TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.13

EVIDENCE REFERENCE:

4-Staff-159

UNDERTAKING(S):

To provide the positions.

RESPONSE(S):

Table A and C provides the existing quantity of supervisor positions, quantity of direct report positions, and average number of direct reports for the JC Programs of Distribution Operations, Engineering & Design, and Metering for 2024 and 2026 respectively. Please note that the undertaking requests information on Supervisors and Managers, however there are only new supervisors being added in these groups. As discussed during the Technical Conference, the proposed reporting structure for 2026 has not been finalized internally and is subject to change. For clarity, please note that 4-Staff-159 considers exclusively full time new positions, whereas this analysis has also included part time employees.

Table B contains the new supervisor positions to be added in 2026 and their proposed direct reports. As noted at the beginning of this response, this reporting structure is subject to change. The proposed direct reports are a combination of existing positions and new positions being added in 2026. Not all new 2026 positions are reflected in the table below, as many new positions will report to existing supervisor positions.

In addition to the positions identified in the tables below, there are approximately 37 co-op and summer student positions that may be reporting to the supervisors identified in the tables at various points in the year.

When comparing the three tables, it is important to note that the ratio of supervisor to direct reports across the three JC programs is relatively consistent from 2024 to 2026. The only JC program increasing in ratio is Metering, underpinning Hydro Ottawa's commitment to hire strategically and with prudence.

The average number of direct reports for Supervisors in Distribution Operations and Metering is higher when compared to Engineering & Design. Aligned with better practice for management span of control, this disparity is rooted in the distinct nature of the work and the role of the supervisor in these functional areas. Trade environments focus on standardized, repetitive tasks that require strict adherence to work procedures and safety protocols. Work in these environments can be managed effectively across larger teams by a single supervisor. Their supervisory oversight focuses on task coordination, safety protocols, and resource deployment over a broader group. In contrast, technical and engineering staff frequently engage in complex problem-solving requiring unique solutions, independent analysis, and specialized project work that demands closer mentorship, more in-depth guidance, and detailed review. This necessitates a smaller span of control for technical supervisors, allowing for the focused intellectual support, review of new options and solutions and quality assurance essential for highly specialized outputs.

Table A - Average Number of Direct Reports for Supervisors in Engineering & Design, Distribution Operations, and Metering, 2024

Appendix 2-JC OM&A Program	Number of Supervisors	Total Direct Reports	Average Number of Direct Reports
Distribution Operations	29	270	9
Engineering & Design	16	94	6
Metering	3	27	9
Total	**48**	**391**	

Table B - Direct Reports for New Supervisors in Engineering & Design and Distribution Operations, 2026

Appendix 2-JC OM&A Program	Supervisor	Direct Report Roles	Quantity
Engineering & Design	Supervisor, Projection & Control (NEW)	Distribution Engineer	2
	Supervisor, Distributed Energy Resources (NEW)	Distribution Engineer	2
	Supervisor, Major Projects (NEW)	Project Engineer	4+2 (contracted resources)
	Supervisor, Program Oversight (NEW)	Data Engineer	*2 + 2 (Field Crews)*
Distribution Operations	Supervisor, Contractor Management (NEW)	QA Inspector	2
		External Field Crews	3-5
		Subtotal	**5-7**
	Supervisor, Control Room (NEW)	Apprentice System Operator	2
		Dispatcher	1
		System Operator	3
		Subtotal	**6**
	Supervisor, Control Room (NEW)	Apprentice System Operator	2
		Dispatcher	1
		System Operator	3
		Subtotal	**6**

Appendix 2-JC OM&A Program	Supervisor	Direct Report Roles	Quantity
	Supervisor, Stations (NEW)	Apprentice - Station Electrician	3
		Station Electrician	3
		Subtotal	**6**

Table C - Average Number of Direct Reports for Supervisors in Engineering & Design, Distribution Operations, and Metering, 2026

Appendix 2-JC OM&A Program	Number of Supervisors (including 2026 hires)	2026 New Hires	Total Direct Reports	Average Number of Direct Reports
Distribution Operations	34	39	309	9
Engineering & Design	20	18	112	6
Metering	3	3	30	10
Total	**57**	**60**	**451**	

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-5.0

EVIDENCE REFERENCE:

3-SEC-62 a) and b)

Attachment 3-SEC-62(B) – Updated Revenue Load Forecast A

UNDERTAKING(S):

SEC 62 a) provides updated actual customer numbers and load for November and December 2024 and up to June 2025.

SEC 62 b) and the accompanying attachment provide the resulting forecast customer numbers and load for 2026-2030 using the updated data.

5.1 Please provide versions of the following files (submitted as part of the initial application) that support the forecast provided in SEC 62 b)

- HOL_Attachment 3-1-1(C) - 1.Load Forecast Data – Customers
- HOL_Attachment 3-1-1(C) - 2.Load Forecast Data – kWh
- HOL_Attachment 3-1-1(C) - 3.Load Forecast Data – kW

5.2 In preparing the update load forecast, did Hydro Ottawa's assumptions change regarding the Savings from DSM programs in 2024-2030? 5.2.1 If so, update Exhibit 3, Attachment 3-1-1(B) – Table 3-2 and explain the changes.

5.3 In preparing the update load forecast, did Hydro Ottawa's assumptions change regarding the Customer Reclassification and LU class disaggregation?

5.3.1 If so, indicate what the changes were in terms of both customer counts and kWh by class by year.

5.4 In preparing the update load forecast, did Hydro Ottawa's assumptions change regarding Electrification and Large Loads?

5.4.1 If so, please provide revised versions of Exhibit 3-1-1, Table 7 and Exhibit 3, Attachment 3-1-1(B) Tables 3-3 and 3-4.

5.5 In Attachment 3-SEC 62(B) the customer count, kWh and billing kW results are not broken down as between the GS 50-1499 and GS1500-4999 classes. Please provide revised schedules with this breakdown.

RESPONSE(S):

5.1 ~~Upon final review of the requested files some information was missing. Hydro Ottawa will update this undertaking response as soon as the information is available.~~

Please refer to the following attachments:

- Attachment JT1.14-VECC-5.0(A) - SEC-62 - Load Forecast Data - Customers
- Attachment JT1.14-VECC-5.0(B) - SEC-62 - Load Forecast Data – kWh
- Attachment JT 1.14-VECC-5.0(C) - SEC-62 - Load Forecast Data – kW

5.2 No, Hydro Ottawa's assumptions regarding the Savings from eDSM programs in 2024-2030 did not change.

5.3 No, Hydro Ottawa's assumptions regarding Customer Reclassification and Large User customer disaggregation did not change.

5.3.1 See response to 5.3

5.4 No, Hydro Ottawa's assumptions regarding Electrification and Large Loads did not change.

5.4.1 See response to 5.4

5.5 Table A, B and C below further break down the kWh, billing kW, and monthly average customer count provided in response to interrogatory Attachment 3-SEC-62(B): OEB Appendix 2-IB - Load Forecast Analysis.

Table A - 3.0-SEC-62 Revenue Load Forecast kWh by Rate Class

	2025	2026	2027	2028	2029	2030
Residential	2,593,073,317	2,598,486,536	2,614,803,988	2,649,631,949	2,672,170,678	2,706,639,658
General Service < 50 kW	745,695,849	738,002,620	734,190,566	736,041,210	734,753,617	733,977,760
General Service 50-1000 kW	2,427,661,397	2,382,325,770	2,365,404,281	2,362,520,550	2,350,966,038	2,341,224,881
General Service 1000-1500 kW	401,177,820	397,411,315	387,061,877	378,492,856	376,655,830	374,989,554
General Service 1500-5000 kW	731,812,726	717,373,164	707,328,036	701,156,164	692,820,640	684,794,186
Large User	513,647,022	534,832,421	557,500,644	604,226,353	657,514,517	691,680,394
Unmetered Scattered Load	14,236,301	14,308,959	14,363,366	14,417,773	14,472,180	14,526,587
Sentinel Lighting	41,366	40,631	39,896	39,161	38,427	37,692
Street Lighting	21,589,898	21,659,543	21,659,543	21,659,543	21,659,543	21,659,543
TOTAL	**7,448,935,696**	**7,404,440,960**	**7,402,352,197**	**7,468,185,559**	**7,521,051,471**	**7,569,530,256**

Table B - 3.0-SEC-62 Revenue Load Forecast kW by Rate Class

	2025	2026	2027	2028	2029	2030
General Service 50-1000 kW	5,979,361	5,840,081	5,797,878	5,790,686	5,761,869	5,737,575
General Service 1000-1500 kW	921,870	896,805	876,820	861,552	857,684	854,175
General Service 1500-5000 kW	1,597,798	1,597,038	1,576,014	1,563,097	1,545,652	1,528,854
Large User	974,070	1,022,952	1,089,883	1,222,323	1,393,895	1,503,860
Sentinel Lighting Connections	120	120	114	108	108	108
Street Lighting Connections	60,239	60,354	60,354	60,354	60,354	60,354
TOTAL	**9,533,458**	**9,417,350**	**9,401,063**	**9,498,120**	**9,619,562**	**9,684,926**

1 **Table C - 3.0-SEC-62 Revenue Load Forecast Monthly Average Customer and Connection Count by Class**

	2025	2026	2027	2028	2029	2030
Residential	344,451	346,478	348,504	352,008	356,364	360,320
General Service < 50 kW	25,821	25,969	26,039	26,162	26,314	26,452
General Service 50-1000 kW	3,015	2,952	2,952	2,952	2,952	2,952
General Service 1000-1500 kW	89	90	91	90	90	91
General Service 1500-5000 kW	79	80	79	79	79	79
Large User	10	11	12	13	14	14
Unmetered Scattered Load Connections	4,140	4,243	4,358	4,472	4,587	4,702
Sentinel Lighting Connections	48	47	46	45	44	43
Street Lighting Connections	64,822	65,686	66,596	67,505	68,415	69,324
TOTAL	**442,475**	**445,556**	**448,677**	**453,326**	**458,859**	**463,977**

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-6.0

EVIDENCE REFERENCE:

3-VECC 15 d) and Attachment 3.0-VECC-15(A)
3-SEC 64 a)
3-Staff 127 b)
3-VECC 29 c)

UNDERTAKING(S):

6.1 Attachment 3.0-VECC-15(A) provides tabs setting out the initial forecast for each class, the reclassification adjustments for each class, the electrification impacts by class and final forecast by customer class. However, for the GS<50, GS5—999, GS1500- 5000 and LU classes – the results in the Initial Forecast, Reclassification and Electrification tabs don't sum to the results set out in the final forecast tab. Please explain why and provide a revised response that reconciles the values in the four tabs.

6.2 It is understood that the customer count forecast also includes the impact of a LU customer being disaggregated into a number of smaller GS customers (per Exhibit 3-1-1, Attachment B, page 17 of 40). Please indicate: When this disaggregation is forecast to occur, and How many GS customers result from this disaggregation by GS customer class?

6.3 In Attachment 3.0-VECC-15(A), the changes in the Reclassification tab net to zero and the changes in the Electrification tab all show increases in the LU customer count. As a result, please explain where the impact of the LU customer disaggregation is captured and provide a revised file that explicitly sets out the impact of the LU disaggregation as part of the response.

6.4 SEC 64 a) states that the "requests included in the revenue load forecast are from current customers". However, in Staff 127 b) (Table A) – the changes in each year do not net out to zero which suggests that the electrification does change the total number of customers. Please reconcile these two responses and revise as necessary.

6.5 The customer class changes due to electrification as set out in Staff 127 b) don't line up with the changes in Attachment 3.0-VECC15(A). For example:

- VECC 15 shows no customers being reclassified from GS 1500-4999 to the LU class whereas Staff 127 shows one customer being reclassified starting in 2027.
- VECC 15 shows one customer in GS 50-999 class being reclassified due to LU starting in 2026 whereas Staff 127 does not show any.
- VECC 15 shows one customer in the GS<50 class being reclassified to LU starting in 2029 whereas Staff 127 does not show any. Please reconcile the two responses and provides revised versions as necessary.

6.6 In VECC 29 c) the results for 2025 and 2026 suggest that electrification resulted in some increase in GS 1000-1500 loads whereas VECC 15 indicates that only LU class load increases due to electrification. Please reconcile and provide revised responses as necessary.

RESPONSE(S):

6.1 In Attachment 3.0-VECC-15(A) the sum of Initial Forecast, Reclassification and Electrification tabs did not add up to the final forecast tab as further adjustments were made to the final forecast for the following reasons:

- An additional large user was removed starting in 2025 to account for the one customer that disaggregated as of January 1, 2025. The kWh and kW impact was accounted for in the baseline load forecast and is explained in the 6.2 and 6.3 responses below.

- An additional GS 1500-4999 kW was removed starting in 2026 as this customer was reclassified at the end of 2024.
- The GS 50-999 rate class count was held constant with the January 2025 forecast count to avoid further decreases based on historical trending.
- Elected to not remove the one GS 50 rate class customer due to electrification; however, its kWh and kW impact was reflected in the revenue load forecast.

In review of this data set, Hydro Ottawa confirms that our current revenue load forecast contains a duplication impact related to one large load in the forecast of kWh and kW.

6.2 The customer disaggregation began in Q4 2023 with the majority of the activity taking place in 2024. The large user account was disaggregated into 13 separate services. The disaggregation completed in 2025. Table A provides the breakdown by rate class, the customer count for the new accounts below are included in the historical baseline counts.

Table A - Customer Disaggregation

Rate Class	Count
General Service 50-1,000 kW	7
General Service 1,000-1,499 kW	1
General Service 1,500-4,999 kW	5

6.3 The original large user account was reclassified in January 2025 however the new disaggregated accounts started in 2023 or 2024 and are captured in the historical count data. Response to undertaking JT1.14-VECC-7.0 provides further detail of the treatment of historical kWh and kW billing determinants.

6.4 Hydro Ottawa confirms all large load requests incorporated into the revenue load and customer forecast are from current customers. Please find an update to Table A from 3-Staff-127, expanded by including 2024 and 2025 and the GS < 50 rate class in Attachment JT1.14-VECC-6.0(A) - Revised 3-Staff-127.

6.5 Please refer to response 6.4.

6.6 Electrification is not expected in the GS 1000-1500 kW class. Table B in 3-VECC-29 c) was derived from removing the LDEV MWh (Table 3-3 from Attachment 3-1-1(B) - Hydro Ottawa Long Term Energy and Demand Forecast) from the Total Electrification and Large Load MWh forecast. Hydro Ottawa notes there are discrepancies when removing the LDEV MWh from the Total Electrification and Large Load MWh forecast and is investigating further and will provide an update.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

3-Staff-127

EVIDENCE REFERENCE:

Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / pp. 31-40 (pdf pp. 54-63)
Ref. 2: Exhibit 3 / Attachment 3-1-1

Preamble:
Customer Models are provided for Residential, GS < 50, GS < 1,500, and a connection model is provided for streetlights.

QUESTION(S):

a) Please explain the derivation of the customer / connection forecasts for all remaining rate classes.
b) Please provide number of connections expected by year and rate class based on discussions with prospective customers.
c) Where expert judgement was used in forecasting, please identify the information considered by the expert.
d) Please explain how the information used extends to 2030.

RESPONSE(S):

a) The remaining rate classes are Large User, Unmetered Scattered Load (USL) and Sentinel Lights. For the Large User class, the forecast baseline count was held constant with adjustments made for anticipated rate reclassifications as result of the electrification and large load forecast, see response to question b). The forecast for USL was calculated by applying its historical growth trend. Conversely, a decreasing trend, based on historical data, was used to determine the connection count for Sentinel Lights during the Bridge and Test years.

b) Hydro Ottawa incorporated anticipated Large Load request customers into the revenue load and customer forecast based on discussions with these customers. These requests from current customers result in forecast customer rate reclassification in the Test years. Table A details the impact to customer forecasts for 2026-2030 for these prospective customers.

~~Table A - 2026-2030 Impact on Customer Count as result of Prospective Customers~~

	~~2026~~	~~2027~~	~~2028~~	~~2029~~	~~2030~~
~~General Service 50-1000 kW~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~General Service 1000-1500 kW~~	~~0~~	~~-1~~	~~-2~~	~~-2~~	~~-2~~
~~General Service 1500-5000 kW~~	~~0~~	~~-1~~	~~-1~~	~~-1~~	~~-1~~
~~Large User~~	~~1~~	~~2~~	~~3~~	~~4~~	~~4~~

Table A - 2026-2030 Electrification Customer Connection Year and Expected Rate Class

	2024	2025	2026	2027	2028	2029	2030
General Service <50 kW						-1	-1
General Service 50-1000 kW			-1	-1	-1	-1	-1
General Service 1000-1500 kW			0	-1	-2	-2	-2
General Service 1500-5000 kW	-1	-1	-1	-1	-1	-1	-1
Large User	1	1	2	3	4	5	5

c) The customer/connection forecasts for the classes not mentioned above are held constant at their October 2024 levels and adjusted as described in response (a). These historical customer/connection counts are not correlated with economic variables used in the residential or GS<50 model.

d) See response (a).

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-13.0

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), Table 3-2 (page 24 of 40)
3-VECC 30 a) and f)
1-Staff 11

UNDERTAKING(S):

VECC 30 a) asked for:
"a schedule for each rate class that set out for, each of the years shown (i.e., 2013-2030), the contribution to the year's cumulative saving made by CDM program savings in that year and in each of the preceding years" and "a similar "schedule for the total cumulative CDM savings in each year (2013-2030)."
The response referred to 1-Staff 11 which provided an excel file – HOL_IRR_Att-1-Staff 11(A).

13.1 According to the text in Exhibit 3, Attachment 3-1-1(B), Table 3-2 sets out the historical and forecast CDM used in the load forecast. Were the CDM values used in the forecast adjusted to reflect the fact that the full annualized savings will not be achieved in the first year of a CDM program?

13.1.1 If yes, is this adjustment reflected in the values set out in Table 3-2?

13.1.2 If not, why not?

13.2 VECC 30 f) states that "The CDM savings for 2023 and 2024 were taken from the IESO's 2021-2024 CDM Framework - Program Plan released on December 15, 2022." Please confirm that for the years 2018-2023 CDM program savings data used is all from IESO reports regarding actual savings achieved.

13.3 For each of the years 2018-2030, the sum the customer class values in Exhibit 3, Attachment 3-1-1(B), Table 3-2 do not match the totals in the file HOL_IRR_ATT_1.Staff 11 (A) – CDM Supporting Data (CDM Summary Tab). Please explain why and update the evidence as necessary.

13.4 The excel file provided in response to Staff 11 just provides totals for each year. It does not provide a breakdown of each year's total as to the contribution from CDM programs in that year and each of the previous years or by customer class – as requested in the original interrogatory VECC 30 a). Please provide the schedules as originally requested in VECC 30 a)?

RESPONSE(S):

13.1.1 Yes, the CDM values were adjusted to reflect a ramp-up period for new programs. This adjustment is reflected in Exhibit 3, Attachment 3-1-1(B) Table 3-2, where the forecast uses a portion of the total new annual savings. This approach provides more accurate and realistic forecasts by avoiding the assumption of immediate, full-year savings.

13.2 Yes, for the years 2018-2023, the CDM program savings data used were taken from IESO reports detailing the actual savings achieved.

13.3 Table A below details the reconciliation of the totals of first year savings taken from Table 3-2 in Exhibit 3, Attachment 3-1-1(B), and the values in Attachment HOL_IRR_ATT_1-Staff-11 (A) – CDM Supporting Data (CDM Summary Tab) for years 2018-2030. Please refer to Attachment JT1.14-VECC-13.0(D) - EnergySaving Reconciliation providing the calculation in Table A.

Table A - Reconciliation of annual energy savings (MWh)

	Table 3-2 iTron's report (A)	Table 3-2 iTron's report did not include IF (B)	Total (A) + (B)	VECC-13.0- First year only (C)	Additional savings (D)	Total (C) + (D)
2018	54,913		**54,913**	54,916		**54,916**
2019	42,528	4,468	**46,996**	46,997		**46,997**
2020	27,229	15,244	**42,473**	42,475		**42,475**
2021	36,777		**36,777**	32,193	4,584	**36,777**
2022	19,160		**19,160**	44	19,116	**19,160**
2023	36,206		**36,206**	36,208		**36,208**
2024	27,640		**27,640**	27,642		**27,642**
2025	75,003		**75,003**	67,104	7,899	**75,003**
2026	68,832		**68,832**	66,272	2,560	**68,832**
2027	70,890		**70,890**	67,325	3,565	**70,890**
2028	73,329		**73,329**	69,800	3,529	**73,329**
2029	76,031		**76,031**	72,311	3,720	**76,031**
2030	76,514		**76,514**	75,443	1,072	**76,515**

13.4 The totals on the summary tab of Attachment 1-Staff-11(A) - CDM Supporting Data are detailed by program and framework in the subsequent tabs. Please refer to Attachment JT1.14-VECC-13.0 (A) - CDM Supporting Data that contains a correction to the 2024-2030 totals, which now accurately reflect the conversion of units from MWh to kWh. This revision supersedes the unit conversion error found in the initial filing, Attachment 1-Staff-11(A) - CDM Supporting Data. Please refer to Attachment 1-Staff-1(R) for each years' savings by customer class. In addition, refer to below attachments for detailed savings by customer class and program for 2016-2020.

- Attachment JT1.14-VECC-13.0 (B) - CDM Supporting Data (2016)
- Attachment JT1.14-VECC-13.0 (C) - CDM Supporting Data (2017-2020)

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-16.0

EVIDENCE REFERENCE:

Exhibit 3-1-1, page 19
3-VECC 30 f)
1-Staff 11
IESO 2025-2027 Electricity Demand Side Management Program Plan
2025-2036 Electricity Demand Side Management Framework
IESO 2021-2024 CDM Framework
2021-2024 Conservation and Demand Management Framework

UNDERTAKING(S):

16.1 VECC 30 f) states "The CDM savings for 2023 and 2024 were taken from the IESO's 2021-2024 CDM Framework - Program Plan released on December 15, 2022." It is noted that the Framework's total provincial savings for 2024 are 1,575 GWh. The CDM 2026- 2030 Tab in the attachment to Staff 11 sets out Hydro Ottawa's assumed savings for 2024. Please provide an excel file that sets out the derivation of Hydro Ottawa's share of the provincial savings for each of the program areas identified in the IESO's 2021-2024 CDM Framework - Program Plan and identify the sources for any additional inputs used.

16.2 Exhibit 3-1-1 states that the eDSM impacts from 2025-2030 programs are based on Ontario's new 12-year eDSM framework that came into effect January 1, 2025. Please provide the total MWh of eDSM provincial savings used for each of the year 2025- 2030 for purposes of deriving Hydro Ottawa's share and provide the basis for each year's value (i.e., either the source or the calculations as to how it was derived).

16.2.1 If the MWh values for the eDSM provincial savings for 2025- 2027 are not equal to those set out in the IESO 2025-2027 Demand Side Management Program Plan, please explain why.

16.3 Please provide a excel file that sets out the derivation of Hydro Ottawa's share of the provincial eDSM MWh savings for each of the years 2025-2030 and identify the sources for inputs used.

RESPONSE(S):

16.1 Please refer to Excel Attachment JT1.14-VECC-16.0(A) - Energy Savings Forecast 2025-2036 for the eDSM kWh provincial savings used for each of the years 2025-2030 as well as Hydro Ottawa's share.

16.2 Please refer to Excel Attachment JT1.14-VECC-16.0(A) - Energy Savings Forecast 2025-2036 for the eDSM kW provincial savings used for each of the years 2025-2030 as well as Hydro Ottawa's share.

16.2.1 The MWh values for the eDSM provincial savings for 2025-2027 in Table A are not equal to those set out in the IESO 2025-2027 Demand Side Management Program Plan. The 2025-2027 Demand Side Management Program Plan was not available at the time the calculations were being made.

16.3 Please refer to Excel Attachment JT1.14-VECC-16.0(A) - Energy Savings Forecast 2025-2036.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-21.0

EVIDENCE REFERENCE:

Exhibit 7-1-3, page 5
VECC 61 f)

UNDERTAKING(S):

Exhibit 7-1-3 sets out the formula for calculating the Backup Overrun demand when Generation is ON and OFF during certain periods as:
Contract Demand – (Metered Peak generator OFF kW – Metered Peak generator ON of kW) – (the lower of Metered Peak generator ON or 500 kW).

21.1 The response to VECC 61 f) states: “if the Contract Demand is 100 kW and the Metered Peak Generator OFF was 550 kW then the Backup Overrun Demand would be 50 kW. The calculation would be as follows: Contract Demand of 100 kW - (Metered Peak generator OFF of 550 kW – Metered Peak generator ON of 200 kW) minus the lower of Metered Peak generator ON or 500 kW.” However, application of the formula as set out in the response would appear to yield a negative value (i.e., 100 – (550-200) – 200 = -450). Please reconcile.

RESPONSE(S):

Through responding to interrogatory questions, Hydro Ottawa discovered an error in the original evidence filed in Schedule 7-1-3 - Standby Service Charge page 5 and corrected the wording in Appendix A Table of Revisions (Filed August 18,2025).[1]

[1] Hydro Ottawa Letter, *Hydro Ottawa Limited (Hydro Ottawa) Custom Incentive Rate-Setting (Custom IR) Application for 2026-2030 Electricity Distribution Rates and Charges - Interrogatory Responses OEB File: EB-2024-0115.* (August 18,2025) Page 12.

For clarification, Section 4.2 of Schedule 7-1-3 - Standby Service Charge should have been written as "In this example the customer has elected for 0 kW Contracted Demand. Billed Backup Overrun Demand would be 250 kW; Contract Demand of 0 kW – (Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW)."

Hydro Ottawa omitted to have this correction reflected in the response provided for 7.0-VECC-61 part f). A revised response for 7.0-VECC-61 part f) has been provided in Attachment JT1.14-VECC-21.0(A) - 7.0-VECC-61

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-61

EVIDENCE REFERENCE:

Exhibit 7-1-3, pages 2 and 4-6
Attachment 8-5-1(A) – Final Tariff Schedule Tab

Preamble:
At page 2 Exhibit 7-1-3 states the following regarding the design of Ottawa Hydro's current Standby Rates:
"The fixed service charge is designed to recover the incremental cost of monitoring, billing and administration related to providing standby services and the distribution volumetric standby charge (either billed backup demand or backup overrun adjustment) is to recover the cost of maintaining standby facilities at any time. This standby rate structure is based on the customer's requirement for reserve capacity under the standby arrangement and the standby charges ensure that the Standby customer pays their fair share of Hydro Ottawa's infrastructure and operating cost to support the standby service."
Exhibit 7-1-3 describes Hydro Ottawa's proposed changes to its Standby rate design.

QUESTION(S):

a) Do the rate design principles set out on page 2 also apply to Hydro Ottawa's proposed Standby rates?

b) Please describe the how the distribution infrastructure required to supply a customer with embedded generation differs from that required to supply a customer without embedded generation where both have the same gross load requirements.

c) Please explain the rationale for each of the following proposed changes to the design of Standby rates and how it aligns with the principles set out on page 2:

I. Setting the standby volumetric charge as 50% of the distribution volumetric charge for the applicable rate class.

Ii. Setting the backup adjustment charge at the distribution volumetric charge for the applicable rate class.

d) The Exhibit states: "The fixed standby charge is applied to all Customers with load displacement generator(s) that exceed 499 kW." Under Hydro Ottawa's proposal are customers with embedded generation of 500 kW (or more) required to contract for Standby Power?

e) With respect to example 3 (page 5), please explain how the Billed Backup Demand value of 250 kW was calculated. Based on the formula provided it appears the value should be 350 kW (i.e., Contract Demand (800 kW) minus ((Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW)=250 kW) minus ((the lower of Metered Peak generator ON or 500 kW)=200 kW).

f) Please provide a revised example of the Backup Overrun Adjustment calculation where the Contract Demand is 100 kW (as opposed to zero kW).

g) Please provide the rationale behind the proposed calculation of the Backup Overrun Adjustment quantity (per page 5)

h) Please confirm that, if the customer's gross load peak demand occurs when the generation is OFF, it is possible for the difference between the "Metered Peak Generator OFF" and the "Metered Peak Generator ON" to exceed the Contract Demand even when the Contract Demand equals the nameplate rating of the generator.

I. If not confirmed, please explain why.

ii.If confirmed, can the proposed Backup Overrun Adjustment calculation produce a kW result that exceed the nameplate rating of the embedded generation and, if so, why is such a result appropriate?

i) Based on the proposed 2026 GS 50-1,499 Rates and the proposed 2026 GS 50-1,499 Standby Rates, please provide a schedules that, for each of the three examples plus example 3 with a 100 kW Contract Demand, set out the calculation of the total monthly bill (i.e., inclusive of billing for the standard distribution rates and the standby rates) would be assuming: i) the customer had embedded generation and a Contract Demand of 800 kW, ii) the customer had embedded generation of 800 kW and no Contract Demand, and iii) the customer had the same gross load requirements and no embedded generation. Please provide the schedules for two different scenarios regarding the customer's gross load:

I. First, where the customer's gross load requirement peak occurs when the generation is ON, and

Ii. Second, where the customer's gross load requirements peak occurs when the generation is OFF.

j) Based on the proposed 2026 GS 50-1,499 Rates and the proposed 2026 GS 50-1,499 Standby Rates, please also provide a schedules that for example 3 set out the calculation of the total monthly bill (i.e., inclusive of billing for the standard distribution rates and the standby rates) would be assuming: i) the customer had embedded generation with a nameplate of 800 kW and a Contract Demand of 100 kW, ii) the customer has embedded generation with a nameplate of 800 kW and no Contract Demand, and iii) the customer has the same gross load requirements and no embedded generation. Please provide the schedules for two different scenarios regarding the customer's gross load:

I. First, where the customer's gross load requirement peak occurs when the generation is ON, and

Ii. Second, where the customer's gross load requirements peak occurs when the generation is OFF.

RESPONSE(S):

a) The proposed Standby rate structure is designed to recover incremental costs while supporting Customers to use their standby generators more strategically.

b) For a customer with embedded generation, the distribution infrastructure must be capable of handling bi-directional power flow. This is a fundamental difference from the infrastructure needed for a conventional customer without embedded generation, which is only designed for uni-directional power flow from the grid to the customer. Even if both customers have the same gross load, the customer's system with embedded generation has to accommodate both the consumption of electricity and the potential export of excess electricity back to the grid. The Customer pays the required bi-directional meter, monitoring and control box. Key differences in infrastructure are listed below-

Power Flow and Protection:

- Uni-directional (No embedded generation): The grid's protection systems are designed to detect faults and isolate them based on the assumption that power flows in one direction. The infrastructure is simpler and built to deliver electricity.
- Bi-directional (with embedded generation): The introduction of embedded generation can cause power to flow in the reverse direction. The distribution infrastructure must be upgraded with bi-directional meters and more sophisticated protective relays that can handle two-way power flow. This is critical for safety and grid stability, as reverse power flow can create safety hazards for crews and interfere with existing protection schemes.

Voltage and Stability Management:

- Uni-directional: The grid is designed with specific voltage and stability parameters that assume a predictable load. The distribution network is a passive system that simply delivers power from a centralized source.

- Bi-directional: Embedded generation can cause voltage fluctuations on the distribution network. When a generator exports power, it can raise the voltage at that point in the grid, which can affect power quality for other customers. The infrastructure for an embedded generation customer must include technologies like smart inverters and other grid-edge controls that can regulate voltage and maintain system stability

Monitoring and Control

- Uni-directional: Monitoring is primarily focused on measuring the amount of electricity consumed by the customer.
- Bi-directional: To manage two-way power flow and ensure the safety and reliability of the grid, real-time visibility and control over the embedded generation source is required. This means advanced supervisory control and data acquisition (SCADA) systems and communication technologies to monitor and control the generation output, especially for larger systems.

c)

i. Hydro Ottawa has proposed to set the volumetric standby rates at 50% of the distribution service charge to balance between costs and benefits of customers that have behind-the-meter generators. In addition, please refer to interrogatory responses 2-Staff-55, 2-Staff-109, 2-CO-22 and 1-PP-7.

ii. Setting the backup adjustment charge at the distribution volumetric charge (i.e. double the standby volumetric rate) is proposed to encourage the customer to contract the appropriate amount of Backup Demand (kW) to support planning needs.

d) No, customers with generation over 499 kW are not required to sign for contracted Standby Service. However, Hydro Ottawa reserves the right to impose a contracted amount should the customer be using Hydro Ottawa in a Standby service capacity.

e) A typo exists, and the value in the example should be 350kW. Please also see interrogatory response 1-Staff-1, Section 7.1 and 1-Staff-196 question (b).

f) In the Backup Overrun Adjustment example provided in Section 4.2 of Schedule 7-1-3 - Standby Service Charge, if the Contract Demand is 100 kW and the Metered Peak Generator OFF was 550 kW then the Backup Overrun Demand would be ~~50 kW.~~ 250 kW The calculation would be as follows; Contract Demand of 100 kW - (Metered Peak generator OFF of 550 kW – Metered Peak generator ON of 200 kW) ~~minus the lower of Metered Peak generator ON or 500 kW~~.

g) Hydro Ottawa has proposed to keep the Backup Overrun Adjustment as it is a mechanism to encourage customers to contract the appropriate amount of Contract Demand kW or load displace should they not want to use standby services. It has been Hydro Ottawa's experience that when the back-up over run rate is set to the same value as the standby variable rate some customers choose to not set a contracted rate however use the system for back-up capacity. This situation is not ideal for system planning.

h)

i) Please note Hydro Ottawa is not proposing to charge standby on a gross load peak basis. Gross load peak in this context is the sum of the hourly peak when the generator is ON and OFF. It is possible for the difference between the Metered Peak Generator OFF (the highest hourly demand when the generator is not running) and the Metered Peak Generator ON (the highest sum of demand measured in five minute intervals when the generator is running) to exceed the Contract Demand. This can happen even if the contract demand is equal to the generator's nameplate rating. The reason for this is it depends on how the generator(s) are deployed. The generator(s) could be off for five minutes while the premise is drawing load greater than the nameplate capacity of the generator(s).

Where the difference of Metered Peak Generation OFF - Metered Peak Generation ON exceeds the Contracted Demand (kW) amount, the Backup Overrun charge applies. As described in Schedule 7-1-3 - Standby Service Charge, section 3.2 the Backup Overrun adjustments charged to the customer never exceed the total nameplate rating of the load displacement generator.

ii) N/A

i) Hydro Ottawa has provided the requested distribution bill impact calculations in Table A, based on the examples provided in Schedule 7-1-3 - Standby Service Charges. The gross load requirement peak of the customer with and without generation has been assumed to be 1,000 kW, and the 800 kW generator is offsetting the full nameplate capacity when it is in use (i.e. Peak Generation ON is always 200kW).

The below examples provided are for illustrative purposes only, showing the standby charge for a single month and calculations have been simplified. One month's comparison does not accurately represent a customer's total annual reserve capacity needs. In addition this comparison should not be considered guidance for making decisions about whether or not to contract for reserve capacity.

Example 3 is a theoretical outcome and Hydro Ottawa has not seen this outcome in historical standby charges. Customers in this situation have likely opted out of a standby contract; standby charges are not applied (see result in the far right column below). Instead, monthly load peaks have been captured and billed through their primary load account. Hydro Ottawa monitors these Customers' peak usage to ensure appropriate standby charges are applied where applicable.

Table A - General Service 50-1,499 kW Proposed Distribution and Standby Charge

	Example 1 - GEN ON ENTIRE PERIOD	Example 2 - GEN OFF ENTIRE PERIOD	Example 3 - 800 kW Contract	Example 3 - 0kW Contract Demand	Example 3 - 100 kW Contract	Example 3 - 800 kW Contract	Example 3 - 0kW Contract Demand	Example 3 - 100 kW Contract	Customer No embedded Generation	Example 3 - No Contract Demand
			Gross load Peak GEN ON	Gross load Peak GEN ON	Gross load Peak GEN ON	Gross load Peak GEN OFF	Gross load Peak GEN OFF	Gross load Peak GEN OFF		Gross load Peak GEN OFF
Monthly Distribution Service & Volumetric Charge	$ 1,806.02	$ 8,230.10	$ 3,813.55	$ 3,813.55	$ 3,813.55	$ 8,230.10	$ 8,230.10	$ 8,230.10	$ 8,230.10	$ 8,230.10
Standby Charge	$1,391.21	$186.89	$1,591.93	$2,194.42	$1,391.41	$588.33	$1,792.91	$989.90	$0.00	$0.00
TOTAL PRE-TAX	**$ 3,197.23**	**$ 8,416.99**	**$ 5,405.48**	**$ 6,007.97**	**$ 5,204.96**	**$ 8,818.43**	**$ 10,023.01**	**$ 9,220.00**	**$ 8,230.10**	**$ 8,230.10**

j) See Table A in response (i).

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.15

EVIDENCE REFERENCE:

2-ED-15 b)

UNDERTAKING(S):

To provide a similar breakdown for the forecast period for 2024.

RESPONSE(S):

Table A within 2-ED-15 part a) provided the forecasted customer connection volumes from 2025-2030, whereby one (1) unit of volume equated to one (1) projected project within the System Access Customer Connection capital program. This approach is not used to project customer volumes for the Hydro Ottawa load forecast, nor is it used to develop budgets. It should also be noted that the connection volume based on part b) of interrogatory 2-ED-15 is derived from data from the customer care and billing system, where the connections are tracked at the individual service point. For clarity, when counting historical volumes, Hydro Ottawa used customer connection data for new services, and service request data for infills. The 2026-2030 volumes are derived using a methodology consistent with budget development, making them incomparable to historical numbers, which use a different approach.

The Customer Connections program consists of three (3) separate budget programs, namely Residential Subdivisions, Commercial Developments, and Infill Services. In the response to 2-ED-15 part a), volumes were projected from two sources: scaling of Hydro Ottawa's historical new residential/commercial customer counts, and extracts from Hydro Ottawa's Salesforce Field Service (SFS) software. SFS tracks "service requests" as opposed to individual meter points. Given limitations within the data extracted from SFS, the forecast method used to respond to this undertaking and interrogatory 2-ED-15 part (a) results in volumes that are overstated. The cause for this is that SFS includes projects that are in-flight, do not proceed, and may not distinguish between multiple service requests at an individual site (duplicate counting for individual projects).

