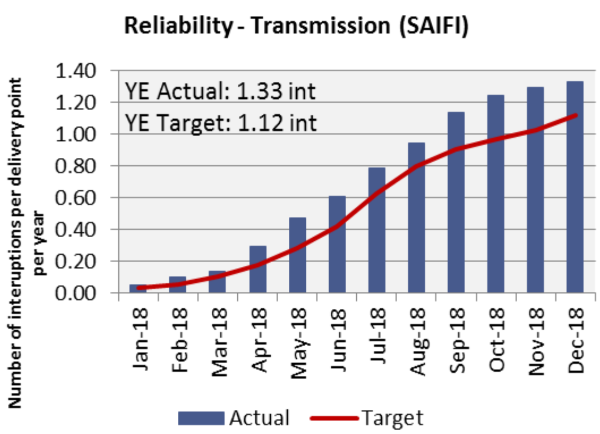


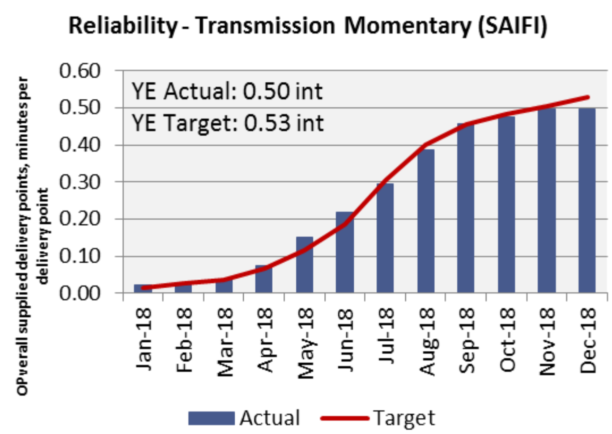


Overall:

Momentary:







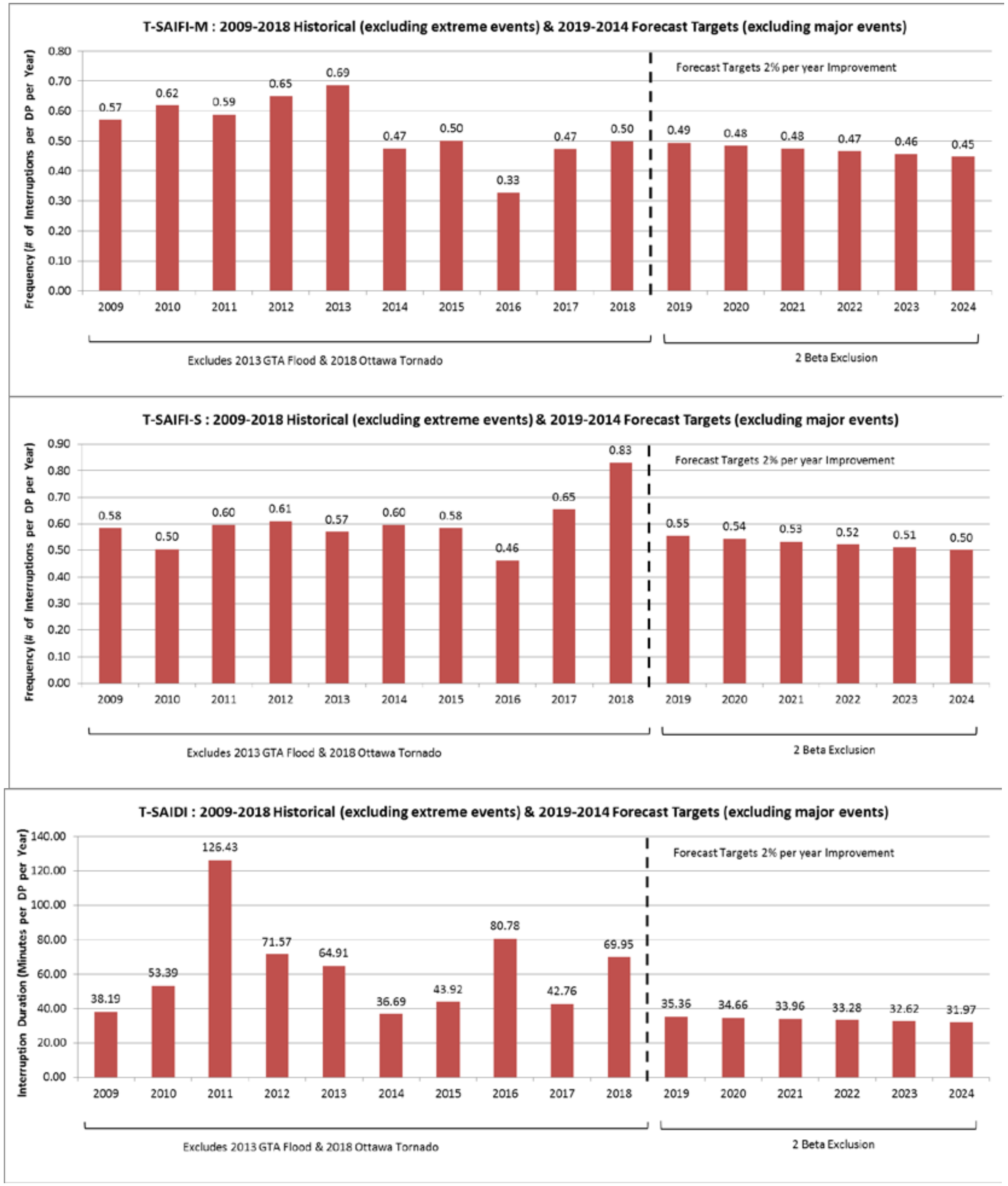
Note: Force Majeure Ottawa Tornado Event – recommend excluding impact of this event consistent with future corporate

2018 December YTD Transmission Regulatory Scorecard

Measures	YTD Actual[3]	YTD Budget	YE Target
T-SAIFI-M (# of interruptions per DP per year)	0.50	0.53	0.53
T-SAIFI-S (# of interruptions per DP per year)	0.83	0.58	0.58
T-SAIDI (interruption minutes per DP per year)	69.95	46.50	46.50
Unsupplied Energy (System Minutes)	19.47	12.61	12.61
System Unavailability (%)[1]	0.67	0.38	0.42
CDPPS Outlier Percentage[2] (annual performance)	9.5%		13.0%

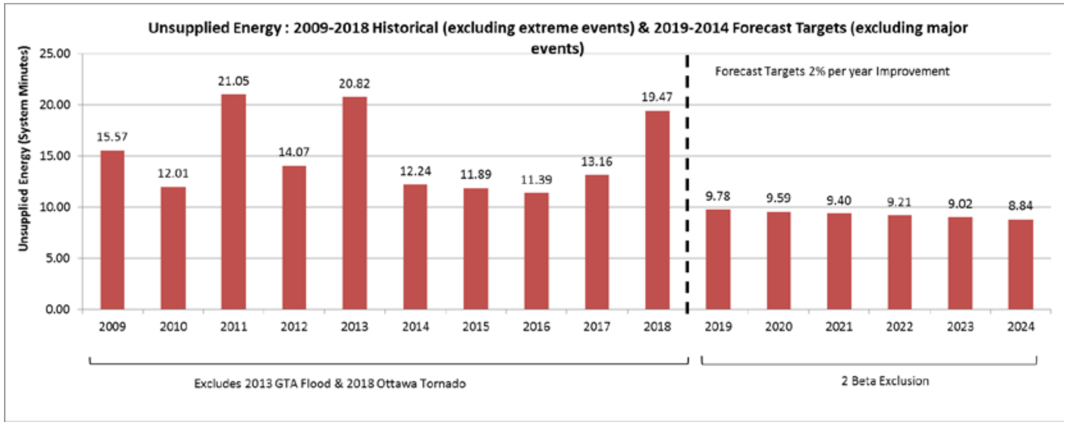
1. Previous month result
2. 2017 result is at 9.5%. 2018 result will be available in June, 2019. YE target is for 2018. There was no target set for 2017.
3. The Sept 21st Merivale TS tornados have been excluded from YTD figures.

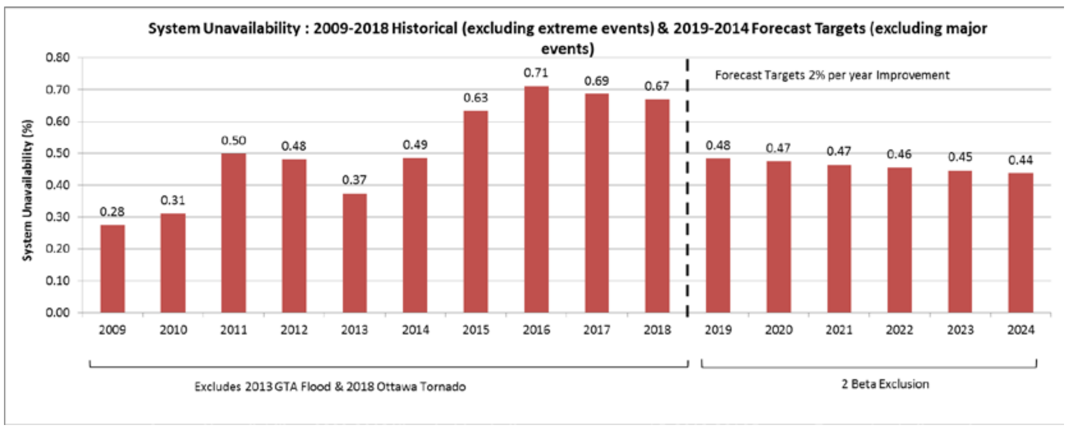
OEB Measures – Overall Transmission SAIFI-Momentary, SAIFI-Sustained and SAIDI



Over the last five years, overall transmission reliability has trended worse

OEB Measures – Overall Transmission Unsupplied Energy and System Unavailability

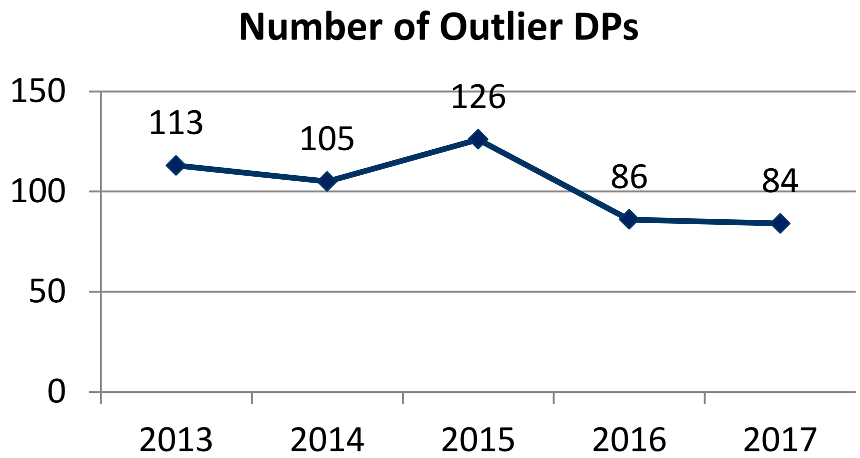


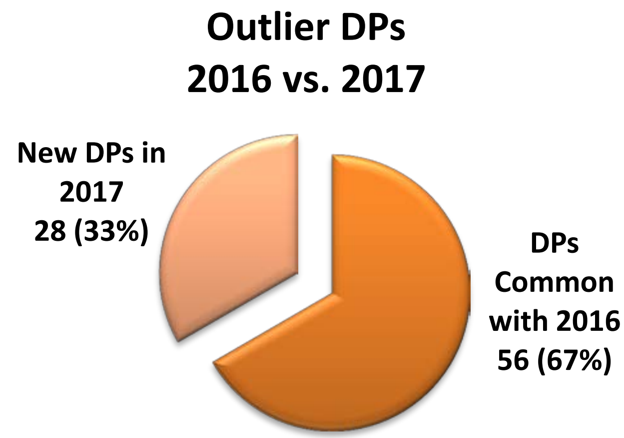


Over the last five years, overall transmission reliability has trended worse

2017 Outlier Delivery Points

- 84 Outlier Delivery Points were identified in 2017, or 9.5% of the 885 Tx DPs
  - over the last 3 years, the number of Outlier DPs has been slowly decreasing



