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BY EMAIL AND RESS

October 24, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2021-0110 – Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution ("Hydro One") – Responses to Pre-Settlement Clarification Questions and Settlement Day 1 Clarification Questions

A settlement conference was held in respect of the above noted proceeding from August 15 to August 24, 2022 in accordance with Procedural Order No. 5. Prior to and on the first day of the settlement conference, intervenors asked clarification questions which Hydro One responded to.

Earlier today, Hydro One filed a Settlement Proposal on behalf of the parties to the settlement. Attached here under separate cover please find Hydro One's responses to intervenors' clarification questions.

An electronic copy of the responses has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Kathleen Burke

Kathleen Burke

cc. EB-2021-0110 parties

SC - SEC INTERROGATORY - 01

Reference:

Exhibit SC-22-SEC-1-1 (SEC CQ 1 - DVA Baseline)

Interrogatory:

The attached spreadsheet includes SEC's understanding of the baseline components (i.e. the embedded amounts in the application) of the proposed AMI 2.0 Variance Account, Externally Driven Distribution Projects Variance Account, and the Externally Driven Distribution Projects Transmission Account. Please confirm it accuracy, and if not accurate, make necessary changes. Please also complete the table and return in Excel format.

Response:

Hydro One has provided the requested information for the original Application evidence (August 5, 2021) and the March 31, 2022 inflationary update (the Evidence Update). As noted in Exhibit O-01-02, page 10, Hydro One provided macro level impacts to ISA for the Evidence Update based on the updated capital plans. The specific ISA investment level impacts reflect the assumptions currently outlined in Exhibit O-01-02, Table 5, as some of the capital expenditures occurred prior to 2023.

As noted in Exhibit O-01-02 Section 2.5.2, Hydro One will update the inflation forecast for 2022 and 2023. For the 2022 rate, Hydro One will employ either the actual 2022 Ontario CPI rate (if available) or the forecast 2022 rate based upon an updated Scotia forecast. For the 2023 rate, an updated Scotia forecast will be used.

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SC-22-SEC-01-01

Please complete the shaded areas

In-Service Additions (Account Baseline on ISA Basis)	As-filed Evidence [August 5, 2021] 2023	2024	2025	2026	2027	Inflationary Update Evidence [March 31, 2022]* 2023	2024	2025	2026	2027
AMI 2.0 Variance Account										
D-SR-12 - AMI 2.0	30.9	60.6	150.3	150.9	153.7	32.5	63.9	158.1	158.9	161.8
Total	**30.9**	**60.6**	**150.3**	**150.9**	**153.7**	32.5	63.9	158.1	158.9	161.8
Externally Driven Distribution Projects Variance Account										
D-SA-01 - Joint Use and Relocations	24.4	28.7	27.1	26.5	27.2	25.6	30.2	28.5	27.9	28.6
D-SA-02 - New Load Connection, Upgrades, Cancellation (System Upgrades Only)	28.8	29.5	30.2	31.1	31.9	30.3	31.0	31.8	32.6	33.5
D-SA-03 - Customer Demand Distribution Energy Resources	2.4	2.4	1.4	1.4	1.4	2.6	2.6	1.5	1.5	1.5
Total	**55.6**	**60.6**	**58.7**	**59.0**	**60.5**	**58.5**	**63.8**	**61.8**	**62**	**63.6**
Externally Driven Transmission Projects Variance Account										
T-SA-04 - Connect Metrolinx Traction Substations	-	6.5	1.4	-	-	-	6.9	1.5	-	-
T-SA-07 - Secondary Land Use Projects	42.3	2.7	2.8	1.3	0.8	44.5	2.8	3.0	1.4	0.9
T-SS-02 - St. Lawrence TS: Phase Shift Replacement	33.9	-	-	-	-	35.7	-	-	-	-
T-SS-03 - Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	9.0	-	-	-	-	9.5	-	-	-	-
T-SS-04 - Richview x Tranfalager 230kv Condictor Upgrade	-	-	-	49.5	-	-	-	-	52.1	-
T-SS-07 - West Chatham Reinforcement	-	-	35.9	-	-	-	-	37.8	-	-
T-SS-09 - West of London Reinforcement	-	-	-	-	76.8	-	-	-	-	80.8
Total	**85.2**	**9.2**	**40.1**	**50.8**	**77.6**	**89.7**	**9.7**	**42.3**	**53.5**	**81.7**

Capital Expenditures (1)	Pre-2023	2023	2024	2025	2026	2027	Pre-2023	2023	2024	2025	2026	2027
AMI 2.0 Variance Account												
D-SR-12 - AMI 2.0 (Net)	-	30.9	60.6	150.3	150.9	153.7	-	32.5	63.9	158.1	158.9	161.8
Total	-	**30.9**	**60.6**	**150.3**	**150.9**	**153.7**	-	**32.5**	**63.9**	**158.1**	**158.9**	**161.8**
Externally Driven Distribution Projects Variance Account												
D-SA-01 - Joint Use and Relocations	-	24.8	29.0	27.0	26.5	27.2	-	26.1	30.5	28.4	27.9	28.7
D-SA-02 - New Load Connection, Upgrades, Cancellation (System Upgrades Only)	-	28.9	29.7	30.5	31.2	32.0	-	30.5	31.3	32.1	32.9	33.7
D-SA-03 - Customer Demand Distribution Energy Resources	2.0	1.4	1.4	1.4	1.4	1.4	2.0	1.5	1.5	1.5	1.5	1.5
Total	**2.0**	**55.1**	**60.1**	**58.9**	**59.1**	**60.6**	**2.0**	**58.1**	**63.3**	**62.0**	**62.3**	**63.9**
Externally Driven Transmission Projects Variance Account												
T-SA-04 - Connect Metrolinx Traction Substations	-	3.5	3.6	0.8	-	-	-	3.7	3.8	0.9	-	-
T-SA-07 - Secondary Land Use Projects**	5.0	37.8	2.8	2.8	0.8	0.8	5.0	39.8	3.0	3.0	0.9	0.9
T-SS-02 - St. Lawrence TS: Phase Shift Replacement**	27.9	6.0	-	-	-	-	27.9	6.3	-	-	-	-
T-SS-03 - Merivale TS to Hawthorne TS: 230kV Conductor Upgrade***	10.7	9.0	-	-	-	-	10.7	9.5	-	-	-	-
T-SS-04 - Richview x Tranfalager 230kv Condictor Upgrade	6.0	12.6	16.4	12.1	2.4	-	6.0	13.3	17.2	12.7	2.5	-
T-SS-07 - West Chatham Reinforcement	2.0	8.3	20.4	5.2	-	-	2.0	8.8	21.4	5.5	-	-
T-SS-09 - West of London Reinforcement	1.0	4.2	4.2	18.7	60.9	54.8	1.0	4.4	4.5	19.6	64.1	57.7
Total	**52.6**	**81.4**	**47.4**	**39.6**	**64.1**	**55.6**	**52.6**	**85.8**	**49.9**	**41.7**	**67.5**	**58.6**

* All figures will be updated to reflect the latest 2022 and 2023 CPI at the time of DRO

** Pre-2023 reflects the subset of work which contributes to ISA in the 2023-2027 period

*** Pre-2023 reflects as-filed amounts

(1) For purposes of this part of the table, assume the account will continue after 2027. For the Externally Driven Transmission Project Variance Account, please include any additional projects/ISDs that will not go in-service by 2027, but Hydro

SC - SEC INTERROGATORY - 02

Reference:

Exhibit O-SEC-253

Interrogatory:

Hydro One notes that "there are various scenarios to achieve the 10% cap depending on the results of inflation at the time of the DRO." SEC understands this to mean that the calculation of the Proration Factor will be different depending on the specific 2022 and 2023 actual/forecast inflation numbers. For example, inflation of 9% in 2022 and 1% in 2023, will lead to a different Proration Factor as compared to inflation of 7% in 2022 and 3% in 2023. In a scenario where the combined inflation is above the 10% cap, how specifically does Hydro One propose to determine the inflation numbers for each specific year for the purpose of calculating the Proration Factor? For example, what would the 2022 and 2023 inflation numbers be for the calculation in a scenario where the actual/forecast inflation numbers are 11% in 2022 and 3% in 2023, versus a scenario where it is 8% in 2022 and 6% in 2023?