The request through this undertaking was to provide a breakdown of new connections versus upgrades within Table A of 2-ED-15 part a), inclusive of 2024. Please see Table A with a breakout of New Customers (New Service) vs Existing Customers (Upgrade/Modify) based on the above. The 2025-2030 comparative view of "New Service" vs "Upgrade/Modify" was determined using the 2021-2025 average of new service vs upgrade/modify service request ratio (65% new service vs 35% upgrade or modify).

Table A - Forecasted Customer Connection Volumes from 2025-2030 Broken Down by New and Existing Customers

	Historical Year	Bridge Year	Test Years				
	2024	2025	2026	2027	2028	2029	2030
New Service	7,378	6,248	6,359	6,464	6,569	6,675	6,781
Upgrade/Modify	2,828	3,285	3,345	3,407	3,469	3,532	3,597
Total	**10,206**	**9,533**	**9,704**	**9,871**	**10,038**	**10,207**	**10,378**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.30

EVIDENCE REFERENCE:

Schedule 2-5-8

UNDERTAKING(S):

To clarify system expansion requirements by adding customer information and a summary of the rationale for each, why they are a system enhancement project based on the DSC.

RESPONSE(S):

All projects under the Capacity Upgrade program are classified as system enhancements. The rationale for this classification is available in Section 2.3.2 of Schedule 2-5-8 - System Service Investments. These projects are considered as system enhancement since the primary driver is to relieve system capacity constraints resulting from general load growth. This is consistent with Section 3.3.1 of the Distribution System Code (DSC) which states that “A distributor shall continue to plan and build the distribution system for reasonable forecast load growth.”

While classified as system enhancements, two of the station capacity upgrade projects are concurrently facilitating the connection of large load customers, and are therefore subject to capital contributions.

- **Greenbank MTS:** Hydro Ottawa identified a need within the South 28kV region to increase 28kV capacity and to provide support to the adjacent Barrhanven and Nepean 8kV regions. The full needs assessment outlining the selection of Greenbank MTS as the preferred solution to solve the identified needs is provided in section 2.3.2.1 of Schedule 2-5-8 - System Service Investments beginning on page 21. While Hydro Ottawa was evaluating options for the required new station, a customer entered into preliminary conversations about the requirements to connect a large load, further reinforcing the needs for the planned new station. Through these conversations, an opportunity was recognized to obtain land easements from the customer for the construction of the station, resulting in a significant amount of avoided capital costs that will translate to a reduced rate base. First, the land easement results in reduced overall project costs as Hydro Ottawa does not need to purchase land for the new station. This direct avoidance of land acquisition expenditure minimizes the capital investment required and lowers the final project cost.

Furthermore, the transmission connection costs associated with the Capital Cost Recovery Agreement (CCRA) with Hydro One is expected to be significantly lower as the land is more optimally located in proximity to the transmission corridor in comparison to other locations that Hydro Ottawa had been evaluating. The expected reduction in CCRA charges directly reduces the capital expenditure attributed to the project, further curtailing the total amount placed into the rate base, which ultimately benefits customers.

- **Cyrville MTS:** Hydro Ottawa identified a need within the East 28kV region being driven by load growth, reliability concerns and capacity limitations within the adjacent East 13kV system. Cyrville was selected as the preferred option to solve the system needs as it will also enable offloading of the constrained 115kV transmission system. The requirement to connect a large load customer within the region was later assessed and the optimal supply option was determined to be from Cyrville MTS, further substantiating the need for the upgrade. The full needs assessment outlining the selection of upgrading Cyrville MTS is provided in Section 2.3.2.1 of Schedule 2-5-8 - System Service Investments beginning on page 25.

It should be noted that each of the customers contributing to Greenbank MTS and Cyrville MTS, respectively, also require activities within the System Access Investment Category, specifically within Distribution System Expansion. These activities encompass the distribution work required to connect to the customer sites. Each customer is responsible for a portion of the cost within this program, as subjected to the methodology dictated by Section 3.2 of the DSC, and run through an economic evaluation as per Appendix B of the DSC. These costs and associated contributions can be found within Table A and Table B of the response to undertaking JT1.31.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.31

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

To provide the analysis behind the economic evaluation on the two projects.

RESPONSE(S):

Hydro Ottawa would like to correct the testimony of Ms. Heuff on Day 1 of the Technical Conference at page 172, lines 2 and 3 of the transcript, by noting that the capital contributions identified in Table 2 of Schedule 2-5-8 - System Service Investments are solely related to the large load customer forecasted to be connected to Greenbank MTS, and do not include the contributed capital related to Cyrville MTS.

At the time of Hydro Ottawa's rate application budget finalization, the Cyrville MTS project was forecasted to go into service in 2032; and only gross capital expenditures associated with the project were included in the rate application submission. These gross costs, included under System Service, Capacity Upgrades, were associated specifically with the substation development required. Since then, Hydro Ottawa had identified the need to advance the energization of the Cyrville station to 2028 in order to serve a large load customer seeking to connect in this area. As a result, a portion of the costs associated with Cyrville MTS, which is a system service enhancement investment as explained in the response to JT1.30, are now forecasted to be apportioned to the large load customer who seeks to connect to this station in 2028. As a result, the capital additions associated with the Cyrville MTS project are now expected to go in-service in 2028, rather than 2032, in order to serve this large customer. Furthermore, with the updated timeline, a Distribution System Expansion project (under the System Access Investment Category) will be also required to expand the distribution system to facilitate connection at the customer site. The capital expenditures, customer contributions and capital additions related to the Distribution System Expansion were not included in the original budget submission.

Table A provides an updated summary of how the Cyrville MTS project costs are currently forecast for allocation between ratepayers and the large load customer who will be connecting to this station, including a summary of the preliminary economic evaluation - updating both the timing of the station in service date and the customer contribution. For the reasons noted above, this analysis and the resulting cost responsibility of [redacted] toward the station capacity upgrade costs and [redacted] toward the system expansion costs were not included in Table 2 of Schedule 2-5-8 - System Service Investments at page 49 and Table 11 of Schedule 2-5-6 - System Access Investments at page 52. The stated cost responsibilities are subjected to the methodology dictated by Section 3.2 of the DSC, and run through an economic evaluation as per Appendix B of the DSC, resulting in a total customer cash contribution of [redacted]

Table B provides an updated summary of how the Greenbank MTS project costs are currently forecasted for allocation between ratepayers and the large load customer who will be connecting to this station, including a summary of the preliminary economic evaluation. This analysis provides an update to the originally forecasted [redacted] of contributed capital to be paid by the customer toward the station cost identified in Table 2 of Schedule 2-5-8 - System Service Investments on page 49. Through further scope revisions, as required by the customer, the currently forecasted cost responsibility is now [redacted] toward the station and distribution capacity upgrade costs. Furthermore, at the time of budget development, the discrete system expansion project (see Table 11 in Schedule 2-5-6 - System Access Investments, page 52) required to expand the distribution system to connect the customer was missed. As a result, the capital expenditures, customer contributions and capital additions related to the distribution system expansion were not included in the original budget submission. The distribution system expansion costs, including the currently forecasted cost responsibility of [redacted], have been included in Table B. The stated cost responsibilities are subjected to the methodology dictated by Section 3.2 of the DSC, and run through an economic evaluation as per Appendix B of the DSC, resulting in a total customer contribution of [redacted]. Given that the updates within Table A and B were not contemplated at the time of budget development, these updates are also not included in the responses to undertaking JT1.24 or undertaking JT1.26.

In providing the information outlined in Tables A and B below, Hydro Ottawa would like to emphasize that the Offers to Connect for these two customer projects have not yet been signed. As such, the forecasts provided in this table are subject to change based on the customers' load and timing requirements, which are key factors outside of Hydro Ottawa's control. The updates provided within Table A and Table B provide material changes to the capital expenditures within the System Access System Expansion capital program and the System Service Capacity Upgrades capital program, as well as the capital additions associated with these programs. As noted throughout the application record, the uncertainty and complexity associated with managing and responding to an increasing number of large load requests represents a unique challenge for Hydro Ottawa in the 2026-2030 rate term. To address this challenge, Hydro Ottawa has proposed two mechanisms, a Large Load Revenue Variance account and modification of the existing Capital Variance Accounts. These accounts serve to reconcile actual versus forecast revenues and costs associated with these unique and economically significant projects. For more information about these accounts please refer to Section 3.5.6 of Schedule 1-3-1 - Rate Setting Framework. Furthermore, it should be noted that as the scope has evolved with these projects, so has the scoping and costing associated with the Connection Cost Recovery Agreements (CCRAs). Preliminary conversations with Hydro One indicate a material change to the submitted CCRA costs. Hydro Ottawa has also proposed to maintain the CCRA variance account.

Table A - Cyrville MTS Economic Evaluation ($’000 000s)

	Gross Cost	Customer Portion	Comments
System Service			
Station Capacity Upgrades[1]	[redacted]	[redacted]	Cost sharing is based on the customer's allocated share of the total capacity of the station
Distribution Capacity Upgrades	N/A	N/A	
Capacity Upgrades Subtotal	[redacted]	[redacted]	
System Access			
Distribution System Expansion	[redacted]	[redacted]	Distribution expansion solely for customer
Distribution System Expansion Subtotal	[redacted]	[redacted]	
Totals & Contributions			
Total	[redacted]	[redacted]	Station Capacity Upgrades + Distribution System Expansion
Less Economic Evaluation Offset (Load Realization)		[redacted]	Expansion Deposit
Customer Contribution		[redacted]	Per preliminary economic evaluation

[1] Please note that the Cyrville MTS capacity upgrade costs of $35.3M identified in Schedule 2-5-8 at page 50 was the gross spend out to 2030 assuming a 2032 energization timeline. The [redacted] provided here is assuming a 2028 energization timeline.

Table B - Greenbank MTS Economic Evaluation ($'000 000s)

	Gross Cost	Customer Portion	Comments
System Service			
Station Capacity Upgrades[2]	[redacted]	[redacted]	Cost sharing is based on the customer's allocated share of the total capacity of the station
Distribution Capacity Upgrades	$ 20.0	N/A	Capacity Upgrade for Greenbank MTS, no customer contribution, and no connection to the customer site.
System Service - Capacity Upgrades Subtotal	[redacted]	[redacted]	
System Access			
Distribution System Expansion	[redacted]	[redacted]	Customer was allocated the cost to expand the system by building a new line to serve their load connection. The incremental cost to further expand/enhance the capacity of that line was considered as a system enhancement as it was necessary to address general distribution system needs in this area of the grid.
System Access - Distribution System Expansion Subtotal	[redacted]	[redacted]	
Totals & Contributions			
Total	[redacted]	[redacted]	Station Capacity Upgrades + Distribution System Expansion
Less Economic Evaluation offset		[redacted]	Expansion Deposit
Customer Contribution		[redacted]	Per preliminary economic evaluation

[2] Please note that the Greenbank MTS Station capacity upgrade costs of $38.5M identified in Schedule 2-5-8 at page 50 was shown net of customer contributions, whereas the costs shown here are gross.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.31

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

To provide the analysis behind the economic evaluation on the two projects.

RESPONSE(S):

Hydro Ottawa would like to correct the testimony of Ms. Heuff on Day 1 of the Technical Conference at page 172, lines 2 and 3 of the transcript, by noting that the capital contributions identified in Table 2 of Schedule 2-5-8 - System Service Investments are solely related to the large load customer forecasted to be connected to Greenbank MTS, and do not include the contributed capital related to Cyrville MTS.

At the time of Hydro Ottawa's rate application budget finalization, the Cyrville MTS project was forecasted to go into service in 2032; and only gross capital expenditures associated with the project were included in the rate application submission. These gross costs, included under System Service, Capacity Upgrades, were associated specifically with the substation development required. Since then, Hydro Ottawa had identified the need to advance the energization of the Cyrville station to 2028 in order to serve a large load customer seeking to connect in this area. As a result, a portion of the costs associated with Cyrville MTS, which is a system service enhancement investment as explained in the response to JT1.30, are now forecasted to be apportioned to the large load customer who seeks to connect to this station in 2028. As a result, the capital additions associated with the Cyrville MTS project are now expected to go in-service in 2028, rather than 2032, in order to serve this large customer. Furthermore, with the updated timeline, a Distribution System Expansion project (under the System Access Investment Category) will be also required to expand the distribution system to facilitate connection at the customer site. The capital expenditures, customer contributions and capital additions related to the Distribution System Expansion were not included in the original budget submission.

Table A provides an updated summary of how the Cyrville MTS project costs are currently forecast for allocation between ratepayers and the large load customer who will be connecting to this station, including a summary of the preliminary economic evaluation - updating both the timing of the station in service date and the customer contribution. For the reasons noted above, this analysis and the resulting cost responsibility of [redacted] toward the station capacity upgrade costs and [redacted] toward the system expansion costs were not included in Table 2 of Schedule 2-5-8 - System Service Investments at page 49 and Table 11 of Schedule 2-5-6 - System Access Investments at page 52. The stated cost responsibilities are subjected to the methodology dictated by Section 3.2 of the DSC, and run through an economic evaluation as per Appendix B of the DSC, resulting in a total customer cash contribution of [redacted].

Table B provides an updated summary of how the Greenbank MTS project costs are currently forecasted for allocation between ratepayers and the large load customer who will be connecting to this station, including a summary of the preliminary economic evaluation. This analysis provides an update to the originally forecasted [redacted] of contributed capital to be paid by the customer toward the station cost identified in Table 2 of Schedule 2-5-8 - System Service Investments on page 49. Through further scope revisions, as required by the customer, the currently forecasted cost responsibility is now [redacted] toward the station and distribution capacity upgrade costs. Furthermore, at the time of budget development, the discrete system expansion project (see Table 11 in Schedule 2-5-6 - System Access Investments, page 52) required to expand the distribution system to connect the customer was missed. As a result, the capital expenditures, customer contributions and capital additions related to the distribution system expansion were not included in the original budget submission. The distribution system expansion costs, including the currently forecasted cost responsibility of [redacted], have been included in Table B. The stated cost responsibilities are subjected to the methodology dictated by Section 3.2 of the DSC, and run through an economic evaluation as per Appendix B of the DSC, resulting in a total customer contribution of [redacted]. Given that the updates within Table A and B were not contemplated at the time of budget development, these updates are also not included in the responses to undertaking JT1.24 or undertaking JT1.26.

In providing the information outlined in Tables A and B below, Hydro Ottawa would like to emphasize that the Offers to Connect for these two customer projects have not yet been signed. As such, the forecasts provided in this table are subject to change based on the customers' load and timing requirements, which are key factors outside of Hydro Ottawa's control. The updates provided within Table A and Table B provide material changes to the capital expenditures within the System Access System Expansion capital program and the System Service Capacity Upgrades capital program, as well as the capital additions associated with these programs. As noted throughout the application record, the uncertainty and complexity associated with managing and responding to an increasing number of large load requests represents a unique challenge for Hydro Ottawa in the 2026-2030 rate term. To address this challenge, Hydro Ottawa has proposed two mechanisms, a Large Load Revenue Variance account and modification of the existing Capital Variance Accounts. These accounts serve to reconcile actual versus forecast revenues and costs associated with these unique and economically significant projects. For more information about these accounts please refer to Section 3.5.6 of Schedule 1-3-1 - Rate Setting Framework. Furthermore, it should be noted that as the scope has evolved with these projects, so has the scoping and costing associated with the Connection Cost Recovery Agreements (CCRAs). Preliminary conversations with Hydro One indicate a material change to the submitted CCRA costs. Hydro Ottawa has also proposed to maintain the CCRA variance account.

1 **Table A - Cyrville MTS Economic Evaluation ($'000 000s)**

2

	Gross Cost	Customer Portion	Comments
System Service			
Station Capacity Upgrades[1]	[redacted]	[redacted]	Cost sharing is based on the customer's allocated share of the total capacity of the station
Distribution Capacity Upgrades	N/A	N/A	
Capacity Upgrades Subtotal	[redacted]	[redacted]	
System Access			
Distribution System Expansion	[redacted]	[redacted]	Distribution expansion solely for customer
Distribution System Expansion Subtotal	[redacted]	[redacted]	
Totals & Contributions			
Total	[redacted]	[redacted]	Station Capacity Upgrades + Distribution System Expansion
Less Economic Evaluation Offset (Load Realization)		[redacted]	Expansion Deposit
Customer Contribution		[redacted]	Per preliminary economic evaluation

3

4

5

6

[redacted]

1 **Table B - Greenbank MTS Economic Evaluation ($'000 000s)**

	Gross Cost	Customer Portion	Comments
System Service			
Station Capacity Upgrades[2]	[redacted]	[redacted]	Cost sharing is based on the customer's allocated share of the total capacity of the station
Distribution Capacity Upgrades	$ 20.0	N/A	Capacity Upgrade for Greenbank MTS, no customer contribution, and no connection to the customer site.
System Service - Capacity Upgrades Subtotal	[redacted]	[redacted]	
System Access			
Distribution System Expansion	[redacted]	[redacted]	Customer was allocated the cost to expand the system by building a new line to serve their load connection. The incremental cost to further expand/enhance the capacity of that line was considered as a system enhancement as it was necessary to address general distribution system needs in this area of the grid.
System Access - Distribution System Expansion Subtotal	[redacted]	[redacted]	
Totals & Contributions			
Total	[redacted]	[redacted]	Station Capacity Upgrades + Distribution System Expansion
Less Economic Evaluation offset		[redacted]	Expansion Deposit
Customer Contribution		[redacted]	Per preliminary economic evaluation

2

3 [redacted]

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.32

EVIDENCE REFERENCE:

2-CCC-29 part d

UNDERTAKING(S):

To provide the cost estimate breakdown and the cost basis per line item of the Greenbank MTS project, with an explanation as to a calculation in the sample as noted, where available.

RESPONSE(S):

With reference to interrogatory response 2-CCC-29, response d) where cost estimation methodology for station projects is explained, the cost breakdown for the Greenbank MTS project as submitted within the rate application and the cost basis for the summary line items associated with that estimate is detailed below.

The estimated net cost for the Greenbank MTS is $38.5M ([redacted] less customer contributions of [redacted]), as stated in Section 2.5.1 on page 50 of Schedule 2-5-8 - System Service Investments. The gross cost breakdown for Greenbank MTS is provided below in Table A, and uses the Piperville MTS project as a historical comparator (including actuals and remaining forecasted expenditure). The Piperville costs were scaled to incorporate minor scope changes between the two projects, increased rates from standing offer agreements, and cost escalations provided by equipment suppliers, ensuring the total figure for Greenbank MTS reflects a realistic project value.

1 **Table A - Piperville MTS and Greenbank MTS Cost Breakdown**

Category	Piperville Estimate	Greenbank Estimate	Incremental Variance (%)	Rationale
Engineering	$ 2,291,241	[redacted]	[redacted]	[redacted] increase to account for cost escalations between 2022 and 2025. Consultant rates have been pre-approved through standing offer agreement and have informed this increase
Procurement				
Land Purchase	$ 1,466,599	[redacted]	[redacted]	Considered for Greenbank due to a previous engagement with the landowner to utilize the required portion of property for the substation resulted in a cost [redacted]
Major Equipment	$ 18,269,000	[redacted]	[redacted]	[redacted] increase to account for cost escalations advised through preliminary consultation with transformer, switchgear and relay panel suppliers
Minor Equipment	$ 1,046,231	[redacted]	[redacted]	The estimate includes a [redacted] increase to cover anticipated cost escalation for materials, specifically copper control wire, circuit breaker panels, communications equipment and other miscellaneous components between 2025 and 2027
Construction				
Civil Construction	$ 18,355,081	[redacted]	[redacted]	[redacted] increase to account for cost escalations anticipated for contractor labour and materials between 2024 and 2026
Electrical Construction	$ 878,663	[redacted]	[redacted]	A [redacted] escalation is applied to cover anticipated labour, fleet, and rental equipment costs (e.g. personnel lifts, generators, site washrooms) between 2025 and 2027
Total	**$42,306,814**	[redacted]	[redacted]	**An overall [redacted] increase is estimated as a result of Greenbank starting three years later than Piperville and anticipating that costs will have increased during this time.**

2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT2.23

EVIDENCE REFERENCE:

1-CCC-1 Table A

UNDERTAKING(S):

Provide dollar values of all equipment and materials for all years from ‘24 to 2030, inflated and uninflated

---

RESPONSE(S):

Please note that the evidence reference 1-CCC-1 Table A has been updated in the response to undertaking JT2.22. See Tables A - D below, which detail the amounts for capital equipment and materials expenditures by the categories presented in Table A of JT2.22. Hydro Ottawa used 2024 as the start year for forecasting the inflation assumptions, thus the adjustments were made relative to 2024 dollars.

Table A presents equipment and materials by category before annual inflation adjustments. Table B presents equipment and materials by category after inflation. Table C presents the associated annual inflation as a percentage and Table D presents the equipment and materials by category in 2024 dollars before any compound inflation relative to the starting year was applied.

Table A - Equipment and Materials Before Annual Inflation Adjustments 2024 - 2030 Bridge and Test Years ($'000s)

<table>
<tr><th>Asset Type</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th><th>2030</th></tr>
<tr><td>Transformer Station Equipment >50 kV</td><td rowspan="14"></td><td rowspan="14">$ 53,486</td><td rowspan="14">$ 80,475</td><td rowspan="14">$ 97,995</td><td rowspan="14">$ 69,854</td><td rowspan="14">$ 73,591</td><td rowspan="14">$ 83,029</td></tr>
<tr><td>Distribution Station Equipment <50 kV</td></tr>
<tr><td>Storage Battery Equipment</td></tr>
<tr><td>Poles, Towers & Fixtures</td></tr>
<tr><td>Overhead Conductors & Devices</td></tr>
<tr><td>Underground Conduit</td></tr>
<tr><td>Underground Conductors & Devices</td></tr>
<tr><td>Line Transformers</td></tr>
<tr><td>Services (Overhead & Underground)</td></tr>
<tr><td>Meters (Smart Meters Excluding Metering Renewal AMI 2.0 Project)</td></tr>
<tr><td>Measurement & Testing Equipment</td></tr>
<tr><td>Power Operated Equipment</td></tr>
<tr><td>Communications Equipment</td></tr>
<tr><td>System Supervisor Equipment</td></tr>
<tr><td>Metering Renewal AMI 2.0 Project</td><td></td><td>-</td><td>$ 7,616</td><td>$ 8,663</td><td>$ 9,036</td><td>$ 11,324</td><td>$ 12,533</td></tr>
<tr><td>Tools, Shop & Garage Equipment</td><td></td><td>$ 557</td><td>$ 806</td><td>$ 947</td><td>$ 864</td><td>$ 858</td><td>$ 1,269</td></tr>
<tr><td>Transportation Equipment</td><td></td><td>$ 2,832</td><td>$ 11,457</td><td>$ 13,455</td><td>$ 10,536</td><td>$ 2,852</td><td>$ 128</td></tr>
<tr><td>Buildings</td><td rowspan="2"></td><td rowspan="2">$ 169</td><td rowspan="2">-</td><td rowspan="2">-</td><td rowspan="2">-</td><td rowspan="2">-</td><td rowspan="2">-</td></tr>
<tr><td>Buildings & Fixtures</td></tr>
<tr><td>Computer Software</td><td rowspan="2"></td><td rowspan="2">$ 960</td><td rowspan="2">$ 3,057</td><td rowspan="2">$ 2,598</td><td rowspan="2">$ 3,618</td><td rowspan="2">$ 3,785</td><td rowspan="2">$ 4,425</td></tr>
<tr><td>Computer Equipment - Hardware</td></tr>
<tr><td>Total Capital Equipment and Materials Costs Before Annual Inflation</td><td></td><td>$ 58,004</td><td>$ 103,410</td><td>$ 123,659</td><td>$ 93,908</td><td>$ 92,410</td><td>$ 101,383</td></tr>
</table>

Table B - Equipment and Materials After Inflation Adjustments 2024 - 2030 Bridge and Test Years ($'000s)

<table>
<tr><th>Asset Type</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th><th>2030</th></tr>
<tr><td>Transformer Station Equipment >50 kV</td><td rowspan="14">$ 54,639</td><td rowspan="14">$ 56,160</td><td rowspan="14">$ 84,499</td><td rowspan="14">$ 102,895</td><td rowspan="14">$ 73,347</td><td rowspan="14">$ 77,270</td><td rowspan="14">$ 87,180</td></tr>
<tr><td>Distribution Station Equipment <50 kV</td></tr>
<tr><td>Storage Battery Equipment</td></tr>
<tr><td>Poles, Towers & Fixtures</td></tr>
<tr><td>Overhead Conductors & Devices</td></tr>
<tr><td>Underground Conduit</td></tr>
<tr><td>Underground Conductors & Devices</td></tr>
<tr><td>Line Transformers</td></tr>
<tr><td>Services (Overhead & Underground)</td></tr>
<tr><td>Meters (Smart Meters Excluding Metering Renewal AMI 2.0 Project)</td></tr>
<tr><td>Measurement & Testing Equipment</td></tr>
<tr><td>Power Operated Equipment</td></tr>
<tr><td>Communications Equipment</td></tr>
<tr><td>System Supervisor Equipment</td></tr>
<tr><td>Metering Renewal AMI 2.0 Project</td><td>-</td><td>-</td><td>$ 7,844</td><td>$ 8,923</td><td>$ 9,307</td><td>$ 11,664</td><td>$ 12,908</td></tr>
<tr><td>Tools, Shop & Garage Equipment</td><td>$ 923</td><td>$ 573</td><td>$ 823</td><td>$ 967</td><td>$ 882</td><td>$ 876</td><td>$ 1,296</td></tr>
<tr><td>Transportation Equipment</td><td>$ 3,216</td><td>$ 2,974</td><td>$ 12,029</td><td>$ 14,128</td><td>$ 11,062</td><td>$ 2,994</td><td>$ 134</td></tr>
<tr><td>Buildings</td><td rowspan="2">$ 175</td><td rowspan="2">$ 175</td><td rowspan="2">-</td><td rowspan="2">-</td><td rowspan="2">-</td><td rowspan="2">-</td><td rowspan="2">-</td></tr>
<tr><td>Buildings & Fixtures</td></tr>
<tr><td>Computer Software</td><td rowspan="2">$ 1,860</td><td rowspan="2">$ 989</td><td rowspan="2">$ 3,121</td><td rowspan="2">$ 2,652</td><td rowspan="2">$ 3,694</td><td rowspan="2">$ 3,865</td><td rowspan="2">$ 4,517</td></tr>
<tr><td>Computer Equipment - Hardware</td></tr>
<tr><td>Total Capital Equipment and Materials Costs After Inflation</td><td>$ 60,813</td><td>$ 60,871</td><td>$ 108,317</td><td>$ 129,565</td><td>$ 98,293</td><td>$ 96,669</td><td>$ 106,036</td></tr>
</table>

Table C - Equipment and Materials Annual Inflation Percentages 2024 - 2030 Bridge and Test Years

<table>
<tr><th>Asset Type</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th><th>2030</th></tr>
<tr><td>Transformer Station Equipment >50 kV</td><td></td><td rowspan="14">5.00%</td><td rowspan="14">5.00%</td><td rowspan="14">5.00%</td><td rowspan="14">5.00%</td><td rowspan="14">5.00%</td><td rowspan="14">5.00%</td></tr>
<tr><td>Distribution Station Equipment <50 kV</td><td></td></tr>
<tr><td>Storage Battery Equipment</td><td></td></tr>
<tr><td>Poles, Towers & Fixtures</td><td></td></tr>
<tr><td>Overhead Conductors & Devices</td><td></td></tr>
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<tr><td>Meters (Smart Meters Excluding Metering Renewal AMI 2.0 Project)</td><td></td></tr>
<tr><td>Measurement & Testing Equipment</td><td></td></tr>
<tr><td>Power Operated Equipment</td><td></td></tr>
<tr><td>Communications Equipment</td><td></td></tr>
<tr><td>System Supervisor Equipment</td><td></td></tr>
<tr><td>Metering Renewal AMI 2.0 Project</td><td></td><td></td><td>3.00%</td><td>3.00%</td><td>3.00%</td><td>3.00%</td><td>3.00%</td></tr>
<tr><td>Tools, Shop & Garage Equipment</td><td></td><td>3.00%</td><td>2.10%</td><td>2.10%</td><td>2.10%</td><td>2.10%</td><td>2.10%</td></tr>
<tr><td>Transportation Equipment</td><td></td><td>5.00%</td><td>5.00%</td><td>5.00%</td><td>5.00%</td><td>5.00%</td><td>5.00%</td></tr>
<tr><td>Buildings</td><td rowspan="2"></td><td rowspan="2">3.50%</td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td>Buildings & Fixtures</td></tr>
<tr><td>Computer Software</td><td rowspan="2"></td><td rowspan="2">3.00%</td><td rowspan="2">2.10%</td><td rowspan="2">2.10%</td><td rowspan="2">2.10%</td><td rowspan="2">2.10%</td><td rowspan="2">2.10%</td></tr>
<tr><td>Computer Equipment - Hardware</td></tr>
<tr><td>Weighted Average</td><td></td><td>4.94%</td><td>4.74%</td><td>4.78%</td><td>4.67%</td><td>4.61%</td><td>4.59%</td></tr>
</table>

Table D - Equipment and Materials Before Compound Inflation Adjustments 2024 - 2030 Bridge and Test Years ($'000s)

Asset Type	2024	2025	2026	2027	2028	2029	2030
Transformer Station Equipment >50 kV	$ 54,639	$ 53,486	$ 76,643	$ 88,885	$ 60,343	$ 60,543	$ 65,055
Distribution Station Equipment <50 kV							
Storage Battery Equipment							
Poles, Towers & Fixtures							
Overhead Conductors & Devices							
Underground Conduit							
Underground Conductors & Devices							
Line Transformers							
Services (Overhead & Underground)							
Meters (Smart Meters Excluding Metering Renewal AMI 2.0 Project)							
Measurement & Testing Equipment							
Power Operated Equipment							
Communications Equipment							
System Supervisor Equipment							
Metering Renewal AMI 2.0 Project	-	-	$ 7,394	$ 8,166	$ 8,269	$ 10,062	$ 10,811
Tools, Shop & Garage Equipment	$ 923	$ 557	$ 782	$ 901	$ 805	$ 782	$ 1,134
Transportation Equipment	$ 3,216	$ 2,832	$ 10,911	$ 12,204	$ 9,101	$ 2,346	$ 100
Buildings	$ 175	$ 169	-	-	-	-	-
Buildings & Fixtures							
Computer Software	$ 1,860	$ 960	$ 2,968	$ 2,470	$ 3,370	$ 3,453	$ 3,953
Computer Equipment - Hardware							
Total Capital Equipment and Materials Costs Before Compound Inflation	**$ 60,813**	**$ 58,004**	**$ 98,699**	**$ 112,626**	**$ 81,887**	**$ 77,186**	**$ 81,053**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

JT2.28

EVIDENCE REFERENCE:

UNDERTAKING(S):

Provide O&M cost of Hydro Ottawa's capacity information map

RESPONSE(S):

As per the information provided by Ms. Flores during day one of the technical conference in an exchange with Mr. Ladanyi (Day 1 Transcript, page 186, line 14), regarding the OM&A costs associated with the provincial capacity information map, Hydro Ottawa's costs to date have been immaterial, and not separately tracked. These costs would have been employee time captured within the Engineering & Design OM&A Program, which is described within Section 3.8 of Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs and the Information Management and Technology OM&A Program, which is described within Section 3.14 of Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs.

For the initial capacity map, Phase 1, published by Hydro Ottawa in March 2025, distributors were specifically directed by the OEB to post capacity maps on their websites that "rely on their current technical capabilities" and thus "avoid making significant investments implementing this phase."[1]

As Hydro Ottawa continues to participate in the OEB working group to develop the Phase 2 province-wide map (including both load and hosting capacity), Hydro Ottawa anticipates that it will be utilizing information already available and does not anticipate significant costs for this work.

[1] Ontario Energy Board, *Letter RE: Distribution System Capacity Information Map - Phase 1 Implementation (EB 2019-0207)*, (October 17, 2024), page 4.

Hydro Ottawa acknowledges and confirms that there will be an ongoing OM&A cost moving forward because the capacity map will require quarterly updates. This will become an ongoing operating expense, which Hydro Ottawa expects will mainly be a relatively small number of FTE hours per quarter to provide the updates.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.14

EVIDENCE REFERENCE:

1-SEC-3

UNDERTAKING(S):

Provide table that shows for each year between 2012 to 2025 actuals, and in the proposed 2026 to 2030 for each rate class: A, the distribution monthly service charge; B, the distribution volumetric charge for that class; C, any fixed DVA riders that would be considered in the OEB subtotal A category under their bill impact model; and D, the volumetric DVA riders that would be considered under the subtotal A and B bill impact model

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RESPONSE(S):

Please refer to Attachment JT3.14(A) - 2012-2030 Distribution Rates and Rate Riders for requested information.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.15

EVIDENCE REFERENCE:

1-SEC-3

UNDERTAKING(S):

Consider providing studies Mr. Rubenstein referenced in the lead up to the question and provide them, if possible, or provide a reason why not

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RESPONSE(S):

Mr. Rubenstein requested the following studies.

1. *The customer capability assessment*
2. *The grid modernization strategy and roadmap phases 1 and 2*
3. *The grid modernization key performance indicator development*
4. *Review of Copperleaf predictive analytics value framework*
5. *Hydro Ottawa AMI 2.0 business case deliverables benefits assessment and value drivers*
6. *AMI 2.0 business case final report*
7. *A fleet process study*
8. *A jurisdictional research and analysis (related to inflation)*
9. *Peer group analysis (only if it is different from what is provided on the record)"*

For item #4, please refer to Attachment JT1.9(A) - HOL PA Distribution Model Review.

For the remaining of SEC's request, please see the below Attachment references and notes:

- Attachment JT3.15(A) - Customer Capability Assessment
- Attachment JT3.15(B) - HOL Grid Modernization Roadmap Ph 1 - Current and Future State Assessment - REDACTED~~(forthcoming, pending confirmation of confidentiality requirements with third party vendor)~~
- Attachment JT3.15(C) - HOL Grid Modernization Roadmap Ph 2 - Grid Modernization Strategy - REDACTED ~~(forthcoming, pending confirmation of confidentiality requirements with third party vendor)~~
- Attachment JT3.15(D) - HOL Grid Modernization Key Performance Indicator (KPI) Development - REDACTED ~~(forthcoming, pending confirmation of confidentiality requirements with third party vendor)~~
- Attachment JT3.15(E) - Hydro Ottawa AMI 2.0 Business Case Deliverable 1 Benefits Assessment & Values Drivers
- Attachment JT3.15(F) - AMI 2.0 Business Case Final Report
- Attachment JT3.15(G) - Fleet Process Study
- Attachment JT3.15(H) - Inflation Jurisdictional Research and Analysis
- Attachment JT3.15(I) - HOL Benchmarking (Master Cust Num Cohort)
- Attachment JT3.15(J) - HOL Benchmarking (Load Distribution Cohort)
- Attachment JT3.15(K) - HOL Benchmarking (Rural Cohort)

As noted in Hydro Ottawa's response to interrogatory 1-SEC-3, these reports, analyses and studies were not directly relied upon in the preparation of evidence for this proceeding. Accordingly, the specific focus areas, timelines, and details included in these materials may not align precisely with the content or parameters of Hydro Ottawa's current application.

In particular, Hydro Ottawa notes that Attachments JT3.15(E) - Hydro Ottawa AMI 2.0 Business Case Del 1 Benefits Assessment and Value Drivers and JT3.15(F) - Hydro Ottawa AMI 2.0 Business Case Final Report, related to the AMI 2.0 Business Case, were based on an analysis of use case benefits and associated implementation costs over a five-year implementation. This does not align with the ten-year implementation plan ultimately proposed in this application. Further details regarding the implementation plan are provided in Section 5.7 of Schedule 2-5-7 - System Renewal Investments.