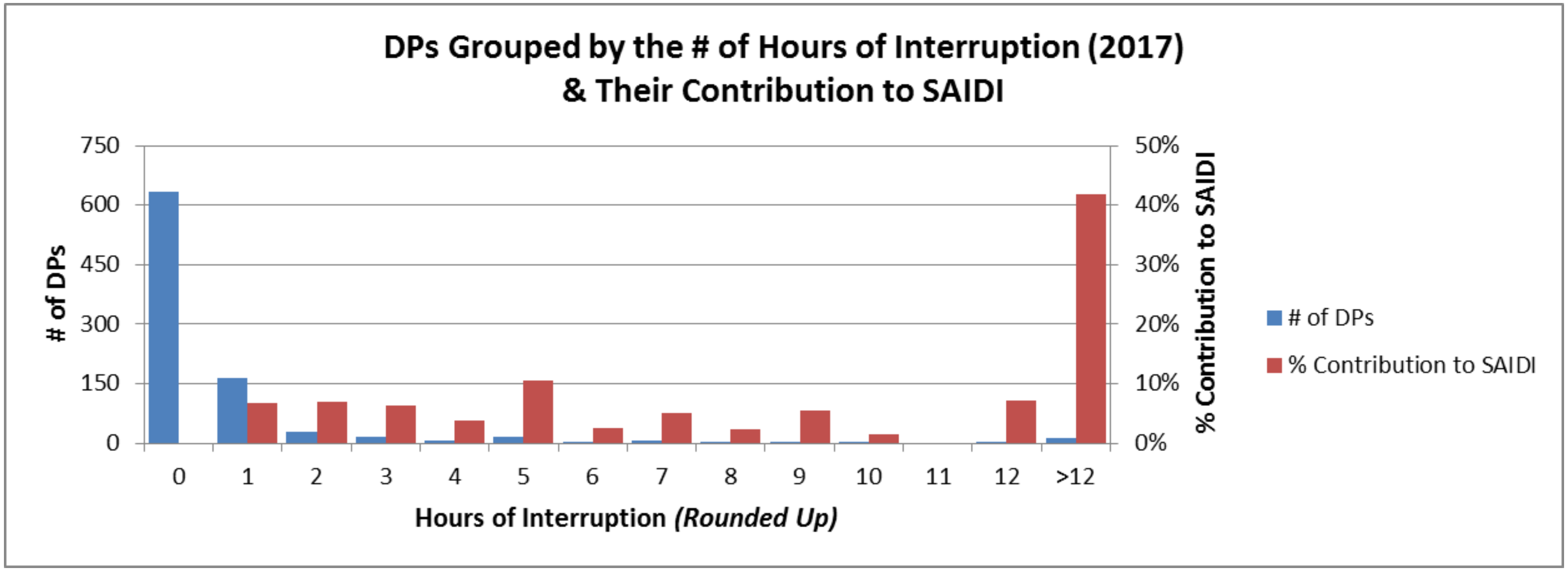


- 19 Assessments have been completed to evaluate the root-cause of poor performance, and develop recommendations for improvement
  - These assessments include 28 New Outlier Delivery Points plus 2 New Worst Performing Circuits identified in 2017
  - 15 Capital Investment Projects in the current Business Plan are expected to improve reliability to some of these Delivery Points. Additional measures are also being planned, including line inspections/condition assessments, installation of new line sectionalizing devices, and animal abatements

- Remaining 56 outlier DPs in 2017 are same as in 2016 (repeat)
  - Assessment of outage/ root cause and development of mitigation strategy is expected to be completed by Q2 2019

2017 Outlier Delivery Points

- **Major contribution to Tx SAIDI is from a small # of DPs**
  - Less than 20 DPs (out of ~900) contribute over 40% to Tx SAIDI every year (some are repeat year over year)
  - Will require targeted mitigation/investments on each of these DPs



New options being considered for 2019:

- Unique Outage Response Plan for 2-4 worse performing lines
- Stringent design for long single circuit lines and seek opportunity to bring off-road section to road side
- Expected completion is Q4 2019

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ENERGY PROBE INTERROGATORY #6

Reference:
A-03-01 Table 2

Interrogatory:
a) Please provide a Table showing the 2018 Baseline costs and the Productivity Saving Forecast.

b) Please explain in more detail the Capital savings in context of the 2019-2024 Capital Plan.

Response:
a) Please see Table 1 of Exhibit B-1-1 TSP Section 1.6 for total productivity savings forecast.

Section 1.6.1.1 Productivity Governance of the above noted exhibit discusses that Hydro One's baseline year for initiative savings was set at 2015 for legacy initiatives in order to show continuity of initiatives and consistency between rate filings. A table showing all baseline costs is not feasible to produce due to the volume and sensitivity of data being presented. Please see response to SEC-26 for a detailed listing of initiatives and measurement description.

b) Please see section 1.6.2.2 Overview of Productivity Savings for details of the 5 year productivity plan in the TSP. The productivity savings plan is discussed and quantified relative to the impact on OM&A and Capital. The primary savings initiatives impacting capital are Procurement and Progressive Initiatives which are described in detail in section 1.6.2.2 of the TSP.

Witness: Joel Jodoin

ENERGY PROBE INTERROGATORY #7

Reference:
A-03-01 p.25

Interrogatory:
Preamble:
In developing its Investment Plan, Hydro One utilized the Ontario Consumer Price Index ("CPI") for its assumptions about inflation. A CPI of 2% was assumed over the planning period. The Global Insight exchange rate forecast was used for other variables such as fleet vehicle related costs, which are typically obtained in US dollars. The exchange rate was forecast to range between 0.793 and 0.803 over the planning period.

a) Please explain why for forecasting its costs, Hydro One uses CPI instead of GDP-IPI (FDD) as per the RCI formula?

b) Please provide the breakdown of Capital and O&M RR costs into those subject to the CPI and those part of IPI FDD.

Response:
a) From an investment planning perspective, CPI is used largely for pragmatic and practical reasons and is not the sole factor to forecast costs. CPI is widely known and recognized, and is the most commonly referenced inflation index in the media. As a result, Hydro One planners and other staff are more familiar with the CPI calculation than GDP-IPI. Further, CPI is published monthly, it is subject to fewer and more minor future revisions compared to GDP-IPI and extended forecasts are widely available from banks and other public institutions, whereas GDP-IPI is not. Other factors which impact Hydro One's assumptions about future costs include changes to volumes, work practices, material and equipment costs, productivity and negotiated union agreements.

b) Please refer to Staff-180.

ENERGY PROBE INTERROGATORY #8

Reference:

A-03-01 p.43 Table 10, F-04-01-05

Interrogatory:

Preamble:

Hydro One's 2019 and 2020 total transmission-allocated compensation costs are summarized in Table 10. The 2020 transmission-allocated costs represent an 8.0% increase over 2019 levels.

a) Please break down the Compensation Increase relative to 2018 into % associated each of with Headcount, negotiated wage increases for each of Executive Management and Union and Incentive pay.

b) Please provide/compare the compensation amount claimed for HO Distribution.

c) Please explain any differences related to staffing profiles and why this level of increase is appropriate.

Response:

a) The compensation increases between 2019 and 2020 based on the latest payroll table which is provided in Exhibit I, Tab 07, Schedule SEC-58 Attachment 1 is summarized below:

Non Represented	2019 Total Compensation	2020 Total Compensation	2019-2020 Difference	Headcount Impact	Escalation Impact	STIP	Other
Consolidated	181,948,030	186,288,823	4,340,793	188,782	4,548,701	335,076	(731,765)
Transmission Allocation	65,506,806	74,018,853	8,512,047	5,162,446	1,637,670	690,195	1,021,736
Distribution Allocation	92,692,386	87,981,412	(4,710,974)	(4,973,664)	2,317,310	(355,119)	(1,699,501)
Shareholder Allocation	23,748,837	24,288,558	539,720		593,721		(54,001)

Society	2019 Total Compensation	2020 Total Compensation	2019-2020 Difference	Headcount Impact	Escalation Impact	Other
Consolidated	278,958,757	283,456,682	4,497,925	(2,034,902)	1,394,794	5,138,032
Transmission Allocation	125,143,693	137,707,506	12,563,812	9,400,320	625,718	2,537,774
Distribution Allocation	153,815,064	145,749,176	(8,065,888)	(11,435,222)	769,075	2,600,259

PWU	2019 Total Compensation	2020 Total Compensation	2019-2020 Difference	Headcount Impact	Escalation Impact	Other
Consolidated	609,747,745	631,933,457	22,185,713	7,238,054	12,194,955	2,752,703
Transmission Allocation	281,748,947	313,335,001	31,586,055	24,090,030	5,634,979	1,861,046
Distribution Allocation	327,998,798	318,598,456	(9,400,342)	(16,851,976)	6,559,976	891,657

Non Regular	2019 Total Compensation	2020 Total Compensation	2019-2020 Difference	Headcount Impact	Escalation Impact	Other
Consolidated	282,479,838	279,120,554	(3,359,284)	(8,919,341)	5,649,597	(89,540)
Transmission Allocation	160,680,791	160,850,913	170,122	(2,892,857)	3,213,616	(150,636)
Distribution Allocation	121,799,047	118,269,640	(3,529,406)	(6,026,484)	2,435,981	61,097

b) See a)

Witness: Sabrin Lila

c) The differences between the staffing profiles (Non- represented, Society and PWU) are mainly impacted by the relative increase/decrease in FTE's between these employee classifications.

ENERGY PROBE INTERROGATORY #9

Reference:
A-04-01 p.6 Table 2

Interrogatory:
Preamble:
The Custom Capital Factor is the percentage change in the Total Revenue Requirement (line 11 of Table 1) attributable to new capital investment that is not otherwise recovered from customers. This includes depreciation, return on equity, interest and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The Capital Related Revenue Requirement (line 6) each year is based on the change in rate base.

a) Please provide for illustrative purposes, the rate base and proxy Capital Factor for the Historic and 2019 years. Please add explanatory notes.

b) Please discuss why the Capital Factor should be based on the prior year closing Rate Base as opposed to Net Assets in Service or some other parameter.

c) When has the Board approved a similar Capital Factor for either distribution or transmission?

d) Discuss why the revenue requirement associated with the Capital Factor should not be based on the actual in-service capital additions.

Response:
a) As discussed in Exhibit A, Tab 4, Schedule 1 the Custom Capital Factor in this Application is designed to recover the incremental revenue in each test year beyond the amount of revenue recovered through the I-X adjustment. The capital factor is represented as a percent change in the revenue requirement. Once determined in this proceeding, these values are to be held constant throughout the Custom IR term. In the proposed application, OM&A is rebased in 2020 and adjusted by the I-X adjustment each year and the cost of capital parameters are held constant throughout the rate term. In prior years, Hydro One’s transmission revenue requirement was deemed using a cost of service approach in each year. Any calculated percent change in revenue requirement for historical years would also capture changes in cost of

capital, as well as changes in OM&A beyond I-X and would not yield an "apples-to-apples" comparison with the Capital Factor proposed in this application.

b) Pages 6-8 of Exhibit A, Tab 4, Schedule 1 indicates that the Custom Capital Factor is the percentage change in Total Revenue Requirement attributable to new capital investment that is not otherwise recovered from customers through the I-X adjustment. As the return on capital is calculated based on a rate base amount, Capital Related Revenue Requirement would also be calculated based on rate base values.

c) The OEB also approved a similar capital factor approach in Toronto Hydro's 2015-2019 Custom IR application (EB-2014-0116). The current Hydro One proposal is also largely consistent with the RCI formula including the Custom Capital Factor which was approved as part of Hydro One's Distribution application in EB-2017-0049 with one difference. Hydro One has not removed amount related to working capital from the derivation of the capital factor. Hydro One believes that circumstances are different for transmission for two reasons: (i) working capital costs in transmission arise from activities related to Hydro One's transmission business only whereas distribution also includes amounts related to the cost of power and (ii) working capital amounts are much smaller in transmission as shown in Exhibit I, Tab 04, Schedule 2 do not materially impact the calculation of the capital factor.

d) The current Custom IR application is based on proposed rate base for the term of the application and supported by capital investments as discussed further in the TSP. As Hydro One is proposing a Capital In-Service Variance Account (CISVA) any negative differences between the revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the OEB-approved in-service capital additions for that year would be captured in the account and returned to customers.

Moreover, as indicated in the OEB Handbook, after rates are set as part of the Custom IR Application, the OEB expects there to be no further updates within the IR term. As such, updating the revenue requirement impact to reflect actual in-service capital additions would result in annual updates which contradict the OEB Handbook.