Response:

Hydro One is proposing that the 10% inflation cap be on a cumulative basis over the 2022 and 2023 years as follows:

- 2022 Ontario CPI (Actuals/Forecast) will be used in the calculation up to a cap of 10% and 2023 Ontario CPI Forecast will be used for the remainder of the 10% cap (up to and including the Forecast for 2023).

Using the inflation rates referenced in the question above:

- 11% Actuals/Forecast inflation in 2022 and 3% Forecast inflation in 2023 would result in inflationary assumptions of 10% for 2022 and 0% for 2023.
- 8% Actuals/Forecast inflation in 2022 and 6% Forecast inflation in 2023 would result in inflationary assumptions of 8% for 2022 and 2% for 2023.

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SC - SEC INTERROGATORY - 03

Reference:

Exhibit O-1-2, Attachment 4D

Interrogatory:

Please provide a revised version of the table that includes 2021 actuals.

Response:

Please refer to Exhibit O-02-01, Attachment 4 for the version of Appendix 2-AA Capital Projects and Programs Table for General Plant ($M) that includes 2021 actuals.[1]

[1] O-02-01, Attachment 4 was provided as an excel attachment on April 8, 2022.

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SC – SEC INTERROGATORY - 04

Reference:

Exhibit JT 2.34

Interrogatory:

With respect to JT 2.34, are each of the facilities listed in parts (a) and (b) included in the rate base through the end of 2027? If not, please provide details.

Response:

Confirmed – each of the four facilities listed in JT 2.34 parts (a) and (b) are in included in the rate base through the end of 2027.

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SC - SEC INTERROGATORY - 05

Reference:

Exhibit B3-SEC-146

Interrogatory:

Please update the response to interrogatory B3-SEC-156 to include 2021 actuals, and updated 2023 to 2027 forecast information.

Response:

Hydro One's response below assumes the reference on line 4 above to Exhibit B3-SEC-146 is correct.

	Historical				Forecast					
LDC/ Category	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Haldimand County Hydro Inc.										
System Access	1.8	1.5	1.9	1.7	2.9	3.2	3.3	3.3	3.4	3.5
System Renewal	1.6	1.3	1.3	0.9	2.1	2.1	2.7	2.7	3.0	2.5
System Service	0.1	0.0	0.1	0.3	0.5	2.1	3.6	0.4	0.3	0.4
General Plant	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0
Sub Total	**3.5**	**2.8**	**3.2**	**2.9**	**5.5**	**7.4**	**9.6**	**6.4**	**6.8**	**6.4**
Norfolk Power Distribution Inc.										
System Access	1.0	1.4	0.7	1.2	1.6	1.7	1.8	1.8	1.8	1.9
System Renewal	0.9	0.9	2.0	0.8	2.6	2.1	4.7	4.0	5.0	3.1
System Service	0.1	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2
General Plant	-	-	-	-	-					
Sub Total	**2.0**	**2.3**	**2.6**	**2.0**	**4.4**	**4.0**	**6.6**	**6.0**	**7.0**	**5.1**
Woodstock Hydro Services Inc.										
System Access	1.0	0.9	0.9	0.6	1.3	1.4	1.5	1.5	1.5	1.6
System Renewal	0.8	0.5	1.6	1.3	1.4	1.5	1.5	1.5	1.6	1.6
System Service	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.4
General Plant	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0
Sub Total	**1.8**	**1.4**	**2.5**	**1.9**	**3.1**	**3.3**	**3.3**	**3.4**	**3.5**	**3.5**
Grand Total	**7.3**	**6.4**	**8.3**	**6.8**	**13.0**	**14.6**	**19.5**	**15.7**	**17.3**	**15.1**

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SC - SEC INTERROGATORY - 06

Reference:

Reference not provided

Interrogatory:

Assume the OEB accepts, or the parties agree, to the application as updated. For each of transmission and distribution, please provide a comprehensive list of all changes and/or updates Hydro One proposes to make as part of the DRO process.

Response:

Should the OEB accept, or the parties agree to, the Application as updated (filed on March 31, 2022), including the proposed confirmation and adjustment process outlined in Section 2.5.2 in Exhibit O-01-02, Hydro One anticipates undertaking the following updates at the time of the DRO.

- Hydro One will incorporate the most recent inflation rates for 2022 and 2023 based on either the actual 2022 Ontario CPI rate (if available) or the most recent Scotia forecast for 2022 Ontario CPI. For the 2023 inflation rate, an updated Scotia forecast for Ontario CPI will be used. The update, up to the proposed 10% inflationary cap, will be applied via proration factor to the base proposed OM&A and capital plans (as filed on August 5, 2021). Refer to SC-SEC-02 for more information on the sequencing and the application of the 10% cap. To the extent that the cumulative inflation for 2022 and 2023 exceeds 10%, Hydro One will aim to manage its work program to the capped amount through investment reprioritization and redirection.
- Hydro One will then recalculate the revenue requirement[1] at this time along with the resulting rates, supporting schedules and cost-based scorecard metrics.[2]

Further, in the normal course and consistent with the DRO process, Hydro One also intends to update the following items at the time of the DRO:

- inflation factors to be used as part of the Custom IR Framework for Transmission and Distribution as issued by the OEB for 2023 applications;

[1] Hydro One intends to update the Regulatory Taxes and incorporate the full Regulatory Taxes related revenue requirement impact into the Transmission and Distribution final revenue requirements at the time of the DRO.

[2] O-Staff-366 part c) i-iv: scorecards would be updated to align with the approved capital and OM&A at that time [of the DRO]

- cost of capital parameters;[3] and
- offsetting adjustments to 2023-2027 capital expenditures to account for the current rate period overspending that cannot be redirected and updating scorecard metrics.[4]

As indicated in Interrogatory Responses to O-Staff-360 and O-LPMA-042, as a result of all adjustments as required in the ordinary course of the DRO process (listed above), Hydro One will also re-calculate the deferred incremental revenue requirement resulting from the inflation update, and the portion of the deferred revenue requirement associated with revenue deficiencies arising from the revised load forecasts.

Furthermore, depending on the timing of the decision in the OEB's Generic Proceeding on the Export Transmission Service (ETS) rate (EB-2021-0243), Hydro One may also need to implement any changes arising from the implementation of the OEB's findings in that proceeding at the time of the DRO.

[3] Hydro One intends to update the revenue requirements for the 2023 to 2027 test years when the OEB releases its 2023 cost of capital parameters around fourth quarter 2022, reflecting: (a) the OEB-approved 2023 return on equity and deemed short term debt rate; and (b) long-term debt rates based on Hydro One's actual 2021 and 2022 debt issuances to-date and forecasted debt issues in 2023 with coupon rates based on the September 2022 Consensus Forecast.