HOL Grid Modernization Roadmap – Ph 1

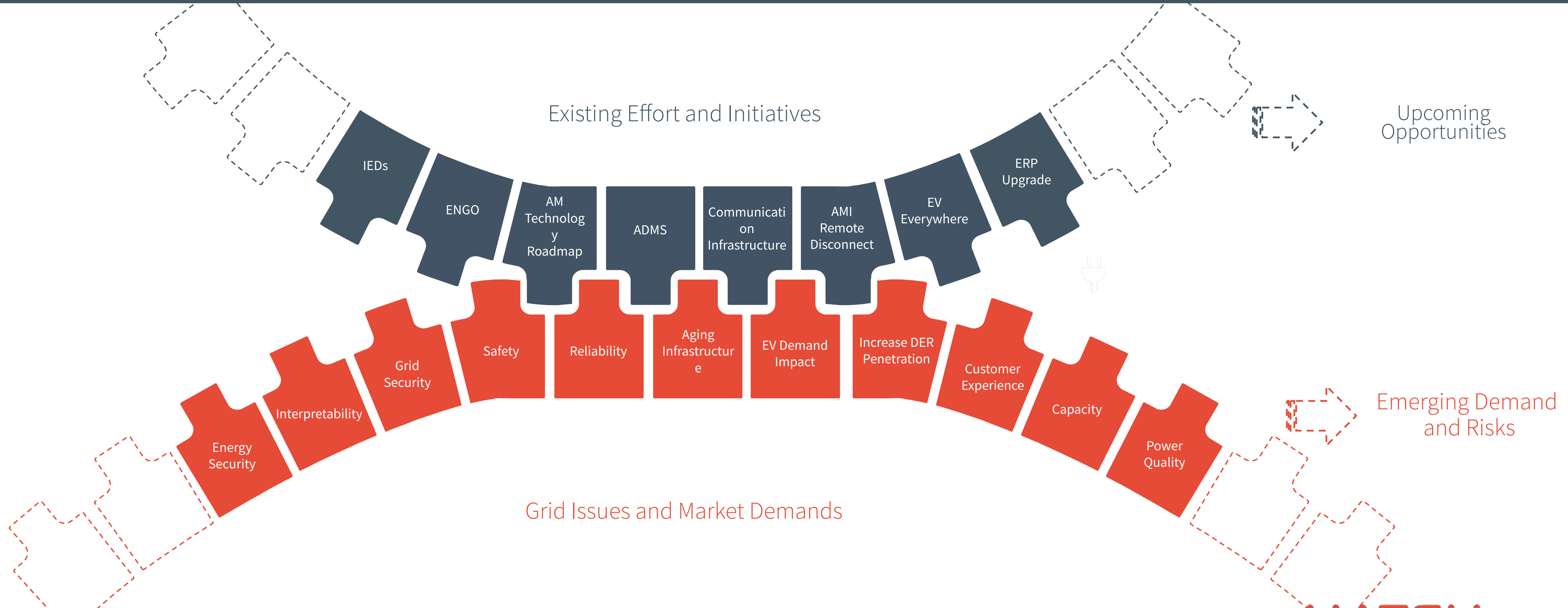

Prepared for Hydro Ottawa Limited
Feb 2023

Table of Contents

HATCH

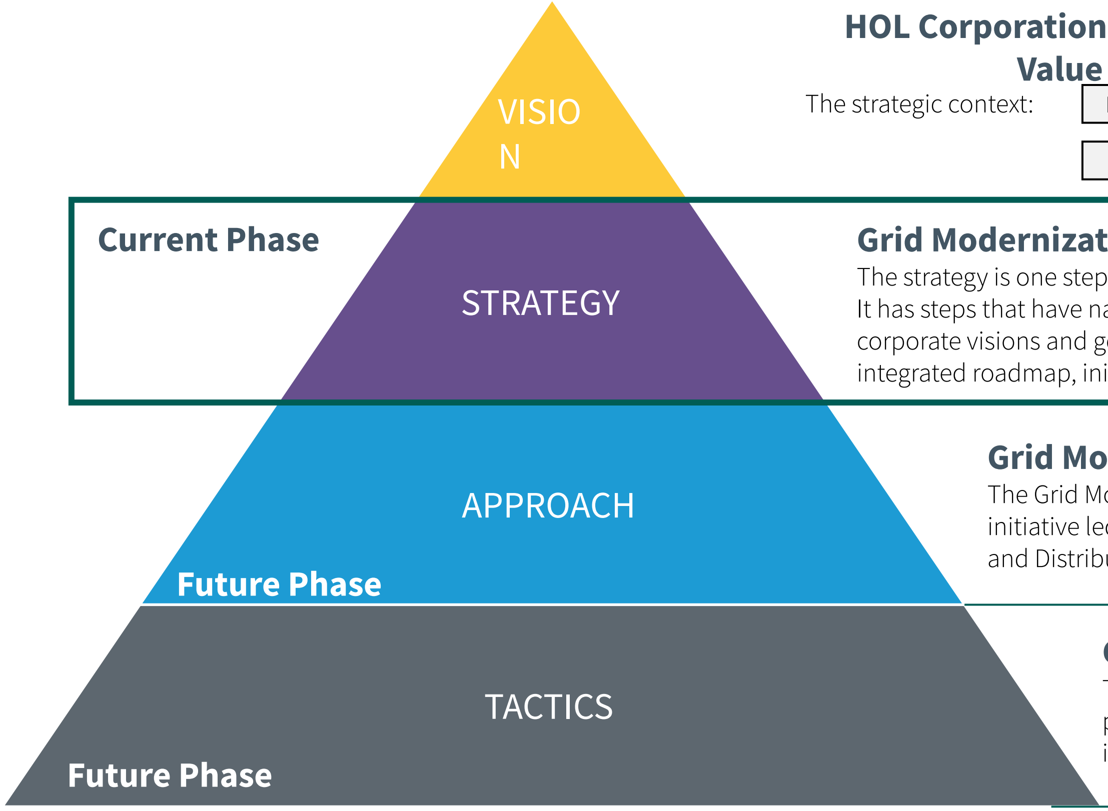
Introduction and Scope Overview

The team had been focused on developing the specific capabilities of the grid, i.e., communication infrastructure upgrade, ADMS for grid reliability improvement, and EV Everywhere for decarbonization. It is recognized there is a need for a holistic view of grid modernization and to develop a cohesive strategy and roadmap.



Introduction and Scope Overview

The objective of the project is to develop a comprehensive grid modernization strategy aligned with corporation vision, value and strategy (i.e., customer-centric decision making).



HOL Corporation Vision and Value

The strategic context: Decarbonization | Digitization | Decentralization | Diversification | Demographics

Current Phase

Grid Modernization Strategy

The strategy is one step in a longer journey to modernize a distribution network. It has steps that have naturally occurred prior to its implementation such as corporate visions and goals, and other steps that occur afterwards such as an integrated roadmap, initiative planning, and project portfolio implementations.

Grid Modernization Roadmap

The Grid Modernization Roadmap will identify ongoing initiatives and new initiative led by various business unit to achieve performance objectives and Distribution System Plan performance Commitments.

Grid Modernization Tactics

The roadmap will also identify benefits, interdependency, prioritization, and timeline for individual and/or a group of initiatives to ensure successful project execution.

Figure 4-2: Hydro Ottawa's Corporate Strategic Objectives

CUSTOMER VALUE

We will deliver value across the entire customer experience

- by providing reliable, responsive and innovative services at competitive rates

FINANCIAL STRENGTH

We will create sustainable growth in our business and our earnings

- by improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people

CORPORATE CITIZENSHIP

We will contribute to the well-being of the community

- by acting at all times as a responsible and engaged corporate citizen

ORGANIZATIONAL EFFECTIVENESS

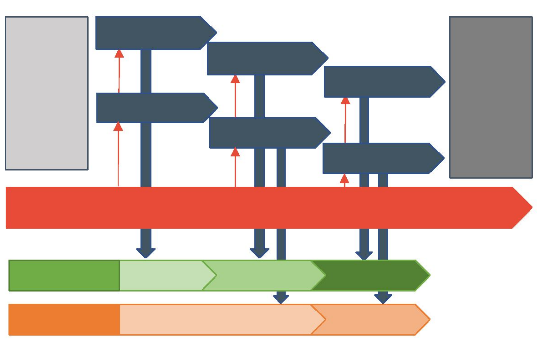
We will achieve performance excellence

- by cultivating a culture of innovation and continuous improvement

Approach & Methodology

Hatch will utilize the Grid Modernization Maturity Assessment Model to establish the baseline of current grid modernization capabilities, as well as desired capabilities. By analyzing the assessments, Hatch will work with HOL to develop actionable initiatives to achieve the performance objectives.

High-level Execution Approach

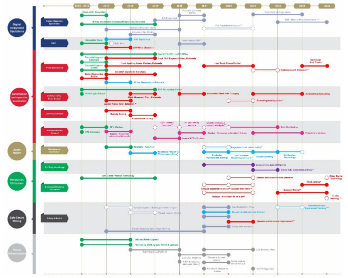


Tool – Grid Modernization Maturity Matrix

[redacted]

Execution Methodology

[redacted]



Synthesising the roadmap involves validation, consolidation and prioritisation of all existing and planned initiatives

5 **Prioritise** on

- Value add
- Industry maturity
- Capex
- Competency
- Existing initiative alignment

Timeline for Current & Future Phases

Phase 1 - Initiating
Maturity Assessment

Phase 2 - Planning
Strategy and Roadmap Development

Phase 3 – Execution

Nov-Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023

Project kick-off and mobilisation

Capability Assessment & Visioning

Objectives & Value Framework

Technology Reference Model Review

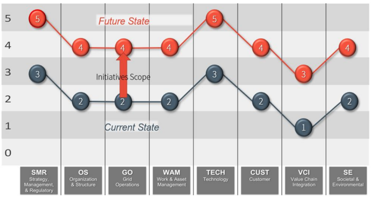
Initiative Development

[redacted]

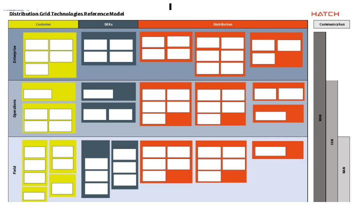
[redacted]

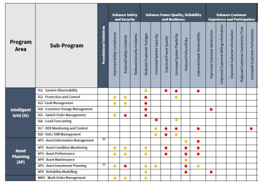
Execution plan design for selected initiatives

Execution of selected initiative



Current and future states


Technologies Reference Model


Initiative benefit review

Conduct Project Management Office activities

Weekly status updates and monthly committee meetings on progress and key risks

RFI and Team mobilisation

Complete current and future state assessment

Grid Modernization Strategy

Grid Modernization Roadmap

Execution Plan

[redacted]

Current & Future State Assessment Overview

Grid Modernization Maturity Assessment Model

- Discussions with HOL internal stakeholders were held to assess the current and future state of capabilities across the [redacted] Grid Modernization Maturity Model Domains

- Each capability domain was assessed based on maturity model (fully, partially, or not existing)

[redacted]

Timeline

Current State
- Existing or In-implementation Capability

Future State (Near-Term)
- Desired Capability by the end of the current rate filing period (2025)

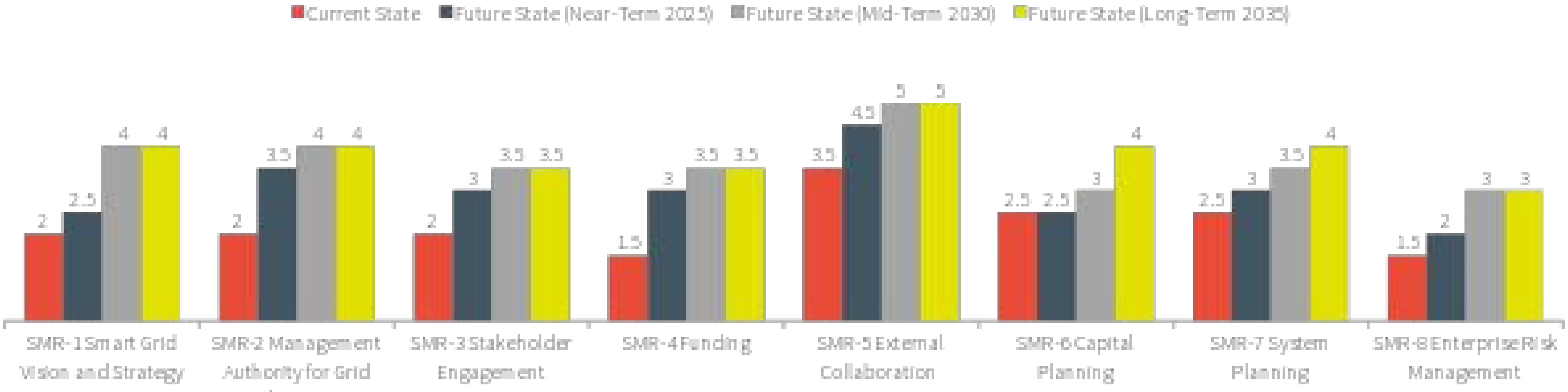
Future State (Mid-Term)
- Desired Capability by the end of the next rate filing period (2030)

Future State (Long-Term)
- Desired Capability by the end of the following rate filing period (2035)

Summary for SMR domain

Current State: Grid modernization is listed as one of the key components in the HOL's 2021-2025 Strategic Direction report. It is also recognized and well-supported as a priority by the executive team. HOL is actively participating in industry working groups to ensure awareness of new technologies and regulatory trends. One of the main objectives of this project is to develop the grid modernization strategy with recommendations around system planning, capital planning, and funding method for grid modernization initiatives, as well as benefits and measurement metrics framework.

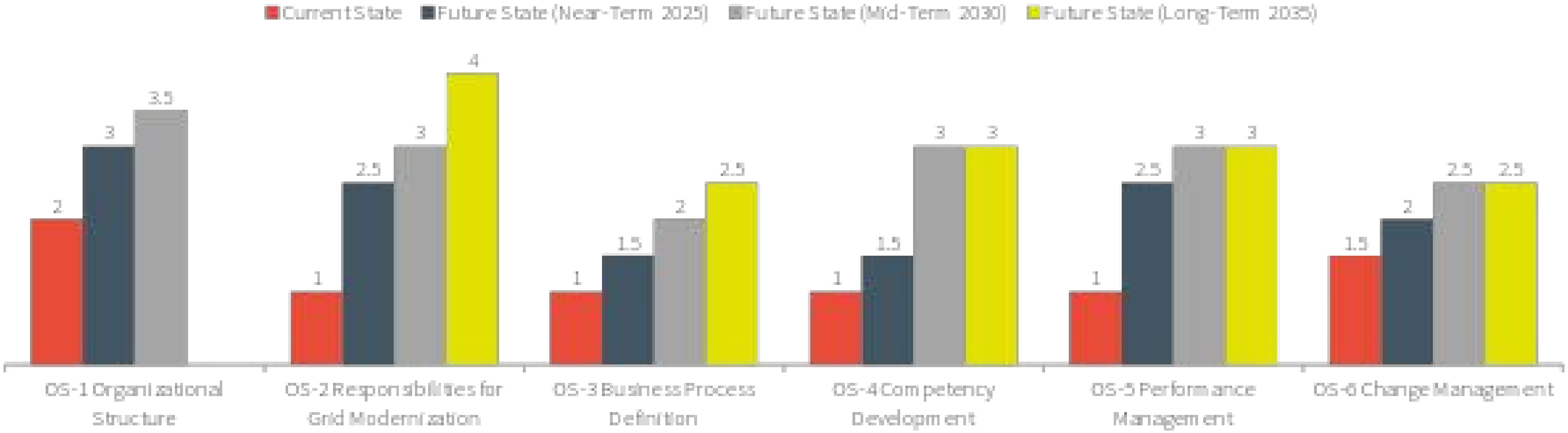
Future State: Grid modernization vision and strategy will be developed and used to guide the grid modernization initiative scoping and planning for HOL's upcoming rate application filling. The grid modernization strategy will be directing or an important component of HOL's corporate strategy and vision. The associated capabilities will be enabled.



Summary for OS domain

Current State: HOL currently has a Smart Energy Steering committee, with executive team support and cross-functional participation. However, the interlock governance structure and R&R matrix need to be established if the same committee is leveraged for grid modernization. Business processes and performance management for grid modernization initiatives are currently built on a project-by-project basis. There are opportunities to build on top of these existing business processes and expand them to cover the larger grid modernization scope. Competency and change management need to be explored further for grid modernization. These opportunities will be addressed as the strategy is developed.

Future State: HOL is working towards an explicit organizational structure for grid modernization. Collaboration and coordination will be promoted among functional departments and accountable leadership will be assigned.



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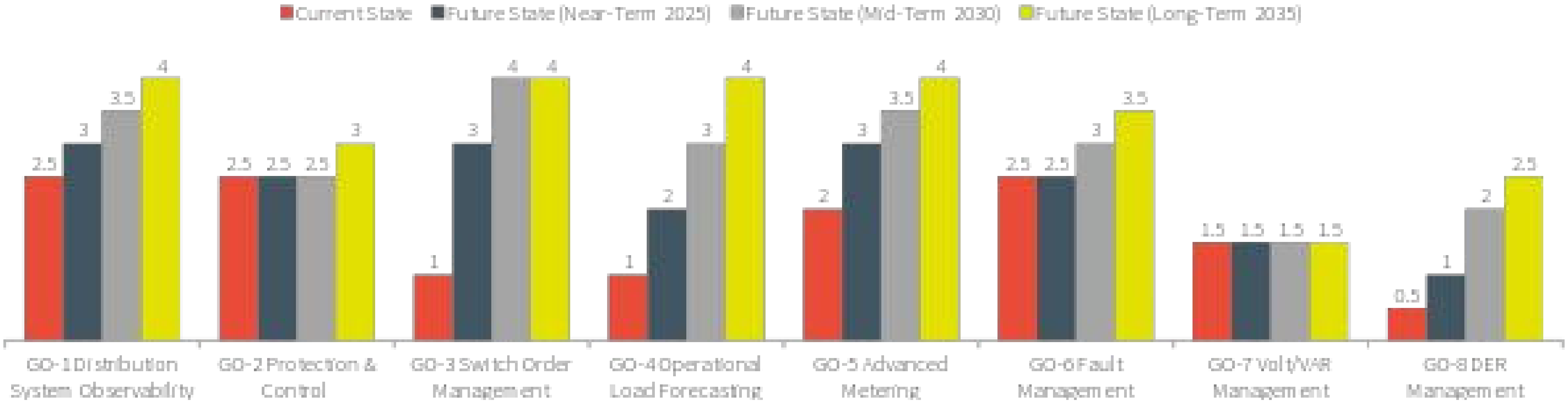
Summary for GO domain

Current State: HOL has piloted different technologies to improve grid visibility (i.e., ENGO, transformer telemetry). There are also IEDs, FCIs, and SCADA-enabled devices installed at the substation and feeder levels for remote monitoring and P&C. ADMS project consists of upgrades of SCADA and OMS, system integration, switching planning and FLISR implementation will integrate multiple technologies. Successful implementation of the project will greatly improve grid situational awareness, SOM, load forecasting, and fault management. AMI 2.0 strategy was developed in 2019, and a refresh is discussed. AMI 2.0 presents another great opportunity for reliability and safety performance improvement. However, deliciated planning and execution are paramount as the cost is high. DER as a grid resource would need to be explored from grid performance and decarbonization perspectives.

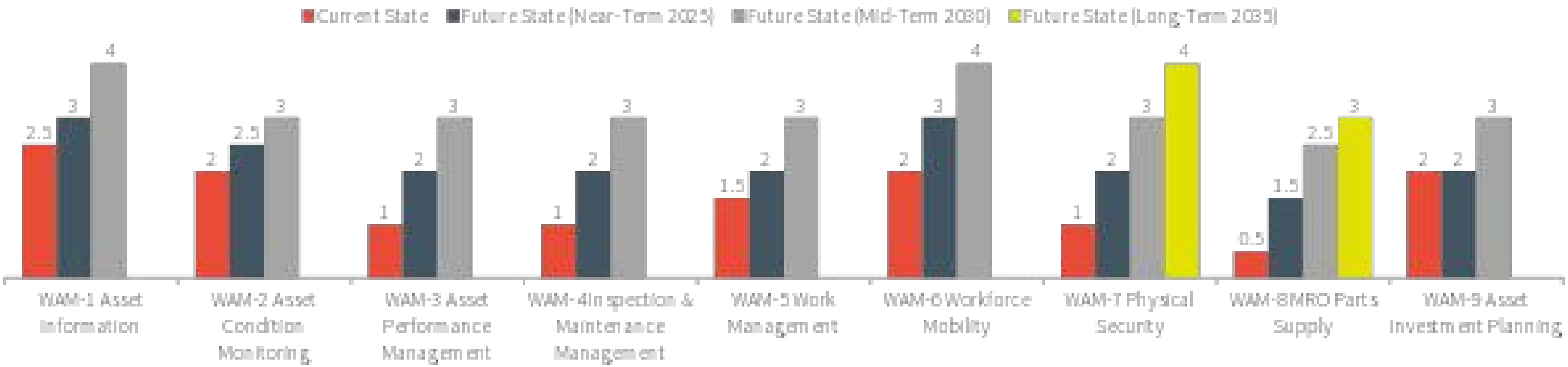
Future State: HOL has successfully and thoroughly integrated various technologies into its Grid Operations processes to further improve and encourage system observability, controllability, and responsiveness while minimizing outage times. Grid observability, SOM automation, and fault management are advanced through the implementation of ADMS. HOL starts exploring different methods for load forecasting that account for DER growth. AMI 2.0 capabilities are explored, and implementation strategy and roadmap are developed.



Summary for WAM domain

Current State: HOL has developed health indices (key assets), failure curves, failure rates, and a CNAIM model, however, advanced asset-related analytics are not performed to enhance asset management insights. Copperleaf C55 was implemented in 2015 and is used for the System Renewable and System Service portfolios, however, the probability of failure and consequence of failure have not been integrated into AIP. Workforce management is currently service request driven, not based on asset condition.

Future State: By 2026, HOL will have a fully functioning EAM, integrating processes and asset data. This will be fed into the AIP system with predictive analytics module for risk-based investment decision making. By 2026/2027, HOL has completed the integration of Salesforce with EAM to enable automatic data upload of inspection / maintenance data. RFI for the ERP system to upgrade from JD Edwards has been issued, and the implementation has taken place. By 2030, HOL is now integrating the AIP, APM, and EAM systems.



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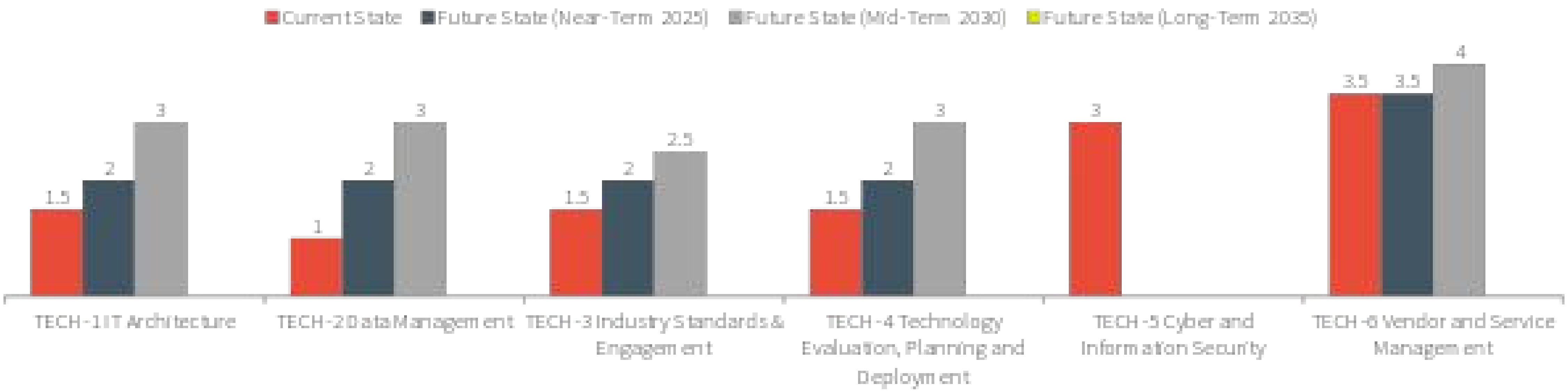
Summary for TECH domain

Current State: HOL has a dedicated team that manages both IT and OT, this provides an advantage for streamlining technology and business process integration. In general, IT is leading OT in the area of technology maturity, cybersecurity and data management. Organization-wide IT architecture, data management strategy, and data governance for grid modernization are discussed on a project-by-project basis and need to be formalized. Vendors and service management are managed through JDE with regular analysis and reporting. The NIST framework is followed, and other industry standards are being investigated. There are opportunities to improve overall technology maturity by defining a formal organization-wide IT and OT strategy and guidelines.

Future State: HOL will advance to close the gaps between IT and OT. By 2025, HOL will have the enterprise IT architecture ready to enable smart grid, and an implantation plan to support smart grid applications. Preliminary data management framework will by available by 2025 and a detailed strategy will be available by 2030. Industry standards for grid technologies will be leveraged with ADMS implementation advancements.



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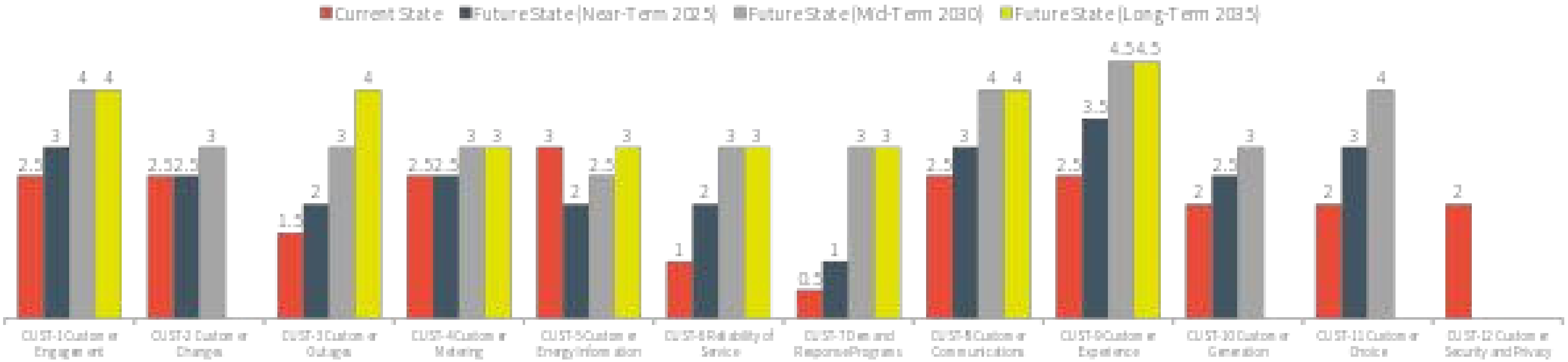
Summary for CUST domain

Current State: HOL is enabling and integrating many customer-related capabilities. The team issues periodic newsletters and conducts regular customer surveys. The online portal enables many self-serving functionalities such as request submission, raw energy data retrieval, regular usage pattern analytics, etc. There are opportunities to improve the overall maturity level by improving customer outage detection methods, leveraging mobile applications, developing Demand Response programs, introducing quantitative reliability models, etc.

Future State: HOL will have improved and integrated the customer experience allowing for new levels of customer engagement, an optimized customer-utility interface experience, improved outage communications, and strengthened information security. ADMS is implemented to improve customer outage management, and modeling of reliability of service (i.e., CI, CMI costs) is used for decision-making. IESO allows HOL to perform DR in 2023. The online DG connection process is implemented, and information is available online for the customer's preliminary assessment for connection.



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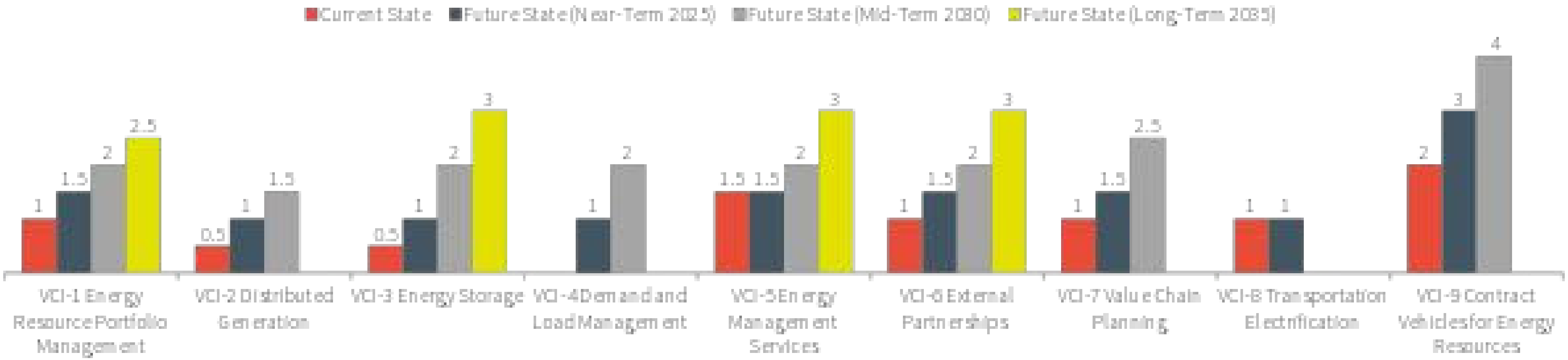
Summary for VCI domain

Current State: HOL has conducted some pilots to support DERs, however, a cohesive strategy is not in place to develop, enable, and manage a diverse resource portfolio. One of the key items missing to enable demand and load management is the controls and communications. HOL deals with third parties with appropriate confidentiality protocols including the use of an external cloud-based software hosting site. HOL is piloting partnership with EV charger and network providers and has contract vehicles in place to accommodate DG for small and mid size customers only.

Future State: HOL will have completed advanced pilots including exploring the DSO role. HOL has incorporated the management of DERs into the corporate strategy and may be utilizing the diverse resource portfolio to their organization's benefit in terms of capacity needs, and reliability. HOL is utilizing storage to provide value-chain benefits. By 2030, HOL is utilizing the DG contracts to optimize value-chain benefits in response to market signals.



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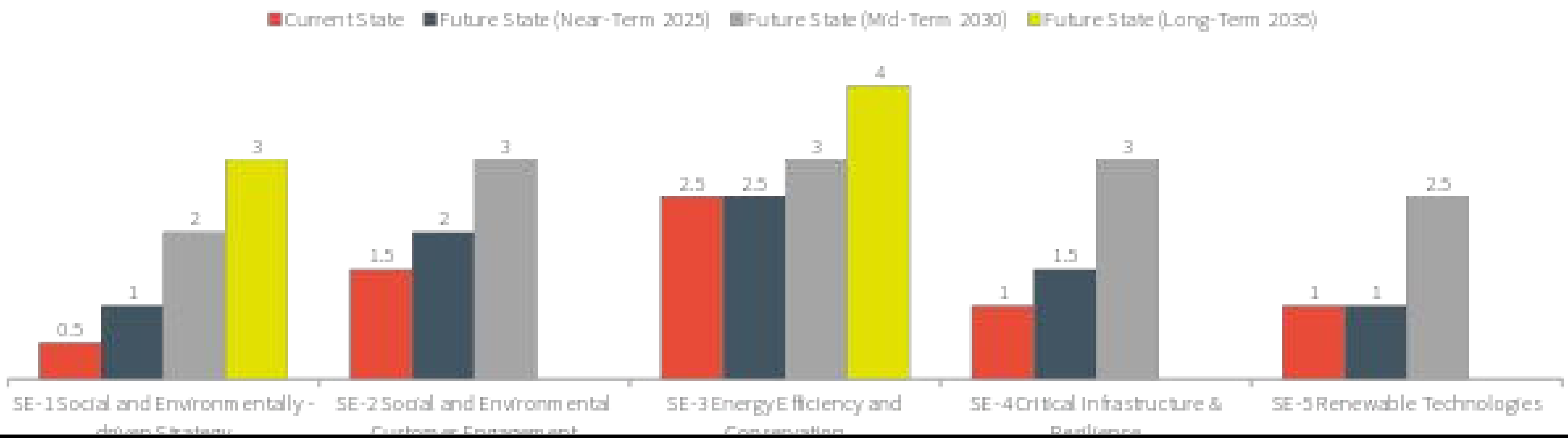
Summary for SE domain

Current State: HOL emphasizes the criticality of ESG in the 2021-2025 Strategic Direction report. Many strategic directions are announced to promote green energy, such as electrification and renewable generation. IESO manages CDM and DR programs centrally, and HOL is actively seeking opportunities and working toward building energy conservation and green initiatives within its premised jurisdiction. As the capital of the country, HOL is aware of the responsibility for critical infrastructure and continues to work with stakeholders to improve system resilience.

Future State: As HOL is committed to achieving net zero by 2030, HOL's grid modernization strategy will further support societal and environmental objectives. Being the capital of Canada, HOL fully realizes the importance of power supply to critical infrastructures and will advance resiliency in the next 10 years and beyond.



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Current & Future State Assessment – Strategy, Management and Regulatory

Note:
- “TBD” indicates more details will follow as part of the follow-up discussions with HOL.
- Some cells are intentionally left blank as long-term vision are not available yet for some subdomains.

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Smart Grid Vision and Strategy	2	Level 1 • In the 2021-2025 Strategic Direction, grid modernization is listed under the key change drivers - the 5 "D"s. "System modernization goes hand-in-hand with system investment" is referred to as the key principle for the 2021 - 2025 program. • There is no strategy report developed specifically for Grid Modernization, however, the overall objectives and priority of Grid Modernization are well recognized by the senior leadership team. Level 2 • A significant amount of capital investment and effort is dedicated to the ADMS implementation and communication infrastructure development in preparation for future Grid Modernization initiatives.	2.5	HOL's next strategic direction setting is in 2026. Gird's modernization vision and strategy will be incorporated into the strategic direction and at the next rate application (2025).	4	By 2030, grid modernization will be directing HOL's strategy and vision on the corporate level.	4	Conservatively speaking, new business model opportunities may not be available by 2035.

[redacted]

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Management Authority for Grid Modernization	2	Level 1 • There is high-level strategic mapping at the executive level for Grid Modernization. Grid Modernization initiatives are supported and approved on a project-by-project basis. Level 2 • HOL has a Smart Energy Steering committee, there is executive sponsorship on that committee. Innovation initiatives and discussions flow up to that committee. • The committee has a governance structure for 3-4 years, with well-documented roadmaps, plans, etc.	3.5	HOL believes it is critical to advance the capability of management authority for grid modernization. A governance model will be available to measure investments and business plans for grid modernization.	4	The costs and benefits framework of investments will be further established and used to evaluate grid modernization investments and business plans.	4	Significant progress not expected

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Stakeholder Engagement	2	Level 1 • Gird Modernization topics and initiatives were discussed in the EDR filing reports with specific investments amount. Level 2 • Limited proactive regulatory drivers at present. HOL recognizes it is important and can be proactive in identifying future reform opportunities and align with the future regulatory landscape. • Capital planning for gird modernization initiatives are put in place (ad-hoc) to get projects done. Various teams supports grid modernization from different perspectives throughout the lifecycle.	3	New and improved KPIs will be developed and start to link to business cases and regulatory fillings by 2025.	3.5	By 2030, a comprehensive set of KPIs will be fully linked to business cases and regulatory fillings. However, the DSO role is dependent on changes in the regulatory framework.	3.5	Further advancements will be dependent on regulatory changes.

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Funding	1.5	Level 1 The cost-recovery methodology is utilized for current gird modernization initiatives, such as ADMS. Level 2 There are quantitative measurements for gird modernization initiatives but most of them are qualitative.	3	By end of 2023, budgets will be established specifically for grid modernization. Scientific Research and Experimental Development Tax Credit will be considered for pilot projects. By 2025, HOL will start to measure the return on investment (ROI) on grid modernization business cases with associated KPIs.	3.5	By 2030, innovative regulatory funding may be available. However, performance-based regulation may not be available in the mid-term future.	3.5	This capability may further advance if the regulatory framework changes.

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
External Collaboration	3.5	Level 1 Active collaboration with external stakeholders. Level 2 HOL is heavily involved in multiple industry working groups, such as IESO working groups. Level 3 The team is getting better at organizing external partnerships across teams, and prioritizing the right working groups and consultations to get involved in. Resource availability is limiting activity and engagement levels. Level 4: HOL is actively working with many big players in the Ottawa region on new approaches to partner with clients, such as Ottawa Airport's green energy strategy.	4.5	HOL is already progressing towards level 5 with multiple pilots with IESO and OEB.	5	HOL aims to be the leading utility in Ontario.	5	HOL aims to be the leading utility in Ontario.

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Capital Planning	2.5	Level 1 System planning team is aware of the options of NWAs. Level 2 HOL is maintaining awareness and understanding of the viability of NWAs. The team is also routinely considering alternatives for system planning, however, NWAs and other alternatives aren't financially viable (i.e., low ROI) at this stage in the Ontario regulatory landscape. Level 3 HOL is working with IESO to leverage the savings from the bulk system and transmission system capital deferrals.	2.5	Not much advancement is envisioned for the next 2 years.	3	By 2030, HOL will routinely consider alternative assets and opportunities for capital deferral in an improved manner.	4	New revenue opportunities may be available from future customer engagement programs such as new assets class and types of ownership. By 2035, a new revenue stream can be leveraged for capital investment planning and enhanced cost recovery.

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
System Planning	2.5	Level 1 and 2 • System planning is conducted with inputs from transmission operators. HOL is part of the regional planning working group for Integrated Resource Planning (IRP). DER impacts are considered for long-term system planning. Level 3 • The locational value of DERs has being assessed and actively worked on with IESO through the regional planning working group. • The cost and benefits are examined at both transmission and distribution levels. The quantitative calculator is developed by IESO, and it is currently tested by HOL [redacted]	3	HOL's system planning capability is already close to level 3 except for the locational value of DERs. With the ongoing program with IESO, the locational value of DERs will be assessed by 2026.	3.5	The actual capability will be dependent on the Integrated Regional Resource Plan (IRRP) discussion with IESO. There will be efforts to further advance the maturity.	4	The actual capability will be dependent on the IRP discussion with IESO. There will be efforts to further advance the maturity.

SMR – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Enterprise Risk Management	1.5	Level 1 Grid modernization initiatives risks are considered as part of the enterprise risk management, however, mostly are project-based. Level 2 The risk identification and evaluation is done qualitatively through AIP questionaries. There are some quantitative components in the business case for DERs, in contrast to the traditional poles and wires replacements.	2	By 2025, the risk management scoring framework will be expanded to the other departments including IT, DERs, and other relevant stakeholders. Initial setup and definitions will be available for the full value framework.	3	A full value framework and a centralized list of risk criteria will be developed with quantitative measures by 2030. The framework will be followed across departments for grid modernization.	3	Significant progress not expected.

Current & Future State Assessment – Organization and Structure

Note:
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OS – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Organizational Structure	2	Level 1 and 2 • Grid modernization initiatives are led by the Smart Energy Steering committee, with executive team support and cross-functional participation. • The existing grid modernization initiative project team has good cross-department representation. • The interlocking governance structures are missing.	3	Regular coordination and meetings will be promoted to enable coordination and collaborations across different committees.	3.5	A holistic matrix, following the same assessment criteria, for the grid modernization decision-making is needed. The approach should be preliminarily available by 2030 but may not be finalized.		
Responsibilities for Grid Modernization	1	• The existing grid modernization initiatives have multiple executive sponsors to encourage integrated responsibilities. • Grid modernization roles and responsibilities are not defined within the organization structure.	2.5	Accountable people will be assigned to grid modernization programs and activities by 2025.	3	Grid modernization leaders will be assigned with explicit authority and accountability for various business functions.	4	Grid modernization expertise will be fundamental to everyone and will be a core area of HOL’s competency.
Business Process Definition	1	• Business processes are documented within each business area and aligned with organization-wide policies and guidelines. • Gird modernization processes are performed ad hoc at the project level.	1.5	Progress will be made towards a centralized business model with assigned leadership.	2	Organizational policies and guidelines will be applied to business models and processes. Collaboration and transparency across different departments will be promoted. Documents for such policies will be ready.	2.5	Progress will be made towards a consistently evolving standard to guide grid modernization processes. More details will be added to the grid modernization policy.