ENERGY PROBE INTERROGATORY #10

Reference:
TSP-01-05 p.29-30, Figures 6,7 and 8

Interrogatory:
a) Please position Hydro One relative to the top quartile of the Transmission peer group. T-SAIDI T- SAIFI and T-MAIFI in terms of number of customers interrupted and duration in last data year (2016) and provide 2018 actuals relative to the top quartile of the Transmission peer group.

b) Please provide the 2019-2024 targets for system reliability by adding bar charts to the referenced Figures 6, 7, 8.

c) Please provide the 2019-2024 targets for delivery point system unavailability and unsupplied load by adding bar charts to the referenced Figures 9 and 10
Ensure the projections are consistent with the Evolved Transmission Scorecard.

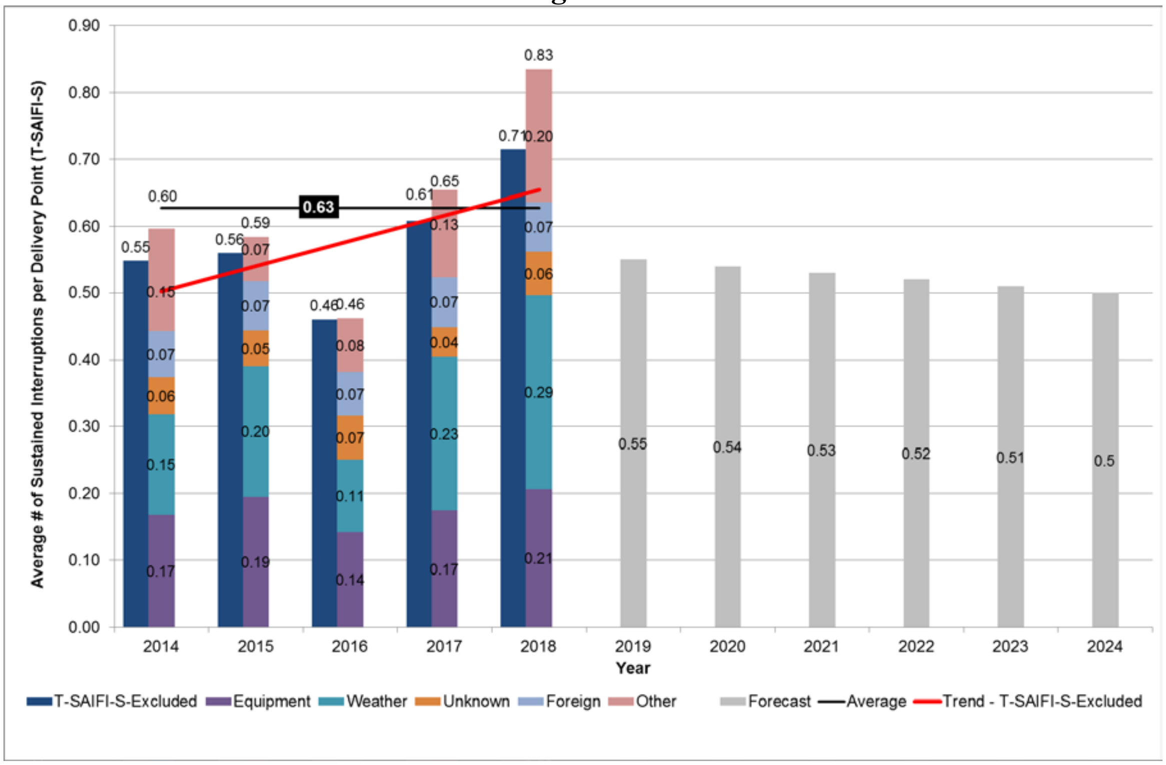
Response:
a)

Quartile	2016	2018
T-SAIDI	Q3	Q2
T-SAIFI	Q1	Q2

Note: T-SAIFI is the system average Interruption frequency index, sustained and momentary combined.

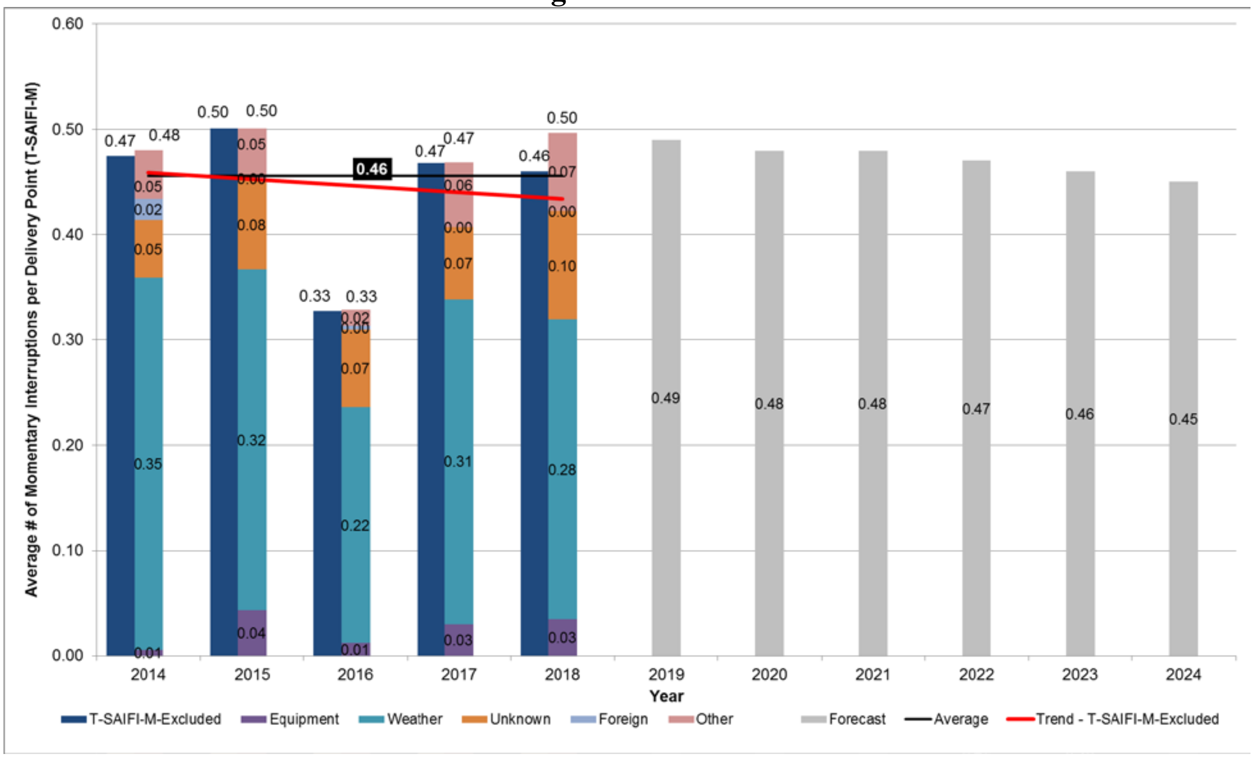
1 b)

2 **Figure 6**



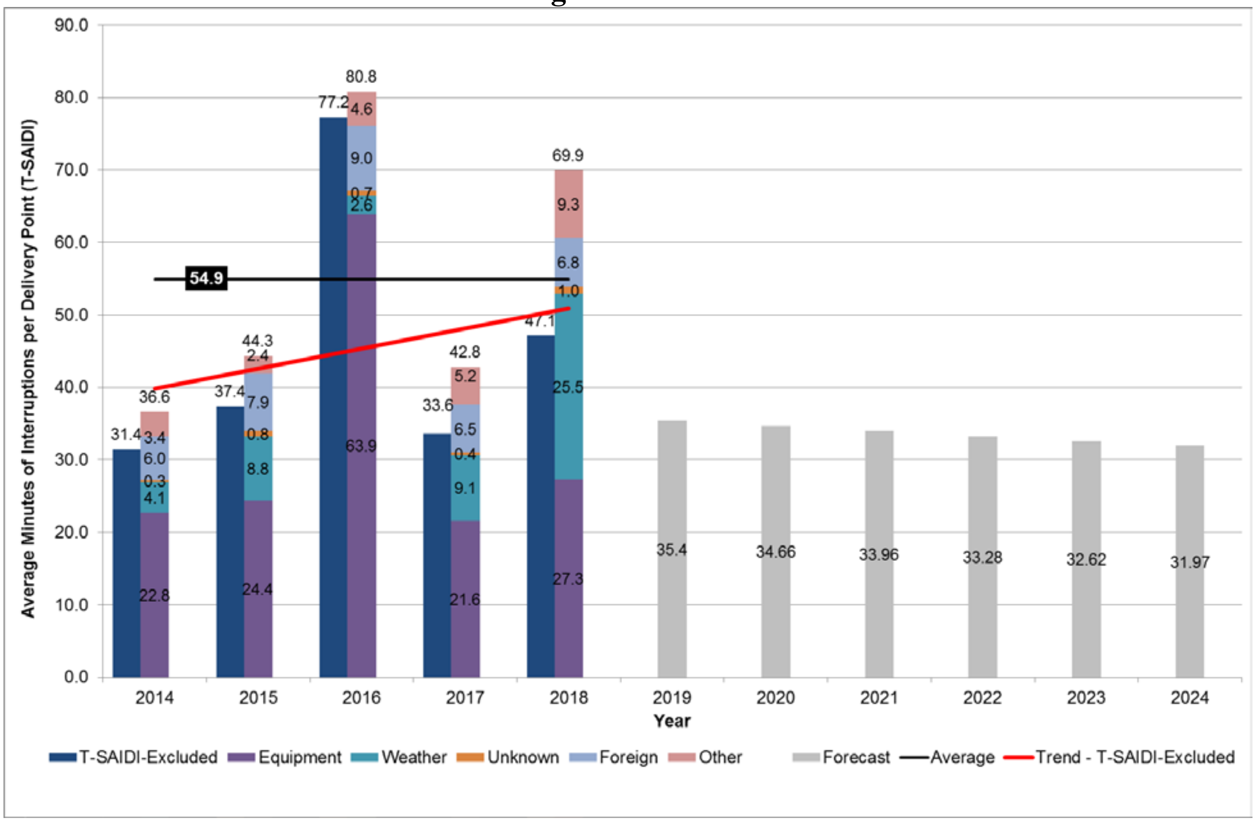
3

1 **Figure 7**


Average # of Momentary Interruptions per Delivery Point (T-SAIFI-M)
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.47 0.48
0.50 0.50
0.33 0.33
0.47 0.47
0.46 0.50
0.46
0.49
0.48
0.48
0.47
0.46
0.45
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Year
T-SAIFI-M-Excluded
Equipment
Weather
Unknown
Foreign
Other
Forecast
Average
Trend - T-SAIFI-M-Excluded