[4] JT2.23: O-Staff-367, if Hydro One does not remain within the as-filed capital envelopes for transmission (2020-2022) and distribution (2018-2022), offsetting adjustments will be made to the capital and in-service additions over the 2023-2027 rate period.

SC - SEC INTERROGATORY - 07

Reference:

Reference not provided

Interrogatory:

SEC would like to better understand the impact on recent market and economic conditions on Hydro One's 2023 cost of capital:

a) Please provide a forecast for the 2023 ROE based on the most recent available data inputted in to the OEB's ROE formula. Please provide the full calculation.

b) Please provide an updated forecast of Hydro One's transmission and distribution long-term debt rate based on actual debt issuances to-date and the most recent available Consensus Forecast.

Response:

a) Hydro One's 2023 ROE forecast for Transmission and Distribution based on August Consensus Forecast is 9.34%. Please see the calculation below:

Initial ROE (September 2009)			9.75	%
Change in Long Canada Bond Yield Forecast (LCBF) from September 2009				
LCBF (August 2022)	3.234	%		
Base LCBF (September 2009)	4.250	%		
Difference	-1.016	%		
0.5 X Difference			-0.51	%
Change in A-rated Utility Bond Yield Spread from September 2009				
A-rated Utility Bond Yield Spread (August 2-10, 2022)	1.609	%		
Base A-rated Utility Bond Yield Spread (September 2009)	1.415	%		
Difference	0.194			
0.5 X Difference			0.10	%
Return on Equity based on August 2-10, 2022 data			**9.34**	**%**

b) Hydro One's forecast for the 2023 long-term debt rate for Transmission is 4.24% and for Distribution is 4.18%. Please refer to Attachment 1 to this response for the details.

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HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2023)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	1/1/2022 Total Amount Outstanding at 12/31/2022 ($Millions)	1/1/2023 Total Amount Outstanding at 12/31/2023 ($Millions)	1/1/2023 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates	
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.400	20.8		
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.272	7.7		
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.000	3.9		
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.000	8.1		
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.000	9.6		
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.000	4.6		
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.000	2.4		
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.000	2.4		
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.900	12.9		
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.500	10.2		
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.000	1.5		
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.000	11.8		
13	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8		
14	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6		
15	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5		
16	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5		
17	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1		
18	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8		
19	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8		
20	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0		
21	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4		
22	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1		
23	29-Jan-14	4.310%	29-Jan-64	30.0	0.2	29.8	99.44	4.34%	30.0	30.0	30.0	1.3		
24	3-Jun-14	4.190%	3-Jun-44	198.0	1.2	196.8	99.40	4.23%	198.0	198.0	198.0	8.4		
25	24-Feb-16	3.910%	24-Feb-46	175.0	1.1	173.9	99.36	3.95%	175.0	175.0	175.0	6.9		
26	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.56	2.82%	245.0	245.0	245.0	6.9		
27	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.50	3.75%	270.0	270.0	270.0	10.1		
28	26-Jun-18	3.630%	25-Jun-49	468.0	2.4	465.6	99.48	3.66%	468.0	468.0	468.0	17.1		
29	26-Jun-18	2.970%	26-Jun-25	218.4	0.9	217.5	99.60	3.03%	218.4	218.4	218.4	6.6		
30	5-Apr-19	3.640%	5-Apr-49	147.5	0.8	146.7	99.43	3.67%	147.5	147.5	147.5	5.4		
31	5-Apr-19	3.020%	5-Apr-29	324.5	1.4	323.1	99.57	3.07%	324.5	324.5	324.5	10.0		
32	5-Apr-19	2.540%	5-Apr-24	413.0	1.6	411.4	99.62	2.62%	413.0	413.0	413.0	10.8		
33	28-Feb-20	2.710%	28-Feb-50	147.9	0.9	147.0	99.42	2.74%	147.9	147.9	147.9	4.0		
34	28-Feb-20	2.160%	28-Feb-30	197.2	0.8	196.4	99.58	2.21%	197.2	197.2	197.2	4.4		
35	28-Feb-20	1.760%	28-Feb-25	197.2	0.7	196.5	99.63	1.84%	197.2	197.2	197.2	3.6		
36	9-Oct-20	2.710%	28-Feb-50	124.0	0.4	123.6	99.68	2.73%	124.0	124.0	124.0	3.4		
37	9-Oct-20	1.690%	16-Jan-31	248.0	1.2	246.8	99.54	1.74%	248.0	248.0	248.0	4.3		
38	9-Oct-20	0.710%	16-Jan-23	124.0	0.9	123.1	99.27	1.04%	124.0	0.0	9.5	0.1		Note 2
39	14-Sep-21	3.100%	15-Sep-51	225.0	1.3	223.7	99.42	3.13%	225.0	225.0	225.00	7.0		
40	14-Sep-21	2.230%	17-Sep-31	225.0	1.1	223.9	99.53	2.28%	225.0	225.0	225.00	5.1		
41	15-Sep-22	4.396%	15-Sep-52	217.9	1.1	216.8	99.50	4.43%	217.9	217.9	217.87	9.6		Note 3
42	15-Sep-22	4.044%	15-Sep-32	217.9	1.1	216.8	99.50	4.11%	217.9	217.9	217.87	8.9		Note 3
43	15-Sep-22	3.923%	15-Sep-27	217.9	1.1	216.8	99.50	4.03%	217.9	217.9	217.87	8.8		Note 3
44	15-Mar-23	4.865%	15-Mar-53	218.1	1.1	217.0	99.50	4.90%	0.0	218.1	167.8	8.2		Note 4
45	15-Jun-23	4.519%	15-Jun-33	218.1	1.1	217.0	99.50	4.58%	0.0	218.1	117.4	5.4		Note 4
46	15-Sep-23	4.364%	15-Sep-28	218.1	1.1	217.0	99.50	4.48%	0.0	218.1	67.1	3.0		Note 4
47		**Subtotal**							7635.9	8166.2	7873.7	325.9		
48		Treasury OM&A costs										2.1		
49		Other financing-related fees										5.8		
50		**Total**							7635.9	8166.2	7873.7	333.9	4.24%	

Note 1 - All debt is 3rd party issued debt with fixed rates
Note 2 - $248 million of the Oct 9th 2020 $372 million 2.25 year 0.71% bond allocated to Tx is being used to finance the deemed short term debt amount equal to 4% of rate base.
Note 3 - As of August 12th no long term debt has been issued by Hydro One in 2022. September 15th offering dates have been used as placeholders for 2022 issuance. Coupon rates are based on Government of Canada bond yields (sourced from the Bank of Canada website) and indicative new issue Hydro One spreads from August 8th.
Note 4 - 2023 forecasted coupon rates are based on August 2022 Consensus Forecast and the average indicative new issue Hydro One spreads for August 2022, as of August 8th.

SC - SEC INTERROGATORY - 08

Reference:

Exhibit JTU-2.23

Interrogatory:

Please provide a breakdown of the forecast capital costs related to the May 2022 storm, broken down for each of transmission and distribution, and the individual program/investments they would be categorized under.

Response:

A breakdown of the distribution capital costs associated with the May 2022 storm can be found in the updated response to JTU2.23.

The transmission capital costs associated with the May 2022 storm were $4.0M.

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SC - SEC INTERROGATORY - 09

Reference:

Exhibit O

Interrogatory:

Hydro One's Inflation Update applied a uniform Proration Factor to as-filed capital expenditures for each year between 2023 and 2027, and for each capital expenditure program/ISD, even though, it expects that inflation may have very different impacts on individual capital programs (see O-1-2, p.7, Table 2). How does Hydro One plan to provide accurate assessments of plan execution (e.g. through capital program performance reports) when any approved program/projects costs and units will no longer be accurate at the program/project level (as opposed to at the overall plan level).