OS – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Competency Development	1	• Gird modernization workforce competencies requirements (i.e., job description and role profiles) are discussed and reviewed on a project basis. • New skills required by grid modernization have not been formally considered in identifying training needs and long-term resource planning. • When new devices are added to the system, some device-specific training is undertaken.	1.5	Grid modernization team to work with the HR team to identify a holistic approach toward grid modernization competency development.	3	The approach is formalized into activities across multiple departments, such as grid modernization skill set identification, talent recruitment, education and training program development, etc. Further progress will require coordination with the HR department.	3	Significant progress not expected.
Responsibilities for Grid Modernization	1	• The performance and achievement of grid mod objectives are rolled out on a project basis. • The process for linking performance evaluation to outcomes and program implementation progress for responsible individuals is pending development.	2.5	Within the grid modernization steering committee and relevant stakeholders, performance will be linked to grid modernization achievements. The HR department will not be involved at this stage.	3	Grid modernization achievements will be linked to performance reviews across the organization in a standard way.	3	Significant progress not expected

OS – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Change Management	1.5	• Public-facing communications on grid modernization are present in EDR documents and the Strategic Direction report. • Senior leadership is aligned on the need for grid modernization, but no formal periodic communication on grid mode initiatives has taken place. • The commitment and advocacy for gird modernization efforts are limited to project team members, other mid-level and front-line leaders do have not a lot of exposure.	2	The current state already fulfilled level 2, with the exception that mid-level and frond-line leaders have not yet demonstrated commitment and advocacy for grid modernization, which will be soon achieved by 2025.	2.5	Progress will be made toward promoting communication among leaders and staff across the organization for grid modernization, with formalized communication and education initiatives. Change management procedures are initiated, implemented, and executed on an ongoing basis.	2.5	Significant progress not expected.

Current & Future State Assessment – Grid Operations

Note:
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GO – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Distribution System Observability	2.5	Level 1 -SCADA implemented in All Substations Level 2 & 3 -ENGO Pilot Project (Not integrated with Ctrl Room) -DVI Voltage Monitoring -Reclosers/Sectionalizers see each other -1-Ph Monitoring on Underground cable and secondary transformers	3	ADMS implementation is in progress, it will integrate OMS, SCADA, sensor, AMI, and DMS. New tools/systems will be integrated into the ADMS and other existing systems.	3.5	HOL starts actively collecting data, improving data quality, and integrating them into the tools for system planning and decision-making.	4	HOL collects and analyzes large volumes of data from field devices to optimize system efficiency, reliability, and resilience through observability. System planning and decision-making will be more data driven.
Protection & Control	2.5	Level 1 -Some stations are still using electrotechnical replays. Level 2 -SCADA switches are installed for selective reclosing, providing coordinated auto-switching and feeder sectionalization capabilities. Level 3 -Many remotely operatable devices (in the station), but remote controllability is not fully automated. ATS installed for station services, tap changers on many stations.	2.5	Significant Progress is not expected. Note: The more detailed evaluation of P&C will be conducted during the "Distribution Technology Reference Model" assessment phase.	2.5	Significant Progress is not expected.	3	All sub-fields expected to be at least level 3 after Subdivision: Allowing for new tools to be integrated into the current Grid Management System (i.e., ADMS).

GO – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Switch Order Management	1	Paper-based SOM, records are scanned and saved electronically.	3	Switching Orders are automatically generated by SOM and reviewed by an Operator prior to switching for safety and accuracy.	4	Switching Orders are automatically generated by SOM that is tightly integrated with ADMS.	4	Switching Orders are automatically generated by SOM that is tightly integrated with ADMS.
Operational Load Forecasting	1	Utility forecasts load using conventional methods (Regression, Time-Series Analysis, Historical Demand Data, Temperature Data). The Itron package is used for load forecasting. Speaking with community stakeholders to better predict DER growth in specific neighborhoods. The forecast is conducted based on regional plans from IESO. Working at exploring EV impact.	2	Utility is exploring different methods to load forecasting that account for DER growth and penetration.	3	HOL begins integrating sophisticated methods and tools to develop load forecasts that account for distributed energy resources (DERs) and have started to develop granular short-term forecast (e.g., hourly level).	4	HOL has successfully integrated a sophisticated load forecasting tool, which can develop granular load forecasts including spatial load forecasting while accounting for DERs.

GO – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Advanced Metering	**2**	The utility has developed an AMI strategy including forecasting metering replacement schedules and focusing on enhancing smart meter capabilities and features as part of next generation AMI (AMI 2.0) scenarios, defining new meter data management requirements and exploring various smart meter data analytics use cases to enhance the existing distribution system operations. AMI 2.0 capabilities are considered when developing the ADMS strategy and plan, but it is not formalized.	**3 (2)**	HOL will investigate the capabilities of AMI 2.0, and its integration with grid management systems (i.e., ADMS). Note: May need to downgrade from Level 3 to 2, since HOL will be investigating AMI 2.0 by 2025. Whereas, Level 3 has the integration started already.	**3.5 (3)**	HOL begins rolling out advanced smart meter (AMI 2.0) capabilities for most customers and integrating AMI with the utility's grid management system. Note: May not be fully deployed by 2030 according to HOL's comment.	**4**	HOL has successfully rolled out advanced smart meter (AMI 2.0) capabilities for most customers. AMI is fully integrated with the utility's grid management system. The utility is successfully leveraging AMI data for outage detection and fault location.

GO – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Fault Management	2.5	Level 1 FCIs are being selectively installed; Reports back to SCADA Level 2 OMS based on Breakers and Customer Phone Calls Ability to open the breaker but not restore Reconfigurations performed with human input	2.5	Remote fault and restoration schemes are installed for feeders, but not for all feeders. Grid reconfiguration scenarios are generated by real-time and/or near real-time feeder information and manually confirmed. AMI 2.0 will not be utilized for fault location.	3	HOL begins using OMS logic to identify fault location as part of the ADMS roadmap. Fault location is enhanced by access to smart meter data.	3.5	Fault location is enhanced by leveraging smart meter data, relay data, and other data analytics. Switching Orders and crews dispatched are automated in OMS.
Volt/VAR Management	1.5	Level 1 The utility is **exploring** different Conservation Voltage Reduction (CVR) and Voltage and VAR Optimization (VVO) technologies to achieve distribution system wide performance benefits including optimized feeder voltage profile, improved distribution system efficiency, reduced technical losses. CVR Capable, not fully implemented, No VVO since No Caps on system	1.5	Significant Progress is not expected.	1.5	Significant Progress is not expected.	1.5	Significant Progress is not expected.

HATCH

GO – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
DER Management	**0.5**	Level 1 Location of DERs known to Control Room No role in the current strategy	**1**	A comprehensive DER management strategy is developed to help monitor and control DERs.	**2**	DER is a focus in corporate strategic direction. HOL is exploring and piloting software platforms/ OT systems (e.g., DERMs) to increase DER observability and controllability to improve distribution system operations.	**2.5**	DER observability and control has been integrated into operational functions. Note: A business case guideline is needed from the regulator to help with ROI.

Current State Assessment – Work and Asset Management

Note:
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WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Asset Information	2.5	Level 1 Asset data has been gathered to a reasonable degree and exists an awareness of the missing information for the power flow model. Level 2 ADMS business case exists and includes ADMS Model Development as part of Phase 2 which will develop a business process for data capture and population, updates, and governance for the connectivity model, phasing correction and validation, load model, and impedance model. Level 3 HOL has an electrical connectivity model and gaps have been identified, which will be filled as part of the ADMS program. GIS has links to the maintenance records, station information is in PowerDB. There is no integration between various systems and databases, system planning analytics is mostly conducted manually in spreadsheets. Systems integration is planned for 2023 to 2025. Level 4 Copperleaf C55 is used to manage and prioritize capital projects.	3	The gaps in the asset data and electrical model (CYME) are filled as part of the ADMS program. Asset information is available to be integrated with asset management systems.	4	By 2026, HOL will have a fully functioning EAM, integrating the processes and existing asset status data, maintenance records, current and future health indices, and connectivity data. Age-driven maintenance is replaced by condition-based maintenance. AIP Predictive analysis model is implemented and utilized for system planning and asset management.		

WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Asset Condition Monitoring	2	Level 1 Visibility of grid operation condition using SCADA systems. Level 2 GIS includes a "typical status" field and PTech operating map gives the location. PTech is planned to be retired in 2023 and HOL will leverage ADMS-Model based geographic view. ENGO is piloted for voltage management and load reduction. Real-time monitoring trials typically for substation assets, not distribution systems that are not SCADA-connected. HOL has deployed temperature and gas sensors on a few transformers and the trial may be extended pending results. Health Index was established for 10 asset types including power transformers, tap changers, poles, switches, manholes, etc. Health Index assessment for vaults is performed on an ad-hoc basis and was last performed 1-2 years ago.	2.5	HOL is expanding real-time asset conditioning monitoring for substation transformers. By 2025, HOL is beginning to integrate the ADMS-Model based geographic view with asset condition monitoring data. HOL has developed a value framework for risk-based decision making to go along with the asset health index framework. This can be used in a future state to automate generation of health indices.	3	The ADMS-Model based geographic view is fully integrated with asset condition monitoring data, providing increased operational visibility on the asset location, status, and connectivity. Predictive analytics within AIP is being used to automate the current and future health indices calculations. Data is integrated into the asset management decision making process. ACM on substation transformers can be performed.		

WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Asset Performance Management	1	Level 1 Health index, failure curves, and failure rates have been developed and an asset performance management tool exists. However, no grid sensing information is integrated with AIP. Level 2 CNAIM model exists, however, advanced asset-related analytics are not performed to determine condition-based advanced failure curves.	2	HOL has implemented the predictive maintenance module in AIP (Copperleaf), providing enhanced insights from condition and health information for system planning and work execution. RFI for the ERP system to upgrade from JD Edwards has been issued, and the implementation has taken place.	3	HOL is exploring potential APM solutions that can be implemented, the predictive maintenance module that was implemented being one component of the APM. HOL will assess the viability and benefits of APM, and the integration of ERP, APM, AIP and EAM.		

[redacted]

WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Inspection & Maintenance Management	1	Level 1 Condition-based inspection/maintenance has been explored but not implemented. The major roadblock was the tool for maintenance being based on spreadsheets, which couldn't be implemented in JD Edwards. Level 2 Field inspection crews use GMobile to record distribution and station maintenance data.	2	HOL has implemented the predictive module integrated into AIP; the functionality and framework will be available and only critical asset classes will have condition-based maintenance.	3	The majority of asset classes will have condition-based maintenance programs; integration of the AIP, APM, and EAM systems will make it a comprehensive approach.		

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WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Work Management	1.5	Level 1 Workforce management is service request driven, currently not based on asset condition. Level 2 HOL has implemented Salesforce (phase 2 of mobile workforce management) to manage work for simple metering. Developed a plan for scheduling small and large capital projects. All trades are dispatched through this software. Emergency responses do not directly go through the reliability team, instead are manually managed through email and/or documentation. HOL intends to expand Salesforce to other programs, a roadmap has not been developed yet. Current workforce management is based on resourcing.	2	Initial phases of integration and automation of workforce management system is being piloted. HOL has developed a global mobile workforce strategy, including a roadmap, that expands the current Salesforce implementation to other programs. (Note: as per the level 2 requirements, not HOL's comment.)	3	HOL has integrated the remote asset monitoring with automated mobile workforce management system for an asset class, likely station transformers. This workforce management is based on asset condition / requirements as opposed to resourcing.		

WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Workforce Mobility	**2**	Level 1 Work orders management are digitalized, and portion of the workforce is dispatched automatically. Level 2 GMobile installed on the tablet has predefined forms to be completed by field crews. All vehicles are also equipped with laptops. Google Forms is the alternative being explored along with a mechanism to link inspection images to GIS (future). Typically used when more details need to be entered. Data is not integrated into other systems and engineers must access and review the record manually. Level 3 Google Forms are cloud-based, however, data is not automatically uploaded to other systems yet.	**3**	HOL has begun the initial stages of integrating the Salesforce workforce management with EAM, allowing automatic data upload to systems. A mechanism to link inspection images to GIS is being implemented.	**4**	BY 2026/2027, HOL has completed the integration of Salesforce with EAM to enable automatic data upload of inspection / maintenance data.		

WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Physical Security	1	Level 1 Security at the front desk has access to cameras throughout the buildings, badge access control, all 5 sites have extensive camera coverage. Cameras at many substations in random view. Level 2 Information is sent to a centralized system that is outsourced. Level 3 HOL has camera views on substation equipment for about 85% of substations, some stations are shared with HONI. The system has intrusion alarms/door alarms sent to the control room via the SCADA system. The camera information is sent to the outsourced centralized system. There is a plan to extend the camera coverage. Data is stored on the camera and requires manual retrieval on-site. The next step could be to update to a live view. A pilot project is ongoing for motion detected perimeter (for stations), where motion lights will come on upon intrusion and issue a warning to the system office. Existing fiber optics infrastructure allows for additional updates if needed. HOL is working on purchasing a remote camera trailer to bring to construction sites. Level 4 Real-time monitoring is a work in progress. On some assets, SCADA communications exist and are monitored for change of state alarms.	2	A centralized threat monitoring solution has been established. HOL has implemented cybersecurity programs in 2023 to strengthen physical security, e.g., integration into SOC.	3	Additional integration of distribution assets into SOC. HOL is working towards updating the camera to live view, from a manual retrieval on-site system.	4	Real monitoring of all station assets. Critical downstream distribution level assets will also be considered.

WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
MRO Parts Supply	0.5	Level 1 and 2 HOL has started to implement a formal MRO parts management process. Designer requests and work orders are put into the ERP system. Spare parts, warehousing, safety stock levels, and min/max levels are set manually in JD Edwards, the legacy ERP system. Hubble Reporting is an add-on system also used. HOL is exploring a quantitative approach to MRO parts/demand planning, expecting this to be part of the new ERP in 2 years. A vendor list (over 4,000) is maintained in the system and Dun & Bradstreet is used to monitor the health of key suppliers. Meetings are held with suppliers monthly to quarterly. A potential add-on is a supplier report card that is regularly updated.	1.5	HOL plans to include stations in the Material/Supply Chain management system for parts and materials, as part of the new ERP implementation.	2.5	HOL has automated parts of the asset inventory process. As part of the new ERP system implemented, HOL uses barcodes and handheld readers at the warehouse for parts and materials handling. HOL is integrating an MRO system that prioritizes cost and schedule efficiency and establishes the optimized parts, location, and timing of orders. HOL will have integrated the ERP and AIP systems in 5 years, allowing capital projects to have a link to the ERP to make orders. This will roll down, for example, to the ordering level per asset for capital planning.	3	HOL will track the full life cycle of a part/material (where beneficial and cost-effective) from the time of ordering to procurement, to the warehouse, to when it is utilized.

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WAM – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Asset Investment Planning	2	Level 1 C55 was implemented in 2015 and is currently only used for System Renewable and System Service portfolios. System Access is not part of C55. Asset probability of failure and consequence of failure was developed in 2016, which has not been implemented into AIP, but is used manually by engineers. Level 2 The risk matrix and value framework are built into C55 which touches on all the operational risks. The last review was done for the ISO certification in 2018. Will be updated again in 2023 to align with the corporate strategy. Documented in the DSP (chapter 5.2). Level 3 Modelling of asset investments is done at a project level but not for each specific asset.	2	By 2023, modelling of asset investments is done at an asset-level, for key asset classes. HOL has integrated the EAM system with AIP.	3	HOL has implemented a predictive analytics module within AIP for maintenance and replacement investments, with health indices being the primary driver.		

Current & Future State Assessment – Technology

Note:
- “TBD” indicates more details will follow as part of the follow-up discussions with HOL.
- Some cells are intentionally left blank as long-term vision are not available yet for some subdomains.

TECH – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
IT Architecture	**1.5**	Level 1 • Enterprise IT architecture exists. OT is managed by the Grid Technology team. There is no designated Security Operations Center (SOC) but there is a cybersecurity team. Level 2 • Changes to the enterprise IT architecture that enable grid modernization are being deployed. Change management is in place. • There are project-specific IT implementation plans. Plans are owned by CITO and collaborated with CEDO. • There is an informal enterprise IT architectural framework, but it's not documented.	**2**	HOL's existing IT architecture is already close to level 2. By 2025, HOL will have the enterprise IT architecture ready to enable grid modernization, and an implementation plan to support smart grid applications. Smart-grid-related IT investments will be aligned with the enterprise IT architecture.	**3**	Business processes that will be impacted by grid modernization initiatives will align with the enterprise IT architecture. HOL's IT systems will adhere to the IT architectural framework. However, optimized business processes may not be achieved by 2030.		

TECH – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Data Management	1 (considering both OT and IT)	Level 1 & 2 In general, IT is more mature with data management compared to OT. Data management strategy is not formally written but in a loosely TOGAF style. Transactional data is used every day by the operation team. Data management and retrieval are fully defined. Non-transactional data such as analytics depends on the specific team. There is a multi-year program planned for non-transactional data to improve collaborations between teams. There is an integration hub allowing collaboration between different teams. Data sharing on the OT side is point-to-point. Data processing procedures, data quality, and data validation are in place. Internal tools instead of commercial tools are used for data promoting. The self-serve analysis is available to staff with the right level of access. Data structures and naming conventions are established. The Data warehouse is well-established for different project needs. Detailed customization is provided. Transactional data only get archived if the application is archived and data needs migration. The data governance framework is not well defined yet.	2	HOL's existing data management is already close to level 2, especially on the IT side. By 2025, HOL will have a defined preliminary framework for data and analytics, which should align with HOL's grid modernization goals and guidelines. Integration Hub will be leveraged to establish an interoperability strategy and guidelines.	3	By 2030, HOL will have a detailed data management strategy with data ownership well defined, including both transactional and non-transactional data. (Data self-service is already available.) Note: Conversations on level 3 capabilities have started.		

TECH – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Industry Standards & Engagement	**1.5**	Level 1 • There is an internal standard regarding grid technologies but the HOL is not following industry standards. There is a plan to comply with industry standards. Level 2 • The National Institute of Standards and Technology (NIST) Framework is implemented. • Utility is considering NERC and IEC 61850 alignment (unpacking through ADMS roll-out).	**2**	With the implementation of ADMS, level 2 will be achieved by 2025. HOL will have standards and procedure for communications, software development, change management, safety and security, and installation and maintenance., and the they will be applied to IT infrastructure.	**2.5**	Advancements will be made towards level 3. By 2030, HOL's systems will start to formalize and align with the enterprise IT architectural framework for grid modernization.		

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TECH – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Technology Evaluation, Planning and Deployment	**1.5**	Level 1 • There is currently no organizational grid modernization strategy. The process to evaluate and select technologies is based on the specific project. Level 2 • Currently, the field devices selection for grid modernization is driven by CEDO, and IT infrastructure and solution selection is driven by CITO. • There is no formally defined evaluation process yet. There are ad-hoc evaluations reactively instead of proactively based on each project. • Early deployments of technology to support smart grid pilots and applications are underway. SIEM (security information management) is available for 4 substations and the goal is to have the SIEM in all substations.	**2**	By solving the gaps with OT, level 2 is achievable by 2025. By 2025, a common technology evaluation and selection process will be applicable for both IT and OT-related grid modernization initiatives.	**3**	By 2030, new technologies will be regularly evaluated and prioritized.		

TECH – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Cyber and Information Security	3	Level 1 & 2: beyond this level Level 3 • The organization implemented NIST Cyber Security Framework and Privacy controls within a detailed IT roadmap and follows OEB standard. • Practices are documented and adequate resources are provided to support the process from both internal and external resources (such as contractors). • Compliance is not centralized but there is an internal risk team. External vulnerability assessment is performed. • The cybersecurity team reports on both qualitative view and quantitative matrices. Self-assessment and auditing are performed every other year for IT and OT. Level 4 • The level of access to the system is different for different employees. Phishing campaigns are available. The entire organization needs to go through the cybersecurity department for a related issue. Intrusions are monitored. However, opportunities are there to improve security such as developing a formal security strategy and evolving with the latest technologies such as implementing biometrics.	4	The IT implementations throughout the enterprise have taken into account and dealt with concerns related to security, privacy, and performance. The breach detection, incident management, and remedy implementation strategies and tactics for security are continuously evolving in response to changes in the operational environment and the lessons learned. IT roadmap is available and covers cybersecurity and information security.	5	Cyber threats are anticipated proactively and the IT system is capable of recovering automatically from cyber incidents., such as prompt recognition and response to such incidents, minimizing or recovering from any adverse effects, and sharing relevant incident data widely and in a timely manner to safeguard the broader community from potential cyber security impacts across the industry.		

TECH – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Vendor and Service Management	3.5	Level 1 & 2: beyond this level Level 3: beyond this level, policies and guidelines are in place for vendors Level 4 • There is no vendor management advisory board, but vendor management is informally driven by IT, business, integrations with tools/processes. There is a history and records of all vendors. Vendors are tracked and can be disqualified/put on probation if insurance expires, financially downgraded, etc. • There is no formal committee that is a cross-functional team that supports vendor management. Procurement maintains this information currently. ISN has information that records details on the vendors (performance) and then procurement pulls this information from ISN and spreads it to the group. • Procurement is centralized. IT needs to go through procurement to purchase anything. • There is no systematic	3.5	Not much advancement will be made within 2 years as vendor and service management is already advanced.	4	The platform is available for a vendor management system to be implemented by 2030. "Service Now" can be utilized for optimized vendor management.		

Current & Future State Assessment – Customer

Note:
- “TBD” indicates more details will follow as part of the follow-up discussions with HOL.
- Some cells are intentionally left blank as long-term vision are not available yet for some subdomains.

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Engagement	2.5	Level 1 & 2 Customers are informed about HOL's strategies. Comprehensive customer engagement activities are included in the 2019/2020 rate application. There is an annual customer satisfaction survey, and a biannual large commercial survey. Net-zero surveys are performed with customer representatives and the public. Surveys are customer-segmented, and results drive customer engagement strategy. Level 3 Customer segmentation is limited to rate classes. Level 4 Occasional Customer modeling is performed by rate classes, such as load forecasting and EV trends.	3	HOL begins using Customer data to further customize messaging for specific customer segments and assess opportunities that meet varying customer needs.	4	HOL begins using behavior modeling to add further sophistication to customer segmentation for creating customer profiles. Customer needs are projected using a predictive model, including peak power demands.	4	HOL continues utilizing Behavior modeling to augment customer segmentation for creating customer profiles to support predictive models.

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Changes	2.5	Level 1 - Customers make connections or change requests through the call center and email. Level 2 - Customer profile data is available to call center staff. - 15% of the existing meters have remote disconnect capabilities. Level 3 & 4 - Customers can submit requests through online portals and there is automation to generate work orders. - Not all customers can be remotely connected or disconnected. Remote (dis)connection is only performed for non-payment activities, not for energizing new accounts. HOL is monitoring empty unit. In general, HOL does not disconnect when the customer moves out.	2.5	More meters with remote connect and disconnect capability are installed (i.e., an average of 5K replacement per year).	3	Customer interface is further aligned and integrated with AMI 2.0 Planning. A remote connect and disconnect capability has been deployed for a significant portion of customers.		

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Outages	1.5	Level 1: beyond this level Level 2 Outage detection is not fully automated, yet still depends on customer reporting by telephone. Outages are posted online and on Twitter, along with estimated restoration time. The outage map is available online. SMS, physical letters, and notifications are sent for planned outages. A limited portion of key accounts receives emails upon outages.	2	HOL will aim to have automated the outage notification process, utilizing the customer information database. Improvements are made through ADMS.	3	Outage detection is automated by utilizing smart meter data, aggregated at the substation level. Data is used to preempting outages. Outage notifications are available to all customers with an estimation of restoration time based on information input from systems such as OMS or AMI.	4	All meters are replaced by 2035. There is automatic outage detection and proactive notification at the circuit (lateral) level. Outage notifications are available to all customers and can be monitored by customers live.

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Metering	2	Level 1 & 2: beyond this level Level 3 AMI 1.0 is in place. Two-way communication is not yet available (but planned). Testing was performed with Home Area Networks (HAN) six to seven years ago.	2.5	Piloting to enable automatic outage detection but not customer energy information.	3	Advanced AMI including two-way meter communication is piloted to enable enhanced customer energy information. Note: No intention to implement HAN. The privacy issue is a concern. Recommendation: to be aligned with AMI 2.0 strategy and capability objectives.		

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Energy Information	2	Level 1: beyond this level Level 2 HOL is performing customer baseload profiling. However, customer load pattern data is not used by HOL. Analysis of customer usage patterns informs planning and operations are performed at the feeder or substation level but not the customer level. Level 3 Sub-hourly data is available on demand with a 24-hr delay. Irregular use pattern is available but is not used for outage detection. DER and EV are disaggregated by the 3rd party. Large appliances are surveyed and the algorithm is refined based on customer-provided information. Overview/estimation is provided on the large appliance usage. Customers have access to the raw data. HOL does not have access.	2	Customer data is analyzed to better understand customers and their usage patterns Analysis of customer usage patterns informs planning and operations (**not customer level but at feeder or substation level**).	2.5	Customer energy information is available in near real-time at the transformer level for EV initiatives. Note: HOL is not looking to use energy information for outage detection.	3	HOL has hourly or more frequent knowledge of residential customer usage. On-peak and off-peak load information are available. Customer energy information is available in near real-time to detect outages, irregular usage patterns (**available but not used real-time**).

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CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Reliability of Service	1	Level 1 • Reliability standards are applied based on standard metrics at the feeder level. • Cost-based metrics are not used currently. • Reliability-related conversations have been conducted with key account customers, but not quantitatively. • Calculations are based on a third-party study in 2017 per customer type using manual analysis based on upstream protection devices.	2	HOL begins collecting Customer data on the cost of outages to enable the calculation of reliability value. Reliability modelling informs investments for priority segments.	3	HOL begins segmenting Customer reliability impacts by customer classes and enabling value-based reliability optimization modelling.	3	HOL begins segmenting Customer reliability impacts by customer classes and enabling value-based reliability optimization modelling.

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Demand Response Programs	0.5	Level 1 • There is no direct demand response program. • HOL provides summary information on the ICI program to Class A clients. • HOL has expressed interest to participate in future IESO programs.	1	IESO program 2023 to allow LDCs to perform DR, but not for all customer classes. Customer load control/management may be operational on a limited basis.	3	Under IESO control. Possible level 3 by 2030. HOL makes Standard demand response programs available to both commercial/industrial and residential customers.	3	HOL makes Standard demand response progra ms available to both commercial/industrial and residential customers.

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Customer Communications	**2.5**	Level 1 Monthly newsletters are emailed to customers. High-level information is communicated to customers. For large C&I customers, tailored services are available from the call center. Level 2 Energy usage is available for viewing on the customer portal in addition to bills. In-person conversations are held with certain commercial customers. Residential customers received mass broad communication. Level 3 There is a disaggregation effort of common loads such as EVs. Level 4 Usage patterns are available for residential customers and commercial customers to help make decision plans as needed for residential and small comm (self-serve online). in person conversations are available through the Customer Service team.	**3**	Residential customers have on-demand access to hourly usage data. Communications include information on specific relevant programs and technologies which can support both customer and utility objectives.	**4**	Residential customers have on-demand access to hourly usage data without delay. Note: The capability is dependent on AMI 2.0 strategy and roadmap. A more detailed path forward discussion is needed for AMI 2.0.	**4**	The capability is dependent on AMI 2.0 strategy and roadmap.

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Experience	2.5	Level 1 & 2: Beyond this level Level 3: • Common self-serve functions are available with the online portal, including energy usage, and bill paying, such as move-in, move-out, and customer service inquiries. • The mobile app is available with limited functions. • For new products/technology, there are different channels for communication and tailored e-marketing. with some level of customer segmentation.	3.5	Level 3 HOL has implemented a common experience across two or more residential customer interface channels. The customer experiences information-rich interactions Level 4 HOL has integrated a common customer experience across all means of interfacing with residential customers and leverages common data sources.	4.5	Level 4 HOL has integrated a common customer experience acros s all means of interfacing with residential customers and leverages common data sources. Level 5 Customer interfaces include leveraging smart appliances, EV chargers, etc. to enable greater automation and provide an enhanced customer experience across the product and service portfolio. Note: Market and external factor driven.	4.5	Level 4 HOL has integrated a common customer exp erience across all means of interfacing with reside ntial customers and leverages common data sources. Level 5 Customer interfaces include leveraging smart appliances, EV chargers, etc. to enable greater automation and provide an enhanced customer experience across the product and service portfolio.

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CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Generation	2	Level 1 & 2: • HOL has no visibility for DGs under 50 kW, is monitoring DGs between 50 and 250 kW, and has on/off control for DGs over 250 kW. Level 3: • Feeder lists with capacity constraints are published online. However, an interactive capacity map is not available. • No dispatch function is implemented yet.	2.5	Online connection process is being piloted. Online capacity availability and connection integration process is implemented for customer generation.	3	Level 3 HOL is piloting DERMS to control and dispatch functionality for customer generation. Note: HOL would like to pilot and test DERMs functionality.		

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Choice	2	Level 1 & 2 • There is a tiered and TOU rates selection available. Customers can purchase renewable energy from 3rd party retailers. Billing is still through HOL. Level 3: • The overnight TOU rate will be made available by OEB. • The EV incentive program is being piloted.	3	Regulatory changes are underway. Rate structures will be rolled out for EV charging, and/or demand response, energy storage.	3.5	Customer rate choices account for a diversity of customer needs and usage scenarios including greater participation in demand response, distributed generation and EV programs.		

CUST – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Customer Security and Privacy	2	Level 1 • Privacy is considered for all new programs based on the general protocol. Level 2 • Privacy requirements are a mandatory component of the OEB Cyber Security Framework and are integrated into cybersecurity processes and governance. HOL is currently not looking at smart grid-related cybersecurity standards. General risk control is deployed. Third-party applications are hosted on HOL systems such as Snowflake. Level 3 • All IP connected substations will have the visibility with cameras, PLCs, RTUs, etc.	2.5	The products and services offered to customers come with inherent security and privacy controls that adhere to both industry and government standards. Security and privacy controls will be achieved by including guidance and recommendations provided by the UCA International Users Group (UCAIug) Smart Grid Security Working Group and the NIST Smart Grid Interoperability Panel Cyber Security Working Group in the RFP to vendors.	5	HOL will be able to guarantee security and privacy for its core services as well as for integration with third-party systems and applications that interface with customer data. This is achieved by simplifying enrollment processes while simultaneously meeting security and privacy requirements. In addition, the security and privacy of all customer data that is stored, transmitted, or processed on the grid are ensured by providing compelling evidence such as design reviews, results from penetration tests, third-party certifications, certifications of secure coding training for programmers, code reviews, and third-party evaluations of security and privacy policies. HOL is already working progress with some of the aforementioned capabilities.		

Current State Assessment – Value Chain Integration

Note:

- "TBD" indicates more details will follow as part of the follow-up discussions with HOL.
- Some cells are intentionally left blank as long-term vision are not available yet for some subdomains.

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Energy Resource Portfolio Management	1	Level 1 HOL does not have a cohesive strategy in place for developing, enabling, and managing a diverse resource portfolio. Preliminary discussions are being held to enable DERs. Level 2 Some pilots have been conducted to support a diverse resource portfolio including EV Everywhere, small storage deployment, MiGen, and demand response. HOL is exploring a DSO role.	1.5	Given that pilots to support a diverse resource portfolio were begun recently, they are not expected to be completed by 2025. Pilots are ongoing. A strategy is developed for the Energy Resource Portfolio Management. Note: HOL would like to be in position of managing DERs as a corporate strategy.	2	HOL will have completed advanced pilots including exploring the DSO role. HOL has incorporated the management of DERs into the corporate strategy.	2.5	Depending on the outcome of the pilots, HOL may be utilizing the diverse resource portfolio to their organization’s benefit in terms of capacity needs, reliability.

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Distributed Generation	0.5	Level 1 HOL has visibility into DG (such as rooftop solar) for operational purposes, but this information is not used for value chain benefits assessment. There are aggregators within the territory with demand response auctions to IESO, where HOL has awareness, but HOL is more of a passive party. Level 2 A standardized business case to value DG has not been released by the OEB, however, consultations are ongoing which may result in one being released in the future. HOL has a strong interest to explore this further.	1	HOL has defined the type of DG and capacity threshold levels to monitor and have visibility on. This definition is based on a clear strategy that includes aspects of quantified benefits of the DG to the value chain.	1.5	Pending standardized business case to value DG being released by the OEB. HOL is beginning to integrate the quantified value of DG to inform planning decisions.		

[redacted]

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Energy Storage	**0.5**	Level 1 A preliminary document has been created to test various energy storage use cases with pilots, however, no detailed plans or implementation yet. HOL is in the early stages of working with Momentum on a pilot to leverage used EV batteries. HOL is expected to receive a decommissioned 45 kVA battery from an NRCan pilot and will test various use cases.	**1**	HOL has developed an understanding of the use cases for energy storage and models for integrating into HOL's value chain. HOL has developed a detailed plan to test the various use cases through pilots.	**2**	HOL is following the detailed plan to understand and manage the various energy storage use cases. Various pilots have been planned to be implemented.	**3**	HOL has multiple pilots completed for various use cases. A deep understanding of the value chain benefits has been achieved. Energy storage is being managed to provide these benefits.

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Demand and Load Management	0	Outreach to some vendors regarding potential technologies to provide demand and load management services, however, details on the use cases and a detailed implementation plan is missing. HOL does not have visibility into the aggregators and their locations that participate in the IESO capacity auction. HOL is engaged on a provincial level with IESO on CDM pilots, however, no communication strategy exists. DER control and communications procedures/method are pending development, it will be the focus in HOL's future state to enable demand and load management.	1	HOL has developed an understanding of the use cases and a detailed implementation plan for demand and load management has been created. This plan includes the assets that will provide demand and load management services, programs to participate in, control and communication requirements, value chain benefits for HOL, a timeline for implementation of programs.	2	HOL is following the detailed plan to understand and manage the various use cases. Various programs or pilots have been planned to be implemented.		

[redacted]

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Energy Management Services	1.5	Level 1 HOL is assessing NWA and other opportunities for energy management but hasn't assessed the opportunity for aggregated customer usage savings. Participant in the green button initiative. Level 2 Customer energy use information is not currently used for value chain purposes, no programs currently exist to reduce customer energy usage. A customer energy management roadmap at the strategy level exists, in addition to a digital strategy from the IT perspective.	1.5	No significant change expected. HOL has reviewed the customer energy management roadmap to align with the desired future state.	2	HOL has a clear understanding of the potential that customer energy management services can provide, including opportunity for aggregated customer usage savings. For commercial customers, customer energy use information is being used for value chain purposes.	3	HOL has enabled customer energy management solutions for commercial and ICI clients.

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
External Partnerships	1	Level 1 A portal has been developed to view EV charger data, and the control of the chargers through the API is working in progress. Confidentiality protocols are followed for EV projects, where customer information is redacted. HOL has deployed Snowflake which allows the hosting of third-party applications. All external party software is assessed with formalized standards before importing into HOL's cyber environment. Level 2 Information sharing with third parties is on an ad-hoc basis as there is no formal business plan. A business plan may exist on the unregulated side; Envari. Potential innovation opportunities are informally reviewed by the cybersecurity and key accounts team. A communication portal with the IESO	1.5	A formalized business plan and model has been developed for information sharing with third parties, with the purpose of identifying new and innovative opportunities that enable efficiency gains and generate new value streams.	2	Potential innovation opportunities are formally reviewed according to the processes identified in the formalized business plan. HOL has an increased frequency and resolution of information sharing with third parties.	3	HOL is routinely collaborating with third parties on a secure and tested platform to work on innovative businesses and value chain integration opportunities. The secure portals have ability to share information securely in near-real time.

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Value Chain Planning	1	Level 1 Business cases are introduced for some projects. Benefits not layered by IT and key account team; value chain benefits not optimized yet. Value chain exercise was completed with AMI 2.0 project through the 2021-2025 rate application, however, specific KPIs have not yet been developed. Level 2 A consistent procedure to identify new products and services does not exist yet across the corporation. The benefit-cost analysis is a mix of quantitative and qualitative impacts.	1.5	HOL has engaged multiple working groups across the organization, including the unregulated arms of HOL, to begin the development of a consistent value-chain oriented procedure to identify new products and services.	2.5	By 2026/2027, HOL has developed a formalized full value-chain model to identify new products and services and their benefits. The procedure caters to and includes inputs from groups across the organization.		

[redacted]

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Transportation Electrification	**1**	Level 1 HOL has limited visibility and data on the locations of EV chargers, only a 3-digit postal code of charges is available. HOL pilot partnering with Flo provides 24-hour visibility into the approximately 100 customers enrolled. A high-level forecast of EV adoption has been performed for system planning, however, it is not on a feeder level. HOL adheres to IESO regional planning. HOL plans to include EV adoption projections in the load forecast for the next rate applications. Level 2 HOL has access to location, status, and usage data for customers that are enrolled in the EV charging pilot only. This is not yet standardized for	**1**	By 2023, HOL has developed the EV strategy, summarizing all potential EV offerings.	**TBD**	The future state is dependent on the corporate strategy.		