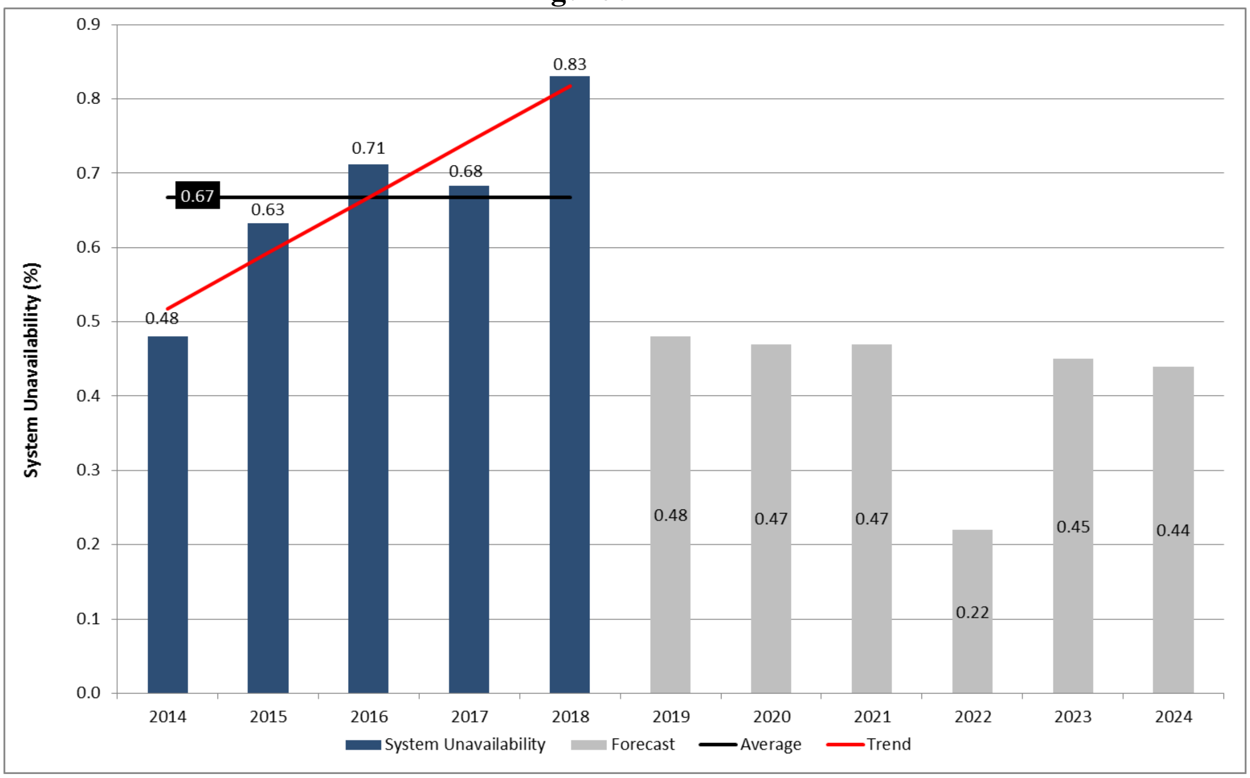
2

Figure 8

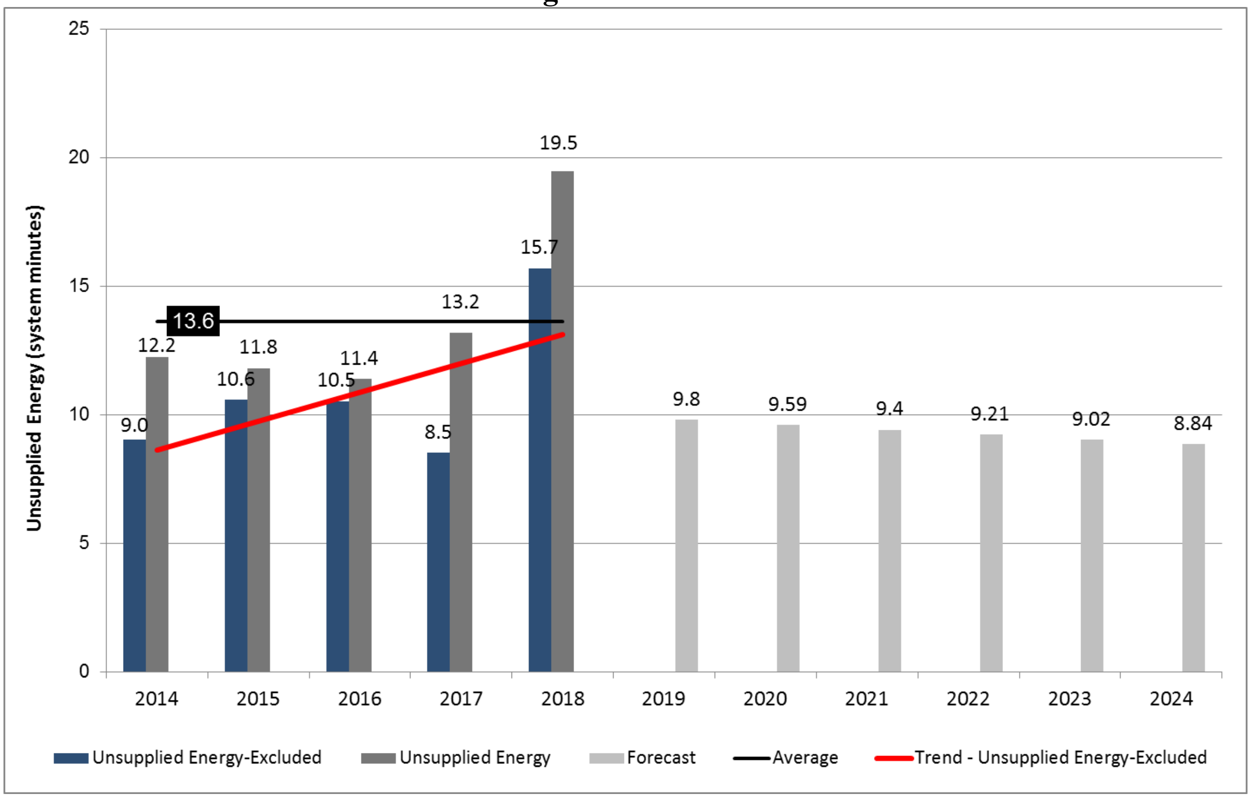

Average Minutes of Interruptions per Delivery Point (T-SAIDI)
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
54.9
31.4
36.6
3.4
6.0
0.3
4.1
22.8
37.4
44.3
2.4
7.9
0.8
8.8
24.4
77.2
80.8
4.6
9.0
0.7
2.6
63.9
33.6
42.8
5.2
6.5
0.4
9.1
21.6
47.1
69.9
9.3
6.8
1.0
25.5
27.3
35.4
34.66
33.96
33.28
32.62
31.97
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Year
T-SAIDI-Excluded
Equipment
Weather
Unknown
Foreign
Other
Forecast
Average
Trend - T-SAIDI-Excluded

c)

Figure 9


0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
System Unavailability (%)
0.48
0.63
0.71
0.68
0.83
0.67
0.48
0.47
0.47
0.22
0.45
0.44
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
System Unavailability
Forecast
Average
Trend

1 **Figure 10**


Unsupplied Energy (system minutes)
25
20
15
10
5
0
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
13.6
9.0
12.2
10.6
11.8
10.5
11.4
8.5
13.2
15.7
19.5
9.8
9.59
9.4
9.21
9.02
8.84
Unsupplied Energy-Excluded
Unsupplied Energy
Forecast
Average
Trend - Unsupplied Energy-Excluded

2

ENERGY PROBE INTERROGATORY #11

Reference:
TSP-01-08, I1-01-03

Interrogatory:
a) Please provide Hydro One Transmission historical and forecast line losses.

b) What are the main drivers factors affecting line losses from Hydro One existing assets e.g. voltage, km of lines, climate etc.?

c) Please provide data showing how Hydro One's line losses compare to other large North American transmitters, including Canadian transmitters.

d) How does the Transmission Cost Allocation Model allocate line losses to Functions and Pools? Please provide details including the cost allocation factors.

e) Provide an example for 2020 showing how line losses are allocated to Network, Line, Transformation and Export.

f) Please provide a breakdown of line kilometers for Network and Line.

g) Please provide Export Line kilometers and Generation Line kilometers as subsets.

h) Comment if a more detailed breakdown of line kilometers could result in a more appropriate allocation of costs related to line Losses

Response:
a) Hydro One does not track losses on the transmission system; and therefore does not have historical or forecast information. The losses are tracked by the Independent Electricity System Operator ("IESO"). The transmission losses for the Ontario Transmission System were about 1.82% for 2018 as provided by the IESO in EB-2019-0002 Exhibit C-5-1.

b) Please refer to Exhibit B, Tab 1, Schedule 1, TSP Section 1.8.

c) As noted in response to part (a) above, the losses for the Ontario transmission system were about 1.82% in 2018. Typical transmission losses as reported by EPRI (Exhibit B, Tab 1, Schedule 1, TSP Section 1.8, Attachment 1) range from 1.5% to 5.8%.

d) The Transmission Cost Allocation Model does not allocate any line losses to Functions and Pools.

e) Lines losses are not allocated to any Transmission Tariff Rate Pools. The costs associated with lines losses are included in the "Wholesale Market Service Charges – Other Hourly Uplift" collected by the IESO from all market participants.

f & g) This information is not readily available. Furthermore, as discussed in part (e), "line kilometers" is not a relevant consideration in the IESO's recovery of the cost of line losses.

h) Please see the response to part (f & g).

ENERGY PROBE INTERROGATORY #12

Reference:
TSP-01-05 p.16 Table 6, p.45-47 Figures 17 and 18

Interrogatory:
Preamble:
In 2018, Hydro One Transmission line clearing and brush control activities accounted for approximately 78 per cent of the overall transmission forestry budget. The unit cost measures are calculated by dividing the annual expenditure on a given program by the number of units completed in that year.

a) Please provide a projection of unit costs for 2019-2024 by adding bars to the referenced figures. Please ensure consistency with Evolved Transmission Scorecard.

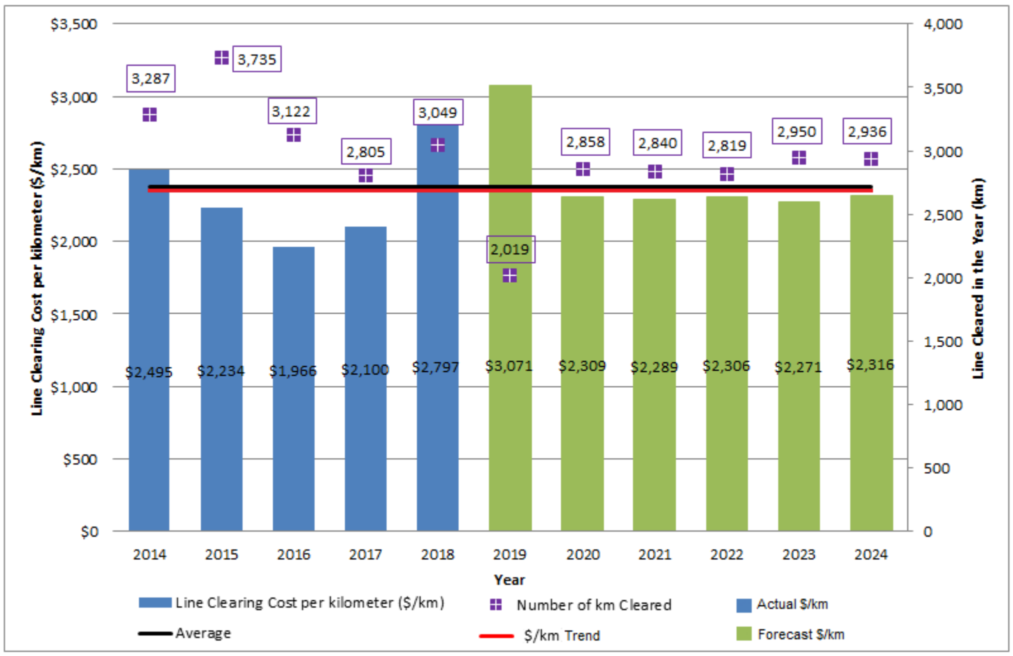
b) Please provide a chart showing the annual cycle times for brush control and line clearing for the historic period showing if/when the cycles were changed.

c) Are the cycle times now consistent with the recommendations of the CNUC Benchmarking Study filed in the prior case (EB-2014-0160)?

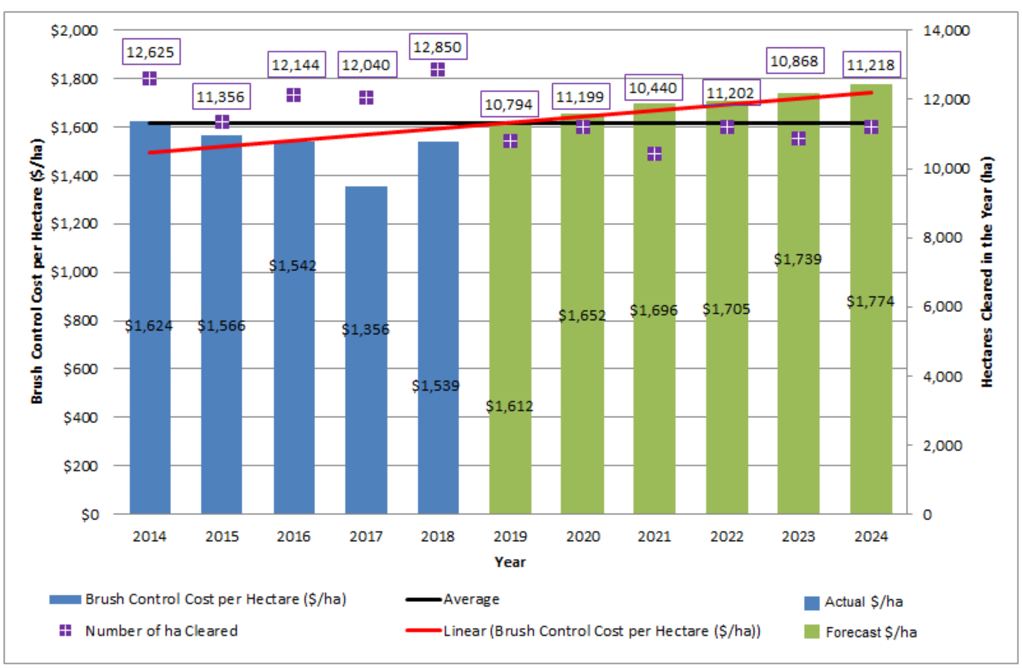
d) How do the cycle times compare to those accepted by the Regie for Hydro Quebec? (CNUC Survey 2016 HQD Doc 1; Decision R-4011-2017)

Response:

a) **Line Clearing Cost per Kilometer and Number of Kilometers Cleared Annually**



Brush Control Cost per Hectare and Hectares Completed Annually



2018 and 2019 Line Clearing unit costs are higher than average due to Hydro One's efforts to ensure that corridors are cleared to design width and increased work requirements to maintain urban corridors to Transmission industry and NERC standards. As this work is completed, unit costs are expected to return to the historical average. 2020-2024 Brush Control unit costs are expected to gradually increase, due to efforts to ensure that maintenance is completed on-cycle.

b) The line clearing and brush control cycle times for Hydro One's Transmission Vegetation Management Program have not changed. Please refer to Exhibit B-1-1, TSP Section 2.2.2.5, pages 92-93 for information regarding Hydro One's transmission vegetation management cycle lengths.

c) The CNUC Benchmarking Study refers to Hydro One's Distribution Vegetation Management Program and is not applicable to the Transmission Vegetation Management Program discussed in this Application.

d) CNUC Survey 2016 HQD Doc 1; Decision R-4011-2017 refers to Hydro Quebec's distribution system. Due to differences in design requirements and vegetation clearance distances, distribution vegetation management cycle times cannot be compared to Hydro One's transmission system.