Response:

As outlined in response to O-Staff-357, Hydro One's proposed inflation update substituted its original Ontario CPI assumptions of 2.0% per year with revised Ontario CPI assumptions as provided by Scotia, which will be updated for actuals or the most recent forecast at the draft rate order stage. This approach preserves the base capital and OM&A investment plans as filed. At the next rebasing Hydro One will provide variance explanations (e.g. through the capital performance reports) which may include inflation if applicable.

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SC - SEC INTERROGATORY - 10

Reference:

Exhibit O-1-2, Page 40
Clearspring/PEG Joint Report, Page 8

Interrogatory:

Hydro One's application proposes an X-Factor for its distribution business be set at 0.3% (see O-1-2, p.40) based on the recommendation of Clearspring. In the Clearspring/PEG Joint Report (p.8), Clearspring has updated its recommended stretch factor for distribution to 0.45%. Is Hydro One's distribution X-Factor proposal still 0.3% or is now 0.45%?

Response:

Both Clearspring Energy Advisors and Pacific Economics Group now recommend a 0.45% stretch factor for Hydro One Distribution. Hydro One is prepared to adopt Clearspring's revised proposal.

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SC - SEC INTERROGATORY - 11

Reference:

Exhibit JTU-2.23

Interrogatory:

Hydro One states that if it "does not remain within the as-filed capital envelopes for transmission (2020-2022) and distribution (2018-2022), offsetting adjustments will be made to the capital and in-service additions over the 2023-2027 rate period."

a) Please confirm that the proposed baseline amounts used for the purposes of the transmission and distribution CISVA, will be the approved 2023-2027 in-service additions.

b) Please confirm that Hydro One will record in Account 1592- Accelerated CCA sub-account, the impact of the Accelerated Investment Incentive (AII) for in-service additions in 2022 related to May storm damage, that it cannot offset in 2022.

Response:

a) Hydro One confirms that the baseline amounts to be used for the purposes of the Transmission and Distribution CISVA calculations will align to OEB-approved in-service additions in the 2023-2027 period.

With respect to the CISVA calculation for both Transmission and Distribution, Hydro One is clarifying that the CISVA calculations would take into account the 2022 Bridge Year forecast included in the as-filed evidence to account for any overspend in 2022 which is then offset by an underspend over the 2023-2027 period. For example, the 2023 CISVA calculation would include 2022 and 2023 in-service additions on a cumulative basis. Hydro One is proposing to update the Draft Accounting Orders for the Transmission and Distribution CISVA accounts at the Draft Rate Order stage to reflect this. This is consistent with the previously approved Transmission CISVA for 2020-2022 in EB-2019-0082 which included the 2019 forecast (bridge year) as part of annual cumulative calculation for 2020-2022.[1]

b) Hydro One notes that no amounts will be recorded in Account 1592-Accelerated CCA sub-account in 2022 for Hydro One Distribution related specifically to the May 2022 Storm costs.[2]

[1] See Exhibit G-01-01, Section 3.14, page 20

[2] Account 1592-Accelerated CCA sub-account is not applicable to Hydro One Transmission as it rebased in 2020 under the Accelerated CCA rules (see Exhibit G-01-01 Attachment 5)

The calculation of the amounts to be included in Account 1592-Accelerated CCA sub-account is based on the OEB approved in-service additions (embedded additions) and not based on actual additions as outlined in Exhibit G-01-01 Attachment 5. Additionally, in response to the G-Staff-308 interrogatory, Hydro One provided the rationale for using embedded additions as opposed to actual additions.

With respect to the 2023-2027 period, the Regulatory Taxes for the 2023-2027 period would incorporate the Accelerated Investment Incentive rules and consequently capture the accelerated CCA impact related to 2023-2027 in-service additions.

SC - SEC INTERROGATORY - 12

Reference:

Reference not provided

Interrogatory:

Please provide details of the new collective agreement between Hydro One and CUSW.

Response:

As previously stated during the Technical Conference on May 31, 2022 (page 61 lines 17-26), the details of the new collective agreement between Hydro One and CUSW are as follows.

4 year term (May 1, 2022 - April 30, 2026)

Overall Total Wage Package increases

- May 1, 2022 - 3%
- May 1, 2023 - 3%
- May 1, 2024 - 2%
- May 1, 2025 - 2%

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SC - VECC INTERROGATORY - 01

Reference:

Exhibit I-24-L-VECC 26 a)
Exhibit JTU-1.22

Preamble:

The response to JTU 1.22 states:

> "To align with the approach determined in Hydro One's internal review, actual 2018 to 2020 Transmission External Revenues (original Exhibit D-02-01, Table 1) were updated to reflect various changes, including additional internal work revenues within the Other External Revenues category that were previously excluded and minor corrections to the groupings/re-classifications within certain line items. These updates were reflected in Table 2 of Exhibit O-01-05. These updates would reflect only a subset of the principal adjustments shown in the response to interrogatory. As such, a comparison of changes between Tables 1 and 2 in the preamble to interrogatory VECC-174 will not correlate to the table in the interrogatory response to O-VECC-173."

Interrogatory:

a) In part a) of VECC 26 the footnote to the table states that the costing of external work is calculated the same way as for internal work and further described in Exhibit C-9-1 to C-9-4. In those exhibits it appears that the "overhead" rates used are related to direct supporting activities (Exhibit C/Tab 9, Schedule 2, page 4). Does the costing of External Sales include an allocation of the costs associated with the Common Corporate Functions and Services (as described in Exhibit E, Tab 4, Schedule 2).
    i. If yes, where in the Application have the CCFS costs attributed to External Sales been netted out of the CCFS costs to be recovered through transmission rates (and similarly distribution rates).

    ii. If not, why not?

b) The response suggests that the updated historical values in Table 2 of O-01-05 don't reflect all of the adjustments made to the historical revenues as a result of the internal review.

i. If this is the case, please provide a revised Table that does reflect all of the adjustments made to the historical external revenues consistent with VECC 173.

ii. If this is not the case (and all of the adjustments have been included) then it is still not clear why the changes between Tables in the VECC 174 preamble don't match the principal changes in VECC 173 since the "minor corrections to the groupings/re-classifications within certain line items" should not affect the total – only the area/source the revenue is reported under. Please reconcile.

Response:

a)

i. Yes, the costing of external sales for Transmission and Distribution identified in Exhibits E-04-06 and E-04-07 respectively include an allocation for the costs associated with the Common Corporate Functions and Services. As further described in Exhibits E-04-06 and E-04-07, the common corporate costs associated with the costs of sales for Transmission and Distribution external work are included in the OM&A component of revenue requirement but are also recognized within Transmission and Distribution external revenues to be netted against the revenue requirement.

ii. Not Applicable. Please refer to the response in part a, i) above.

b)

i. Not Applicable.

ii. Hydro One confirms that the updated historical values in Table 2 of Exhibit O-01-05 reflect all of the adjustments made to the historical revenues as a result of Hydro One's internal review. As noted in the preamble of this question, the changes between Tables 1 and 2 in the O-VECC 174 preamble (specifically from 2018 to 2020) do not match the principal adjustment for these corresponding years in O-VECC 173, as the principal adjustment in O-VECC 173 is the sum of:

i) The change between Tables 1 and 2 of O-VECC 174, which reflects revenues that were inadvertently excluded in the reporting of historical actual Transmission External Revenues, subsequently identified through our completeness reviews; and

ii) Other net revenues, inclusive of the associated cost of sales impact relating to the internal work revenues. These revenues were included in the tables in O-VECC-174, but excluded in the 'actual net revenues' used to compute the balance in the External Station Maintenance, E&CS and Other External Revenue variance account.