VCI – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Contract Vehicles for Energy Resources	2	Level 1 Service level agreement exists for DERs. HOL identified that terms and conditions for storage connections need to be clearer. Information regarding DG connection applications on the external website is unclear, a near-term focus for HOL is to update the website. HOL actively partners with customers to develop the contracting vehicle for large customers. This is working in progress. Level 2 HOL has contract vehicles in place to accommodate DG for small and mid-size customers. Level 3: Exploring alternative contracting models is the next step for HOL	3	Alternative contract models ready to pilot with customer DG. These may include dispatch based on operational or market signals. HOL has revisited the design and information provided on external website regarding DG connection applications. Website updated to be clearer.	4	HOL is utilizing the DG contracts to optimize value-chain benefits in response to market signals.		

Current & Future State Assessment – Social and Environmental

Note:
- “TBD” indicates more details will follow as part of the follow-up discussions with HOL.
- Some cells are intentionally left blank as long-term vision are not available yet for some subdomains.

SE – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Social and Environmentally - driven Strategy	0.5	Level 1 • Currently, there is no organizational grid modernization strategy. The corporate strategy leverages some grid modernization visions and broad strategic directions such as net zero, sustainability organization designation, etc. • An ESG scorecard is coming in 2023. ESG is not considered by current initiatives yet.	1	HOL's grid modernization strategy will support societal and environmental objectives .	2	HOL is committed to achieve net zero by 2030.	3	Societal and environmental performance of grid modernization initiatives will be tracked and monitored towards HOL's net zero goals.

[redacted]

SE – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Social and Environmental Customer Engagement	1.5	Level 1 HOL is publicly promoting environmental benefits, including the introduction of HOL's green projects. However, the information is not standardized with limited details. There are discussions with commercial customers to support their ESG activities. Level 2 Environmental benefits are promoted to customers on an ad-hoc basis. The "Keeping Ottawa Connected" program will further formalize the communication and standardized the newsletters and will enable communication with customers on a routine basis. Environmental and societal benefits and costs are discussed with some customers in person and it has become increasingly regular.	2	By 2025, environmental benefits will be promoted routinely both internally and to customers.	3	HOL has already started on some capabilities on Level 3. HOL will provide tailored information on environmental and societal benefits and costs to segmented customers.		

SE – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Energy Efficiency and Conservation	2.5	Level 1 • Conservation, efficiency, and "green" programs are provincially driven and delivered. • There is a small conversation team that proactively engages customers and system operators for the green programs. Level 2 & 3 • In general, utility is following regulatory framework and enabling energy efficiency programs where available. • Enhanced measurement and verification (M&V) of energy and demand savings are being explored but pending resources.	2.5	Coordination with IESO is required to fulfill this capability. Not much change in regulatory framework is anticipated in 2 years.	3	With SCADA on/off signal from IESO, HOL will be able to provide enhanced measurement and verification od energy and demand saving programs to customers. Optimistically, DERMS will be implemented by 2030 and able to send automatic signal.	4	With more mature DERMS technology, real-time information will be leveraged to enhance conservation and demand management programs.

[redacted]

SE – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	**Description**	**Level**	**Description**	**Level**	**Description**	**Level**	**Description**
Critical Infrastructure & Resilience	**1**	Level 1 • HOL understands the importance in protecting critical infrastructure. The critical infrastructures are addressed with feeder design. • There are contingency plans based on operator's knowledge but no written procedures for critical infrastructures. • HOL plans to perform predictive analytics with EAM tools (planned next year, no detailed timeline yet). System optimization and new normal state is considered by operators but is not formalized in writing. Level 2 • HOL meets with customers for reliability targets and offers what customer requests, but there is no criticality evaluation (index) of the system yet. • The safety stock of certain equipment is part of the risk management, but there is no holistic high-level risk management plan, no resiliency metrics, only reliability metrics. Societal consequences are not analyzed. • There is no visibility on customer backup generators. HOL has to rely on customer calls during an event. • There is no formalized restoration plan based on the [redacted]	**1.5**	HOL will aim to achieve level 2 but admit that it would be a big leap. Some advancements towards level 2 will be made by 2025, such as an update of the list of critical infrastructure to be included.	**3**	By 2030, risk management and resilience strategy for critical infrastructure will be implemented across relevant departments. Standards , resilience metrics, and emergency response and restoration processes will be developed to enhance resiliency of the critical infrastructure.	**TBD**	Further discussion needed.

[redacted] HATCH

SE – Current & Future State Assessment

	Current State		Future State (Near-term 2025)		Future State (Mid-term 2030)		Future State (Long-term 2035)	
	Level	Description	Level	Description	Level	Description	Level	Description
Renewable Technologies	1	Level 1 • Enabling DERs is one of the corporate strategies. • No formal targets or forecasts for renewable energy integration or deployment have been established.	1	Not much advancement anticipated by 2025.	2.5	As HOL is committed to achieve net-zero by 2030, renewable energy forecasts and targets should be incorporated into a formal or semi-formal plan and strategy to deploy renewable technologies should be developed.		

Hydro Ottawa Grid Modernization Strategy

Prepared for Hydro Ottawa

Project Ref:
H-369154

Dec 12th, 2023

HydroOttawa

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Our manifesto

Objectives

01 Present Grid Modernization Strategy & Roadmap

02 Approve The Strategy & Roadmap

03 Align on Next Steps

Agenda

01 Project Overview (11:05 – 11:10)

02 Grid Modernization Strategy (11:10 – 11:20)

03 Roadmap (11:20 – 11:40)

04 Q & A (11:40 -12:00)

Project Overview

Strategy Development Workflow

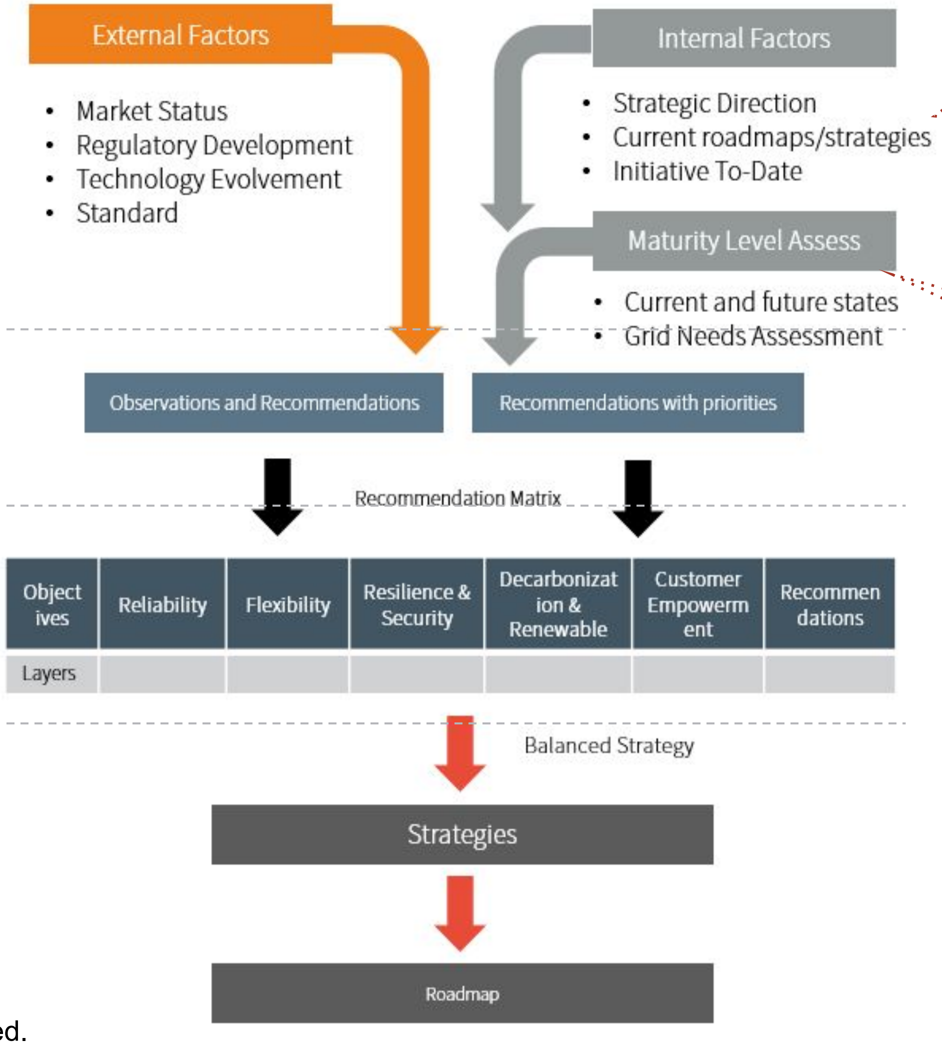
The flow of the strategy development is illustrated in the diagram below.

Step 1: Conduct Internal and External Review to Establish Strategic Context

Step 2: Provide recommendations based on the jurisdiction scan and maturity level assessment

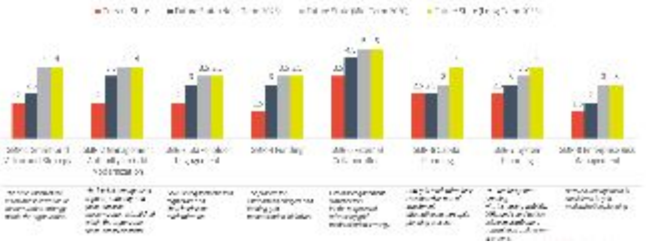
Step 3: Consolidate recommendations for each grid modernization component

Step 4: Develop Strategy for each component



Customer Experience Strategy

Telecommunication Master Plan



Maturity Level Assessment Result

Grid Modernization Strategy

Performance-Based Grid Modernization

[redacted]

Strategic Direction and Objectives

Strategic Direction

Grid Modernization Objectives

To support HOL's contributions to the corporation's 8-Point Strategy, five key objectives were defined as part of the grid modernization plan.

- **Enhanced Reliability**
- **Adaptive Grid Flexibility**
- **Fortified Resilience & Robust Security**
- **Strengthened Customer Engagement & Empowerment**
- **Sustainable Decarbonization & Renewable Integration**

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Grid Modernization Objectives

Enhanced Reliability

Improving the grid's reliability through advanced monitoring, proactive failure detection, fast fault detection, automated power quality control, automated system restoration, and reduced outage times

Adaptive Grid Flexibility

Enabling the grid to adapt to the changing energy demand and incorporate different energy generation sources

Fortified Resilience & Robust Security

Improving the grid's ability to withstand service disruptions due to system faults or climate events and safeguarding the grid's assets against cyber threats

Strengthened Customer Engagement & Empowerment

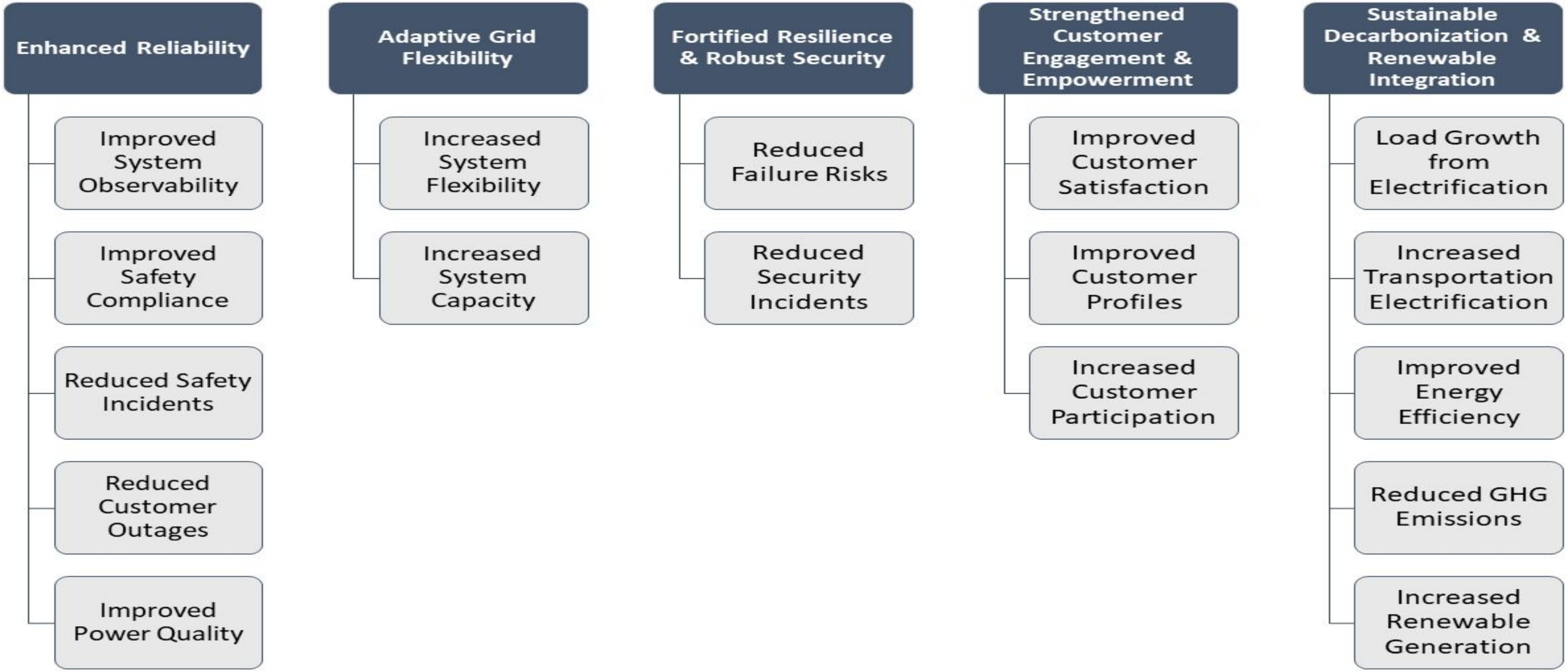
Engaging and empowering customers through real-time data, efficient billing, and tools to manage their energy use

Sustainable Decarbonization & Renewable Integration

Enabling carbon emissions reduction by optimizing planning and operations to support the integration of renewable energy sources into the grid and promote sustainability

Benefits

Grid Modernization initiatives offer utilities a wide range of benefits covering **operational, financial, and customer satisfaction** aspects. They enable utilities to adapt to **changing energy landscapes and regulation, enhance system resiliency, and prepare for future energy demands**. Below we have mapped out the benefit of grid modernization to each of the 5 key objectives outlined in The Strategy.



Strategy Components and Sub-Components

Components and Sub-Components

Physical Infrastructure
- DERs
- Electric Vehicle
- Vulnerable Distribution Assets

Sensing and Measurement
- AMI
- Sensors

Communication
- Communication Technologies and Protocols

Data Management and Analytics
- Data Management and Asset Management System
- Data analytics

Control and Optimization
- FLISR and VVO
- ADMS and DERMS

Business and Regulatory
- Market Drivers and Advancement
- Operation Structure and Processes
- Regulatory Policies
- Standards

Components & 8-Point Strategy Alignment

The different technologies, operational processes, and business processes covered by the six key components in the strategy aim to provide HOL with a structured implementation approach that ensures it can achieve its five key objectives while maintaining alignment with its 8-Point Strategy.

	HOHI's 8-Point Strategic Direction							
Grid Modernization Strategy Key Component	Achieve net zero operations by 2030	Become the partner of first choice for signature green energy and carbon reduction projects in our community	Accelerate digital transformation to enable sustainable business practices	Leverage and promote distributed energy resources	Continue to grow and diversify our revenue sources	Grow our social license to operate	Ensure organizational capacity, culture, and leadership to deliver in a post-pandemic environment	Continue to provide best-in-class customer service
Physical Infrastructure	✓	✓	✓	✓	✓	✓		✓
Sensing and Measurement	✓	✓	✓	✓				✓
Communication			✓	✓		✓		✓
Data Management Analytics	✓	✓	✓	✓	✓	✓		✓
Control and Optimization	✓	✓	✓	✓	✓	✓		✓
Business and Regulatory	✓	✓	✓	✓	✓	✓	✓	✓

Grid Modernization Roadmap

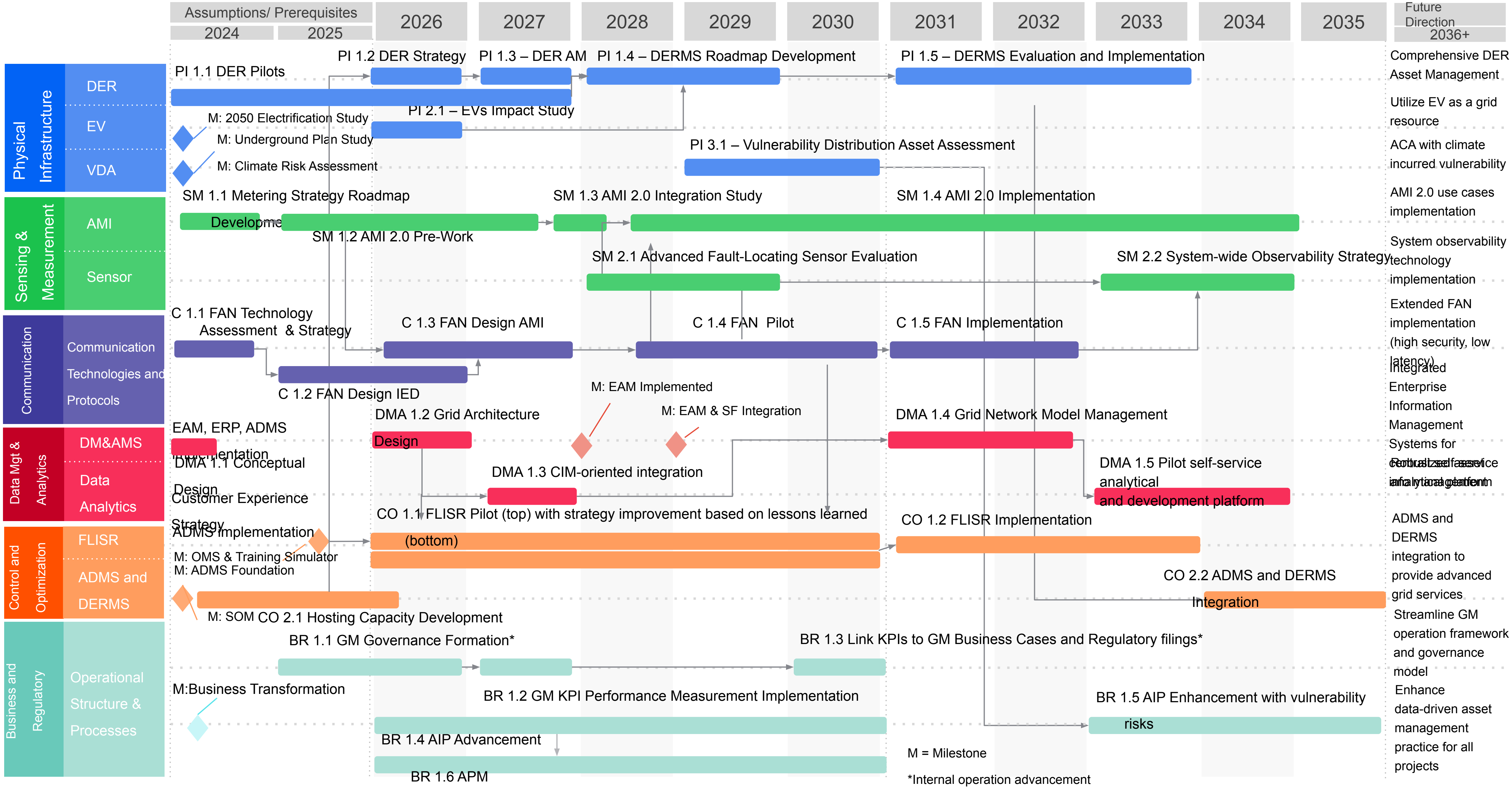
Grid Modernization Roadmap

The roadmap outlines the **initiatives** derived from the **Strategy** and provide a clear **plan** for their execution/implementation during the **three timeframes** identified:

1. *Short-term - to 2025*
2. *Medium-term - 2026 to 2030*
3. *Longer-term - 2031 to 2035.*

The roadmap is intended to be a **dynamic document**, evolving as HOL develops a better understanding of the overall grid modernization project and the threats and opportunities that will arise in the process.

The initiatives include both **technology** and **process improvement-oriented** activities. These initiatives are associated with either the **development or the change of a process or set of processes** that will help achieve the grid modernization objectives.


Assumptions/ Prerequisites
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Future Direction
2036+
Physical Infrastructure
DER
EV
VDA
Sensing & Measurement
AMI
Sensor
Communication
Communication Technologies and Protocols
Data Mgt & Analytics
DM&AMS
Data Analytics
Control and Optimization
FLISR
ADMS and DERMS
Business and Regulatory
Operational Structure & Processes
PI 1.1 DER Pilots
PI 1.2 DER Strategy
PI 1.3 – DER AM
PI 1.4 – DERMS Roadmap Development
PI 1.5 – DERMS Evaluation and Implementation
M: 2050 Electrification Study
PI 2.1 – EVs Impact Study
M: Underground Plan Study
M: Climate Risk Assessment
PI 3.1 – Vulnerability Distribution Asset Assessment
SM 1.1 Metering Strategy Roadmap Development
SM 1.2 AMI 2.0 Pre-Work
SM 1.3 AMI 2.0 Integration Study
SM 1.4 AMI 2.0 Implementation
SM 2.1 Advanced Fault-Locating Sensor Evaluation
SM 2.2 System-wide Observability Strategy
C 1.1 FAN Technology Assessment & Strategy
C 1.2 FAN Design IED
C 1.3 FAN Design AMI
C 1.4 FAN Pilot
C 1.5 FAN Implementation
EAM, ERP, ADMS Implementation
DMA 1.1 Conceptual Design
DMA 1.2 Grid Architecture Design
M: EAM Implemented
M: EAM & SF Integration
DMA 1.3 CIM-oriented integration
DMA 1.4 Grid Network Model Management
DMA 1.5 Pilot self-service analytical and development platform
Customer Experience Strategy
ADMS implementation
M: OMS & Training Simulator
M: ADMS Foundation
M: SOM
CO 1.1 FLISR Pilot (top) with strategy improvement based on lessons learned (bottom)
CO 1.2 FLISR Implementation
CO 2.1 Hosting Capacity Development
CO 2.2 ADMS and DERMS Integration
BR 1.1 GM Governance Formation*
BR 1.2 GM KPI Performance Measurement Implementation
BR 1.3 Link KPIs to GM Business Cases and Regulatory filings*
BR 1.4 AIP Advancement
BR 1.5 AIP Enhancement with vulnerability risks
BR 1.6 APM
M:Business Transformation
M = Milestone
*Internal operation advancement
Comprehensive DER Asset Management
Utilize EV as a grid resource
ACA with climate incurred vulnerability
AMI 2.0 use cases implementation
System observability technology implementation
Extended FAN implementation (high security, low latency)
Integrated Enterprise Information Management Systems for
ADMS and DERMS integration to provide advanced grid services
Streamline GM operation framework and governance model
Enhance data-driven asset management practice for all projects

Next Steps

Next Steps

- Agree on Initiatives to implement
  - AMI Strategy & Roadmap
  - KPI Development
  - DER Strategy & Roadmap
  - HCA Tool Development

Thank you!

For more information,
please visit www.hatch.com

DER Initiatives

Physical Infrastructure

PI 1.1 – DER Strategy Development

Description

Develop a cohesive DER strategy for HOL to prepare for increasing DER penetration.

The strategy will encompass a variety of DER use cases, such as:

- Premium power
- Backup power
- Peak shaving

The benefits of these use cases will be quantified against distribution system upgrades and the value of the deferral of other system investments, including upstream transmission and generation deferral if supported by the OEB.

The DER strategy will include, at minimum:

- Objectives and benefits
- High-level action plans
- Priorities
- Risk and mitigation plans
- Operational impacts and opportunities

HATCH

DER Initiatives

PI 1.2 – DER Asset Management

Dependencies: PI.1.1

Physical Infrastructure

Description

Develop a comprehensive tracking process and system(s) to collect, update, and access DER asset information, including reviewing and establishing DERs' data requirements.

This initiative will focus on physical DER asset management including:

- Information tracking
- Technology deployment for monitoring and control
- Remote control/disconnect for safety and reliability

Monitoring and control requirements will be clearly outlined, considering at minimum the type and capacity of the DER.

These requirements will follow OEB's codes and guidelines, with additional HOL system specific considerations regarding the benefits and costs of monitoring and controlling prospective DERs.

A DER asset management plan will be developed to guide performance tracking mechanisms, lifecycle management, future cost forecasting, resource planning, ownerships, and responsibilities.

DER Initiatives

PI 1.3 – DERMS Roadmap Development

Dependencies: PI 1.2 and PI 2.1

Physical Infrastructure

Description

Develop a DERMS roadmap, with clear timelines and milestones to further improve the integration and utilization of DERs.

The roadmap will support both management and dispatch of flexible DERs including:

- EVs
- Solar PV
- Energy storage
- Flexible residential/commercial load management

The DERMS use cases will be based on an evaluation of existing DER technologies within HOL's service territory, as well as other trending technologies in the industry.

As part of this initiative, existing and legacy systems will be reviewed for architecture design and technology gaps. A system integration plan will be established (i.e., DERMS integrated with ADMS and EAM).

Additionally, the initiative involves a review to determine whether a standalone HOL DERMS platform or a shared platform with other LDCs and/or the IESO would be optimal.

DER Initiatives

PI 1.4 – DERMS Evaluation and Implementation

Dependencies: PI 1.3

Physical Infrastructure

Description

DERMS will be evaluated against the specifications and criteria defined in the DERMS roadmap. The fundamental capabilities of a DERMS should include aggregating, coordinating, forecasting, and dispatching of DERs.

A pilot project will be conducted to test the DERMS' functionalities. The pilot areas will be selected based on factors such as:

- DER penetration levels
- DER types and aggregation methods within the area
- Feeder and bus loading condition
- System's hosting capacity studied from CO 2.1

Regulatory priorities and supporting programs, such as the IESO DER Roadmap and the OEB innovation sandbox, will be considered to ensure alignment between HOL and the regulators.

Lessons learned from the pilot project will be applied to the creation of a prioritization plan and business case for a global roll-out of a DERMS. Change management, risk management, and data management processes will be actively monitored, and the corresponding guidelines and standards will be followed.

EV Initiatives

PI 2.1 – EVs Impact Study

Physical Infrastructure

Description

Review and provide comprehensive insights into the impact of EVs on distribution assets and on the grid.

The current penetration and long-term forecast of electric vehicles will be studied at both the overall distribution system level and at more discrete levels, such as:

- Substation
- Feeder
- Local loops

With a periodic load forecast of EV chargers, the impact on grid capacity will be incorporated into system planning.

Given the various challenges that can accompany DER integration (i.e., equipment overloading, voltage and frequency violations, power quality issues, etc.), the impact of EV charging management and V2G technologies will also be studied.

Vulnerability Distribution Asset (VDA) Initiatives

PI 3.1 – Vulnerability Distribution Asset Assessment

Physical Infrastructure

Description

Incorporate an additional layer of vulnerabilities into existing asset condition assessments.

A Climate Adaptation and Vulnerability Assessment (CAVA) framework will be established to support:

- System planning
- Asset maintenance and management
- Integration of advanced technologies

Addressing climate-induced reliability risks, which will build on HOL's existing climate change adaptation plan.

The CAVA analysis will consider both probability and consequence of failure for each asset under various climate hazards and evaluate relevant prevention options and remedy procedures. The analysis will begin by identifying the scope of CAVA and determining each asset's sensitivity and associated vulnerability to various climate hazards within the scope. The impact of climate hazards by asset class will have a risk level assigned, along with associated adaptation and mitigation plans.
The risks identified through CAVA will be linked to enterprise risks and incorporated into the Asset Management risk procedure.

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Advanced Metering Infrastructure (AMI) Initiatives

SM 1.1– Metering Strategy Roadmap Development

Sensing & Measurement

Description

Develop a roadmap to implement a metering strategy highlighting key milestones and objectives.

The Metering system can enable two-way communication between customers and utilities. Data collected will provide valuable insight into customer behavior and energy consumption patterns, which can be leveraged to develop energy-saving recommendations. The roadmap will outline:

- Current state of the system
- Use cases
- Integration requirements
- Prioritization of projects

Timelines and detailed procedures need to be defined for the use cases of the Metering Strategy, including additional capabilities compared to AMI 1.0.

A phased plan will be established, clearly defining current and future state, opportunities, governance structure, and measurement metrics. The plan will encompass elements such as assets, business processes, and communication.

Advanced Metering Infrastructure (AMI) Initiatives

SM 1.2 – AMI 2.0 Integration Study

Dependencies: SM 1.1

Sensing & Measurement

Description

Analyze the benefits of leveraging AMI 2.0 capabilities in ADMS applications to enhance grid management.

AMI 2.0 integrated into ADMS, enables utilities to record the time and location of an outage, number of customers affected, outage duration, and the amount of power lost (kVA) with better accuracy, which helps identify the outage scale and area and aid outage restoration efforts.

Other benefits include faster fault detection and localization, voltage regulation, and potential avoidance of system failure.

Furthermore, by integrating AMI data with ADMS, HOL can accurately monitor real-time load profiles, detect peak demand, and implement automated load shedding and demand response programs.

AMI-ADMS integration goes beyond operational benefits. By leveraging AMI data, utilities can offer customers detailed energy usage information, enabling them to make informed decision regarding their energy consumption and manage their bills more effectively. It also facilitates quicker resolution of billing disputes, leading to a higher customer satisfaction.

Advanced Metering Infrastructure (AMI) Initiatives

SM 1.3 – AMI 2.0 Implementation

Sensing & Measurement

Dependencies: SM 1.2 and C 1.3

Description

Roll out the AMI 2.0 implementation, including both smart meter replacements and IT infrastructure upgrades.

A comprehensive rollout plan will be designed addressing:

- Infrastructure
- Processes
- People
- Data flow
- Change management

The communication network and IT infrastructure will be assessed for interoperability based on meter operational requirements.

During the planning phase, multiple technology partners that align with HOL's needs, priorities, and targets will be selected. Considerations will include technical capabilities, compatibility with HOL systems, desired features, and costs. Throughout the execution phase, a staged approach will be required for the implementation, enabling adequate technology validation, testing of data analytics functionalities, and staff training.

Sensors Initiatives

SM 2.1 – Advanced Fault-Locating Sensor Evaluation

Sensing & Measurement

Description

Document in-depth research of fault-locating technologies, evaluate their potential to enhance grid observability and controllability, and provide recommendations for implementation.

Local Field Devices and Integrated System Solution/Central Platform technologies will be assessed. Local Field Devices can work independently or semi-independently and do not require significant integration topology. Some examples include:

- Fault Circuit Indicators (FCIs)
- Powerline Sensors
- Line Differential Relays
- Conventional Impedance Relays
- High-Impedance Relays
- Line Relays
- Time Domain
- Reflectometers
- Cable Thumpers
- Smart Meters

The Integrated System Solution/Central Platform requires system integration and advanced network modeling. The Central Platform group includes FLISR, SCADA, advanced current-based and impedance-based algorithms, adaptive protection schemes, voltage-based methods, and artificial intelligence (AI) methods.

HATCH

Sensors Initiatives

SM 2.2 – System-Wide Observability Strategy

Dependencies: SM 2.1 and C 1.3

Sensing & Measurement

Description

Identify HOL's system observability goals and develop a strategy to achieve them.

Observability can be defined as the degree of visibility of the system from electrical, thermal, and physical perspectives.

Gathering real-time data about the state and behavior of the grid allows utilities to:

- Optimize system performance
- Monitor asset conditions
- Detect anomalies
- Respond effectively to failures

The desired level of observability for each feeder and station will be established based on characteristics such as load profile, DER capacity, and criticality. System analysis can determine the optimal number and placement of sensors.

Communication Technologies and Protocols

Communication

C 1.1 – FAN Design

Dependencies: SM 1.1

Description

Assess communication technologies to enhance the FAN capabilities and identify upgrade opportunities.

HOL needs to upgrade FAN design for seamless integration of AMI 2.0, DERMS, and SCADA applications.
- Real-time data
- Fast, reliable communication network with low energy consumption for data transmission.

A high-performing FAN design option for HOL to review is a hybrid topology that combines the benefits of dense mesh networking suitable for smart meter clusters and distribution automation zones with wide-area communication for remote locations with sparse device clusters.

The technologies need offer interoperability and scalability that ensure flexible deployment.

- Standardization efforts
- Technical capabilities
- Wide vendor support

Communication Technologies and Protocols

Communication

C 1.2 – FAN Pilot

Dependencies: C 1.1

Description

Pilot new FAN technologies and practices.

To ensure optimal operation of the FAN, HOL needs to

- Assess coverage needs
- Identify deployment areas
  - Strategically deploy base stations, gateways, and access points
  - Evaluate backhaul
  - Optimized device placement for efficient coverage, minimum interference, and maximum network performance
- Understand technical and operational constraints
- Define access mechanisms and interference management techniques
- Implementing cybersecurity measures
- Define KPIs to measure implementation success

Communication Technologies and Protocols Initiatives

Communication

C 1.3 – FAN Implementation

Dependencies: C 1.2

Description

Install new communication systems and upgrade the existing network infrastructures to fulfill new performance requirements.

Successful FAN implementation requirements

- Comprehensive evaluation of communication requirements for new devices to be installed
  - Field devices supporting various grid applications (i.e., Metering, EV, and ESS)
- Assessment of the existing infrastructure's capability to accommodate the above-mentioned requirements
  - Explore the possibility of leveraging the same communication networks
- Accurate determination of the data throughput necessary for reliable and efficient functionality across different grid applications.
  - Factor in DER and load growth projections
- Careful selection of communication protocols and backhaul medium
- Engage with vendors to validate the compatibility of current devices with proposed protocols and determine their capacity for upgrades to allow integration into the FAN.

DM and AMS Initiatives

DMA 1.1 – Grid Architecture Design

Data Management and Analytics

Description

Review and update the enterprise IT architecture to support grid modernization initiatives and plan the integration of core systems such as ADMS, EAM, GIS, and ERP.

- Data governance policy will be developed to address data gaps and ensure data quality and accuracy align with the updated design and user requirements.
- Enterprise semantic will be clearly defined, with explicit diagrams depicting the roles and functionalities of each application as well as their relationships.
- Address concerns related to cybersecurity, privacy, and performance.
- Cyber security functionalities will be integrated into the architecture to help regularly monitor risks and continuously improve the system in response to changes in the operational environment
    - Breach detection
    - Incident management
    - Remedy implementation plans

DM and AMS Initiatives

DMA 1.2 – CIM-Oriented Integration

Dependencies: DMA 1.1

Data Management and Analytics

Description

Create a CIM (Common Information Model)-oriented IT system integration plan

Systems such as EAM, AIP, ERP, GIS, and ADMS will be integrated to facilitate seamless data flow and enhance overall data analytic capabilities by following CIM. Data use cases and reporting requirements will be clearly documented and regularly updated to accommodate newly integrated applications

CIM schema, specifications, and metamodels will:

- Define the interrelation between different systems and provide a foundation for the grid network model implementation
- Define the integration syntax and expressions of existing and new new systems/applications

HATCH

DM and AMS Initiatives

DMA 1.3 – Grid Network Model Management

Dependencies: DMA 1.2

Data Management and Analytics

Description

Develop a grid network model tool to ensure the network model is up to date for ADMS applications and other simulation needs

- Review of HOL's existing grid model data management practices across all functional departments to identify gaps and misalignments.
- Establish a shared vision and understanding of an enterprise-level network model.
- Develop action plans to evaluate benefits and required efforts for sub-projects
- Develop a framework to categorize the sub-projects
  - Quick-Win Projects (high benefits and low efforts)
  - Nice-to-Have Projects (low benefits and low efforts)
  - Major Projects (high benefits and high efforts)
  - Low-Priority Projects (low benefits and high efforts)

DA Initiatives

DMA 1.4 – Pilot Self-Service Analytical Platform

Dependencies: DMA 1.3

Data Management and Analytics

Description

Implement a platform that provides self-serve analytical capabilities to engineers and planners.

The platform will:

- Be compatible with common data processing and programming environments
- Connect to all major systems such as AIP, EAM, ADMS, DERMS, and GIS
- Have access to asset information, historical operation and maintenance records, system loading, and reliability data for centralized analysis.
- Serve as an analysis and development environment for scenario planning, load forecasting, and complex grid operation simulations.
- Facilitate sandbox planning by providing access to cloned data from the integrated platforms

FLISR Initiatives

Control and Optimization

CO 1.1 – FLISR Pilot

Dependencies: DMA 1.1, SM 1.2

Description

Define the requirements and outline the plan for FLISR implementation

Implementing FLISR is a complex process that is usually executed in a phased approach

- Develop the business case and identify the functional requirements
- Target implementation to sites where improved performance would provide measurable returns
- Identify the pilot feeder for the proof of concept considering
    - Current feeder KPIs
    - Availability of capacity in the adjacent feeders
    - Existing devices and their condition
    - Existing protection philosophy
    - Availability of communication infrastructure
    - The operational criticality of the feeder
- Complete the upgrades for the FLISR operation
- Develop and implement a change management program
- Develop operating procedures and operator trainings

HATCH

FLISR Initiatives

Control and Optimization

CO 1.2 – FLISR Implementation

Dependencies: CO 1.1

Description

Complete implementation of the FLISR solution and integration of FLISR with ADMS and other systems.

It is recommended to deploy FLISR in phased approach

- PH1 - Manual mode: FLISR will detect faults. Operators will create the switch orders (SO) for isolation and load segmentation
- PH2- Semi-automatic mode: FLISR will detect faults and creates SO for isolation and load segmentation; operators will review and approve SO for execution
- PH3- Fully-automatic mode: FLISR will independently detect faults and create and execute SOs for fault isolation and load segmentation.