ENERGY PROBE INTERROGATORY #13

Reference:
C-02-01 p.13

Interrogatory:
Does Hydro One have a prioritization system for capital projects? If the answer is yes, please explain how it was used for the allocation of capital reductions in the DRO process. If the answer is no, please explain why not.

Response:
Hydro One has a prioritization process for candidate investments which includes capital projects as part of the overall investment planning process outlined in Exhibit B, Tab 1, Section 1, TSP Section 2.1.

Capital Reductions made as part of the DRO process for EB 2016-0160 were based on key considerations outlined in the above exhibit including customer needs and preferences, risk mitigation per dollar, absolute risk mitigation, flagging criteria, resourcing, material availability and outage feasibility. Discussions were facilitated through cross functional review sessions, resulting in trade-offs and reductions informed by the high-level guidance of the OEB's DRO Order.

In Hydro One's "DRO Update" dated November 16, 2017 which was submitted in response to the DRO Order, Hydro One addressed the points raised by the OEB in the DRO Order with an explanation about how it allocated capital reductions in the draft rate order for 2017 (where possible) and 2018 by providing the following additional information:

- In "Overhead Lines Refurbishment Projects, Component Replacement", the company reduced the tower coating and shieldwire replacement programs and its deferred line refurbishment projects.
- In "Integrated Stations", at the time the Decision was issued, 98% and 75% of the portfolios for 2017 and 2018, respectively, were already in execution. Cancelling those projects would result in significant inefficiencies and stranded costs. Deferring the remaining 25% of the 2018 "Integrated Stations" projects would negatively impact reliability. These projects include investments at Kingsville,

Leaside, Cherrywood, Sheppard, Detweiler, Minden, Gage and Stanley transformer stations.

Reductions in the Development capital forecast were largely driven by changes in customer demand and project forecasts. The Development projects most impacted are investments at Clarington TS (-$38 million), Lisgar TS (-$7 million), Runnymede TS (-$13 million) and Hanmer TS (-$8 million).

ENERGY PROBE INTERROGATORY #14

Reference:
C-02-01-01 p.48

Interrogatory:
Preamble:
The explanation for the variance in the Inter Area Network Transfer Capability mentions that "project risks did not materialize" in the Clarington TS project.

Did the Clarington TS project cost estimate include contingency? If the answer is yes, please provide a table that shows the contingency for the DRO and the Actuals. If the answer is no, please explain why not.

Response:
The Clarington TS project cost estimate used in the DRO did include contingency. The following table demonstrates the use of contingency for 2017 and 2018 on the project.

($ in millions)

2017				2018			
DRO Budget	Included Contingency	Actuals	Contingency Use	DRO Budget	Included Contingency	Actuals	Contingency Use
30.4	0.7	29.7	0	21.5	2.6	14.6	0

Witness: Andrew Spencer

ENERGY PROBE INTERROGATORY #15

Reference:
F-01-06 p.2 Tables 1 and 2

Interrogatory:
Please explain why Actual Customer Care costs were higher than Plan for 2017 and 2018 while Corporate Affairs and Outsourcing Actual costs were lower than Plan for those years.

Response:
Please refer to interrogatory response I-01-OEB-188.

ENERGY PROBE INTERROGATORY #16

Reference:
F-01-07
EB-2016-0160 B2-02-01

Interrogatory:
Preamble:
In EB-2016-0160 Hydro One indicated that although the hourly cost of overtime, which is driven by negotiated labour contracts, was higher than the peer group (Figure 30), Hydro One's overtime usage, as a percent of total hours, was consistent with other companies in the peer group (Figure 31). However, under the existing labour agreements, it also means that additional hours begin at double-time pay, rather than time and a half. Overtime cost for Hydro One was generally higher than the other reporting companies. Significant benefit can be realized by minimizing overtime. (Page 30 of Report).

a) Please indicate the basis of the current overtime policy.

b) Please provide the data showing base year overtime paid relative to the peer group (include explanations for normalizing data).

c) Please indicate the average overtime in 2018 as a percentage of base pay for Union, Society and MCP employees.

d) Please provide the calculation of total overtime paid in 2018 and provide an alternative cost with time and half (except for statutory holidays).

Response:
a) MCP employees are compensated on a salary basis and have not historically attracted overtime. For both PWU and Society represented employees, overtime is governed by the appropriate collective agreements.

b) Hydro One does not have the information readily available.

c) As per Exhibit F, Tab 4, Schedule 1, Attachment 5, MCP employees do not receive overtime. The average overtime in 2018 as a percentage of base pay for Society and PWU Represented employees is 6.4% and 22% respectively.

d) It should be noted that overtime is variable year to year due to a number of factors, such as the frequency of storms which result in restoration work, often on “off hours”. For example, 2018 had more storms than 2017 which partially accounts for the increased number of overtime hours and the resulting overtime spend. Table 1 and Table 2 show the actual overtime spend, overtime hours worked and the overtime spend if all overtime was paid at 1.5 times base rate for 2017 and 2018. Due to the complexity of separating overtime paid on statutory holidays, all overtime was considered to be paid at 1.5 times base in this analysis.

Table 1:

2018 Overtime						
	OT $ per EX F Tab 4 Schedule 1 Attachment 5	Hrs OT worked	Avg Hrly rate	rly Rate @ 1.5	OT at 1.5	Difference in OT between Actual OT spend vs OT only at 1.5X
Regular PWU	$ 78,317,562	848,107	$ 43.50	$ 65.25	$55,337,586	$ 22,979,977
Regular Society	$ 9,903,383	92,197	$ 61.25	$ 91.88	$ 8,470,807	$ 1,432,576
Non Regular OT	$ 31,148,187	421,904	$ 42.98	$ 64.47	$27,200,151	$ 3,948,036
						$ 28,360,588

Table 2:

2017 Overtime						
	OT $ per EX F Tab 4 Schedule 1 Attachment 5	Hrs OT worked	Avg Hrly rate	Hrly Rate @ 1.5 X	OT at 1.5	Difference in OT between Actual OT spend vs OT only at 1.5X
Regular PWU	$ 60,810,410	682,826	$ 43.65	$ 65.48	$44,708,026	$ 16,102,384
Regular Society	$ 7,725,212	74,889	$ 61.15	$ 91.73	$ 6,869,194	$ 856,018
Non Regular OT	$ 18,250,449	247,519	$ 42.22	$ 63.33	$15,675,404	$ 2,575,045
						$ 19,533,447

Table 3 and Table 4 show the same analysis as above at the Transmission level.

Table 3:

2018 Overtime (Transmission)						
	TX OT $ per EX F Tab 4 Schedule 1 Attachment 5	Hrs OT worked	Avg Hrly rate	Hrly Rate @ 1.5 X	OT at 1.5	Difference in OT between Actual OT spend vs OT only at 1.5X
Regular PWU	$ 46,990,537	508,864	$ 43.50	$ 65.25	$33,202,551	$ 13,787,986
Regular Society	$ 5,942,030	55,318	$ 61.25	$ 91.88	$ 5,082,484	$ 859,545
Non Regular OT	$ 18,688,912	253,142	$ 42.98	$ 64.47	$16,320,091	$ 2,368,822
						$ 17,016,353

Table 4:

2017 Overtime (Transmission)						
	TX OT $ per EX F Tab 4 Schedule 1 Attachment 5	Hrs OT worked	Avg Hrly rate	Hrly Rate @ 1.5 X	OT at 1.5	Difference in OT between Actual OT spend vs OT only at 1.5X
Regular PWU	$ 36,486,246	409,696	$ 43.65	$ 65.48	$26,824,815	$ 9,661,430
Regular Society	$ 4,635,127	44,933	$ 61.15	$ 91.73	$ 4,121,517	$ 513,611
Non Regular OT	$ 10,950,269	148,512	$ 42.22	$ 63.33	$ 9,405,242	$ 1,545,027
						$ 11,720,068

The use of overtime and the overtime spend is closely monitored by managers and executives. All overtime requires pre approval and must be submitted and approved on employee’s time sheets. The use of overtime is often a prudent deployment of resources to complete necessary work. The alternative approach to hire more regular employees to reduce overtime spend may not always be a fiscally responsible approach due to the inherent employment commitments.

Overtime may be required mainly in the following situations:

- Trouble Calls /Storm Response
- Demand Corrective (Equipment failure, High Priority defects)
- Planned outages in support of the O&M work program
- Switching Requests
- Cold Weather Monitoring (specific to high pressure air systems)
- Large Customer Plant Shutdowns (GM, Ford, OPG, Bruce Power etc.)
- Oil Handling (Degassifier runs which require overnight work)
- Customer Interruptions (Distribution customers)

Hydro One endeavours to coordinate outages with large customers. This is often when the load is low (non-peak times). For example, coordinating an outage on a weekend with a large industrial customer, while they have an operations shut down, which results in overtime.

ENERGY PROBE INTERROGATORY #17

Reference:
F-02-06 p.18, F-02-01-01

Interrogatory:
a) Please provide a summary of the 2020 costs and allocation for
   i. Office of the CEO
   ii. Board of Directors
   iii. Corporate Secretary
   iv. Other Governance costs

b) For the following functions please provide a summary of the costs and the allocation of these for 2020:

   i. Ombudsman Office
   The Ombudsman Office commenced activity following the Initial Public Offering, in order to address complaints escalated from the Customer Service. Prior to that, the Province of Ontario's Ombudsman had authority to investigate issues related to Hydro One customers.

   ii. Investor Relations
   Investor Relations commenced activity following the Initial Public Offering, in order to communicate with Shareholders and potential investors and address their concerns.

c) Please confirm that the costs of EVP Strategy Office (Corporate Development) are directly assigned to the shareholder only.

Response:
a)
   i. Please see Exhibit F, Tab 2, Schedule 2 Table 4 for Total Cost of President/CEO Office.

   ii. Please see Exhibit F, Tab 2, Schedule 2 Table 5 for Costs allocated to Transmission of President/CEO Office.

Please see Exhibit F, Tab 2, Schedule 2 Table 4 for Total Cost of Board and Chair Office.

Please see Exhibit F, Tab 2, Schedule 2 Table 5 for Costs allocated to Transmission of Board and Chair in initial filing.

On February 21 2019, the Government of Ontario issued a Directive that impacted board compensation. This is further described on page 35 and 36 of Exhibit F, Tab 4, Schedule 1. On April 19 2019 Hydro One filed a Blue Page update incorporating bottom line reductions to OM&A and Capital Exhibits which translated to a reduction in Revenue Requirement. The impact to Table 4 “Board” and “Chair Office” is a reduction of $0.5M, and the impact to Table 5 “Board” and “Chair Office” is a reduction of $0.2M.

iii. Please see Exhibit F, Tab 2, Schedule 2 Table 4 for Total Cost of Corp. Secretary.

Please see Exhibit F, Tab 2, Schedule 2 Table 5 for Costs allocated to Transmission of Corp. Secretary.

iv. Hydro One does not have a cost classification for ‘Other Governance Costs’

b)

i. Please see Exhibit F, Tab 2, Schedule 2 Table 4 for Total Cost of Ombudsman.