Based on the above, the difference in Tables 1 and 2 of O-VECC 174 will not exactly reconcile to the O-VECC-173 principal adjustment.

As previously noted in Exhibit O-01-05 of the updated evidence, Hydro One has confirmed that the assessment of the 2021-2027 test year forecasts for Transmission External Revenues continue to remain appropriate, as they are unaffected by the adjustment to historical Transmission external revenues that has been recorded in the External Station Maintenance, E&CS and Other External Revenue variance account.

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SC - VECC INTERROGATORY - 02

Reference:

Exhibit JT-VECC TCQ 1, Attachment 1
Exhibit I-24-G-VECC 92, Attachment 1
Exhibit G-1-1, Attachment 3, Page 4

Interrogatory:

a) Please reconcile the 2016 ICI amounts in VECC 92 (less than 1,000 kW in all months) with the amount reported in VECC TCQ#1 – Attachment 1, 2006-2017 Tally Tab, Row 748 (~1,200 kW – Net Peak Demand Reduction).

b) Please reconcile the 2016 DR amounts in Exhibit G (summer max of 406 MW) with the VECC TCQ #1 – Attachment 1 value of more than 600 MW of Net Peak Demand Reductions due to DR exclusive of TOU and ICI.

Response:

a) The DR and ICI peak savings in VECC TCQ#1 – Attachment 1, 2006-2017 Tally Tab were not used because the IESO suggested not to use this information for the variance analysis when they provided it to Hydro One. In addition, the IESO does not have access to LDCs' class A customers meter data and its ICI impact analysis is an approximate estimation. In the EB-2019-0082 decision the OEB approved Hydro One's methodology used to calculate the CDM and DR variance account. Hydro One is applying the same methodology in this proceeding.

b) See response to part a). Hydro One used the information provided by the IESO related to the demand measures that were dispatched. The demand measures include both the dispatchable load and the resources activated through the demand response auction.

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SC - VECC INTERROGATORY - 03

Reference:

Exhibit E-4-1, Page 3
Exhibit E-4-7, Page 2

Interrogatory:

a) In Exhibit E, Tab 4 Schedule 1 (page 3) the cost of Distribution external sales is indicated to be $4.4 M. However, in Exhibit E, Tab 4, Schedule 7 (page 2) the total cost is quoted as $5.4 M. Which number is correct and does the required correction impact (change) the base distribution revenues used to determine the proposed 2023 rates?

b) How does the Board's EB-2021-0306 Decision to set the 2022 pole attachment rate at $34.76 impact the forecast for Other Revenues?

Response:

a) The correct number is $4.4M found in Exhibit E, Tab 4 Schedule 1 (page 3). Corrections to Table 1 and Table 2 in Exhibit E, Tab 4, Schedule 7 have been made below. Furthermore, the Cost of Unregulated Revenue in 2021 should be $2.6M instead of $2.9M found in Table 1 and 3 in Exhibit E, Tab 3, Schedule 7. This correction does not impact the proposed 2023 rates.

Table 1 - Summary of OM&A Costs of External Revenue ($M)

	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Cost of Regulated Revenue	1.2	1.2	1.3	1.4	1.4	1.4
Cost of Unregulated Revenue	9.2	4.1	2.8	2.6	2.9	2.9
Total	**10.4**	**5.3**	**4.1**	**4.0**	**4.3**	**4.3**

Table 2 - Cost of Regulated Revenues OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Cost of Regulated Revenue	1.2	1.2	1.3	1.4	1.4	1.4
Total	**10.4**	**5.3**	**4.1**	**4.0**	**4.3**	**4.3**

b) Refer to response for SC-22-SEC-05

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SC - VECC INTERROGATORY - 04

Reference:

Exhibit JT-VECC TCQ 13 a)

Interrogatory:

a) VECC TCQ 13 a) sets out the methodology used to derive the CDM savings for HONI distribution from the total energy savings for Ontario. The response states that HONI's share of LDC savings was based on HONI's share of the total 2015-2020 savings target. For those years where the IESO reported savings totals for all LDC and for HON-Dx, how does HON-Dx share of actual savings compare with its share of target savings?

Response:

a) The share of actual savings compared with the share of target savings for 2015-2017 is provided below:

	2015	2016	2017	2018	2019	2020
CDM Net Verified Energy Savings *	20.6%	19.6%	20.7%	Not available		
CDM target energy savings	16.6%	16.6%	16.6%	16.6%	16.6%	16.6%

** including savings of the acquired LDCs*

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SC - VECC INTERROGATORY - 05

Reference:

Exhibit JT-VECC TCQ 19
Exhibit I-22-O-SEC 252
Exhibit I-24-O-VECC 164

Preamble:

VECC 164 outlines how HON proposed to determine the distribution rates for purposes of the DRO as follows:

> "1. Use updated load forecast and total revenue requirement (with updated inflation adjustment) to run the Cost Allocation Model (CAM). This CAM is provided in response to O-SEC-252 (b).
> 2. Follow the rate design process, including revenue-to-cost ratio adjustments, using the updated charge determinants and revenue requirement allocation to rate classes from the above-noted CAM.
> 3. Deduct the deferred revenues related to the inflation update and load forecast shortfall (as shown in O-1-4, Tables 2 and 4 and updated at the time of the DRO) from the total revenue requirement mentioned in Step 1 and allocate this revised revenue requirement to rate classes using the same % share as derived in Step 2 above."

Interrogatory:

a) Please confirm that Tables 1, 2 and 3 in VECC TCQ 19 reflect just the impact of correcting 1815 and including retirements.

b) Do the distribution cost allocation model results presented in SEC 252-Attachment 1 reflect: i) the March updated load forecast, ii) the March updated distribution revenue requirement and iii) the model corrections described in VECC TCQ 19?

   i. If not, please provide a revised 2023 Cost Allocation Model that reflects all of these changes and also provide updates to SEC 252 Attachments 2-4. In addition, please also provide the resulting rates and bill impacts by customer class after reducing the resulting rates by the percentage required (per step 3) to account for the deferred revenues.

   ii. If yes, please also provide the resulting 2023 rates by customer class after reducing the resulting rates and bill impacts by the percentage required (per step 3) to account for the deferred revenues.

Response:

a) Confirmed.

b) Yes, the distribution cost allocation model results presented in SEC 252-Attachment 1 reflect:
i) the March updated load forecast,
ii) the March updated distribution revenue requirement and
iii) the model corrections described in VECC TCQ 19

i. Not applicable

ii. As noted in exhibit O-1-1, Section 1.4, Hydro One is proposing to record the incremental revenue requirement associated with higher (i) inflation assumptions and (ii) revenue deficiency arising from the changes in billing determinants due to the load forecast update in a deferral account, for recovery commencing in 2028. As a result, the distribution rates and bill impacts for 2023-2027 are not expected to change materially from those presented in the as filed evidence (Rates: Exhibit L-02-01, Bill Impacts: Exhibit L-06-01).