ADMS and DERMS Initiatives

CO 2.1 – Hosting Capacity Development

Control and Optimization

Description

Conduct the hosting capacity analysis at the feeder level and create an online GIS map with hosting capacity limitation information

- Developing a methodology for Hosting Capacity Analysis (HCA) is important for DER integration. HCA helps ensure short circuit capacity, thermal rating, voltage levels and power quality are within the operational limits .
- Data for conducting the HCA will be sourced from various systems such as GIS, SCADA, AMI and/or CIS.
- The quality and update frequency of the data coming from these systems must be assessed to ensure feasibility for the HCA
- GIS and online-mapping tools will also enable geospatial analysis to identify optimal locations for DER integration

ADMS and DERMS Initiatives

CO 2.2 – ADMS and DERMS Integration

Dependencies: PI 1.4

Control and Optimization

Description

Integrate ADMS and DERMS.

DERMS and ADMS need to be tightly integrated for holistic visibility, aggregation, forecasting, control, and optimization of the grid.
ADMS is designed to provide situational awareness and system-wide control capabilities. DERMS monitor, manage and dispatch DERs to provide different grid capacity services.

- DERMS have limited visibility that doesn't usually extend past the feeder level.
- DERMS relies on real-time data sent from ADMS, including grid conditions and constraints and DR signals to optimize DERs during DR events.
- ADMS needs DERMS aggregated data concerning DERs condition, output and available capacity for system optimization.
- Both systems need to work from the same network model and have seamless bidirectional data exchange to eliminate siloed operations.

Operational Structure and Processes Initiatives

BR 1.1 – Grid Modernization Governance Formation

Business & Regulatory

Description

Build a comprehensive governance model with assigned leadership and a consistent framework.

The model comprises:

- Performance targets
- Roles and responsibilities
- Integrated business cases among all initiatives
- Grid modernization-specific performance management

The Grid Modernization Steering Committee will oversee the portfolio of grid modernization initiatives to ensure objectives are being achieved within planned timelines and budgets.

The steering committee will ensure appropriate resourcing to allow for successful outcomes while providing guidance to overall priorities.

The GMSC will own the Grid Modernization Strategy and Roadmap.

Operational Structure and Processes Initiatives

BR 1.2 – Grid Modernization Performance Measurement Implementation

Dependencies: BR 1.1

Business & Regulatory

Description

Design and implement grid modernization oriented KPIs.

Examples of performance measurements to be considered are:

- System observability
- System controllability

KPIs will allow HOL to track the performance and benefits realized through the progress of grid modernization and prepare HOL for the potential to implement the Performance Based Regulation (PBR) framework.

PBR will allow HOL to receive compensation based on performance targets defined by Performance Incentive Mechanisms (PIM).

Additionally, this model will enable improved financial success, customer satisfaction, and foster trusting relationships among HOL, ratepayers, and regulators.

Operational Structure and Processes Initiatives

BR 1.3 – Link KPIs to GM Business Cases and Regulatory Filings

Dependencies: BR 1.2

Business & Regulatory

Description

Utilize GM performance measurements for business case development.

These KPIs will serve as targets to provide references for project progress and benefit quantification in the business case.

The KPIs can also be used for regulatory filling depending on the regulatory environment and executive decision.

The incorporation of KPIs into the regulatory filing can be done by embedding them into the existing corporate balance scorecard.

For instance, system observability can be a subcomponent of the reliability KPI in the balanced scorecard.

Consistent monitoring and reporting of progress toward the specified targets will be required.

Operational Structure and Processes Initiatives

BR 1.4 – AIP Advancement

Business & Regulatory

Description

Support the development of HOL's investment portfolio and long-term asset management strategy.

This initiative will identify functionalities and integration opportunities to be implemented in AIP, further enhancing the efficiency and effectiveness of the AIP procedure through implementation of data-driven asset management processes.

The predictive analytics module within AIP includes the quantification of risk and benefits, establishing the prioritization of higher-risk assets as the initial step for such AIP advancement.

Integration of more comprehensive historical asset maintenance data, asset failure, and condition information will be leveraged to further improve the accuracy of decision-making.

Automation of current and future health index calculations will be based on predictive analytics, which will be incorporated into the asset management decision-making process to inform maintenance and replacement investments.

HATCH

Operational Structure and Processes Initiatives

BR 1.5 – AIP Enhancement with Vulnerability Risks

Dependencies: PI 3.1

Business & Regulatory

Description

Incorporate the outcomes from the Vulnerability Distribution Asset Assessment (PI 3.1) into AIP for decision making.

AIP's value framework is currently established based on asset condition assessment results (i.e., Heath Indices). Through integration of the vulnerability assessment outcomes, the value framework will expand from conventional health indices to include assets' climate-related risks.

For instance, the conventional health index calculation of an overhead transformer only accounts for asset age, physical condition, and electrical performance.

This initiative will overlay operation condition risks such as tree proximity during high winds and snowstorms, enabling AIP to take both asset conditions and climate-incurred risks into account for project prioritization at the asset level.

This could be achieved by utilizing and refining HOL's existing location exposure input for each asset.

Hydro Ottawa KPI Metrics Presentation

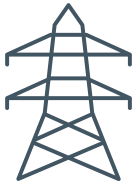

July 25, 2024

Prepared for Hydro Ottawa

Safety Share

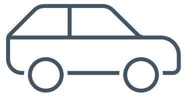
Staying safe on rainy days

Make sure to bring rain jackets/umbrellas/ponchos and PPE to avoid getting drenched



Avoid working on exposed electrical equipment if possible. Be aware of any exposed wires.

Be prepared for slips by looking out for puddles, mud, and slippery surfaces. Try to bring rain boots or slip-resistant shoes.



Drive to work with caution by driving slowly and patiently. Ensure windshield wipers work and remember to begin braking earlier.

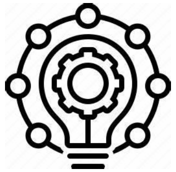
HATCH

Table of Contents

Introduction

Project Objectives:

Develop a tool to measure HOL's grid modernization progress and track Goals/Milestones via a set of focused KPIs.



Outcome:

The following 8 KPIs below were each identified with calculation methodologies that will serve as a valuable tool to effectively monitor and evaluate the performance and impact of the grid modernization initiatives

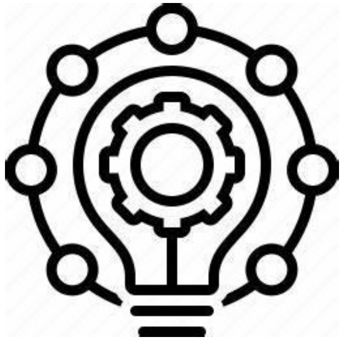
1. System Observability	2. System Controllability	3. Improved Grid Accuracy	4. Feeder Loading	5. Station Loading	6.Load Constraint Mgmt.	7. DER Visibility/Management	8. DER Hosting Capacity

The tool further benefits by aiding future EDR filing for funding application and business case.

HATCH

Dashboard

The dashboard helps quickly visualizes and displays the results of the 8 KPIs. It is an interactive, user friendly, and easily maintainable tool. Furthermore, it welcomes user input and calculates/outputs data almost immediately. The legend below indicates the type of values in each cell throughout the workbook so users can edit/maintain the sheet to their liking.



Legend	Description
Input	Update current data with manual input. Frequent update needed.
Target	Adjust target with manual input. Update as needed.
Calculation	Cell will automatically update with pre-defined formula. No input required.
Linked Cell	Cell is linked to Dashboard input (seen in other sheets) or Cells on the dashboard linked to a cell from another sheet (no calculations done on it).
System Information	System information such as station name, feeder name, voltages etc.
Red text	Placeholder numbers

Overview

Definition: To measure the capability to monitor the grid for situational awareness, enable better system planning, operation control, and optimize investment decision-making.

Scope

- Feeder: FCI, AMI 2.0 Meters, Scada-mate switches
- Station: Digital Relays, RTUs, PQ Meters, Physical Security (Cameras)

Objectives

- Situational awareness for system planning and operation control.

Source Data

a. Feeder IED.xlsx
b. OH Switches.xlsx and UG_switches_2024-04-22.xlsx
c. Station Relays.xlsx
d. 5-Year Outage and WPF Record.xlsx

Target

- Target Data.xlsx provided by HOL

Outcome measured

A. Number of devices installed
B. Performance of devices (temporarily turned off due to data availability)
C. Intended benefit materialization

[redacted]

Calculation Method – feeder observability

The proposed metrics calculation is A * B * C, [redacted]

FCI Program as an example

A = Each feeder requires 100 units of FCI
B = FCI uptime/data availability (i.e., 96% data, calculate by hr.)
C = FCI data is used for grid operation monitoring (and fault locating), maintenance planning, and/or capital planning.

Intended Benefit Level	Benefit (Examples)
1	Data used for asset condition and grid operation monitoring
2	Data used for maintenance planning
3	Data used for capital planning
4	Data used for control and operation
5	Data used for investment and strategic decision making

Station	Feeder	Voltage (k	FPI Condit	FCIs Weight	FCIs Quantity – Number of FCIs pe	FCIs Quantity- Target New Installatio	FCIs Quantity- Ta	FCIs Quantity – Percentage A	FCIs Performance (i.e., uptime, data av	FCIs Target Perform	FCIs – Achieved benef	FCIs – Target benefi	FCI Observabil
Parkwood Hills DS	190F4	44/8.32	Fair	50%	10	2	12	83%	92%	100%	2	3	56%
Parkwood Hills DS	190F5	44/8.32	Poor	50%	3	2	5	60%	90%	100%	2	3	40%
Nepean TS	22M23	230/44	Very Good	50%	5	5	10	50%	98%	100%	2	3	33%
Nepean TS	22M24	230/44	Very Good	50%	10	10	20	50%	98%	100%	2	3	33%
Nepean TS	22M25	230/44	Very Good	50%	2	3	5	40%	93%	100%	2	3	27%
Nepean TS	22M26	230/44	Fair	50%	5	8	13	38%	90%	100%	2	3	26%
Nepean TS	22M27	230/44	Poor	50%	4	5	9	44%	100%	100%	2	3	30%
Nepean TS	22M28	230/44	Very Good	50%	7	7	14	50%	96%	100%	2	3	33%
Orleans MS	325M8	115/27.6	Poor	50%	378	7	385	98%	97%	100%	2	3	65%

A1: Installed units per feeder

A2: Planned units per feeder

A3: New Total units per feeder (A1 + A2)

A1/A3 x 100%

B1: Actual FCI performance per feeder

B2: Target performance per feeder

C1: Benefit Achieved

C2: Target Benefit

A1/A2 x B1/B2 x C1/C2 x 100%

Calculation Method – station observability

The proposed metrics calculation is A * B * C, [redacted]

Digital Relay Program as an example

A = Planned station requires 100% of digital relays
B = digital relay uptime/data availability (i.e., 96% data, calculate by hr.)
C = digital relay data is used for grid operation monitoring (and fault locating), maintenance planning, and/or capital planning.

Intended Benefit Level	Benefit (Examples)
1	Data used for asset condition and grid operation monitoring
2	Data used for maintenance planning
3	Data used for capital planning
4	Data used for control and operation
5	Data used for investment and strategic decision making

Station	Voltage (k	Digital Re	Digital Relays Quantity - # of Electromechanic	Digital Relays Quantity - # of Digit	Total Relays	% of Digital Rel	Target Digital Relay	Target Achieved	Digital Relays - Performance (i.e., uptime, data availabilit	Digital Relays - Target Performan	Digital Relays - Achieved benefit le	Digital Relays - Target benefit le	Digital Relays C
Albion TA	230/13.2	100%	76	1	77	1.3%	100.0%	1.3%	98%	100%	1	2	1%
Albion UA	13.2/4.16	100%	27	0	27	0.0%	100.0%	0.0%	90%	100%	1	2	0%
Augusta UD	13.2/4.16	100%	33	0	33	0.0%		100.0%	100%	100%	1	2	50%
Bantree AL	13.2/4.16	100%	39	0	39	0.0%		100.0%	95%	100%	1	2	50%
Barrhaven DS	44/8.32	100%	0	7	7	100.0%		100.0%	99%	100%	1	2	50%
Bayshore DS	44/8.32	100%	12	2	14	14.3%		100.0%	91%	100%	1	2	50%
Bayswater UJ	13.2/4.16	100%	0	14	14	100.0%		100.0%	94%	100%	1	2	50%
Beaconhill MS	44/8.32	100%	0	12	12	100.0%		100.0%	95%	100%	1	2	50%
Beaverbrook MS	44/12.42	100%	0	7	7	100.0%		100.0%	98%	100%	1	2	50%
Beechwood UB	13.2/4.16	100%	0	11	11	100.0%		100.0%	94%	100%	1	2	50%
Bells Corner DS	44/8.32	100%	0	9	9	100.0%		100.0%	93%	100%	1	2	50%
Bilberry TS	115/27.6	100%	4	0	4	0.0%		100.0%	97%	100%	1	2	50%
Blackburn MS	44/8.32	100%	0	9	9	100.0%		100.0%	90%	100%	1	2	50%
Borden Farm DS	44/8.32	100%	0	12	12	100.0%		100.0%	100%	100%	1	2	50%
Bridlewood MS 28kV	115/27.6	100%	0	7	7	100.0%		100.0%	91%	100%	1	2	50%

A1: Installed digital relays per station

A2: Total relays per station

A1/A2 x 100%

A3: Planned Station Digital Relays

B1: Actual relay performance per station

B2: Target performance per station

C1: Benefit Achieved

C2: Target Benefit

A1/A2 x B1/B2 x C1/C2 x 100%

HATCH

Excel Dashboard for Observability

The Observability Dashboard is separated by feeder and station and displays the results for different programs and overall observability individually.

1.a Observability - Feeder

*Targets are embedded in the calculation under tab "Feeder Observability". Targets include: planned installation quantity of the devices for each program (FCI, AMI 2.0, and Scadamate Switches), performances, and benefits

Assign weights for each program

Turn on/off performance and/or benefit layer

	Weights	Target Benefit	Current Benefit	Performance Layer On? (On = 1, Off = 0)	Benefit Layer On? (On = 1, Off = 0)
User Input: FCI	50%	3	2	0	1
User Input: AMI 2.0	0%	3	1	0	1
User Input: Scadamate switches (for monitoring purposes)	50%	3	1	0	1

Note: Feeder Observability = IED Sensor Observability * IED Sensor Weight + AMI 2.0 Observability * AMI 2.0 Weight + Scadamate Switches Observability * Scadamate Switches Weight

Year	Overall Observability	FCI Observability	AMI 2.0 Observability	Scadamate Switches (for monitoring purposes) Observability
2024	45%	65%	7%	26%
2025	38%	53%	7%	23%
2026	38%	53%	7%	23%
2027	38%	53%	7%	23%
2028	38%	53%	7%	23%
2029	38%	53%	7%	23%
2030	38%	53%	7%	23%

Results Overview

*Currently using placeholder numbers where data unavailable

1.b Observability - Station

*Targets are embedded in the calculation under tab "Station Observability". Targets include: planned installation quantity of the devices for each program (Digital Relay, RTUs, PQ Meters, and Physical Security Monitoring), performances, and benefits.

	Weights	Target Benefit	Current Benefit	Performance Layer On? (On = 1, Off = 0)	Benefit Layer On? (On = 1, Off = 0)
User Input: Digital Relay Weight	100%	2	1	0	1
User Input: RTU Weight	0%	3	2	0	1
User Input: PQ Meter Weight	0%	1	1	0	1
User Input: Physical Security Monitoring	0%	1	1	0	1

Note: Station Observability = Digital Relay Observability * Digital Relay Weight + RTU Observability * RTU Weight + PQ Meter Observability * PQ Meter Weight + Physical Security Observability * Physical Security Weight

Year	Overall Observability	Digital Relay Observability	RTU Observability	PQ Meter Observability	Physical Security Monitoring Observability
2024	46%	46%	37%	14%	62%
2025	46%	46%	0%	0%	0%
2026	46%	46%	0%	0%	0%
2027	46%	46%	0%	0%	0%
2028	46%	46%	0%	0%	0%
2029	46%	46%	0%	0%	0%
2030	46%	46%	0%	0%	0%

*Currently using placeholder numbers where data unavailable

[redacted]

Overview

Definition: To measure the capability to remotely control the grid for security, safety and reliability performance.

Scope

- Feeder level: tie switch, loop switch and sectionalizer.

Objectives

- Higher automation level enables more flexible control for better security, safety and reliability.

Source Data:

a. OH Switches.xlsx and UG_switches_2024-04-22.xlsx

b. Cust Count per Feeder.xlsx

c. 5-Year Outage and WPF Record.xlsx

Target

- Target Data.xlsx provided by HOL

Outcome Measured

A. Number of switches to be automated for remote control

B. Intended performance (*for this calculation all switches were considered 100% working*)

C. Intended benefit – Productivity Measurement (i.e., Truck rolls, labour costs and outage duration)

[redacted]

Calculation Method

The proposed metrics calculation is A * B, [redacted]

[redacted]

Tie Switch Automation as an example

A = Install and automate X Tie Switches/year

B = Tie Switches are all working as expected (i.e., 100%)

Criteria 2: Total # of sensors > 2 AND Total # of sensors > average number of customer/feeder

Criteria 1: Total # of sensors > 2.5

Year	Region	Station	Feeder	Voltage (kV)	Switches	Sectionalizer	Total # of Switche	Criteria 1	Meet Criteri	Criteria 2	Meet Criteri	Performance	Target
2024	Central	Carling TM	301	13.2	0	0	0	2.5	Fail	0.069230769	Fail	98%	100%
2024	Central	Carling TM	302	13.2	0	0	0	2.5	Fail	0.003076923	Fail	98%	100%
2024	Central	Carling TM	303	13.2	0	0	0	2.5	Fail	0.689230769	Fail	98%	100%
2024	Central	Carling TM	304	13.2	0	0	0	2.5	Fail	0.010769231	Fail	98%	100%
2024	Central	Carling TM	305	13.2	0	0	0	2.5	Fail	0.003076923	Fail	98%	100%
2024	Central	Carling TM	306	13.2	0	0	0	2.5	Fail	0.006153846	Fail	98%	100%
2024	Central	Carling TM	307	13.2	0	0	0	2.5	Fail	2.390769231	Fail	98%	100%
2024	Central	Carling TM	308	13.2	0	0	0	2.5	Fail	0.001538462	Fail	98%	100%
2024	Central	Carling TM	309	13.2	0	0	0	2.5	Fail	0.901538462	Fail	98%	100%

A: Total switches per Feeder

B1: Actual performance per station

B2: Target performance per station

Calculation Method

The proposed metrics calculation is based on outage duration * % outage duration reduction * costs

C: Benefit: Improved performance – Productivity/Outage Duration Reduction

Benefit		
S = A* B* C		
Metric	*Description*	*Value*
A	Average Outage Duration (Hours)	6.43
B	% Outage duration reduction	15%
C	Costs (Truck + 2 Crews) - $/hr	$ 220.00
S	Savings	$ 212.19

Based on average outage duration (2019-2023) = 386 Minutes

Based on Microsoft PowerPoint - DA Cost Effectiveness WTC.ppt (ieee.org)

Considered each crew member = $89 and truck = $42

Outage Duration Reduction

Outage Restoration Steps	Without Remote Controlability (SW)		With Remote Controlability (SW)	
Customer Reports Outage/Crew Dispatched	5	10	2	5
Crew Travel Time	20	30	20	30
Find the Fault	15	25	5	10
Manual Switching	10	15	0	0
Fault Repair	60	300	60	300
Total Outage Time	**110**	**380**	**87**	**345**
% Time Savings			**21%**	**9%**

Excel Dashboard for Controllability

The controllability Dashboard is separated by voltage level and display the results for Criteria 1 and Criteria 2 separately.

2.a-1 Controllability - Feeder

Criteria 1 (Each feeder shall have at least 2.5 switches)

Criteria 1

Assign Criteria 1

User Input: Minimum number of switches per feeder - system wide: 2.5

Note: Feeder Controllability = Tie Switch + Sectionalizer

[redacted]

Feeder Controllability - 44kV	Metric	Improvement	Target	[redacted]
2024	Pass Count			6
* Testing data is 2023 data	Pass Percentage			38%
2025	Pass Count	4	10	10
	Pass Percentage		63%	63%
2026	Pass Count	0	10	10
	Pass Percentage		63%	63%
2027	Pass Count	0	10	10
	Pass Percentage		63%	63%
2028	Pass Count	0	10	10
	Pass Percentage		63%	63%
2029	Pass Count	0	10	10
	Pass Percentage		63%	63%
2030	Pass Count	0	10	10
	Pass Percentage		63%	63%

Results Overview

2.a-2 Controllability - Feeder

Criteria 2 (Every 650 customers should have 1 switch)

Criteria 2

Note: Criteria 1 is a prerequisite of Criteria 2

Voltage level

Target

[redacted]

Feeder Controllability - 44kV	Metric	Improvement	Target	Business-as-usual Scenario
2024	Pass Count			0
* Testing data is 2023 data	Pass Percentage			0%
2025	Pass Count	2	2	2
	Pass Percentage		13%	13%
2026	Pass Count	0	2	2
	Pass Percentage		13%	13%
2027	Pass Count	0	2	2
	Pass Percentage		13%	13%
2028	Pass Count	0	2	2
	Pass Percentage		13%	13%
2029	Pass Count	0	2	2
	Pass Percentage		13%	13%
2030	Pass Count	0	2	2
	Pass Percentage		13%	13%

Overview

Definition: To measure the clean up process of the grid network model and the simulation progress of feeder-level hosting capacity.

Scope

- Feeder-level errors and simulations

Objectives

- An accurate grid model will help improve simulations, ADMS implementation, etc.

Source Data

a. CYME Error Reports - May 2024.xlsx

Target

- Target Data.xlsx provided by HOL

Outcome Measured

A. Low priority warnings in CYME
B. High priority warnings in CYME
C. Errors in CYME
D. Feeders with hosting capacity simulated

[redacted]

Calculation Method

This metric tracks the number of low priority warnings, high priority warnings, and errors in CYME, as well as the number of feeders with hosting capacity simulated.

Number of Low Priority Warnings from CYME for each feeder

Number of High Priority Warnings from CYME for each feeder

Number of Errors from CYME for each feeder

If the feeder has been simulated to calculate hosting capacity

Year	Area	Station	Voltage (kV)	Feeder	Number of Low Priority Warning:	Number of High Priority Warning	Number of Errors	Hosting Capacity Simulate
2024	Central	Carling TM	115/13.2	301	1	3	1	N
2024	Central	Carling TM	115/13.2	302	1	2	1	N
2024	Central	Carling TM	115/13.2	303	20	3	1	N
2024	Central	Carling TM	115/13.2	304	0	2	1	N
2024	Central	Carling TM	115/13.2	305	0	2	1	N
2024	Central	Carling TM	115/13.2	306	25	2	1	N
2024	Central	Carling TM	115/13.2	307	3	4	1	N
2024	Central	Carling TM	115/13.2	308	0	2	1	N
2024	Central	Carling TM	115/13.2	309	0	2	1	N
2024	Central	King Edward TK	115/13.2	401	1	2	1	N
2024	Central	King Edward TK	115/13.2	402	0	2	1	N
2024	Central	King Edward TK	115/13.2	403	22	3	1	N
2024	Central	King Edward TK	115/13.2	404	3	3	1	N
2024	Central	King Edward TK	115/13.2	405	0	0	0	N

Excel Dashboard for Improved Grid Model Accuracy

The Improved Grid Model Accuracy Dashboard tracks number of total system warnings/errors from CYME (upper figure), as well as the number of feeders with simulated hosting capacity (bottom figure) each year.

Total # of Low Priority warnings after target improvement is achieved

Target

Total # of Low Priority warnings retrieved from CYME

% of treated/resolved warnings based on improvement achieved and existing # of warnings

Target Number Low Priority Warnings	Actual Number of Low Priority Warnings	Target Number of High Priority Warnings	Actual Number of High Priority Warnings	Target Number of Errors	Actual Number of Errors
	5592		1504		565
5592	5592	1504	1504	0	565
0	0	0	0	565	0
0%		0%		0%	
5592	5592	0	1504		
0	0	1504	0		
0%		0%			
2796	5592				
2796	0				
0%					
2796	5592				
2796	0				
0%					

# of Low Priority warnings to be treated/resolved (improvement)

Total # of errors treated/resolved based on the difference between 2025 count and 2024 count

Year	Target Number of feeders with Hosting Capacity Simulated	Actual Number of feeders with Hosting Capacity Simulated
2024		0
2025	141	0
2025 Improvements	141	0
2025 KPI	0%	
2026	141	0
2026 Improvements	141	0
2026 KPI	0%	
2027	141	0
2027 Improvements	141	0
2027 KPI	0%	
2028	141	0
2028 Improvements	141	0
2028 KPI	0%	
2029	141	0
2029 Improvements	141	0
2029 KPI	0%	
2030	142	0
2030 Improvements	142	0
2030 KPI	0%	

[redacted]

Excel Dashboard for Improved Grid Model Accuracy

The Overall KPI column tracks the ***progress*** of system errors/warnings treated/resolved each year based on targets defined for each category.

Year	Overall KPI
2024	
2025	
2025 Improvements	
2025 KPI	0%
2026	
2026 Improvements	
2026 KPI	0%
2027	
2027 Improvements	
2027 KPI	0%
2028	
2028 Improvements	
2028 KPI	0%

Overview

Definition: To measure loading at the feeder level for optimal grid operation and planning.

Scope

- All feeders

Objectives

- Improve visibility on system loading, avoid system overloading and bottleneck, and aid system planning.

Source Data

- Feeder List.xlsx

Load Index Threshold Selection:

- Based on current percentage loading distribution (see next page)

Outcome Measured

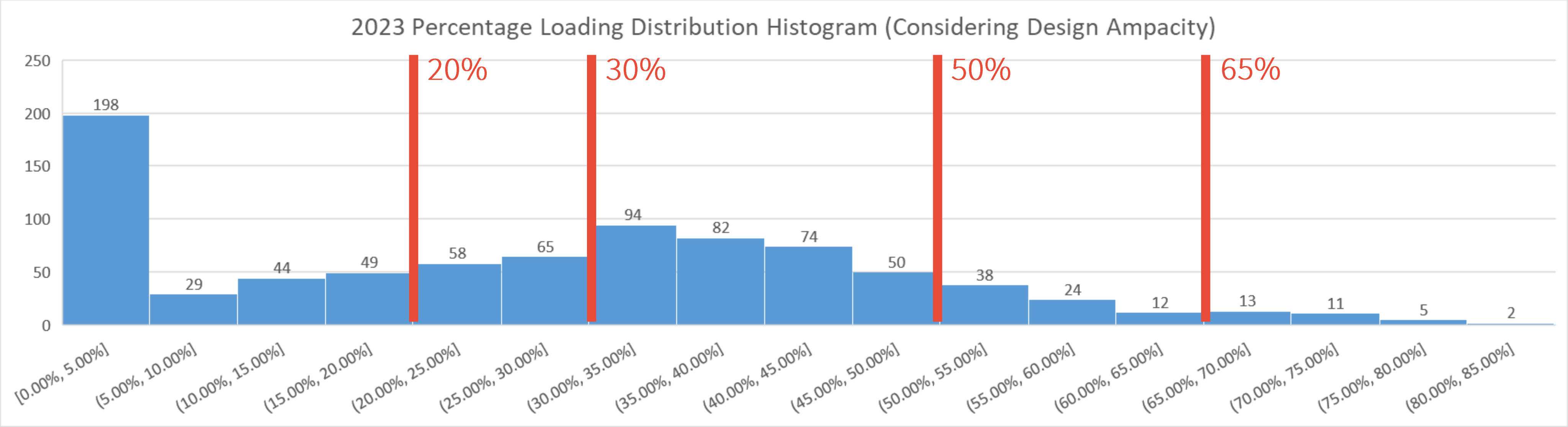
System-wide Feeder Load Index Distribution

[redacted]

Load Index	Percentage Loading
5	65% +
4	50% - 65%
3	30% - 50%
2	20% - 30%
1	0 – 20%

Load Index Threshold Selection

The main data to be collected under the proposed method are the **2023 Revised Load (AVERAGE Amps)**and **Design Ampacity**.



Calculation Method

The calculation is based on the **2023 Revised Load (Average amps) and Design Ampacity.**

2023 Revised Load (Average Amps)/Design Ampacity

Respec	Area	Station	Voltage (k	Feeder	Design Ampacity	Planned Ampacity	2023 Revised Load (AVERAGE Amps)	% Loading (Consider Design Ampacity)	Load Index
2024	Central	Carling TM	115/13.2	301	425	255	169	40%	3
2024	Central	Carling TM	115/13.2	302	425	255	32	8%	1
2024	Central	Carling TM	115/13.2	303	425	255	138	32%	3
2024	Central	Carling TM	115/13.2	304	425	255	81	19%	1
2024	Central	Carling TM	115/13.2	305	425	255	142	33%	3
2024	Central	Carling TM	115/13.2	306	425	255	216	51%	3
2024	Central	Carling TM	115/13.2	307	425	255	239	56%	4
2024	Central	Carling TM	115/13.2	308	425	255	0	0%	1
2024	Central	Carling TM	115/13.2	309	425	255	138	32%	3
2024	Central	King Edward TK	115/13.2	401	425	255	0	0%	1
2024	Central	King Edward TK	115/13.2	402	425	255	138	32%	3
2024	Central	King Edward TK	115/13.2	403	425	255	0	0%	1
2024	Central	King Edward TK	115/13.2	404	425	255	117	28%	2
2024	Central	King Edward TK	115/13.2	405	425	255	0	0%	1
2024	Central	King Edward TK	115/13.2	406	425	255	205	48%	3
2024	Central	King Edward TK	115/13.2	407	425	255	205	48%	3
2024	Central	King Edward TK	115/13.2	408	425	255	164	39%	3
2024	Central	King Edward TK	115/13.2	409	425	255	163	38%	3
2024	Central	King Edward TK	115/13.2	410	425	255	164	39%	3

Based on Feeder load index threshold

Excel Dashboard for Feeder Load Index

The Feeder Load Index Dashboard depicts # of feeders that are approaching the designed load capacity.

Load Index	Calculated Percentage Loading Lower Bound
5	65%
4	55%
3	30%
2	20%
1	0%

Load Index thresholds can be updated as needed

Results Overview

Planned improvements

Feeder Load Index		Feeder Count (Actual)	Feeder Improved (Actual)	Feeder Improved (Planned)	Target # of Feeders
Baseline - 2024 *Testing data is 2023 data	5	31			
	4	36			
	3	338			
	2	123			
	1	319			
2025 *Placeholder Numbers	5	31	0	-2	29
	4	36	0	-1	35
	3	338	0	0	338
	2	123	0	1	124
	1	319	0	2	321
2026 *Placeholder Numbers	5	31		-2	
	4	36		-1	
	3	338		0	
	2	123		1	
	1	319		2	
2027 *Placeholder Numbers	5	31		-2	
	4	36	0	-1	35
	3	338	0	0	338
	2	123	0	1	124
	1	319	0	2	321
2028 *Placeholder Numbers	5	31	0	-2	29
	4	36	0	-1	35
	3	338	0	0	338
	2	123	0	1	124
	1	319	0	2	321
2029 *Placeholder Numbers	5	31	0	-2	29
	4	36	0	-1	35
	3	338	0	0	338
	2	123	0	1	124
	1	319	0	2	321
2030 *Placeholder Numbers	5	31	0	3	34
	4	36	0	4	40
	3	338	0	5	343
	2	123	0	6	129
	1	319	0	7	326

Difference between 2024 and 2025

Sum of actual & improved

Overview

Definition: To measure loading at the Station and Bus level for optimal grid operation and planning.

Scope

- Station & Bus loading

Objectives

- Improve visibility on system loading, avoid system overloading and bottleneck, and aid system planning.

Source Data

- Station List Loading.xlsx
- Breaker and Capacity_Bus.xlsx

Load Index Threshold Selection:

- Based on current percentage loading distribution (see next page)

Outcome Measured

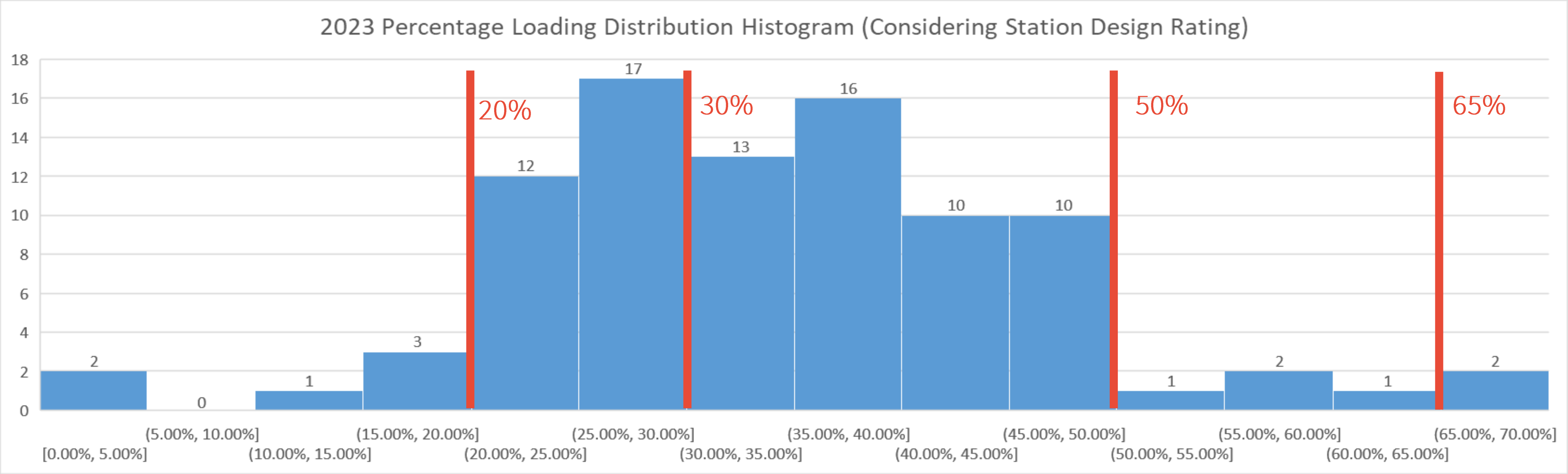
System-wide Station Load Index distribution

[redacted]

Load Index	Percentage Loading
5	65% +
4	50% - 65%
3	30% - 50%
2	20% - 30%
1	0 – 20%

Load Index Threshold Selection

Load distribution profile based on the **SUM of 2023 loading MVA** and **Station Design Rating MVA.**



Calculation Method

The calculation is based on the **SUM of 2023 loading MVA and Station Design Rating MVA. The results consider two different scenarios: 1 – Only the load index; 2 – Load index taking into consideration number of breaker position left.**

Sum of Loading/Station Design Rating

Target at station level is a sum of all targets at a bus level on that station

Station Information										
General Information				Based on 2023 data		Station (bus-level) Load Index Calculation: Breaker Position			% Loading Approach	
Area	Station	BUS	Station Design Rating (MVA)	SUM of Loading (MVA)	% Loading	Target # of breakers	Number of existing connected breakers	Breaker positions left	Load Index (based on loading only)	Load Index (include breaker position)
East	ALBION TA		196	59.2	30%	12	28	-16	3	3
East	ALBION TA	Albion TA-Y				3	7	-4		
East	ALBION TA	Albion TA-Q				3	7	-4		
East	ALBION TA	Albion TA-B				3	7	-4		
East	ALBION TA	Albion TA-J				3	7	-4		
East	ALBION UA		26	6.9	27%	15	9	6	2	2
East	ALBION UA	Albion UA-X1				3	2	1		
East	ALBION UA	Albion UA-X2				3	3	0		
East	ALBION UA	Albion UA-X3				3	2	1		
East	ALBION UA	Albion UA-K1				3	1	2		
East	ALBION UA	Albion UA-K2				3	1	2		

If a station is at level 4 and there is no breaker position left, it will be escalated to level 5

Target at the bus level is based on average # of existing breaker positions.

Excel Dashboard for Station Load Index

The Station Load Index Dashboard depicts # of stations that are approaching the designed load capacity.

5. Loading Index - Station

Load Index thresholds

Load Index	Calculated Percentage Loading
5	65%
4	50%
3	30%
2	20%
1	0%

User Input to decide which results to use

User Input: Include Breaker/Feeder position Consideration?	Yes

Results Overview

Planned improvements

Station Load Index		Station Count (Actual)	Station Improved (Actual)	Station Improved (Planned)	Target # of Station
Baseline - 2024 *Testing data is 2023	5	3			
	4	3			
	3	49			
	2	29			
	1	5			
2025 *Placeholder Numbers	5	3	0	-3	0
	4	3	0	0	3
	3	49	0	3	52
	2	29	[illegible]	0	[illegible]
	1	5	[illegible]	0	[illegible]
2026 *Placeholder Numbers	5	3	[illegible]	-2	[illegible]
	4	3	[illegible]	0	[illegible]
	3	49	[illegible]	2	[illegible]
	2	29	[illegible]	0	[illegible]
	1	5	[illegible]	0	[illegible]
2027 *Placeholder Numbers	5	3	0	0	3
	4	3	0	0	3
	3	49	0	0	49
	2	29	0	0	29
	1	5	0	0	5
2028 *Placeholder Numbers	5	3	0	0	3
	4	3	0	0	3
	3	49	0	-3	46
	2	29	0	3	32
	1	5	0	0	5
2029 *Placeholder Numbers	5	3	0	0	3
	4	3	0	0	3
	3	49	0	-3	46
	2	29	0	3	32
	1	5	0	0	5
2030 *Placeholder Numbers	5	3	0	0	3
	4	3	0	0	3
	3	49	0	-3	46
	2	29	0	3	32
	1	5	0	0	5

Difference between 2024 and 2025

Sum of actual & improved

Overview

Definition: To measure conductors, cables, and distribution transformers loading for optimal grid operation and planning.

Scope

- Primary conductors, Primary cables and Distribution transformers

Objectives

- Improve visibility on system loading, avoid system overloading and bottleneck, and aid system planning.