Please see Exhibit F, Tab 2, Schedule 2 Table 5 for Costs allocated to Transmission for Ombudsman.

ii. Please see Exhibit F, Tab 2, Schedule 2 Table 4 for Total Cost of Investor Relations.

Please see Exhibit F, Tab 2, Schedule 2 Table 5 for Costs allocated to Transmission for Investor Relations. As described on page 7 of the referenced exhibit, Investor Relations costs are not recoverable from transmission or distribution customers, and are paid fully by shareholders.

c) Confirmed.

Witness: Joel Jodoin

ENERGY PROBE INTERROGATORY #18

Reference:
F-04-01 p.13, F-04-01-05

Interrogatory:

a) Please confirm the following: relative to 2018, by 2022 Hydro One has/will hire an additional ~ 500 regular employees and will add in total 800 employees.

b) Please provide OEB Form 2K for both historic years and projection to 2022.

c) Using the Exhibit in the second reference, please compute the % increases in the Headcount and Total Compensation from 2018-2022 and map these to each of Distribution and Transmission.

Response:

a) For Hydro One Networks (Transmission and Distribution), as per F-04-01 Table 2 page 13 between the period 2018 – 2022 regular employees increase by 604 with a total increase of 731 FTEs. For Transmission, over the same period, regular employees increase by 453 with a total increase of 366 FTEs.

b) Historically, Hydro One has filed compensation exhibits that substantially contains the data in the OEB Form 2K. Please see Exhibit I, Tab 7, Schedule SEC-58.

c)

% Change from 2018 to 2022		
	Transmission	**Distribution**
Headcount	9%	9%
Total Compensation	17%	15%

Note: Headcount calculation is based on FTE Headcount.

Witness: Sabrin Lila

ENERGY PROBE INTERROGATORY #19

Reference:
F-04-01 p.40 Figure 7 and Table 9

Interrogatory:
Preamble:
In summary, Hydro One has been successful in reducing pension costs, including by:

- making incremental increases in employee pension contributions for all employee groups;
- improving the ratio of employer and employee cost sharing by moving towards the 50%-50% cost sharing ratio;
- closing the Defined Benefit Pension for new Management employees and introducing a lower cost Defined Contribution Plan; and
- changing the early undiscounted pension thresholds for PWU and Legacy Society employees starting in 2025.

a) Please confirm the following from the evidence and Figure 7 and add explanatory notes
   i. For the PWU employee pension contributions (YMPE) have increased to 11.3%.
   ii. The Service Cost Ratio has decreased to 1.5
   iii. The Target service Cost Ratio Target is 1.0 (50:50)

b) Please Indicate how much of the employer saving shown in Table 9 is attributed to Distribution and Transmission.

c) Has Hydro One benchmarked its PWU pension costs to its peer group? Please provide a copy of the latest studies.

Response:
a)
   i. At the start of the year, PWU employees contribute 8.75% of their pensionable earnings until their year-to-date earnings reaches the Year's Maximum Pensionable Earnings (YMPE). Contributions then increase to 11.25% for the rest of the year.
   ii. Confirmed.

iii. Hydro One is moving towards a cost sharing ratio of pension expenses of 1.0 (50:50).

b) Exhibit F, Tab 4, Schedule 1 Table 9 shows the cost savings resulting from increased employee pension contributions for Hydro One. The reference to (DX) is a typo. Please refer to Exhibit I, Tab 02, Schedule EnergyProbe-20.

c) Pension costs have not been benchmarked relative to the Peer Group. Hydro One has focused on reducing pension costs. Please refer to evidence document Exhibit F, Tab 4, Schedule 1, pages 38-41.

ENERGY PROBE INTERROGATORY #20

Reference:
F-04-01 p.42-47 Appendix A, Figures A1-A6

Interrogatory:
a) Please confirm the following and add explanatory notes

For the Society
- Employee pension contributions (YMPE) have increased to 11.3% (legacy) and 10.8% (post 2005 hires).
- The Service Cost Ratio has decreased to 1.7 (Legacy) and 1.0- 1.1 (Post 2005 hires)
- The Target service Cost Ratio Target is 1.0 (50:50)

For MCP
- Employee Pension contributions (YMPE) have increased to 11.3% (Pre 2004)) and 10.8% (post 2004 hires).
- The Service Cost Ratio has decreased to 1.7(Pre 2004) and 1.0- 1.1 (Post 2004 hires)
- The Target service Cost Ratio Target is 1.0 (50:50)

b) Please provide a table similar to Table 9 showing Employer Savings and the allocations to Distribution and Transmission.

c) Has Hydro One benchmarked its Society and MCP pension costs to its Peer Group? Please provide a copy of the latest studies.

Response:
a) For the Society
- At the start of each year, Legacy Society represented employees contribute 8.75% of their pensionable earnings until their year-to-date earnings reaches the Year's Maximum Pensionable Earnings (YMPE). Contributions then increase to 11.25% for the rest of the year. Post 2005 Society represented employees contribute 8.25% up to the YMPE and then 10.75% for the rest of the year.
- Confirmed.

- Hydro One is moving towards a cost sharing ratio of pension expenses of 1.0 (50:50).

<u>For MCP:</u>

- At the start of each year, Legacy MCP employees contribute 8.75% of their pensionable earnings until their year-to-date earnings reaches the YMPE. Contributions then increase to 11.25% for the rest of the year. Post 2003 MCP employees contribute 8.25% up to the YMPE and then 10.75% for the rest of the year.
- Confirmed.
- Hydro One is moving towards a cost sharing ratio of pension expenses of 1.0 (50:50).

b)

Savings ($M))	2018	2019	2020	2021	2022
Hydro One	$ 22.50	$ 22.70	$ 22.50	$ 21.90	$ 21.50
Transmission	$ 10.22	$ 10.06	$ 10.85	$ 10.88	$ 10.40
Distribution	$ 12.28	$ 12.64	$ 11.65	$ 11.02	$ 11.10

c) Pension costs have not been benchmarked relative to the Peer Group. Hydro One has focused on reducing pension costs. Please refer to Exhibit F, Tab 4, Schedule 1, pages 38-41 for further details on the initiatives that Hydro One is undertaking to reduce pension costs.

ENERGY PROBE INTERROGATORY #21

Reference:

F-04-01 Table 8 and Table B1, F-04-01-02 Table 1

Interrogatory:

a) Please confirm the following for 2017 and add explanatory notes
   i. Non-Represented Employee Compensation was at Market Median
   ii. Energy Professional Employee Compensation increased to 1.12 -12% premium to Market
   iii. Trades & Technical Employee Compensation decreased to 1.12 -12% premium to Market

b) Please update the benchmark to 2020 using the assumption that the peer group compensation has increased at inflation (CPI) and using Hydro One's actual compensation increases for 2018 and 2019. Discuss if the market premium has increased or decreased from 2017-2020 under this scenario.

c) With respect to the Controller position shown in Table B1 please provide the basis for this position at Hydro One being compensated at 20.3 % above the Median.

Response:

a)
   i. Confirmed.
   ii. Confirmed.
   iii. Confirmed.

Mercer has reviewed the 2017 Compensation Cost Benchmarking Study findings relative to the previous finding. Within the limits of the Study and given the planned changes to the peer group and the jobs benchmarked, the findings are aligned with our expectations. The Non-represented group remains aligned with its target positioning at market median; Energy Professionals are up slightly which is possibly the result of programmatic changes designed to reduce compensation costs going forward; and Trades & Technical are down somewhat as past programmatic changes to reduce compensation cost going forward take effect.

b) As requested the benchmark has been updated to October 1, 2020. Total employee compensation decreased to 1.10 – 10% premium to market, see Table 2, below. In

Mercer's opinion, the assumption, noted below are reasonable for purposes of this projection.

Assumptions used in the projection:

- Actual Hydro One base salary/wage increases for non-represented staff, the Society of Energy Professional, and the Power Workers' Union were used for 2018 and 2019 as being representative of the increase for the Non-Represented, Energy Professional, Trade & Technical employee groups, respectively
- Projected Hydro One base salary/wage increases for non-represented staff, the Society of Energy Professional, and the Power Workers' Union used for 2020 as being representative of the increase for the Non-Represented, Energy Professional, Trade & Technical employee groups, respectively; this assumption is conservative as the Trade & Technical employee group includes CUSW and EPSCA employees who have a less generous total wage package and differing negotiated increases
- CPI used as Market increase for Energy Professional and Trade & Technical employee groups; Non-Represented Market increases based on CPI +0.6% representing average annual merit increase, in addition to CPI, per Mercer Compensation Planning Survey results
- The Benchmark is adjusted to be effective October 1 of each year
- CPI and Base Salary/Wage adjustments in Table 1, on the following page, were provided by Hydro One

Table 1 - CPI and Actual and Projected Salary/Wage Adjustments: 2018 to 2022

	Desc.	2018	2019	2020	2021	2022
MCP	Merit Budget	2.50% (actual)	2.30% (CPI)	2.00% (CPI)	2.50% (est.)	2.50% (est.)
PWU	Negotiated Step Increase	1.80% (Apr. 1, 18)	2.00% (Apr. 1, 19)	2.00% (Jan. 1, 20)**	2.00% (est.)	2.00% (est.)
SOCIETY	Negotiated Step Increase	0.50% (Apr. 1, 18)	2.00% (Apr. 1, 19)	2.00% (Apr. 1, 20)	2.00% (est.)	2.00% (est.)
CPI (Ontario)*	BoC Rate Tables / Analyst Projections	2.30% (actual)	2.30% (actual)	2.00% (projection)	1.90% (projection)	2.00% (projection)

*Table 1 Notes: * CPI blended rate for Ontario; **PWU has agreed to a 0.6% wage adjustment on January 1, 2020. A projected annual adjustment of 2.0% has been used as the projection for 2020 to reflect the opportunity in 2020 for a wage adjustment associated with the new collective agreement*

Table 2 - Updated Benchmark Based on Stated Assumptions: 2018 to 2022

	2017*	2018	2019	2020	2021	2022
Non-Represented		103.5	105.9	108.0	110.7	113.5
Market**		102.9	105.9	108.6	111.4	114.2
Multiple of P50	1.01	1.01	1.00	0.99	0.99	0.99
Energy Professionals		112.6	114.8	117.1	119.4	121.8
Market		102.3	104.7	106.7	108.8	110.9
Multiple of P50	1.12	1.10	1.10	1.10	1.10	1.10
Trades and Technical		114.0	116.3	118.6	121.0	123.4
Market		102.3	104.7	106.7	108.8	110.9
Multiple of P50	1.12	1.11	1.11	1.11	1.11	1.11
Total						
Multiple of P50	**1.12**	**1.11**	**1.10**	**1.10**	**1.10**	**1.10**

*Table 2 Notes: * Mercer Compensation Cost Benchmark Study was effective October 1, 2017; ** Market project based on CPI + 0.6% based on Mercer Compensation Survey results.*

For segregated, transmission related, dollar costs associated with the updated benchmark for 2020 through 2022 please see Exhibit I, Tab 07, Schedule SEC-55.

c) The Controller position in Table B1 is compared to a mix of Ontario Local Distribution Companies (LDCs) and Canadian utilities. The Hydro One Controller performs the role of the LDC operator on the Hydro One distribution system and is also accountable for the safe and reliable operation of the Transmission system and the applicable compliance rules. Therefore, the Hydro One Controller role is not comparable to the other LDCs.

The LDC operator works on distribution voltages and generally has no operations in the Bulk Power System (i.e. no control of the system 115kV and above). The

Controller (in conjunction with the IESO) is responsible for the reliability of the transmission system, and solely the physical operation of the transmission facilities.

The following chart recasts the Controller results against non LDC organizations.

	Hydro One Classification	Controller
Enmax		$61.16
Epcor		$57.58
FortisAlberta		$56.08
BC Hydro		$50.41
NB Power		$48.47
	Hydro One Rate	**$58.30**
	# of Incumbents	96
	Median	$56.08
	% above/below median	3.8%
	Mean	$54.74
	Max	$61.16
	# of responses	5

The Hydro One Controller is 3.8% relative to the median Controller rate.

ENERGY PROBE INTERROGATORY #22

Reference:
F-04-01-03

Interrogatory:

a) Please Confirm the following:
On average, the Sample group base salary is 9% and TRC 7% above Market Median
The Core Services group base salary is at 63% and TTC 64% above Market Median
(For the comparator group TTC includes incentive pay and for Hydro One the Share Grant Plan).

b) Please Provide the 2020 annual cost of the 64% Premium for Core Services Compensation?

c) Given the finding that Hydro One Core Services TTC is well above norm for both MCP and Society represented positions, what is Hydro One going to do about this situation?