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SC - VECC INTERROGATORY - 06

Reference:

Exhibit I-24-L-VECC-107
Exhibit JT-VECC TCQ 15
Exhibit JT-VECC TCQ 16 c)
HONI's Cost Allocation Model (L-1-3-1), Tab I4
Exhibit L-2-1, Page 21
HONI's Conditions of Service, Page 48

Interrogatory:

a) HONI's Conditions of Service list its typical Primary Voltages as: i) 44,000 Volts – Three Phase three-wire, ii) 16,000/27,600 Volts – Three Phase four-wire, iii) 14,400/25,000 Volts – Three Phase four-wire, iv) 8,000/13,800 Volts – Three Phase four-wire, v) 7,200/12,470 Volts – Three Phase four-wire, vi) 4,800/8,320 Volts – Three Phase four-wire, and vii) 2,400/4,160 Volts – Three Phase four-wire. For purposes of the Cost Allocation Model (see Tab I4) HONI records the cost of transformers with primary voltages below 50 kV in accounts 1820-2 and 1850. Please provide a schedule that lists the types of HONI transformer (i.e., primary voltage, secondary voltage and KVA) with a primary voltage below 50 kV that are recorded in each of USOA 1820-2 and USOA 1850. Note: Please ensure the schedule includes HONI's Planned Standard Service Transformers for ST Rate Class per VECC 107, Table 1.

b) VECC TCQ 16 c) states "Hydro One believes that local transformation ownership should be eliminated as a consideration in determining a customer's rate class. The costs associated with local transformation are minor compared to the costs associated with the amount of distribution assets required to serve the customer (i.e. being supplied from the sub-transmission level vs lower voltage distribution system)." Using the gross book values for distribution assets as set out in the CAM (Tab I4), please provide a schedule that supports this claim.

c) At Exhibit L, Tab 2, Schedule 1, page 21 the Application states: "Current non-ST customers that are connected to Hydro One owned local transformation, and meet all of the ST class requirements, will be reclassified as ST customers." Is it possible for non-residential customers with loads in excess of 500 kW to be served from transformers connected at primary voltages less than 13.8 kV?

i. If not, how would a non-residential customer with a load in excess of 500 kW be provided service if locating in an area where the primary voltage is less than 13.8 kV and in what rate classification would the customer be placed?
ii. If not, does this mean that, if the new ST definition is approved, all non-residential customers with a load in excess of 500 kW will be classified as ST customers?
iii. If not, does this mean that, if the new ST definition is approved, all HONI`s GS_d customers will have loads of less than 500 kW?
iv. If yes, does this mean that all non-residential customers with demands in excess of 500 kW who are located in areas where the primary voltage is 13.8 or greater will become ST customers while similar sized customers in areas where the primary voltage is less than 13.8 kV will be classified as GS_d customers?
v. If yes, please provide the monthly distribution bill for a non-residential customer with a billing demand of 1,000 kW based on: i) the proposed 2023 ST rates and ii) the proposed 2023 GS_d rates.

d) At Exhibit L, Tab 2, Schedule 1, page 21 the Application states: "Current ST customers will have the option to sell their existing local transformers to Hydro One. At a customer's request, Hydro One will assess the customer's transformer, and offer to purchase for those that meet Hydro One's standards". How will HONI determine the price it will pay for customer owned transformers? In particular, will it take into account the age/expected remaining life of the transformer station and also take into account the fact that it would normally only pay for a station of up to 501 kVA?

e) Will ST customers who continue to own their own transformer be eligible for the $0.60/kW TOA?

Response:

a) Hydro One's standard specifications for service transformers (included in USoA 1850) are provided below in Tables 1 through 9. Specifications for transformers within USoA 1820-2 have not been provided, as USoA 1820-2 is for distribution station transformers. They are not service transformers (i.e. local transformation that steps down to the customer utilization voltage).

Table 1 - Standard Single-phase Pole-mount Transformer Sizes

Transformer Size (kVA)
5
10
25
50
75
100
167

Table 2 - Standard Single-phase Pole-mount Transformer Primary Voltages

Standard Primary Voltages (kV)
2.4
4.8
7.2
8.0
14.4
16

Table 3 - Standard Single-phase Pole-mount Secondary Voltages

Standard Secondary Voltages (V)
120/240
347

Table 4 - Standard Single-phase Pad-mount Transformer Sizes

Transformer Size (kVA)
10
25
50
75
100
167

Table 5 - Standard Single-phase Pad-mount Transformer Primary Voltages

Standard Primary Voltages (kV)
2.4
4.8
7.2
8.0
14.4
16

Table 6 - Standard Single-phase Pad-mount Transformer Secondary Voltages

Standard Secondary Voltages (V)
120/240

Table 7 - Standard Three-phase Pad-mount Transformer Sizes

Transformer Size (kVA)
150
300
500
750
1000
2000
3000

Table 8 - Standard Three-phase Pad-mount Transformer Primary Voltages

Standard Primary Voltages (L-N/L-L) (kV)
2.4/4.16
4.8/8.32
7.2/12.47
8.0/13.8
14.4/24.94
16/27.6
44 (L-L)*

* Transformers with primary voltage of 44kV will be added to Hydro One's standards to allow Hydro One to provide service transformers for larger customers.

Table 9 - Standard Single-phase Pad-mount Transformer Secondary Voltages

Standard Secondary Voltages (V)
120/208
347/600

Table 10 below provides the gross book values (GBV) for distribution assets for GSd, UGd and ST rate classes1. Also included in the table is the total GBV (excluding local transformers 1850) per kW of demand for each class.

Table 10 - GBV for Distribution Assets for GSd, UGd and ST Rate Classes

USofA	GSd	UGd	ST
1805	$6,465,171	$1,216,546	$3,097,865
1806	$29,447,818	$5,541,174	$14,110,280
1808	$8,385,834	$1,578,131	$19,421,239
1815	$23,202,646	$4,365,934	$54,296,900
1820	$171,170,197	$33,569,998	$43,540,908
1830	$383,979,185	$71,361,968	$325,119,676
1835	$230,582,623	$42,669,534	$142,162,572
1840	$3,489,876	$642,333	$4,008,842
1845	$55,045,278	$10,131,419	$63,230,854
1850	$640,179,949	$110,120,722	$0
1855	$0	$0	$0
1860	$18,772,166	$5,434,029	$7,798,460
Total (non-1850)	**$930,540,794**	**$176,511,067**	**$676,787,596**
2023 Forecast Demand (kW)	**6,937,130**	**2,284,824**	**30,627,361**
Gross Book Value/kW	**$134**	**$77**	**$22**

[1] Based on the revenue requirement and load forecast submitted in March 31st, 2022 evidence update. The figures in the table can be found in the Cost Allocation Model filed as Exhibit I-22-O-SEC-252-01_20220516. Refer to tab "O4 Summary by Class & Accounts" for USofAs 1805 and 1806 (rows 22-26) and tab "E2 Allocators" for USofAs 1808-1860 (rows 476-507).

b) As shown in the table above, while transformer costs do represent a significant portion of the total assets for the GSd and UGd classes, the total distribution line assets (excluding 1850) required per kW of demand served is much lower for the ST rate class as compared to GSd and UGd. This cost differential is mainly attributed to the fact that ST customers are connected at 13.8 KV or higher, and as such, do not use as many distribution assets as GSd/UGd customers that are connected at voltages below 13.8 KV. For this reason, Hydro One has proposed that the voltage/connectivity criterion remain in place and only transformer ownership criterion is eliminated.

c) Yes, Hydro One may supply customers with loads in excess of 500 kW connected at less than 13.8kV from transformers connected at primary voltages less than 13.8 kV on an exception basis, if the higher voltage system is far from the customer location and the lower voltage system has sufficient capacity available.

i. Not applicable
ii. Not applicable
iii. Not applicable
iv. Yes. While such customers may be similarly sized, providing them service requires the use of distribution assets below 13.8kV (i.e. non-ST assets).
v. The monthly distribution bill for a customer at 1,000 kW based on the proposed ST, GSd and UGd rates are provide below:

	2023 Distribution Monthly Charge ($)
ST Rates	$2,527
GSd Rates	$18,979
UGd Rates	$10,867

d) Hydro One will pay the customer the lesser of the estimated and agreed upon remaining net book value based on type and age of the unit, up to a maximum of the cost of 501 kVA overhead transformation.

e) No, the ST customers who continue to own their own transformers will not be eligible for TOA. This is consistent with the current arrangement that ST customers are required to own and maintain their local transformers and are not eligible for TOA.