Source Data

- No data was provided, numbers are placeholders

Load Index Threshold Selection:

- Based on Feeder Load Index

Outcome Measured

System-wide Load Index distribution

Performance Metric calculation

[redacted]

Load Index	Percentage Loading
5	65% +
4	50% - 65%
3	30% - 50%
2	20% - 30%
1	0 – 20%

Calculation Method

These numbers are for **illustration purpose only.**

Insert cable identification

Calculation will be updated automatically.
Based on 2023 load / designed ampacity

Year	Area	Cable	Designed Ampacity	Planned Ampacity	2023 Load (AVERAGE)	% Loading 2023	Classification
2024	Central	ID	100	80	60	60%	4
2024	Central	ID	100	80	65	65%	4
2024	South	ID	100	80	82	82%	5
2024	East	ID	100	80	91	91%	5
2024	West	ID	100	80	96	96%	5
2024	West	ID	100	80	60	60%	4

Classification based on Feeder Load Index Threshold

Year	Area	D-Transformer	Designed Capacity (	Planned Capacity (KVA)	2023 Load (AVERAGE KVA)	% Loading 2023	Load Index
2024	Central	ID	100	80	65	65%	4
2024	South	ID	100	80	82	82%	5
2024	East	ID	100	80	20	20%	1
2024	West	ID	100	80	40	40%	3
2024	South	ID	100	80	22	22%	2

Excel Dashboard for Load Constraint Management

The Load Constraint Management Dashboard depicts # of cable, conductors and D-Transformers that are approaching the designed load capacity.

6. Loading Constraint Management - D-Transformer

Load Index thresholds

Classification	Percentage Loading
5	65%
4	55%
3	30%
2	20%
1	0%

Results Overview

Planned improvements

Loading Constraint - D-Transformer		Count (Actual)	Improved (Actual)	Improved (Planned)	Target
Baseline - 2024 *Placeholder Numbers	5	1			
	4	1			
	3	1			
	2	1			
	1	1			
2025 *Placeholder Numbers	5	1	0	-1	0
	4	0	1	-1	0
	3	2	1	3	4
	2	0	1	1	2
	1	2	1	2	3
2026 *Placeholder Numbers	5	2	1	-1	0
	4	0	0	0	0
	3	1	1	3	5
	2	0	0	1	1
	1	2	0	2	4
2027 *Placeholder Numbers	5	2	0	-1	1
	4	1	1	0	0
	3	2	1	3	4
	2	0	[illegible]	1	[illegible]
	1	0	[illegible]	2	[illegible]
2028 *Placeholder Numbers	5	0	[illegible]	-1	[illegible]
	4	0	[illegible]	-1	[illegible]
	3	2	[illegible]	3	[illegible]
	2	2	[illegible]	1	[illegible]
	1	1	1	2	2
2029 *Placeholder Numbers	5	1	1	0	0
	4	1	1	0	0
	3	3	1	3	5
	2	0	2	1	3
	1	0	1	2	3
2030 *Placeholder Numbers	5	1	0	-1	0
	4	2	1	-1	0
	3	1	2	3	6
	2	0	0	1	1
	1	1	1	2	2

Difference between 2024 and 2025

Sum of actual & improved

Overview

Definition: To measure HOL's monitoring capability of DERs connected to the grid.

Scope

- All types of DGs (including synchronous generator, induction generators, and inverter-based).
- Batteries should be included in the DER list. Demand Response is excluded since it's a separate program.

Objectives

- Track HOL's monitoring capability of DERs larger than 10 kW

Source Data

- DER connection process & application forms | Hydro Ottawa
- DER - Feeder Short Circuit Capacity & DG Info.xlsx
- EOY 2023 Gen Data.xlsx
- NM GEN data - 2023_R1.xlsx

Outcome measured

A. For DERs larger than 10 kW (Non-Microgeneration), the monitoring capability of DERs, including:
   1. MCB CLASSIC
   2. MCB LITE - MONITORING ONLY
   3. MCB LITE - WITH CONTROL

[redacted]

Year	Area	Station	Voltage (k	Feeder	Total Number of DERs Interconnected	Total kW Interconnected	Number of Microgenerations	Percentage of Microgenerations	Number of non-Microgeneration DERs	Number of DERs with monitoring capability by HOL	Percentage of Non-Microgeneration DERs with monitoring capability by HOL
2024	Central	Carling TM	115/13.2	301	1	100	0	0%	1	0	0%
2024	Central	Carling TM	115/13.2	302	0	0	0	0%	0	0	N/A
2024	Central	Carling TM	115/13.2	303	1	3	1	100%	0	0	N/A
2024	Central	Carling TM	115/13.2	304	0	0	0	0%	0	0	N/A
2024	Central	Carling TM	115/13.2	305	0	0	0	0%	0	0	N/A
2024	Central	Carling TM	115/13.2	306	1	633	0	0%	1	0	0%
2024	Central	Carling TM	115/13.2	307	3	30	0	0%	3	0	0%

Excel Dashboard for DER Visibility

The DER Visibility Dashboard tracks percentage of non-microgeneration DERs that can be monitored by HOL.

Results Overview

Input targets for each year

How much progress has HOL met out of the target (e.g. 5%) set for the year (e.g. 2025)

7a. DER Visibility

Year	Overall DER Visibility	Target DER Visibility	Target Achieved
2024	3.23%		
2025	4%	5%	88%
2026	7%	20%	34%
2027	1%	40%	2%
2028	2%	60%	3%
2029	9%	80%	11%
2030	5%	100%	5%

[redacted]

Overview

Definition: To measure HOL's control capability of DERs connected to the grid.

Scope

- All types of DGs (including synchronous generator, induction generators, and inverter-based).
- Batteries should be included in the DER list. Demand Response is excluded since it's a separate program.

Objectives

- Track HOL's control capability of DERs larger than 10 kW

Source Data

- DER connection process & application forms | Hydro Ottawa
- DER - Feeder Short Circuit Capacity & DG Info.xlsx
- EOY 2023 Gen Data.xlsx
- NM GEN data - 2023_R1.xlsx

Outcome measured

A. For DERs larger than 10 kW (Non-Microgeneration), the control capability of DERs, including:
   1. MCB LITE - WITH CONTROL
   2. TRANSFER TRIP PANEL

[redacted]

Year	Area	Station	Voltage (I	Feeder	Total Number of DERs Interconnected	Total kW Interconnected	Number of Microgenerations	Percentage of Microgenerations	Number of non-Microgeneration DERs	Number of DERs with MCB Lite Control	Overall DER Management - MCB Lite Control	Percentage of Non-Microgeneration DERs with MCB Lite Control	Number of DERs with Transfer Trip Control	Overall DER Management - Transfer Trip Control	Percentage of Non-Microgeneration DERs with Transfer Trip Control
2024	Central	Carling TM	115/13.2	301	1	100	0	0%	1	0	0.15%	0%	0	2.05%	0%
2024	Central	Carling TM	115/13.2	302	0	0	0	0%	0	0	0.15%	N/A	0	2.05%	N/A
2024	Central	Carling TM	115/13.2	303	1	3	1	100%	0	0	0.15%	N/A	0	2.05%	N/A
2024	Central	Carling TM	115/13.2	304	0	0	0	0%	0	0	0.15%	N/A	0	2.05%	N/A
2024	Central	Carling TM	115/13.2	305	0	0	0	0%	0	0	0.15%	N/A	0	2.05%	N/A
2024	Central	Carling TM	115/13.2	306	1	633	0	0%	1	0	0.15%	0%	0	2.05%	0%
2024	Central	Carling TM	115/13.2	307	3	30	0	0%	3	0	0.15%	0%	0	2.05%	0%

Excel Dashboard for DER Management

The DER Visibility Dashboard tracks percentage of non-microgeneration DERs that can be controlled by HOL. The control mechanisms are separated by MCB Lite Control and Transfer Trip Control.

How much progress has HOL met out of the target (e.g., 5%) set for the year (e.g., 2025)

Results Overview | Input targets for each year | Results Overview | Input targets for each year

Year	Overall DER Management - MCB Lite Control	Target DER Management - MCB Lite Control	Target Achieved - MCB Lite Control	Overall DER Management - Transfer Trip Control	Target DER Management - Transfer Trip Control	Target Achieved - Transfer Trip Control
2024	0.15%			2.05%		
2025	9%	5%	185%	9%	5%	185%
2026	2%	20%	11%	2%	20%	11%
2027	5%	40%	11%	5%	40%	11%
2028	2%	60%	3%	2%	60%	3%
2029	16%	80%	20%	16%	80%	20%
2030	16%	100%	16%	16%	100%	16%

[redacted]

HATCH

Overview

Definition: To measure HOL's capability to host additional DERs.

Scope

- Feeders

Objectives

- Current scopes uses HOL's existing restricted feeder list. Once the hosting capacity for each feeder is simulated, the simulated hosting capacity should be referred to identify restricted feeders.

Source Data

- DER connection process & application forms | Hydro Ottawa
- Remaining capacity from DER - Feeder Short Circuit Capacity & DG Info.xlsx

Once hosting capacity is simulated, the simulated hosting capacity should be used.

Outcome measured

A. Number of feeders that are restricted from connecting new DERs due to limited hosting capacity

Performance metric calculation for feeders

Year	Area	Station	Voltage (k	Feeder	Hosting Capacity [kW]	Is feeder restricted by hosting capacity
2024	Central	Carling TM	115/13.2	301	69.88	N
2024	Central	Carling TM	115/13.2	302	69.98	N
2024	Central	Carling TM	115/13.2	303	60.18	N
2024	Central	Carling TM	115/13.2	304	69.98	N
2024	Central	Carling TM	115/13.2	305	60.19	N
2024	Central	Carling TM	115/13.2	306	60.19	N
2024	Central	Carling TM	115/13.2	307	69.95	N
2024	Central	Carling TM	115/13.2	308	60.19	N
2024	Central	Carling TM	115/13.2	309	60.19	N
2024	Central	King Edward TK	115/13.2	401	92.39	N
2024	Central	King Edward TK	115/13.2	402	101.23	N
2024	Central	King Edward TK	115/13.2	403	92.39	N
2024	Central	King Edward TK	115/13.2	404	92.38	N
2024	Central	King Edward TK	115/13.2	405	101.23	N

Excel Dashboard for DER Hosting Capacity

The DER Hosting Capacity Dashboard tracks number of feeders that are restricted by DER hosting capacity.

Results Overview

Year	Number of Restricted Feeders
2024	55
2025	24
2026	408
2027	103
2028	170
2029	183
2030	64

[redacted]

Thank you.

For more information,
please visit www.hatch.com

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.16

EVIDENCE REFERENCE:

1-SEC-11
1-Staff-8
Schedule 1-3-1, Table 3 & 4

UNDERTAKING(S):

Provide revenue requirement on a per initiative basis

RESPONSE(S):

For greater clarity, this undertaking is to provide the per initiative capital related revenue requirement for productivity initiatives that balance to Table 4 in Schedule 1-3-1 - Rate Setting Framework. Table 4 should be updated for the correction as submitted as part of 1-SEC-24 as updated September 22, 2025. In addition, to also include an Updated Table B from interrogatory response 1-Staff-8.

Undertaking JT3.16 requested the detailed supporting calculations of the capital-related revenue requirement as a result of the $23.6M capital expenditures in 2021-2025 as provided in Table A of the Updated response to interrogatory 1-SEC-24.

Please note that for the purpose of the revenue requirement calculation for capital additions, the same methodology as 1-Staff-8 was used which assumed additions timing matched capital expenditure years. The Payments in Lieu of Taxes (PILs) impact was based on a change in return only. As noted in Schedule 1-3-1 - Rate Setting Framework property tax was not considered. Attachment JT3.16(A) - Capital Related Revenue Requirement serves to complete both JT3.16 and JT3.17.

Table A below provides the requested update to Table 4 from Schedule 1-3-1 - Rate Setting Framework.

Table A – 2026-2030 Capital Related Revenue Requirement Savings ($'000s) from Schedule 1-3-1 - Rate Setting Framework

	2026-2030			
	Required	Proposed	Stretch $	Average Stretch %
Capital Related Revenue Requirement	$1,024,842	$1,015,114	($9,728)	-0.95%

Table B below is an update to Table B from interrogatory response 1-Staff-8 as requested.

Table B - Capital Related Revenue Requirement from 1-Staff-8

Capital Related Revenue Requirement				
Year	Required Revenue Requirement	Proposed Revenue Requirement	Stretch	Stretch
	$000	$000	$000	%
2026	$163,925	$163,112	($813)	-0.50%
2027	$181,185	$179,837	($1,348)	-0.74%
2028	$210,024	$207,881	($2,143)	-1.02%
2029	$226,826	$224,292	($2,535)	-1.12%
2030	$242,882	$239,993	($2,889)	-1.19%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.17

EVIDENCE REFERENCE:

1-SEC-24

UNDERTAKING(S):

Provide capital-related revenue-requirement impact of savings over five-year period along with supporting calculations

---

RESPONSE(S):

Please see Attachment JT3.16(A) - Capital Related Revenue Requirement for the detailed supporting calculations of the capital-related revenue requirement as a result of the $23.6M capital expenditures in 2021-2025 as presented in Table A of Updated response to interrogatory 1-SEC-24.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT3.21

EVIDENCE REFERENCE:

9.0-VECC-72

UNDERTAKING(S):

Provide forecasted compared to actual by month.

RESPONSE(S):

For clarity, the undertaking was to provide the Large Load electrification transition by month that is embedded into the Load Forecast.

Please see response to undertaking JT1.14-VECC-6.0 part 6.2.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT3.24

EVIDENCE REFERENCE:

3.1-BOMA-8

UNDERTAKING(S):

Show impacts on highest peaks of the year with assumptions considered

---

RESPONSE(S):

At the current customer count[1], assuming 10% of Residential customers implemented the 10kW solar and battery storage equates to 34,495 homes having solar installed. As of June 30, 2025 Hydro Ottawa has 571 Residential customers with solar installed under the net-metering program. Assuming 10% of Residential customers install DERs would require exponential growth and does not take into consideration the number of residential customers whose residence would not allow for solar installation, for example a premise in a multi-unit building, or homes where the roof has heavy shading or an unfavorable orientation. Furthermore, the new eDSM program introduced by the IESO (Home Renovations Saving Program or HRSP) allows for solar PV rebates for residential customers with the requirement that the solar panels are installed for load displacement purposes only. The program prevents the participant from entering into a net-metering agreement or any other compensation agreement for electricity that is generated and injected into the grid by the solar system.

[1] June 2025 month end count

As requested, the impact on summer and winter peak with the assumption of having 10% of Residential customers with 10 kW solar installed has been detailed in Table A below. The summer and winter system peak values are the MW without embedded generation amounts reported as part of annual RRRs 2.1.5.5. As noted in 3.1-BOMA-3, Hydro Ottawa does not track system peak by rate class. Residential MWh at the system peak hour(s) has been derived from the hourly class level analysis completed for Cost Allocation Demand Profiles, and does not reflect the top coincident peak (1CP) value or top non-coincident peak (1NCP) value used for Cost Allocation purposes.

The MWh impact has been based on a sample set of Residential net-metering customers with 10kW solar installed and completing analysis on the hourly load trend of these customers before and after the solar installation. The solar generation average at 3 p.m, 4 p.m. and 5 p.m. in the summer and 4 p.m, 5 p.m, 6 p.m and 7 p.m in the winter is used as a proxy to model residential solar's impact on the system peak since the peak has historically varied across those hours.

A reduction in kWh was observed in all customers in the summer months sampled (June, July, and August). In contrast, in the winter months (January, February, and December) kWh increased for all customers after the solar was installed. Hydro Ottawa is not able to confirm the exact cause for the increase in winter surge but the increase may be due to customers simultaneously installing electric source heating, such as heat pumps, or installed level 2 chargers alongside their new solar installation. For the purpose of the requested analysis, Hydro Ottawa has assumed the hypothetical solar customers have the same summer and winter trend after installing the generation as the sample set.

Table A - Estimate Residential Solar Installation Impact on 2024 System Peak

System Peak	Total MWh	Residential MWh (at system peak)	Number of Residential Load Customers	kWh Per Load Customer	Solar kWh Impact	kWh Per Solar Customer	Solar Customers	Adjusted Res MWH	MWh Change	Impact on System MWh
	A	B	C	D = B/C	E	F= D x (1+E)	G	H=(C-G) x D + (G x F)	J = H - B	K = J / A
Summer	1,515	688	338,537	2.03	(67)%	0.67	34,495	640	(47)	(3.11)%
Winter	1,165	452	342,255	1.32	22%	1.61	34,495	462	10	0.85%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA & ONTARIO ENERGY BOARD STAFF

JT3.27

EVIDENCE REFERENCE:

Schedule 9-1-3 Tables 12-14

UNDERTAKING(S):

Put on record details supportive of the disposition request

RESPONSE(S):

As noted in Table AO of interrogatory response 1-Staff-1, Hydro Ottawa is seeking disposition of Group 2 DVAs for a total amount of $(4,604k). Per Attachment 1-Staff-1(C) - OEB Workform Deferral and Variance Account (Continuity Schedule), principal balances of $(3,806k) are up to December 31, 2024 and interest is forecasted to December 31, 2025 of $(799k).

Table A shows the balances added to the proposed Group 2 DVA Dispositions. The 2023 values are from column BO, BS, and BT in Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account (Continuity Schedule). The revised total disposition amount ties to the total claim (column BT) from Attachment 1-Staff-1(C) - OEB Workform Deferral and Variance Account (Continuity Schedule).

Please see Schedule 9-1-3 - Group 2 Accounts and Schedule 9-1-4 - Account 1592 PILS and Tax Variance for more detailed descriptions of each 2 Account.

1 **Table A - 2024 Additions to Group 2 DVA Dispositions[1]**

Group	USofA Number	Group 2 Deferral/Variance Account Description	2023 Amount (Principal & Interest) ($)	2023 Principal ($)	Interest on 2023 principal ($)	2024 Principal ($)	Interest adjustments in 2024 ($)	Revised Total Disposition Amount ($)
			A	B	C	D	E	F = A + D + E
2	1508	Pole Attachment Revenue Variance	$ 802,348	$ 697,316	$ 105,032	-	$ (3,401)	$ 798,947
2	1508	GOCA Variance Account	$ 802,545	$ 737,748	$ 64,797	$ 270,780	$ 4,938	$ 1,078,263
2	1508	Gains and Loss on disposal of Fixed Assets Variance Account	$ (1,185,023)	$ (1,042,505)	$ (142,518)	$ (203,344)	$ (31,295)	$ (1,419,661)
2	1508	Earnings Sharing Mechanism (ESM) Variance Account	$ (1,355,491)	$ (1,151,693)	$ (203,797)	-	$ 5,616	$ (1,349,874)
2	1508	Connection Cost Recovery Agreement (CCRA) Payments Differential Variance Account	$ (611,206)	$ (566,398)	$ (44,807)	$ (543,226)	$ (14,362)	$ (1,168,794)
2	1508	Efficiency Adjustment Mechanism (EAM) Deferral Account	$ (343,296)	$ (300,816)	$ (42,480)	-	$ 1,467	$ (341,829)
2	1508	OEB Cost Assessment Variance	$ 553,119	$ 486,987	$ 66,132	-	$ (2,375)	$ 550,744
2	1508	RCVA Retail Incremental Revenue	$ 54,037	$ 46,028	$ 8,009	-	$ (224)	$ 53,813
2	1508	STR Incremental Revenue	$ 1,721	$ 1,467	$ 254	-	$ (7)	$ 1,714

[1] Totals may not sum due to rounding.

Group	USofA Number	Group 2 Deferral/Variance Account Description	2023 Amount (Principal & Interest) ($)	2023 Principal ($)	Interest on 2023 principal ($)	2024 Principal ($)	Interest adjustments in 2024 ($)	Revised Total Disposition Amount ($)
2	1508	Performance Outcomes Account Mechanism (POAM) Deferral Account	$ (890,453)	$ (800,000)	$ (90,453)	$ (200,000)	$ (2,403)	$ (1,092,856)
2	1508	Capital Variance Account	$ (619,989)	$ (552,268)	$ (67,721)	$ 518,955	$ 19,052	$ (81,982)
		Sub-Total of 1508 Sub-Accounts	**$ (2,791,686)**	**$ (2,444,135)**	**$ (347,552)**	**$ (156,835)**	**$ (22,993)**	**$ (2,971,515)**
2	1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	$ (208,445)	-	$ (208,445)	-	$ (21,068)	$ (229,512)
2	1592	PILs and Tax Variance - Sub-Account Capital Cost Allowance (CCA) Changes	$ (925,668)	$ (814,810)	$ (110,857)	$ 194,424	$ 10,020	$ (721,224)
		Group 2 Sub-total (Prior to Lost Revenue Adjustment Mechanism (LRAM)	**$ (3,925,799)**	**$ (3,258,945)**	**$ (666,854)**	**$ 37,589**	**$ (34,041)**	**$ (3,922,251)**
2	1568	LRAM Variance Account (LRAMVA)	$ (684,996)	$ (584,266)	$ (100,730)	$ -	$ 2,833	$ (682,163)
	TOTAL DVA BALANCE (Group 2) TO BE MOVED TO 1595 (2026)		**$ (4,610,795)**	**$ (3,843,211)**	**$ (767,584)**	**$ 37,589**	**$ (31,208)**	**$ (4,604,414)**

1

The below provides an update to Group 2 accounts with the exception of:

- 1568 Lost Revenue Adjustment Mechanism (LRAM) Variance Account (for details on this Account, please see Schedule 9-1-5 - LRAM Variance Account); and
- 1508 Sub-Accounts that are now closed.

1508 Sub-Account - GOCA Variance Account

The OEB-approved amount embedded in rates for the period April 2023 to December 31, 2025 is \$5,770k and actual costs incurred for the same period is \$6,778.9k; therefore \$1,008.5k of claim (principal) has been recorded into this sub-account.

Please see Table B for the balance in the GOCA as of December 31, 2024.

Table B - GOCA Variance Account - 2024[2]

	Historical Year
	2024
OEB approved amount for the period April 2023 - December 2024	$ 5,770,356
Actual cost for the period April 2023 - December 2024	$ 6,778,884
Sub Account GOCA - Principal balance	**$ 1,008,528**
Interest, including portion projected to December 31, 2025	$ 69,735
TOTAL BALANCE	**$ 1,078,263**

1508 Sub-Account - Gains and Loss on disposal of Fixed Assets Variance Account

The OEB-approved loss for 2024 was \$336k and actual loss was \$132k; therefore \$203k credit has been recorded into this sub-account. The total principal balance as at December 31, 2024 is \$1,245.8k.

[2] Totals may not sum due to rounding.

Please see Table C for the 2020-2024 amounts embedded in rates versus the actual gains/loss incurred over the same period.

Table C - 2020 to 2024 Loss from Retirement of Utility and Other Property ($'000s)[3]

	Historical Years				
	2020	2021	2022	2023	2024
USofA 4362 OEB-Approved (gain)/loss	$ (198)	$ 389	$ 751	$ 323	$ 336
USofA 4362 Actual (gain)/loss	$ 87	$ (202)	$ 1,234	$ (897)	$ 132
USOFA 1508 VARIANCE (PRINCIPLE)	**$ 285**	**$ (590)**	**$ 483**	**$ (1,220)**	**$ (203)**

1508 Sub-Account - POAM

In 2024 Hydro Ottawa recorded a credit of $200k into this account as wood pole replacement POAM metric (#4) was not met.

Account 1592 - PILS and Tax Variance

In 2024 Hydro Ottawa recorded a debit of $195k to record the impact of the 2021 immediate expensing for the 2021-2024 period. Refer to Table 2 - Impact of 2021 Immediate Expensing for 2021-2025 of Schedule 9-1-4 - Account 1592 PILS and Tax Variance for more information.

1508 Sub-Account - CCRA Payments Differential Variance Account (2021-2025):

In 2024, a credit of ($384k) and a credit of ($159k)[4] were recorded in this sub-account. Table D provides a detailed breakdown of the yearly difference between actual and forecasted CCRA additions for the period 2021 - 2024. The recovery of depreciation is determined by the approved depreciation amount embedded in rates for 2021-2025.

[3] Totals may not sum due to rounding.
[4] Relates to A6R; for further information on A6R adjustment, please refer to section 2.3 of Schedule 9-1-3 Group 2 Accounts

1 **Table D - CCRA Revenue Requirement Calculation 2020 - 2024 ($'000s)**[5]

	Historical Years				
	2021	**2022**	**2023**	**2024**	**Total**
Opening Gross Cumulative Asset Balance	$ (588)	$ (23,363)	$ (2,747)	$ (8,318)	
(Under)/Over additions	$ (22,775)	$ 20,616	$ (5,571)	$ (837)	
Closing Gross Cumulative Asset Balance	**$ (23,363)**	**$ (2,747)**	**$ (8,318)**	**$ (9,155)**	
Opening Accumulated Depreciation	$ (21)	$ (142)	$ (247)	$ (343)	
Current Year Depreciation	$ (122)	$ (104)	$ (96)	$ (165)	
Closing Accumulated Depreciation	**$ (142)**	**$ (247)**	**$ (343)**	**$ (508)**	
Average Cumulative Net Book Value	**$ (11,894)**	**$ (12,860)**	**$ (5,237)**	**$ (8,311)**	
Financial Net Income	$ (397)	$ (429)	$ (175)	$ (306)	
Add Depreciation	$ (122)	$ (104)	$ (96)	$ (165)	
Deduct CCA	$ 1,735	$ (165)	$ 533	$ 685	
Net Income For Tax Purposes	**$ 1,216**	**$ (698)**	**$ 262**	**$ 214**	
Tax Rate	26.50%	26.50%	26.50%	26.50%	
PILS	$ 322	$ (185)	$ 70	$ 57	
PILS Grossed-up	**$ 439**	**$ (252)**	**$ 95**	**$ 77**	
Depreciation	$ (122)	$ (104)	$ (96)	$ (165)	
Short Term Interest	$ (8)	$ (9)	$ (4)	$ (6)	
Long-Term Interest	$ (220)	$ (238)	$ (97)	$ (154)	
ROE	$ (397)	$ (429)	$ (175)	$ (306)	
PILS Grossed-up	$ 439	$ (252)	$ 95	$ 77	
Capital stretch factor	-	$ 6	$ 3	$ 10	
TOTAL (RETURN) REVENUE REQUIREMENT	**$ (308)**	**$ (1,026)**	**$ (273)**	**$ (543)**	**$ (2,150)**

2

3 Hydro Ottawa's total CCRA claim for disposition of a principal balance of $1,109k which comprises
4 the 2021-2024 balance and the 2020 balance.

5

[5] Totals may not sum due to rounding.

1508 Sub-Account - Capital Variance Accounts:

There is a total net principal credit of ($519k) recorded in 2024 to be recovered from customers. Depreciation in each sub-account is apportioned by the approved depreciation amount embedded in rates for 2021-2025.

System Access Asymmetrical Account (excluding Residential & Plant Relocates): recorded ($1.1M) to return to ratepayers as actual cumulative underspending was less than forecasted for years 2021-2024.

Table E provides a detailed breakdown of the yearly difference between actual and forecasted cumulative capital additions (net of capital contributions) as well as the annual revenue requirement amounts.

Table E - System Access Capital Additions Revenue Requirement (excluding Residential & Plant Relocates) Differential Variance Account ($'000s)

	Historical Years			
	2021	2022	2023	2024
Opening Gross Cumulative (Under)/Over Asset Addition	-	$ (6,157)	$ (10,577)	$ (14,514)
(Under)/Over additions	$ (6,157)	$ (4,420)	$ (3,937)	$ 6,308
Closing Gross Cumulative (Under)/Over Asset Addition	**$ (6,157)**	**$ (10,577)**	**$ (14,514)**	**$ (8,206)**
Opening Accumulated Depreciation	-	$ (95)	$ (374)	$ (794)
Current Year Depreciation	$ (95)	$ (278)	$ (421)	$ (365)
Closing Accumulated Depreciation	**$ (95)**	**$ (374)**	**$ (794)**	**$ (1,159)**
Average Cumulative Net Book Value	**$ (3,031)**	**$ (8,133)**	**$ (11,962)**	**$ (10,383)**
Financial Net Income	$ (101)	$ (271)	$ (399)	$ (383)
Add Depreciation	$ (95)	$ (278)	$ (421)	$ (365)
Deduct CCA[6]	$ 734	$ 834	$ 1,131	$ 391
Net Income For Tax Purposes	**$ 538**	**$ 285**	**$ 312**	**$ (357)**
Tax Rate	26.50%	26.50%	26.50%	26.50%
PILS	$ 143	$ 75	$ 83	$ (95)
PILS Grossed-up	**$ 195**	**$ 102**	**$ 113**	**$ (129)**
Depreciation	$ (95)	$ (278)	$ (421)	$ (365)
Short Term Interest	$ (2)	$ (6)	$ (8)	$ (7)
Long-Term Interest	$ (56)	$ (150)	$ (221)	$ (192)
ROE	$ (101)	$ (271)	$ (399)	$ (383)
PILS Grossed-up	$ 195	$ 102	$ 113	$ (129)
Capital stretch factor	-	$ 4	$ 11	$ 19
TOTAL (RETURN) REVENUE REQUIREMENT	**$ (60)**	**$ (600)**	**$ (925)**	**$ (1,057)**

[6] Please see Table F below and Attachment JT3.27(A) - CCA Schedule for Systems Access for supporting CCA calculations.

Table F is a summary of the differences in CCA between OEB Approved Final Settlement and Actual Additions for 2021 - 2024 Historical Years for System Access additions (excluding Residential and Plant Relocates). The supporting CCA calculations can be found as Attachment JT3.27(A) - CCA Schedule for System Access.

Table F – Difference in CCA for System Access additions (excluding Residential & Plant Relocates) between OEB Approved Final Settlement and Actual Additions for 2021 - 2024

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	1,597	$863	$ 734
2022	$2,227	$1,393	$834
2023	$2,870	$1,739	$1,131
2024	$3,059	$2,668	$391

<u>System Access Symmetrical Account (Residential & Plant Relocates):</u>
$1.6M was recorded to collect from customers as actual cumulative capital net additions exceeded forecast for years 2021-2024.

Table G provides a detailed breakdown of the yearly difference between actual and forecasted cumulative capital additions (net of capital contributions) as well as the annual revenue requirement amounts.

1 **Table G - System Access Capital Additions Revenue Requirement (Residential & Plant**
2 **Relocates) Differential Variance Account ($'000s)**

	Historical Years			
	2021	**2022**	**2023**	**2024**
Opening Gross Cumulative (Under)/Over Asset Addition	-	$ 6,431	$ 10,726	$ 15,758
(Under)/Over additions	$ 6,431	$ 4,294	$ 5,032	$ 5,947
Closing Gross Cumulative (Under)/Over Asset Addition	**$ 6,431**	**$ 10,726**	**$ 15,758**	**$ 21,704**
Opening Accumulated Depreciation	-	$ 120	$ 431	$ 902
Current Year Depreciation	$ 120	$ 311	$ 471	$ 682
Closing Accumulated Depreciation	**$ 120**	**$ 431**	**$ 902**	**$ 1,584**
Average Cumulative Net Book Value	**$ 3,156**	**$ 8,303**	**$ 12,575**	**$ 17,489**
Financial Net Income	$ 105	$ 277	$ 420	$ 644
Add Depreciation	$ 120	$ 311	$ 471	$ 682
Deduct CCA[7]	$ (756)	$ (961)	$ (1,316)	$ (1,486)
Net Income For Tax Purposes	**$ (530)**	**$ (373)**	**$ (425)**	**$ (160)**
Tax Rate	26.50%	26.50%	26.50%	26.50%
PILS	$ (141)	$ (99)	$ (113)	$ (42)
PILS Grossed-up	**$ (192)**	**$ (135)**	**$ (154)**	**$ (57)**
Depreciation	$ 120	$ 311	$ 471	$ 682
Short Term Interest	$ 2	$ 6	$ 9	$ 12
Long-Term Interest	$ 58	$ 153	$ 232	$ 323
ROE	$ 105	$ 277	$ 420	$ 644
PILS Grossed-up	$ (192)	$ (135)	$ (154)	$ (57)
Capital stretch factor	-	$ (4)	$ (12)	$ (29)
TOTAL (RETURN) REVENUE REQUIREMENT	**$ 94**	**$ 609**	**$ 966**	**$ 1,576**

3

[7] Please see Table H below and Attachment JT3.27(B) - CCA Schedule for Residential & PR for supporting CCA
4 calculations.

Table H is a summary of the differences in CCA between OEB Approved Final Settlement and Actual Additions for 2021 - 2024 Historical Years for System Access (Residential & Plant Relocates). The supporting CCA calculations can be found as Attachment JT3.27(B) - CCA Schedule for Residential & PR.

Table H – Difference in CCA for System Access additions (Residential & Plant Relocates) between OEB Approved Final Settlement and Actual Additions for 2021 - 2024

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	$747	$ 1,503	($756)
2022	$1,298	$2,259	($961)
2023	1,771	$3,087	($1,316)
2024	$1,757	$3,243	($1,486)

<u>General Plant Asymmetrical Account:</u>

In 2024 actual capital net additions was $12,356k. By 2024, the cumulative capital net additions of $45,945k exceeded the forecasted cumulative additions of $38,294 therefore no amount was recorded into this account in 2024.

1 **Table I - General Plant Capital Additions Revenue Requirement (excluding CCRA) Differential**
2 **Variance Account ($'000s)**

	Historical Years			
	2021	**2022**	**2023**	**2024**
Opening Gross Cumulative (Under)/Over Asset Addition	-	$ (8,522)	$ (7,494)	$ 1,041
(Under)/Over additions	$ (8,522)	$ 1,028	$ 8,535	$ 6,610
Closing Gross Cumulative (Under)/Over Asset Addition	**$ (8,522)**	**$ (7,494)**	**$ 1,041**	**$ 7,651**
Opening Accumulated Depreciation	-	$ (615)	-	-
Current Year Depreciation	$ (615)	$ (717)	-	-
Closing Accumulated Depreciation	**$ (615)**	**$ (1,332)**	**-**	**-**
Average Cumulative Net Book Value	**$ (3,953)**	**$ (7,034)**	**-**	**-**
Financial Net Income	$ (132)	$ (235)	-	-
Add Depreciation	$ (615)	$ (717)	-	-
Deduct CCA	$ 4,480	$ 730	-	-
Net Income For Tax Purposes	**$ 3,733**	**$ (221)**	-	-
Tax Rate	26.50%	26.50%	-	-
PILS	$ 989	$ (59)	-	-
PILS Grossed-up	**$ 1,346**	**$ (80)**	**-**	**-**
Depreciation	$ (615)	$ (717)	-	-
Short Term Interest	$ (3)	$ (5)	-	-
Long-Term Interest	$ (73)	$ (130)	-	-
ROE	$ (132)	$ (235)	-	-
PILS Grossed-up	$ 1,346	$ (80)	-	-
Capital stretch factor	-	$ 7	-	-
TOTAL (RETURN) REVENUE REQUIREMENT	**$ 522**	**$ (1,159)**	**-**	**-**

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A summary of the differences in CCA between OEB Approved Final Settlement and Actual Additions for 2021 - 2024 Historical Years for General Plant additions. There is no update to the CCA supporting schedules for 2024 and these supporting CCA schedules can be found in as attachment 9-Staff-206(A) - CCA Schedule for GP in interrogatory response 6-Staff-206. For 2023 and 2024, the cumulative capital net additions exceeded the forecasted cumulative additions of therefore no CCA difference was recorded into this account. Therefore no update is required.

<u>System Renewal/System Service Differential Variance:</u>

In 2024 actual capital net additions was $73,800k. In 2024, the actual cumulative capital net additions of $296,128k were higher than forecasted cumulative additions of $273,153k, as a result no amount was recorded into this account in 2024.

<u>1568 Sub-Account - Lost Revenue Adjustment Mechanism Variance Account (LRAMVA):</u>

The LRAMVA claim in Attachment 1-Staff-1(C) - OEB_Workform - 2026 Deferral and Variance Account (Continuity Schedule) was updated to include interest for 2024 and 2025. The principal amount was not changed, and remains at $(584,266). The total claim is $(682,162).

Attachment 1-Staff-1(R) - OEB LRAMVA Workform was provided in order to reflect a change in the original LRAMVA Workform in Schedule 9-1-5 - LRAM Variance Account, due to a duplication error found in the persistence tab and calculates interest amount up to December 31, 2023. This version was not to be used for the LRAMVA claim amount as the interest amount does not include forecasted interest to December 31, 2025.

Table J shows the difference in LRAMVA between Attachment 1-Staff-1(R) - OEB LRAMVA Workform and Attachment 1-Staff-1(C) - OEB_Workform - 2026 Deferral and Variance Account (Continuity Schedule).

1 **Table J – LRAMVA Claim Reconciliation**

	GS<50 kW	GS 50 TO 1,499 KW	GS 1,500 TO 4,999	Large User	Unmetered Scattered Load	Streetlighting	Total
Principal to 2023 per 1-Staff-1 LRAM workform	$ 228,024	$ 176,838	$ (531,225)	$ (420,907)	$ (6,180)	$ (31,220)	$ (584,670)
Interest to 2023 per 1-Staff-1 LRAM workform	$ 6,192	$ 6,034	$ (29,121)	$ (30,033)	$ (320)	$ (2,152)	$ (49,400)
Total LRAM (balance to 2023)	**$ 234,216**	**$ 182,871**	**$ (560,346)**	**$ (450,940)**	**$ (6,499)**	**$ (33,372)**	**$ (634,070)**
Principal change not requested	$ 800	-	-	-	-	$ (396)	$ 404
Interest in 2024-2025	$ 19,011	$ 14,678	$ (44,092)	$ (34,935)	$ (513)	$ (2,646)	$ (48,497)
Total LRAM claim	**$ 254,027**	**$ 197,549**	**$ (604,437)**	**$ (485,875)**	**$ (7,012)**	**$ (36,413)**	**$ (682,162)**

2

3 There were no other changes to the Group 2 principal balances.

As noted in Table AM of interrogatory response 1-Staff-1, Hydro Ottawa is seeking disposition of Group 1 DVAs for a total amount of $10,337k. Per Attachment 1-Staff-1(C) - OEB Workform Deferral and Variance Account (Continuity Schedule), principal balances of $9,885 are up to December 31, 2024 and interest is forecasted to December 31, 2025 of $452k.