Response:

a) Based on the results of the PWU Benchmarking study presented in Exhibit F, Tab 4, Schedule 1 Attachment 3:
   - Confirmed. On average, benchmarked PWU positions (including both Operations and Core Services segments) had base salaries of 9% above market median, and target total cash (TTC) opportunities of 7% above market median.
   - Confirmed. On average, benchmarked PWU positions categorized in the Core Service segment had base salaries of 63% above market median, and target total cash opportunities of 64% above market median.
   - To clarify, this data is specific to the Core Service positions represented by the PWU and does not include any comparison of MCP positions.
   - Confirmed. The elements of compensation included in target total cash, for the comparator group are base salary and incentive pay, while Hydro One figures include base pay and awards under the share grant plan (both market data and Hydro One results are based on the target opportunity rather than the actual payment).

b) The estimated 2020 annual cost of the premium is $8,926,027 (estimated 18% premium relative to P50 in 2020). When looking at the results for PWU overall (including the Core Services Segment), the 2020 annual cost of the differential to market median is -$14,367,138 (Exhibit I, Tab 07, Schedule SEC-57). This value was calculated based on the results of the PWU Benchmarking (Exhibit F, Tab 4, Schedule 1 Attachment 3), projected to 2020 based on the following set of assumptions:

1. External market increases at a rate of 2.5% per annum for 2020, 2021 and 2022. PWU data is increased by 2.0% per annum over the same period

    a. Based on Willis Towers Watson's annual Salary Increase Budget survey, typical Canadian salary increase budgets ranging from 2.0 - 3.0% per annum (midpoint used).

    b. PWU increases were projected based on the highest annual increase from the most recent collective agreement.

    c. Assumes that headcount increases occur as per the business plan (Exhibit F, Tab 4, Schedule 1 Table 2) and the proportion of PWU incumbents in Core Services remains consistent (13%)

2. The allocation of compensation to Transmission related activities is based on the following percentage for 2020: 48.22%

c) Based on the results of the Willis Towers Watson studies, Hydro One's target total cash opportunity for MCP and PWU positions was competitive with the market. For the purposes of comparison the Willis Towers Watson study defined a competitive range as within +/- 10% of the market median.

- Based on the results of the PWU Benchmarking (Exhibit F, Tab 4, Schedule 1 Attachment 3), overall PWU target total cash compensation was 7% above market median.
- Based on the results of the Willis Towers Watson, Salary Structure Positioning to Market Median (Exhibit F, Tab 4, Schedule 1 Table 4), overall MCP total direct compensation was 3% above market median.

Hydro One remains committed to the ongoing review of its compensation programs to ensure they are equitable, sustainable and reflect competitive practices. To ensure that the compensation programs continue to support the stated philosophy, the company regularly reviews its compensation programs including:

- Regularly benchmark the compensation levels for represented employees and MCP employees relative to the external market to assess competitiveness. The results of these studies are used to inform future compensation decisions and potential compensation program revisions.
- Continue to engage with union counterparts on a variety of committees and initiatives to assist in identifying opportunities to improve and modernize the compensation programs. For example, as an outcome of the most recent round of bargaining with the Society of United Professionals, a committee was formed between management and the union with a mandate to review compensation programs and propose potential improvements.
- Various steps have been taken to reduce pension costs. These include steps to increase employee contributions and reduce benefits for all employee groups. Specific details regarding cost reduction initiatives have been outlined under "Pensions and Other Post Employment Benefit Costs" (Exhibit F, Tab 4, Schedule 1 pages 38 to 41)
- Engage with third party independent experts to provide guidance on industry best practices and compensation.

ENERGY PROBE INTERROGATORY #23

Reference:
F-04-01-04

Interrogatory:

a) Why does the Team Scorecard only include T-SAIDI and not T-SAIFI and T-MAIFI?

b) Other than the Evolved TX scorecard where are T-SAIFI and T-MAIFI used in Hydro One Transmission Scorecards? Please provide examples

Response:

a) In order to maintain the total number of measures under control, only one transmission reliability measure is selected for the Team Scorecard. From a transmission customer's point of view, the interruption duration, provided by T-SAIDI is critical since interruption durations are related to the degrees of customers' loss of production.

b) T-SAIFI-S and T-SAIFI-M are measured and reviewed by Hydro One executives through the monthly performance review process.

ENERGY PROBE INTERROGATORY #24

Reference:
G-01-01 p.2

Interrogatory:
a) Please provide the Historic ROE for Hydro One Networks and the ROE for the Transmission Business.

b) Please provide a Table and a chart that shows for the Transmission Business, the Revenue Requirement and allowed and actual ROE for each of the 5 historic years.

c) Please discuss the reasons for any material over-earning

Response:
a) The ROE for Hydro One Transmission is included in the table below.

The Hydro One consolidated ROE is calculated on a GAAP basis, includes many non-regulatory items and therefore cannot be compared to the Transmission ROE.

b) The approved revenue requirement, and allowed and achieved ROE for Hydro One Transmission for the 5 historical years 2014-2018 are shown in the table below.

$millions	2018	2017	2016	2015	2014
Approved Revenue Requirement*	1,510.7	1,437.8	1,480.7	1,477.3	1,446.4
Allowed Return	9.00%	8.78%	9.19%	9.30%	9.36%
Achieved Return	11.08%	9.03%	10.02%	10.93%	13.12%

**Rates Revenue Requirement*

c) For 2018, return was higher due to a number of factors including lower income taxes due to the recognition of the deferred tax asset, lower depreciation and interest costs due to lower fixed assets and removal costs, and these reductions were partially offset by higher OM&A.

For 2017 and 2016, the achieved ROE was not materially (less than 100 basis points) different than the approved level.

Witness: Samir Chhelavda

For 2014 to 2015, favourable weather resulted in higher peak demand and greater than expected revenues. Additionally, cumulative in-service additions were less than planned resulting in lower depreciation expense and lower rate base. This also affects the amount of equity and therefore, mathematically, the level of ROE.

ENERGY PROBE INTERROGATORY #25

Reference:
G-01-02 p.4 and 5 Tables 2,3 and 4

Interrogatory:

a) Please provide a version of Tables 2, 3 and 4 with columns added to show the original March 21 filing coupon rates and bond rates.

b) Please indicate/discuss with reference to the requested version of Table 4 why coupon rates for forecast debt issues have increased since March 2019.

c) What Coupon Rates for 2019 and 2020 LT debt issues did the Board Approve in EB-2018-0049?

d) Please compare and contrast the cost of LT debt issues using EB-2019-0082 March values and update values.

e) How much will the difference in coupon rates cost ratepayers over the term of the new Debt Issues?

Response:

a) Please see tables below.

Table 2: Forecast Debt Issues for 2019

Year	Principal Amount ($Millions)	Term (Years)	Coupon	
			March Filing	June Update
2019	426.2	5	3.14%	3.45%
	426.2	10	3.57%	3.81%
	426.2	30	4.00%	4.19%

Table 3: Forecast Debt Issues for 2020

Year	Principal Amount ($Millions)	Term (Years)	Coupon	
			March Filing	June Update
2020	165.0	5	3.74%	3.85%
	165.0	10	4.17%	4.21%
	165.0	30	4.60%	4.59%

Table 4: Forecast Yield for 2019-2020 Issuance Terms (March Filing vs. June Update)

	2019								
	March Filing			June Update			Change		
	5-year	10-year	30-year	5-year	10-year	30-year	5-year	10-year	30-year
Government of Canada	2.43%	2.60%	2.64%	2.61%	2.70%	2.71%	0.18%	0.10%	0.07%
Hydro One Spread	0.72%	0.97%	1.36%	0.84%	1.11%	1.48%	0.12%	0.14%	0.12%
Forecast Hydro One Yield	3.14%	3.57%	4.00%	3.45%	3.81%	4.19%	0.31%	0.24%	0.19%

	2020								
	March Filing			June Update			Change		
	5-year	10-year	30-year	5-year	10-year	30-year	5-year	10-year	30-year
Government of Canada	3.03%	3.20%	3.24%	3.01%	3.10%	3.11%	-0.02%	-0.10%	-0.13%
Hydro One Spread	0.72%	0.97%	1.36%	0.84%	1.11%	1.48%	0.12%	0.14%	0.12%
Forecast Hydro One Yield	3.74%	4.17%	4.60%	3.85%	4.21%	4.59%	0.11%	0.04%	-0.01%

b) The changes in coupon rates for forecast debt issues from the March filing to the June update are provided in the response to part a) above. The changes to the 2019 forecast Hydro One yield are due to an increase in the Government of Canada bond yield from the May 2018 Consensus Forecast to October 2018 Consensus Forecast, and an increase in the Hydro One credits spread obtained from May 2018 to September

2018. The changes to the 2020 forecast Hydro One yield are due to a decrease in the Government of Canada bond yield spreads from the May 2018 Consensus Forecast to October 2018 Consensus Forecast, and an increase in the Hydro One credits spread obtained from May 2018 to September 2018.

c) In the most recent Hydro One Distribution rate application, EB-2017-0049, the OEB did not approve any specific coupon rates for 2019 and 2020. EB-2017-0049 was a five-year Custom IR application, with 2018 as the test year. The distribution rates for subsequent years, i.e. 2019 to 2022, are set based on the approved 2018 rates, using a Custom Revenue Cap Index Adjustment approach; therefore, the OEB did not approve any coupon rates for 2019 and 2020 long-term debt issues.

d) The costs of long-term debt for 2020 Test year can be found in Exhibit G, Tab 1, Schedule 3, Page 2, in both the March filing and the June update. Hydro One Transmission's cost of long-term debt rate has changed from 4.52% in the March filing to 4.57% in the June update, translating to $307.7 million in March filing and $311.0 million in the June update.

Please note that Hydro One plans to update the forecast long-term debt rates using any actual debt issued in 2019 and the most recent parameters prior to the OEB's final decision on setting Transmission rates for 2020 in the Final Draft Rate Order, consistent with Chapter 2 of the OEB's Filing Requirements issued on February 11, 2016 and with Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160.

Please see response to LPMA IR 19 part c) with regard to the updated cost of long-term debt schedule for 2019 actual issuances.

e) As stated on Page 3 of Exhibit G, Tab 1, Schedule 1, Hydro One plans to update the long-term debt rate for 2020 based on Hydro One's actual 2019 new debt issuances, and the September 2019 consensus forecast, as part of its final Draft Rate Order for setting rates in 2020. This is consistent with the OEB's Decision in EB-2016-0160. The currently assumed forecast coupon rate will be updated and will not be applicable for rate-setting purposes over the entire term of the new debt issues.

ENERGY PROBE INTERROGATORY #26

Reference:

A-02-01, G-01-01

Interrogatory:

Preamble:

At Exhibit G (updated), Tab 1, Schedule 1, p.1, the Application states that the purpose of this evidence is to summarize the method and cost of financing Hydro One Transmission's capital requirements for the rebasing year 2020.

The Application states that the applicant is Hydro One Networks Inc. (which it refers to as "Hydro One"), a subsidiary of Hydro One Limited (Exhibit A, Tab 2, Schedule 1, p.1). The Application refers to the transmission business of Hydro One as Hydro One Transmission, the latter not shown in Exhibit A, Tab 5, Schedule 1, p.1 of 1: Corporate Organization Charts.

At Exhibit G (updated), Tab 1, Schedule 1, p.1, the Application states that the deemed capital structure of Hydro One Transmission for rate-making purposes is 60% debt and 40% common equity of utility rate base . It also states that the Hydro One Transmission return on equity is 8.96% according to the Board's required approach (p.2).

a) Is it correct that Hydro One Transmission is not a subsidiary of Hydro One, but rather a division of Hydro One?

b) Please confirm/disconfirm that Hydro One acquires the debt issued by its subsidiaries and divisions or businesses other than Hydro One Transmission.

c) Does Hydro One have any subsidiaries or divisions or businesses other than Hydro One Transmission that will be affected by the Custom Incentive Rate-Setting ("IR") framework that is the subject of this Application? If so, please identify.

d) Please confirm/disconfirm that the long-term debt rate for Hydro One Transmission (i.e. 4.57% for 2020 to 2022) as stated in the Application at Exhibit G (updated), Tab 1, Schedule 1, p.3, is the same as the long-term debt rate for Hydro One for the same period (as shown at Schedule 4, p.6).

e) Please confirm whether or not all other debt rates specified for Hydro One Transmission in the Application are the same as those of Hydro One.

f) The Application states that the return on equity for Hydro One Transmission is 8.98% based on the cost of capital parameters issued by the Board on November 22, 2018, and is calculated according to the Board's approach in its 2009 report on the Cost of Capital for Ontario's Regulated Utilities (Exhibit G (updated), Tab 1, Schedule 1, p. 2). Please confirm/disconfirm that the return on equity for Hydro One Transmission is calculated solely by reference to the long-term debt of Hydro One. Does this indicate that that the cost of equity to Hydro One Transmission is the same as that of the applicant Hydro One? If not, how would the two equity costs differ?