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SC – DAY 1 – QUESTION A

Hydro One provided an evidence update on March 31, 2022 to reflect updated planning assumptions for inflation using Ontario CPI (3.5% for 2021, 4.5% for 2022, and 3.3% for 2023 relative to the 2.0% per year previously forecasted) with an associated Proration Factor of 1.0525.[1]

As outlined in Section 2.5.2 *Confirmation and Adjustment of Inflation Forecast* in Exhibit O-01-02, the values provided for 2023-2027 will be adjusted at the time of the Draft Rate Order (DRO) to incorporate the most recent inflation rates for 2022 and 2023 based on either the actual 2022 Ontario CPI rate (if available) or the most recent Scotia forecast for 2022 and the Scotia forecast for 2023 Ontario CPI.

As an example, based on the latest Scotia forecast, 2022 Ontario CPI is 7.3% and 2023 Ontario CPI is 3.6%.[2] Taking into consideration the 10% cap on inflation as proposed by Hydro One, the inflation forecast would result in 7.3% for 2022 and 2.7% for 2023. As a result, the proration factor applied to OM&A costs, capital expenditures and in-service additions would be adjusted to 1.0744. This is approximately 2% higher than the figures provided in the March 31, 2022 update.

Revenue Requirement

Please refer to Exhibit O-01-02 Attachments 5A through to 5E provided in Excel Format for full Transmission Revenue Requirement calculations for 2023-2027.

Additionally, Table 26 in Exhibit O-01-02 provides the Transmission Revenue Requirement (Line 14 Total Revenue Requirement).

$M	2023	2024	2025	2026	2027
Total Revenue Requirement Transmission	1,849.3	1,968.2	2,063.0	2,182.5	2,266.6

Please refer to Exhibit O-01-02 Attachments 5F through to 5J provided in Excel Format for full Distribution Revenue Requirement calculations for 2023-2027.

Additionally, Table 28 in Exhibit O-01-02 provides the Distribution Revenue Requirement (Line 14 Total Revenue Requirement).

[1] Exhibit O-01-02, p. 7-8.

[2] Scotiabank Global Economics, Scotiabank's Forecast Tables, July 18, 2022: forecast_20220718.pdf (scotiabank.com)

$M	2023	2024	2025	2026	2027
Total Revenue Requirement Distribution	1,669.1	1,753.3	1,832.2	1,934.8	2,024.6

Capital Expenditures

Please refer to Exhibit O-02-01, Attachments 1 and 7 for the transmission and distribution capital expenditures, respectively. These attachments include actual costs for 2021, the 2022 as-filed forecast and the 2023-2027 capital expenditure forecast updated for inflation as of March 31, 2022.

$M	2021 Actual	2022 Bridge (As-Filed Forecast)	Forecast Period					Exhibit Reference
			2023	2024	2025	2026	2027	
Transmission Capital Expenditures	1,287.0	1,179.7	1,509.3	1,540.7	1,526.6	1,538.5	1,524.3	Exhibit O-02-01, Attachment 1
Distribution Capital Expenditures	762.8	664.6	1,057.9	1,081.9	1,179.7	1,127.9	1,127.2	Exhibit O-02-01, Attachment 7

OM&A

Please refer to Exhibit O-02-01, Attachments 6 and 10 for the transmission and distribution OM&A costs, respectively. These attachments include actual costs for 2021, 2022 as-filed forecast costs and the 2023 test year costs updated for inflation as of March 31, 2022.

$M	2021 Actual	2022 Bridge (As-Filed Forecast)	2023 Test Year	Exhibit Reference
Transmission OM&A	401.8	393.4	442.6	Exhibit O-02-01, Attachment 6
Distribution OM&A	582.3	535.8	628.9	Exhibit O-02-01, Attachment 10

Compensation

Compensation costs are provided in Exhibit O-02-01, Attachment 11 and summarized below.

$M	2021 Actual	2022 Bridge (As-Filed Forecast)	2023 Test Year	Exhibit Reference
Total Transmission Compensation Costs	628.5	667.1	693.8	Exhibit O-02-01, Attachment 11
Total Distribution Compensation Costs	752.1	774.5	797.7	Exhibit O-02-01, Attachment 11

Other Revenue

The 2023-2027 Transmission Other Revenue reflected in Interrogatory O-PP-022 part d) is summarized below.

Transmission $M	2023	2024	2025	2026	2027
Other Revenue[1, 2]	-87.4	-54.7	-54.4	-53.1	-53.5

[1] Other includes Deferral and Variance Accounts, external revenues, export service credit, and Low Voltage Switch Gear as well as a refund of the $27.5M credit for External Revenue Variances to customers in 2023, and excludes the 2023 Deferred Tax Asset ("DTA") amount (+$43.5M), approved in EB-2021-0185 on December 16, 2021.
[2] Also see Exhibit O-01-02 Attachment 5A-5E p. 3 and p. 5, and O-Staff-390.

The 2023-2027 Distribution Other Revenue reflected in Interrogatory O-PP-022 part d) is summarized below. For updated Distribution Other Revenues, reflecting the pole attachment charge amendments, please refer to SC-1 part C.

Distribution $M	2023	2024	2025	2026	2027
Other Revenue[1, 2]	-63.9	-64.1	-64.0	-63.5	-63.6

[1] Other includes Deferral and Variance Account balances and External Revenues (see SC part C for details, Table 1, Annual Recoveries for Distribution Regulatory Accounts) and excludes the 2023 Deferred Tax Asset ("DTA") amount (+$24.0M), approved in EB-2021-0185 on December 16, 2021.
[2] Also see Exhibit O-01-02 Attachment 5F-5J p. 3 and p. 5.

SC – DAY 1 – QUESTION B

RCI Formula

Please provide most recent proposed numbers in respect of Hydro One's proposed custom IR framework.

Response:

Please see below:

Distribution

Custom IR parameter	Proposed value
Inflation Factor	Two-factor input price index as detailed in Exhibit A-4-3; updated annually to reflect latest values issued by the OEB
Productivity Factor	**0.3%**, equal to the sum of industry productivity (0%) and stretch factor (0.3%) *Note, however, as indicated in SEC-06, Hydro One would be prepared to adopt revised recommendation of Clearspring of 0.45% in respect of the stretch factor
Custom Capital Factor	Updated annually to reflect changes in inflation; includes supplemental stretch of **0.15%**

Transmission

Custom IR parameter	Proposed value
Inflation Factor	Two-factor input price index detailed in Exhibit A-4-2; updated annually to reflect latest values issued by the OEB
Productivity Factor	**0%**, equal to the sum of industry productivity (0%) and stretch factor (0%)
Custom Capital Factor	Updated annually to reflect changes in inflation; includes supplemental stretch of **0.15%**

SC – DAY 1 – QUESTION C

VECC Pre-Settlement Conference Question 3B

How does the Board's EB-2021-0302 Decision to set the 2022 pole attachment rate at $34.76 impact the forecast for Other Revenues?

Response:

The forecast has been updated to reflect the new pole attachment charge consistent with the OEB's decision in EB-2021-0302.[1]

Table 1 - As-Filed External Revenues

	Test	Forecast Period			
	2023	2024	2025	2026	2027
Total External Revenues and Other	46.4	46.6	46.5	46.0	46.1
Annual Recoveries for Distribution Regulatory Accounts (G-1-4, Table 2)	17.5	17.5	17.5	17.5	17.5
Total Other Revenues[2]	63.9	64.1	64.0	63.5	63.6

Table 2 - Updated External Revenues for Revised Pole Attachment Charge

	Test	Forecast Period			
	2023	2024	2025	2026	2027
Total External Revenues and Other	43.1	43.3	43.2	42.6	42.8
Annual Recoveries for Distribution Regulatory Accounts (G-1-4, Table 2)	17.5	17.5	17.5	17.5	17.5
Total Other Revenues[3]	60.6	60.8	60.7	60.1	60.3
Net Impact on Total Other Revenues	(3.3)	(3.3)	(3.3)	(3.4)	(3.3)

VECC Pre-Settlement Conference Question 5

Please provide details in support of response to VECC 5 b) ii).

[1] EB-2021-0302, Decision and Order, Wireline Pole Attachment Charge, Ontario Energy Board, December 16, 2021, p 2-3.
[2] excludes the 2023 Deferred Tax Asset ("DTA") amount (+$24.0M), approved in EB-2021-0185 on December 16, 2021.
[3] Ibid

Response:

The table below compares the as-filed 2023 distribution rates (including the corrections provided in VECC TCQ-19) compared with the 2023 rates arising from the March evidence update (including the proposed revenue deferral).

Rate Class	2023 DX Rates per VECC TCQ 19			2023 DX Rates as Proposed in March Evidence Update		
	Fixed Charge ($/month	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)	Fixed Charge ($/month	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)
UR	$35.88	$0.0000		$35.89	$0.0000	
R1	$57.22	$0.0052		$57.20	$0.0052	
R2	$116.58	$0.0081		$116.52	$0.0081	
GSe	$30.95	$0.0647		$30.59	$0.0651	
GSd	$99.80		$18.2761	$98.32		$18.3102
UGe	$24.10	$0.0311		$23.82	$0.0312	
UGd	$91.19		$10.5427	$89.89		$10.5669
St Lgt	$2.97	$0.1064		$2.93	$0.1065	
Sen Lgt	$2.80	$0.1533		$2.63	$0.1461	
USL	$34.55	$0.0216		$33.53	$0.0213	
DGen	$192.51		$9.9393	$186.93		$10.4405
AUR	$29.59	$0.0000		$29.63	$0.0000	
AUGe	$24.83	$0.0144		$25.60	$0.0148	
AUGd	$149.74		$2.3077	$155.26		$2.3928
AR	$35.94	$0.0000		$35.99	$0.0000	
AGSe	$37.65	$0.0171		$37.71	$0.0173	
AGSd	$174.48		$4.0355	$181.92		$4.1353

ST Rates		
Charge Description	**As Filed (per VECC TCQ 19)**	**March Update**
Service Charge ($/month)	$771.17	$766.79
Meter Charge ($/month)	$391.39	$398.10
ST Common Line ($/kW)	$1.4611	$1.4560
HVDS-high	$2.6926	$2.8204
HVDS-low ($/kW)	$4.5301	$4.7211
LVDS-low ($/kW)	$1.8375	$1.9007
Specific ST lines ($/km)	$587.1287	$599.6911

SC – DAY 1 – QUESTION D

Re SEC Pre-Settlement Conference Question 6

The request was to provide a detailed list of all changes and updates to be made as part of the DRO, beyond those items provided in response to SC-SEC-06. The following is additional to the updates outlined in response to SC-SEC-06 and consists of changes and updates identified through the course of this proceeding (on a best effort basis), which Hydro One intends to update at the time of the DRO.

1. Regulatory Taxes

As noted in Exhibit O-01-02, Section 4 and in response to Interrogatory E-Staff-295, the updated Regulatory Taxes for inflation (March 31, 2022) and the as-filed calculations from August 5, 2021 have not taken into account the amount related to the unintended exclusion of depreciation and amortization expense for Regulatory Tax purposes. Hydro One intends to update the Regulatory Tax calculation to reflect this change at the time of the Draft Rate Order. In response to E-Staff-295, Hydro One previously quantified the impact of this update as an approximate increase of $12M on a cumulative basis on revenue requirement over 5 years for Transmission and Distribution.

2. Distribution Deferral and Variance Accounts Balance for Disposition

In accordance with the Decision and Order in EB-2022-0071 (Motion to Review and Vary aspects of the EB-2021-0033 Decision and Order relating to Account 1576 and Account 1592),[1] Hydro One will dispose of its Account 1592, Sub-account CCA Changes calculated using the Actual Additions Method for the Acquired Utilities, inclusive of carrying charges to December 31, 2022, in the current proceeding (EB-2021-0110). As such, these balances will be added to the final Distribution regulatory account balance for disposition and disposed of to the customers of the Acquired Utilities. This update would result in approximately $1.2M (and any applicable interest) to be given back to the customers via a rate rider.

[1] EB-2021-0033 was Hydro One's application for approval of 2022 distribution rates for its Acquired Utilities (Norfolk, Haldimand and Woodstock)

3. Distribution Capital

Update to D-SA-04 Net Investment Costs for 2023-2027 (B3-EnergyProbe-031)

The forecast net investment cost for the 2023-2027 period for the Metering Sustainment program (D-SA-04) was incorrect due to overstating removal costs. The resulting impact of this correction is an increase of $9.4M resulting in a Total Net Investment Cost of $188.5M.[2]

Update to D-SR-05 Net Investment Costs for 2023-2027 (B3-EnergyProbe-033)

The forecast net investment cost for the 2023-2027 period for the Trouble Call and Storm Damage Response program (D-SR-05) was incorrect due to omitting the 2005 capital expenditure datapoint in the calculation of the forecast amount. The resulting impact of this correction is a decrease of $1.7M resulting in a Total Net Investment Cost of $550.0M.

Update to D-SR-12 Net Investment Costs for 2023-2027 (B3-EnergyProbe-038)

The forecast net investment cost for the 2023-2027 period for the Advanced Meter Infrastructure 2.0 (AMI2.0) program (D-SR-12) was incorrect due to understating removal costs. The resulting impact of this correction is a decrease of $11.9M resulting in a Total Net Investment Cost of $546.4M.[3]

Over the five-year plan period on a cumulative basis, the impact of the above capital updates is less than $2M to Distribution Rates Revenue Requirement.

4. Distribution External Revenues

Consistent with Hydro One's response to SC-VECC-05 and VECC settlement question 3b) and the clarification to that question, Hydro One intends to update the Distribution External Revenue to reflect the OEB's decision in EB-2021-0306 to the 2022 pole attachment rate of $34.76.

5. Reclassification Among Residential Rate Classes

Excel attachment JT-VECC-TCQ-09_01.xlsx, parts b) and c), provided the number of customers forecast considering both upward (lower density to higher density) and downward (higher density to lower density) reclassifications amongst residential rate classes consistent with VECC-109 b). Originally, in I-24-VECC 47, Attachment 1, only the upward reclassifications were considered. Over the five-year plan period on a cumulative basis, the impact of this update is not material to distribution rates.

[2] D-SA-04 As-Filed Net Investment Cost, Exhibit O, Tab 1, Schedule 1, Attachment 8
[3] D-SR-12 As-Filed Net Investment Cost, Exhibit O, Tab 2, Schedule 1, Attachment 8