Response:

a) Hydro One Transmission is an operating segment of Hydro One Networks Inc., which is a subsidiary of Hydro One Inc.

b) Yes, as stated on Page 1 of Exhibit G, Tab 1, Schedule 2, Section 1, Hydro One Transmission is allocated a portion of the debt issued by Hydro One Networks Inc. to Hydro One Inc. Hydro One Networks Inc. issues debt to Hydro One Inc. to reflect debt issued by Hydro One Inc. to third-party public debt investors.

c) With regard to cost of capital parameters used for rate setting purposes, no other subsidiaries or divisions or businesses of Hydro One other than Hydro One Transmission will be affected by the Custom Incentive Rate-Setting ("IR") framework that is the subject of this Application.

d) The long-term debt rate for Hydro One Transmission (i.e. 4.57% for 2020 to 2022) as stated in the Application at Exhibit G (updated), Tab 1, Schedule 1, p.3, is the same as the long-term debt rate (as shown at Schedule 4, p.6). Page 6 of Exhibit G, Tab 1, Schedule 4 provides a detailed derivation of the 4.57% weighted average debt rate.

e) The coupon rate for each debt issue shown in column (b) of Exhibit G, Tab 1, Schedule 4 allocated to Hydro One Transmission in the Application is the same as the coupon rate for the corresponding debt issued by Hydro One Inc. to third party public debt investors.

f) The return on equity for Hydro One Transmission is not calculated solely by reference to the long-term debt of Hydro One. As stated on Page 2 of Exhibit G, Tab 1, Schedule 1, Section 3, Hydro One Transmission calculated the 2020 ROE to be 8.98% based on the most recent parameters, as per the OEB's formula set out in Appendix B of the Cost of Capital for Ontario's Regulated Utilities report, dated December 11, 2009 in EB-2009-0084.

Please note that, Hydro One Transmission will apply the ROE calculated and released by the OEB in the fall of 2019 to set the final Transmission rates for 2020.

ENERGY PROBE INTERROGATORY #27

Reference:
G-01-02

Interrogatory:
Preamble:
The Application states that "Hydro One Transmission is allocated a portion of the debt issued by Hydro One Networks Inc. to Hydro One Inc. Hydro One Networks issues debt to Hydro One Inc. to reflect the debt issues by Hydro One Inc. to third-party public debt investors. … Third-party public debt investors hold all of the long-term debt issued by Hydro One Inc. …" (p.1 of 8)

a) To simplify the above, it is correct that the issuer of the third-party debt that ultimately finances Hydro One Transmission is Hydro One Inc.?

b) How is Hydro One Transmission's allocated share of the debt issued by Hydro One determined? In particular, does that share of debt include only the borrowing requirements of Hydro One Transmission for its transmission business?

c) Is the yield-to-maturity on the Hydro One debt always identical to the yield-to-maturity on the corresponding debt that Hydro One Inc. subsequently issues to public investors, after taking into account any discount/premium, legal fees and other costs that Hydro One Inc. incurs?

d) In regard to embedded debt, the Application refers to the "effective cost rates" (p.3 of 8). Please clarify whether those effective cost rates are used to establish the cost of embedded debt for determining the cost of capital to Hydro One Transmission.

e) In regard to new debt, the Application refers to the issuance of $300 million of three-year notes in June 2018. Would Hydro One Inc. normally classify three-year fixed-rate notes as long-term debt?

f) The Application states that those three-year notes were part of an interest-rate swap to convert those notes into floating-rate, short-term debt. What is the cost of this debt issuance plus interest rate swap arrangement for rate-making purposes?

Witness: Samir Chhelavda

g) Does Hydro One Transmission issue any variable-rate debt to Hydro One? How is variable-rate debt treated in determining Hydro One Transmission cost of capital, and where does the Application discuss this treatment?

Response:

a) Yes.

b) As stated on Page 2, Line 20, of Exhibit G, Tab 1, Schedule 2, the amount of each Hydro One Networks Inc. debt issue that is allocated to the Transmission business is based on its most recent forecast of borrowing requirements. Borrowing requirements are driven mainly by debt retirement, capital expenditures net of internally generated funds, and the maintenance of its capital structure.

c) Yes.

d) The effective cost rates for Hydro One Transmission's embedded debt are shown in column (h) on Page 6 of Exhibit G, Tab 1, Schedule 4. The embedded debt shown in Line 1 to 31 represents the debt issuances that have been approved by the OEB in Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0016 and that will still be outstanding in 2020.

e) If Hydro One did not convert the three year fixed rate note into floating rate debt by entering into an interest rate swap, it would normally classify the three year note as long term debt. Please note that Hydro One currently has no 3-year debt that is not converted to floating rate debt.

f) The actual floating rate costs of this debt issuance including the interest rate swap are not applicable for rate-setting purposes.

For rate-making purposes, the three-year note that was converted into floating-rate is used to finance the deemed short-term debt component of Hydro One Transmission's capital structure, which is 4% of its rate base. Therefore, this particular debt issuance earns the OEB deemed short term debt rate calculated and released by the OEB in the fall of 2019 for 2020 rates.

g) Yes. Please refer to Hydro One's response to parts e and f above.

Witness: Samir Chhelavda

ENERGY PROBE INTERROGATORY #28

Reference:
H-01-01 Table 1

Interrogatory:
Please confirm whether the totals in Updated Table 1 have changed. If so please provide the originals and explain the differences.

Response:
The totals in Table 1 changed from the initial submission as a result of the Blue Page update filing. As indicated previously in Exhibit H, Tab 1, Schedule 3, Section 2, Planned Disposition of Regulatory Accounts, 2018 balances would be updated to reflect audited actuals.

Original numbers from the March 21, 2019 submission are provided below:

Table 1: Summary of Regulatory Accounts Balances Outstanding ($ Million)[1]

Description	Balance as at Dec 31, 2016	Balance as at Dec. 31, 2017	Balance as at Dec. 31, 2018 (Forecast)	Balance as at Dec. 31, 2019 (Forecast)
Total Regulatory Accounts Seeking Disposition	(126.5)	(83.6)	(23.0)	14.5
Total Regulatory Accounts Not Seeking Disposition	15.9	81.5	73.8	74.1
Total Regulatory Accounts	(110.7)	(2.2)	50.8	88.6

[1] Note that rounded numbers presented in charts may not add to the total due to rounding.

Witness: Samir Chhelavda

ENERGY PROBE INTERROGATORY #29

Reference:

I1-01-02 p.12, I1-01-03 p.4 Table 2, I2-04-01 p.2

Interrogatory:

a) In allocating NBV to Functions and then Pools are there any dedicated assets related to Exports? If so, please identify these in terms of NBV and how these are dealt with in accordance with Elenchus Report on cost allocation.

b) Are there OM&A costs related to the Export Function? If so, are these costs allocated/recovered in accordance with the Elenchus Report.

c) Does Export Revenue (second reference Table 2) recover all related Asset and operating costs? If there is a difference how is this addressed? Please discuss.

Response:

a) Yes, there are dedicated assets related to Exports (i.e. interconnection facilities). The NBV of these assets is $66.8 million, which is 1.2% of the $5,563.7 million in NBV of Hydro One's network functional category (as shown in Exhibit I1, Tab 4, Schedule 1). In accordance with Elenchus' recommended methodology on cost allocation, this percentage (1.2%) is used to derive the amount of each revenue requirement component specifically associated with assets dedicated to Exports.

b) Yes. The OM&A costs that are directly associated with assets dedicated to Exports is determined using the methodology described in part (a). A portion of the OM&A costs associated with assets that are shared between export and domestic customers are also allocated to export customers using composite allocators, which are based on 12 CP, as described in Exhibit I2, Tab 4, Schedule 1.

c) The forecast 2020 export revenue of $35.9 million, shown in Exhibit I1, Tab 1, Schedule 3, Table 2, is calculated using the currently approved tariff of $1.85/MWh and the three year historical rolling average volume.

Using the cost allocation methodology recommended by Elenchus, in EB-2014-0140, Hydro One's asset and operating costs associated with Exports were estimated as

$22.1 million. To include other Transmitters' revenue requirement, this figure needs to be escalated by 6.6%, resulting in a provincial cost associated with Exports of $23.5 million[1].

The difference of $12.4 million ($35.9 million - $23.5 million) is part of the revenue offset as described in Exhibit I1, Tab 1, Schedule 1, page 2. This revenue offset is a benefit to transmission customers in Ontario as it lowers the revenue requirement used to determine the Ontario Uniform Transmission Rates.

[1] See Exhibit I, Tab 3, Schedule APPrO-001, part b.

ENERGY PROBE INTERROGATORY #30

Reference:
I2-01-01 p.2 Table 1, I2-02-01 Table 1

Interrogatory:
a) Please indicate what changes occurred to forecast UTR Rates (first reference table 1) between March and June, and discuss the reasons for this.

b) Please indicate what changes occurred to forecast Charge Determinants (Second reference Table 1) between March and June, and discuss the reasons for this.

Response:
a) The table below provides the forecast UTRs as filed in the initial Application in March and as filed in the subsequent update in June.

Year	Network ($/kW)		Line Connection ($/kW)		Transformation Connection ($/kW)	
	March	June	March	June	March	June
2020	4.34	4.35	0.83	0.93	2.43	2.44
2021	4.58	4.61	0.87	0.88	2.57	2.59
2022	4.83	4.88	0.92	0.93	2.71	2.74

As noted in the table, the UTR forecast filed in the June update is only marginally higher than what was filed in March. The main driver of this increase is the increase in overall rates revenue requirement resulting from increase in the total revenue requirement forecast and reduction in Export Transmission Service revenue forecast.

In addition, as described in Exhibit I1, Tab 5, Schedule 1 (June update), Hydro One has adopted the methodology approved by the OEB (Decision and Order, EB-2018-0130) for allocating 2021 and 2022 rates revenue requirement among the three rate pools.

b) There was no change to forecast Charge Determinants between the initial Application in March and the update in June.

Witness: Clement Li

ENERGY PROBE INTERROGATORY #31

Reference:
I2-04-01 p.3 and 4, Table 1 and 2

Interrogatory:
Preamble:
The decrease in the calculated ETS rate as compared to the 2015 study primarily reflects a decrease in Hydro One's OM&A costs relative to what was proposed at the time the 2015 study was completed, and an increase in forecast exports (MWh) from what was assumed in the 2015 study.

a) Please provide more details on how changes in allocated OM&A costs affected the calculated ETS rate.

b) Have other allocated costs changed such as NBV of assets? Please provide more details.

c) Has the ETS rate fully recovered its allocated costs? Please provide the Revenue/Cost Ratios for historic years.

Response:
a) Hydro One's proposed OM&A costs used in the ETS calculation decreased by 29.7% between 2015 and 2020, and the resulting ETS rates decreased by 28.0%, respectively. The supporting values are provided below:

Year	Total OMA	OMA allocated to Domestic	OMA allocated to Export	Calculated ETS (excludes other transmitters' revenue requirement)
2015	$385,654,281	$366,391,831	$19,262,450	$1.63
2020	$307,693,346	$294,150,465	$13,542,881	$1.17
Change			-29.7%	-28.0%

b) Yes. As described in Exhibit I2, Tab 4, Schedule 1, page 2, in this Application, Hydro One updated the 2015 Elenchus cost allocation model utilizing the latest available information. Please see response to Exhibit I, Tab 3, Schedule APPrO-1 part (c) for the list of specific updates.

Witness: Clement Li

c) Using the allocated export service costs based on Elenchus' recommended methodology and the revenue expected from the approved ETS Rates of $1.85/MWh, the revenue/cost ratios for 2015 and 2016 are 1.10 and 1.11, respectively. Since the revenue/cost ratios are greater than 1, the ETS rate has more than fully recovered its allocated costs in 2015 and 2016. As discussed in Exhibit I, Tab 2, Schedule EnergyProbe-29 part (c), the recovery of export revenues in excess of costs is used to offset the rates revenue requirement to be collected from transmission customers in Ontario.

Hydro One did not calculate the allocated costs associated with export service in 2017 and 2018, and as such, is not able to determine the revenue/cost ratios for those years.