As part of this undertaking's request, the below provides further information on the disposition of 1580 and 1586:

<u>Account 1580 RSVA – Wholesale Market Service charge ('Account 1580'):</u>
The wholesale market service charges (WMSC) include the Rural or Remote Electricity Rate Protection (RRRP) charge and various market uplift charges. In addition, Account 1580 includes wholesale market service revenue (including RRRP revenue) Hydro Ottawa collects based upon the Board approved wholesale market service (WMS) rate and RRRP.

For the fiscal year of 2024, the main drivers for the decrease in Account 1580 from 2023 is the rate difference between the 2023 and 2024 IESO WMSC incurred by Hydro Ottawa and the WMS and RRRP rates that Hydro Ottawa charges its customers. Table K below shows the breakdown of the balances recorded in Account 1580 in 2023 and 2024. In 2023 Hydro Ottawa charged its customers the approved WMS rate of $0.0048 and the WMSC rate charged to Hydro Ottawa was $0.0043; therefore Hydro Ottawa recorded a credit principal amount of $8.1M to RSVA - WMS.

In 2024, the approved WMS rate increased to $0.0055, caused by the RRRP charge increasing from $0.0007 to $0.0014, while the WMSC rate charged to Hydro Ottawa increased to $0.0049. Hydro Ottawa still recorded a credit principal amount in 2024, but smaller than 2023. The new amount for 2024 is a credit principal amount of $4.1M to RSVA - WMS (a total of $4.3M including principal and interest).

Table K - 2023 & 2024 Account 1580 Breakdown

	2023 ($)	2024 ($)
WMS Collected from Customers	($30,528,367)	($30,838,175)
WMS Expense	$22,765,521	$27,504,365
WMS Variance	**($7,762,846)**	**($3,333,810)**
RRRP Collected from Customers	($5,212,003)	($10,517,714)
RRRP Expense	$4,868,990	$9,769,709
RRRP Variance	**($343,013)**	**($748,006)**
RVSA Wholesale Market Service Principal	($8,105,859)	($4,081,815)
Interest	($577,524)	($194,943)
RVSA Wholesale Market Service (Principal and Interest)	($8,683,383)	($4,276,759)

Hydro Ottawa purchases approximately 90% of its power supply from the IESO and the remaining 10% from Hydro One and embedded generators. Hydro One charges Hydro Ottawa the 2024 WMS approved rate. Table L below provides a comparison of the WMSC rate incurred by Hydro Ottawa and the 2024 WMS approved rate billed for WMS revenue to distribution customers.

Table L - Wholesale Market Service Charge Revenue & Expense Rates (Principal)

	2024 Revenue Collected	2024 Total WMS Charge
WMS Collected from Customers	($30,838,175)	$27,504,365
RRRP Collected from Customers	($10,517,714)	$9,769,709
Adjusted kWh	**7,499,777,866**	**7,551,358,287**
Average $/kWh	($0.0055)	$0.0049

Account 1586 RSVA – Transmission Connection charge (‘Account 1586’):

The transmission connection charge includes Transmission Line Connection Service Charge (TLCC) and Transformation Connection Service Charge (TCSC). In addition, Account 1586 includes transmission connection charge (TCC) Hydro Ottawa collects based upon the Board approved rates and Hydro One switchgear credits.

For the fiscal year of 2024, the main drivers for the decrease in Account 1586 from 2023 is the rate difference between the 2023 and 2024 IESO TLCC and TCSC incurred by Hydro Ottawa and the TCC rates that Hydro Ottawa charges its customers. Table M below shows the breakdown of the balances recorded in Account 1586 in 2023 and 2024.

In 2023 Hydro Ottawa charged its customers the average approved TCC rate of $0.0057/kWh for non commercial customers and an average rate of $2.29/kW for commercial customers. The TLCC rate charged to Hydro Ottawa was an average rate of $0.090 and the TCSC rate charged to Hydro Ottawa was an average rate of $3.04, resulting in an overall average rate of $2.45/kW.

Hydro Ottawa recorded a debit principal amount of $90k to RSVA - Transmission Connection (a total of $128k when including principal and interest). In 2024, the approved TCSC rate increased to an average rate of $0.0063/kWh for non commercial customers and an average rate of $2.47/kW for commercial customers, while the TLCC rate charged to Hydro Ottawa increased to $0.095 and TCSC rate increased to a rate of $3.21, resulting in an increased overall rate of $2.59/kW. With the change in rates, and an increase of Hydro One switchgear credits from $3.7M to $4.0M, Hydro Ottawa recorded a credit principal amount in 2024 of $4.2M to RSVA - Transmission Connection (a total of $4.4M when including principal and interest).

Table M - 2023 & 2024 Account 1586 Breakdown

	2023 ($)	2024 ($)
Transmission Connection Collected from Customers	($39,968,482)	($44,754,301)
HONI Switchgear Credit	($3,741,637)	($4,005,081)
Transmission Connection Expense	$43,799,637	$44,594,758
Transmission Connection Variance	**$89,517**	**($4,164,624)**
RVSA Transmission Connection Principal	$89,517	($4,164,624)
Interest	$38,068	($219,275)
RVSA Transmission Connection (Principal and Interest)	$127,586	($4,383,898)

Hydro Ottawa purchases approximately 90% of its power supply from the IESO and the remaining 10% from Hydro One and embedded generators. Hydro One charges Hydro Ottawa the 2024 TCSC approved rate. Tables N-P below provides a comparison of the WMSC rate incurred by Hydro Ottawa and the 2024 WMS approved rate billed for WMS revenue to distribution customers.

Table N - 2023 & 2024 Non Commercial Transmission Connection Revenue Rates (Principal)

	2023 Revenue Collected	2024 Revenue Collected
Transmission Connection Collected from Customers	($18,622,598)	($21,088,548)
Non Commercial Adjusted kWh	**3,283,515,756**	**3,356,413,668**
Average $/kWh	($0.0057)	($0.0063)

Table O - 2023 & 2024 Commercial Transmission Connection Revenue Rates (Principal)

	2023 Revenue Collected	2024 Revenue Collected
Transmission Connection Collected from Customers	($21,345,884)	($23,665,753)
Total kW	**9,301,809**	**9,587,412**
Average $/kW	($2.29)	($2.47)

Table P - 2023 & 2024 Connection Charge Expense Rates (Principal)

	202 Revenue Collected	2024 Revenue Collected
Transmission Connection Charge IESO	$42,216,382	$42,855,234
Transmission Connection Charge HONI	$1,583,255	$1,739,525
Units Billed IESO - Line Charge	**13,166,876**	**12,872,883**
Units Billed IESO - Transformation Charge	**10,024,759**	**9,583,284**
Units Billed HONI	**535,865**	**520,754**
Average $/kW	$2.45	$2.59

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA & ONTARIO ENERGY BOARD STAFF

JT3.27

EVIDENCE REFERENCE:

Schedule 9-1-3 Tables 12-14

UNDERTAKING(S):

Put on record details supportive of the disposition request

RESPONSE(S):

As noted in Table AO of interrogatory response 1-Staff-1, Hydro Ottawa is seeking disposition of Group 2 DVAs for a total amount of $(4,604k). Per Attachment 1-Staff-1(C) - OEB Workform Deferral and Variance Account (Continuity Schedule), principal balances of $(3,806k) are up to December 31, 2024 and interest is forecasted to December 31, 2025 of $(799k).

Table A shows the balances added to the proposed Group 2 DVA Dispositions. The 2023 values are from column BO, BS, and BT in Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account (Continuity Schedule). The revised total disposition amount ties to the total claim (column BT) from Attachment 1-Staff-1(C) - OEB Workform Deferral and Variance Account (Continuity Schedule).

Please see Schedule 9-1-3 - Group 2 Accounts and Schedule 9-1-4 - Account 1592 PILS and Tax Variance for more detailed descriptions of each 2 Account.

Table A - 2024 Additions to Group 2 DVA Dispositions[1]

Group	USofA Number	Group 2 Deferral/Variance Account Description	2023 Amount (Principal & Interest) ($)	2023 Principal ($)	Interest on 2023 principal ($)	2024 Principal ($)	Interest adjustments in 2024 ($)	Revised Total Disposition Amount ($)
			A	B	C	D	E	F = A + D + E
2	1508	Pole Attachment Revenue Variance	$ 802,348	$ 697,316	$ 105,032	-	$ (3,401)	$ 798,947
2	1508	GOCA Variance Account	$ 802,545	$ 737,748	$ 64,797	$ 270,780	$ 4,938	$ 1,078,263
2	1508	Gains and Loss on disposal of Fixed Assets Variance Account	$ (1,185,023)	$ (1,042,505)	$ (142,518)	$ (203,344)	$ (31,295)	$ (1,419,661)
2	1508	Earnings Sharing Mechanism (ESM) Variance Account	$ (1,355,491)	$ (1,151,693)	$ (203,797)	-	$ 5,616	$ (1,349,874)
2	1508	Connection Cost Recovery Agreement (CCRA) Payments Differential Variance Account	$ (611,206)	$ (566,398)	$ (44,807)	$ (543,226)	$ (14,362)	$ (1,168,794)
2	1508	Efficiency Adjustment Mechanism (EAM) Deferral Account	$ (343,296)	$ (300,816)	$ (42,480)	-	$ 1,467	$ (341,829)
2	1508	OEB Cost Assessment Variance	$ 553,119	$ 486,987	$ 66,132	-	$ (2,375)	$ 550,744
2	1508	RCVA Retail Incremental Revenue	$ 54,037	$ 46,028	$ 8,009	-	$ (224)	$ 53,813
2	1508	STR Incremental Revenue	$ 1,721	$ 1,467	$ 254	-	$ (7)	$ 1,714

[1] Totals may not sum due to rounding.

Group	USofA Number	Group 2 Deferral/Variance Account Description	2023 Amount (Principal & Interest) ($)	2023 Principal ($)	Interest on 2023 principal ($)	2024 Principal ($)	Interest adjustments in 2024 ($)	Revised Total Disposition Amount ($)
2	1508	Performance Outcomes Account Mechanism (POAM) Deferral Account	$ (890,453)	$ (800,000)	$ (90,453)	$ (200,000)	$ (2,403)	$ (1,092,856)
2	1508	Capital Variance Account	$ (619,989)	$ (552,268)	$ (67,721)	$ 518,955	$ 19,052	$ (81,982)
		Sub-Total of 1508 Sub-Accounts	**$ (2,791,686)**	**$ (2,444,135)**	**$ (347,552)**	**$ (156,835)**	**$ (22,993)**	**$ (2,971,515)**
2	1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	$ (208,445)	-	$ (208,445)	-	$ (21,068)	$ (229,512)
2	1592	PILs and Tax Variance - Sub-Account Capital Cost Allowance (CCA) Changes	$ (925,668)	$ (814,810)	$ (110,857)	$ 194,424	$ 10,020	$ (721,224)
		Group 2 Sub-total (Prior to Lost Revenue Adjustment Mechanism (LRAM)	**$ (3,925,799)**	**$ (3,258,945)**	**$ (666,854)**	**$ 37,589**	**$ (34,041)**	**$ (3,922,251)**
2	1568	LRAM Variance Account (LRAMVA)	$ (684,996)	$ (584,266)	$ (100,730)	$ -	$ 2,833	$ (682,163)
	TOTAL DVA BALANCE (Group 2) TO BE MOVED TO 1595 (2026)		**$ (4,610,795)**	**$ (3,843,211)**	**$ (767,584)**	**$ 37,589**	**$ (31,208)**	**$ (4,604,414)**

The below provides an update to Group 2 accounts with the exception of:

- 1568 Lost Revenue Adjustment Mechanism (LRAM) Variance Account (for details on this Account, please see Schedule 9-1-5 - LRAM Variance Account); and
- 1508 Sub-Accounts that are now closed.

1508 Sub-Account - GOCA Variance Account

The OEB-approved amount embedded in rates for the period April 2023 to December 31, 2025 is \$5,770k and actual costs incurred for the same period is \$6,778.9k; therefore \$1,008.5k of claim (principal) has been recorded into this sub-account.

Please see Table B for the balance in the GOCA as of December 31, 2024.

Table B - GOCA Variance Account - 2024[2]

	Historical Year
	2024
OEB approved amount for the period April 2023 - December 2024	$ 5,770,356
Actual cost for the period April 2023 - December 2024	$ 6,778,884
Sub Account GOCA - Principal balance	**$ 1,008,528**
Interest, including portion projected to December 31, 2025	$ 69,735
TOTAL BALANCE	**$ 1,078,263**

1508 Sub-Account - Gains and Loss on disposal of Fixed Assets Variance Account

The OEB-approved loss for 2024 was \$336k and actual loss was \$132k; therefore \$203k credit has been recorded into this sub-account. The total principal balance as at December 31, 2024 is \$1,245.8k.

[2] Totals may not sum due to rounding.

Please see Table C for the 2020-2024 amounts embedded in rates versus the actual gains/loss incurred over the same period.

Table C - 2020 to 2024 Loss from Retirement of Utility and Other Property ($'000s)[3]

	Historical Years				
	2020	**2021**	**2022**	**2023**	**2024**
USofA 4362 OEB-Approved (gain)/loss	$ (198)	$ 389	$ 751	$ 323	$ 336
USofA 4362 Actual (gain)/loss	$ 87	$ (202)	$ 1,234	$ (897)	$ 132
USOFA 1508 VARIANCE (PRINCIPLE)	**$ 285**	**$ (590)**	**$ 483**	**$ (1,220)**	**$ (203)**

1508 Sub-Account - POAM

In 2024 Hydro Ottawa recorded a credit of $200k into this account as wood pole replacement POAM metric (#4) was not met.

Account 1592 - PILS and Tax Variance

In 2024 Hydro Ottawa recorded a debit of $195k to record the impact of the 2021 immediate expensing for the 2021-2024 period. Refer to Table 2 - Impact of 2021 Immediate Expensing for 2021-2025 of Schedule 9-1-4 - Account 1592 PILS and Tax Variance for more information.

1508 Sub-Account - CCRA Payments Differential Variance Account (2021-2025):

In 2024, a credit of ($384k) and a credit of ($159k)[4] were recorded in this sub-account. Table D provides a detailed breakdown of the yearly difference between actual and forecasted CCRA additions for the period 2021 - 2024. The recovery of depreciation is determined by the approved depreciation amount embedded in rates for 2021-2025.

[3] Totals may not sum due to rounding.
[4] Relates to A6R; for further information on A6R adjustment, please refer to section 2.3 of Schedule 9-1-3 Group 2 Accounts

1 **Table D - CCRA Revenue Requirement Calculation 2020 - 2024 ($'000s)[5]**

	Historical Years				
	2021	2022	2023	2024	Total
Opening Gross Cumulative Asset Balance	$ (588)	$ (23,363)	$ (2,747)	$ (8,318)	
(Under)/Over additions	$ (22,775)	$ 20,616	$ (5,571)	$ (837)	
Closing Gross Cumulative Asset Balance	**$ (23,363)**	**$ (2,747)**	**$ (8,318)**	**$ (9,155)**	
Opening Accumulated Depreciation	$ (21)	$ (142)	$ (247)	$ (343)	
Current Year Depreciation	$ (122)	$ (104)	$ (96)	$ (165)	
Closing Accumulated Depreciation	**$ (142)**	**$ (247)**	**$ (343)**	**$ (508)**	
Average Cumulative Net Book Value	**$ (11,894)**	**$ (12,860)**	**$ (5,237)**	**$ (8,311)**	
Financial Net Income	$ (397)	$ (429)	$ (175)	$ (306)	
Add Depreciation	$ (122)	$ (104)	$ (96)	$ (165)	
Deduct CCA	$ 1,735	$ (165)	$ 533	$ 685	
Net Income For Tax Purposes	**$ 1,216**	**$ (698)**	**$ 262**	**$ 214**	
Tax Rate	26.50%	26.50%	26.50%	26.50%	
PILS	$ 322	$ (185)	$ 70	$ 57	
PILS Grossed-up	**$ 439**	**$ (252)**	**$ 95**	**$ 77**	
Depreciation	$ (122)	$ (104)	$ (96)	$ (165)	
Short Term Interest	$ (8)	$ (9)	$ (4)	$ (6)	
Long-Term Interest	$ (220)	$ (238)	$ (97)	$ (154)	
ROE	$ (397)	$ (429)	$ (175)	$ (306)	
PILS Grossed-up	$ 439	$ (252)	$ 95	$ 77	
Capital stretch factor	-	$ 6	$ 3	$ 10	
TOTAL (RETURN) REVENUE REQUIREMENT	**$ (308)**	**$ (1,026)**	**$ (273)**	**$ (543)**	**$ (2,150)**

3 Hydro Ottawa's total CCRA claim for disposition of a principal balance of $1,109k which comprises
4 the 2021-2024 balance and the 2020 balance.

[5] Totals may not sum due to rounding.

1508 Sub-Account - Capital Variance Accounts:

There is a total net principal credit of ($519k) recorded in 2024 to be recovered from customers. Depreciation in each sub-account is apportioned by the approved depreciation amount embedded in rates for 2021-2025.

System Access Asymmetrical Account (excluding Residential & Plant Relocates): recorded ($1.1M) to return to ratepayers as actual cumulative underspending was less than forecasted for years 2021-2024.

Table E provides a detailed breakdown of the yearly difference between actual and forecasted cumulative capital additions (net of capital contributions) as well as the annual revenue requirement amounts.

1 **Table E - System Access Capital Additions Revenue Requirement (excluding Residential & Plant**
2 **Relocates) Differential Variance Account ($'000s)**

	Historical Years			
	2021	**2022**	**2023**	**2024**
Opening Gross Cumulative (Under)/Over Asset Addition	-	$ (6,157)	$ (10,577)	$ (14,514)
(Under)/Over additions	$ (6,157)	$ (4,420)	$ (3,937)	$ 6,308
Closing Gross Cumulative (Under)/Over Asset Addition	**$ (6,157)**	**$ (10,577)**	**$ (14,514)**	**$ (8,206)**
Opening Accumulated Depreciation	-	$ (95)	$ (374)	$ (794)
Current Year Depreciation	$ (95)	$ (278)	$ (421)	$ (365)
Closing Accumulated Depreciation	**$ (95)**	**$ (374)**	**$ (794)**	**$ (1,159)**
Average Cumulative Net Book Value	**$ (3,031)**	**$ (8,133)**	**$ (11,962)**	**$ (10,383)**
Financial Net Income	$ (101)	$ (271)	$ (399)	$ (383)
Add Depreciation	$ (95)	$ (278)	$ (421)	$ (365)
Deduct CCA[6]	$ 734	$ 834	$ 1,131	$ 391
Net Income For Tax Purposes	**$ 538**	**$ 285**	**$ 312**	**$ (357)**
Tax Rate	26.50%	26.50%	26.50%	26.50%
PILS	$ 143	$ 75	$ 83	$ (95)
PILS Grossed-up	**$ 195**	**$ 102**	**$ 113**	**$ (129)**
Depreciation	$ (95)	$ (278)	$ (421)	$ (365)
Short Term Interest	$ (2)	$ (6)	$ (8)	$ (7)
Long-Term Interest	$ (56)	$ (150)	$ (221)	$ (192)
ROE	$ (101)	$ (271)	$ (399)	$ (383)
PILS Grossed-up	$ 195	$ 102	$ 113	$ (129)
Capital stretch factor	-	$ 4	$ 11	$ 19
TOTAL (RETURN) REVENUE REQUIREMENT	**$ (60)**	**$ (600)**	**$ (925)**	**$ (1,057)**

3

[6] Please see Table F below and Attachment JT3.27(A) - CCA Schedule for Systems Access for supporting CCA calculations.

Table F is a summary of the differences in CCA between OEB Approved Final Settlement and Actual Additions for 2021 - 2024 Historical Years for System Access additions (excluding Residential and Plant Relocates). The supporting CCA calculations can be found as Attachment JT3.27(A) - CCA Schedule for System Access.

Table F – Difference in CCA for System Access additions (excluding Residential & Plant Relocates) between OEB Approved Final Settlement and Actual Additions for 2021 - 2024

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	1,597	$863	$ 734
2022	$2,227	$1,393	$834
2023	$2,870	$1,739	$1,131
2024	$3,059	$2,668	$391

<u>System Access Symmetrical Account (Residential & Plant Relocates):</u>

$1.6M was recorded to collect from customers as actual cumulative capital net additions exceeded forecast for years 2021-2024.

Table G provides a detailed breakdown of the yearly difference between actual and forecasted cumulative capital additions (net of capital contributions) as well as the annual revenue requirement amounts.

Table G - System Access Capital Additions Revenue Requirement (Residential & Plant Relocates) Differential Variance Account ($'000s)

	Historical Years			
	2021	**2022**	**2023**	**2024**
Opening Gross Cumulative (Under)/Over Asset Addition	-	$ 6,431	$ 10,726	$ 15,758
(Under)/Over additions	$ 6,431	$ 4,294	$ 5,032	$ 5,947
Closing Gross Cumulative (Under)/Over Asset Addition	**$ 6,431**	**$ 10,726**	**$ 15,758**	**$ 21,704**
Opening Accumulated Depreciation	-	$ 120	$ 431	$ 902
Current Year Depreciation	$ 120	$ 311	$ 471	$ 682
Closing Accumulated Depreciation	**$ 120**	**$ 431**	**$ 902**	**$ 1,584**
Average Cumulative Net Book Value	**$ 3,156**	**$ 8,303**	**$ 12,575**	**$ 17,489**
Financial Net Income	$ 105	$ 277	$ 420	$ 644
Add Depreciation	$ 120	$ 311	$ 471	$ 682
Deduct CCA[7]	$ (756)	$ (961)	$ (1,316)	$ (1,486)
Net Income For Tax Purposes	**$ (530)**	**$ (373)**	**$ (425)**	**$ (160)**
Tax Rate	26.50%	26.50%	26.50%	26.50%
PILS	$ (141)	$ (99)	$ (113)	$ (42)
PILS Grossed-up	**$ (192)**	**$ (135)**	**$ (154)**	**$ (57)**
Depreciation	$ 120	$ 311	$ 471	$ 682
Short Term Interest	$ 2	$ 6	$ 9	$ 12
Long-Term Interest	$ 58	$ 153	$ 232	$ 323
ROE	$ 105	$ 277	$ 420	$ 644
PILS Grossed-up	$ (192)	$ (135)	$ (154)	$ (57)
Capital stretch factor	-	$ (4)	$ (12)	$ (29)
TOTAL (RETURN) REVENUE REQUIREMENT	**$ 94**	**$ 609**	**$ 966**	**$ 1,576**

[7] Please see Table H below and Attachment JT3.27(B) - CCA Schedule for Residential & PR for supporting CCA calculations.

Table H is a summary of the differences in CCA between OEB Approved Final Settlement and Actual Additions for 2021 - 2024 Historical Years for System Access (Residential & Plant Relocates). The supporting CCA calculations can be found as Attachment JT3.27(B) - CCA Schedule for Residential & PR.

Table H – Difference in CCA for System Access additions (Residential & Plant Relocates) between OEB Approved Final Settlement and Actual Additions for 2021 - 2024

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	$747	$ 1,503	($756)
2022	$1,298	$2,259	($961)
2023	1,771	$3,087	($1,316)
2024	$1,757	$3,243	($1,486)

<u>General Plant Asymmetrical Account:</u>

In 2024 actual capital net additions was $12,356k. By 2024, the cumulative capital net additions of $45,945k exceeded the forecasted cumulative additions of $38,294 therefore no amount was recorded into this account in 2024.

1 **Table I - General Plant Capital Additions Revenue Requirement (excluding CCRA) Differential**
2 **Variance Account ($'000s)**

	Historical Years			
	2021	**2022**	**2023**	**2024**
Opening Gross Cumulative (Under)/Over Asset Addition	-	$ (8,522)	$ (7,494)	$ 1,041
(Under)/Over additions	$ (8,522)	$ 1,028	$ 8,535	$ 6,610
Closing Gross Cumulative (Under)/Over Asset Addition	**$ (8,522)**	**$ (7,494)**	**$ 1,041**	**$ 7,651**
Opening Accumulated Depreciation	-	$ (615)	-	-
Current Year Depreciation	$ (615)	$ (717)	-	-
Closing Accumulated Depreciation	**$ (615)**	**$ (1,332)**	**-**	**-**
Average Cumulative Net Book Value	**$ (3,953)**	**$ (7,034)**	**-**	**-**
Financial Net Income	$ (132)	$ (235)	-	-
Add Depreciation	$ (615)	$ (717)	-	-
Deduct CCA	$ 4,480	$ 730	-	-
Net Income For Tax Purposes	**$ 3,733**	**$ (221)**	-	-
Tax Rate	26.50%	26.50%	-	-
PILS	$ 989	$ (59)	-	-
PILS Grossed-up	**$ 1,346**	**$ (80)**	**-**	**-**
Depreciation	$ (615)	$ (717)	-	-
Short Term Interest	$ (3)	$ (5)	-	-
Long-Term Interest	$ (73)	$ (130)	-	-
ROE	$ (132)	$ (235)	-	-
PILS Grossed-up	$ 1,346	$ (80)	-	-
Capital stretch factor	-	$ 7	-	-
TOTAL (RETURN) REVENUE REQUIREMENT	**$ 522**	**$ (1,159)**	**-**	**-**

3

A summary of the differences in CCA between OEB Approved Final Settlement and Actual Additions for 2021 - 2024 Historical Years for General Plant additions. There is no update to the CCA supporting schedules for 2024 and these supporting CCA schedules can be found in as attachment 9-Staff-206(A) - CCA Schedule for GP in interrogatory response 6-Staff-206. For 2023 and 2024, the cumulative capital net additions exceeded the forecasted cumulative additions of therefore no CCA difference was recorded into this account. Therefore no update is required.

System Renewal/System Service Differential Variance:

In 2024 actual capital net additions was $73,800k. In 2024, the actual cumulative capital net additions of $296,128k were higher than forecasted cumulative additions of $273,153k, as a result no amount was recorded into this account in 2024.

1568 Sub-Account - Lost Revenue Adjustment Mechanism Variance Account (LRAMVA):

The LRAMVA claim in Attachment 1-Staff-1(C) - OEB_Workform - 2026 Deferral and Variance Account (Continuity Schedule) was updated to include interest for 2024 and 2025. The principal amount was not changed, and remains at $(584,266). The total claim is $(682,162).

Attachment 1-Staff-1(R) - OEB LRAMVA Workform was provided in order to reflect a change in the original LRAMVA Workform in Schedule 9-1-5 - LRAM Variance Account, due to a duplication error found in the persistence tab and calculates interest amount up to December 31, 2023. This version was not to be used for the LRAMVA claim amount as the interest amount does not include forecasted interest to December 31, 2025.

Table J shows the difference in LRAMVA between Attachment 1-Staff-1(R) - OEB LRAMVA Workform and Attachment 1-Staff-1(C) - OEB_Workform - 2026 Deferral and Variance Account (Continuity Schedule).

1 **Table J – LRAMVA Claim Reconciliation**

	GS<50 kW	GS 50 TO 1,499 KW	GS 1,500 TO 4,999	Large User	Unmetered Scattered Load	Streetlighting	Total
Principal to 2023 per 1-Staff-1 LRAM workform	$ 228,024	$ 176,838	$ (531,225)	$ (420,907)	$ (6,180)	$ (31,220)	$ (584,670)
Interest to 2023 per 1-Staff-1 LRAM workform	$ 6,192	$ 6,034	$ (29,121)	$ (30,033)	$ (320)	$ (2,152)	$ (49,400)
Total LRAM (balance to 2023)	**$ 234,216**	**$ 182,871**	**$ (560,346)**	**$ (450,940)**	**$ (6,499)**	**$ (33,372)**	**$ (634,070)**
Principal change not requested	$ 800	-	-	-	-	$ (396)	$ 404
Interest in 2024-2025	$ 19,011	$ 14,678	$ (44,092)	$ (34,935)	$ (513)	$ (2,646)	$ (48,497)
Total LRAM claim	**$ 254,027**	**$ 197,549**	**$ (604,437)**	**$ (485,875)**	**$ (7,012)**	**$ (36,413)**	**$ (682,162)**

2

3 There were no other changes to the Group 2 principal balances.

As noted in Table AM of interrogatory response 1-Staff-1, Hydro Ottawa is seeking disposition of Group 1 DVAs for a total amount of $10,337k. Per Attachment 1-Staff-1(C) - OEB Workform Deferral and Variance Account (Continuity Schedule), principal balances of $9,885 are up to December 31, 2024 and interest is forecasted to December 31, 2025 of $452k.

As part of this undertaking's request, the below provides further information on the disposition of 1580 and 1586:

Account 1580 RSVA – Wholesale Market Service charge ('Account 1580'):

The wholesale market service charges (WMSC) include the Rural or Remote Electricity Rate Protection (RRRP) charge and various market uplift charges. In addition, Account 1580 includes wholesale market service revenue (including RRRP revenue) Hydro Ottawa collects based upon the Board approved wholesale market service (WMS) rate and RRRP.

For the fiscal year of 2024, the main drivers for the decrease in Account 1580 from 2023 is the rate difference between the 2023 and 2024 IESO WMSC incurred by Hydro Ottawa and the WMS and RRRP rates that Hydro Ottawa charges its customers. Table K below shows the breakdown of the balances recorded in Account 1580 in 2023 and 2024. In 2023 Hydro Ottawa charged its customers the approved WMS rate of $0.0048 and the WMSC rate charged to Hydro Ottawa was $0.0043; therefore Hydro Ottawa recorded a credit principal amount of $8.1M to RSVA - WMS.

In 2024, the approved WMS rate increased to $0.0055, caused by the RRRP charge increasing from $0.0007 to $0.0014, while the WMSC rate charged to Hydro Ottawa increased to $0.0049. Hydro Ottawa still recorded a credit principal amount in 2024, but smaller than 2023. The new amount for 2024 is a credit principal amount of $4.1M to RSVA - WMS (a total of $4.3M including principal and interest).

Table K - 2023 & 2024 Account 1580 Breakdown

	2023 ($)	2024 ($)
WMS Collected from Customers	($30,528,367)	($30,838,175)
WMS Expense	$22,765,521	$27,504,365
WMS Variance	**($7,762,846)**	**($3,333,810)**
RRRP Collected from Customers	($5,212,003)	($10,517,714)
RRRP Expense	$4,868,990	$9,769,709
RRRP Variance	**($343,013)**	**($748,006)**
RVSA Wholesale Market Service Principal	($8,105,859)	($4,081,815)
Interest	($577,524)	($194,943)
RVSA Wholesale Market Service (Principal and Interest)	($8,683,383)	($4,276,759)

Hydro Ottawa purchases approximately 90% of its power supply from the IESO and the remaining 10% from Hydro One and embedded generators. Hydro One charges Hydro Ottawa the 2024 WMS approved rate. Table L below provides a comparison of the WMSC rate incurred by Hydro Ottawa and the 2024 WMS approved rate billed for WMS revenue to distribution customers.

Table L - Wholesale Market Service Charge Revenue & Expense Rates (Principal)

	2024 Revenue Collected	2024 Total WMS Charge
WMS Collected from Customers	($30,838,175)	$27,504,365
RRRP Collected from Customers	($10,517,714)	$9,769,709
Adjusted kWh	**7,499,777,866**	**7,551,358,287**
Average $/kWh	($0.0055)	$0.0049

Account 1586 RSVA – Transmission Connection charge (‘Account 1586’):

The transmission connection charge includes Transmission Line Connection Service Charge (TLCC) and Transformation Connection Service Charge (TCSC). In addition, Account 1586 includes transmission connection charge (TCC) Hydro Ottawa collects based upon the Board approved rates and Hydro One switchgear credits.

For the fiscal year of 2024, the main drivers for the decrease in Account 1586 from 2023 is the rate difference between the 2023 and 2024 IESO TLCC and TCSC incurred by Hydro Ottawa and the TCC rates that Hydro Ottawa charges its customers. Table M below shows the breakdown of the balances recorded in Account 1586 in 2023 and 2024.

In 2023 Hydro Ottawa charged its customers the average approved TCC rate of $0.0057/kWh for non commercial customers and an average rate of $2.29/kW for commercial customers. The TLCC rate charged to Hydro Ottawa was an average rate of $0.090 and the TCSC rate charged to Hydro Ottawa was an average rate of $3.04, resulting in an overall average rate of $2.45/kW.

Hydro Ottawa recorded a debit principal amount of $90k to RSVA - Transmission Connection (a total of $128k when including principal and interest). In 2024, the approved TCSC rate increased to an average rate of $0.0063/kWh for non commercial customers and an average rate of $2.47/kW for commercial customers, while the TLCC rate charged to Hydro Ottawa increased to $0.095 and TCSC rate increased to a rate of $3.21, resulting in an increased overall rate of $2.59/kW. With the change in rates, and an increase of Hydro One switchgear credits from $3.7M to $4.0M, Hydro Ottawa recorded a credit principal amount in 2024 of $4.2M to RSVA - Transmission Connection (a total of $4.4M when including principal and interest).

Table M - 2023 & 2024 Account 1586 Breakdown

	2023 ($)	2024 ($)
Transmission Connection Collected from Customers	($39,968,482)	($44,754,301)
HONI Switchgear Credit	($3,741,637)	($4,005,081)
Transmission Connection Expense	$43,799,637	$44,594,758
Transmission Connection Variance	**$89,517**	**($4,164,624)**
RVSA Transmission Connection Principal	$89,517	($4,164,624)
Interest	$38,068	($219,275)
RVSA Transmission Connection (Principal and Interest)	$127,586	($4,383,898)

Hydro Ottawa purchases approximately 90% of its power supply from the IESO and the remaining 10% from Hydro One and embedded generators. Hydro One charges Hydro Ottawa the 2024 TCSC approved rate. Tables N-P below provides a comparison of the WMSC rate incurred by Hydro Ottawa and the 2024 WMS approved rate billed for WMS revenue to distribution customers.

Table N - 2023 & 2024 Non Commercial Transmission Connection Revenue Rates (Principal)

	2023 Revenue Collected	2024 Revenue Collected
Transmission Connection Collected from Customers	($18,622,598)	($21,088,548)
Non Commercial Adjusted kWh	**3,283,515,756**	**3,356,413,668**
Average $/kWh	($0.0057)	($0.0063)

Table O - 2023 & 2024 Commercial Transmission Connection Revenue Rates (Principal)

	2023 Revenue Collected	2024 Revenue Collected
Transmission Connection Collected from Customers	($21,345,884)	($23,665,753)
Total kW	**9,301,809**	**9,587,412**
Average $/kW	($2.29)	($2.47)

Table P - 2023 & 2024 Connection Charge Expense Rates (Principal)

	202 Revenue Collected	2024 Revenue Collected
Transmission Connection Charge IESO	$42,216,382	$42,855,234
Transmission Connection Charge HONI	$1,583,255	$1,739,525
Units Billed IESO - Line Charge	**13,166,876**	**12,872,883**
Units Billed IESO - Transformation Charge	**10,024,759**	**9,583,284**
Units Billed HONI	**535,865**	**520,754**
Average $/kW	$2.45	$2.59

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION OTTAWA

JT3.28

EVIDENCE REFERENCE:

BOMA-3

UNDERTAKING(S):

Provide year-by-year comparison of CAGR for 2026, 2027, 2028, 2029 and 2030

RESPONSE(S):

Table A provides the requested comparison of the Compound Annual Growth Rates (CAGR) in References 1, 2 and 4 provided within 3.1-BOMA-3, along with other references as noted in Table A. In providing this information, Hydro Ottawa cautions that these references are not directly comparable due to fundamental differences in their methodologies and objectives. Hydro Ottawa further submits that the appropriateness and usefulness of this comparison is limited by the fact that these three forecasts serve very different purposes and have different scopes and metrics. These differences are summarized in Table B below and further explained in the narrative following the table.

Table A - Peak Demand (MW) CAGR Comparison

3.1-BOMA-3 Reference Number	Forecast Name	Peak Demand (MW)				
		2024	2025	2026	2030	CAGR
Reference 1	Decarbonization Study Reference Scenario		1,620		2,357	7.8%
N/A	IRRP Forecast		1,635	1,732	2,463	8.5%
N/A	Planning Forecast		1,792	1,947	2,336	5.4%
Reference 2	Cost Allocation Model			1,408	1,420	0.2%
Reference 4	Itron Revenue Load Forecast	1,535	1,541	1,556	1,615	0.9%

Table B - Comparison of Forecast Assumptions

Source	Purpose	Assumption type	Source	Comments
3-BOMA-3.1 Reference 1: Decarbonization Study Reference Scenario	Scenario modelling to inform long-term regional planning and near-term cost-effective asset sizing investment decisions.	Population	2023-2026: Based on planned substation capacity expansion 2027-2050: Based on population growth projections from City of Ottawa	2030 Population: 1,203,968; 2050: 1,448,120
		Historical load	Station level, weather normalized from time of system coincident peak Weather normalized	Ten years of actual metered hourly load data by customer class, 2012-2022
		Equipment efficiency	Gatineau Corridor End-of-Life Study	
		Electrification load profile	Decarbonization Profile- Target for Buildings in Canada by Canadian Federal Government as well as decarbonization levers from Black & Veatch	HOL provided adjusted short term load data
IRRP Forecast (Section 9.4.2 of Schedule 2-5-4)	Long term regional planning leveraging the Decarbonization Study Reference Scenario and	N/A	All factors are the same as the Decarbonization Study Reference Scenario	

Source	Purpose	Assumption type	Source	Comments
	other information related to large load requests.	Large Load Requests	Signed offer to connect and submitted load summary	Considers non-coincident peak demand requirement per customer request
Planning Forecast (Section 9.4.1 of Schedule 2-5-4)	Determine near-term capacity investments requirements to address already constrained regions and areas with immediate investment needs to meet the utility's obligation to serve customers	Population	Growth projections for Official Plan- Population, Housing, Employment	Average Annual growth%
		Historical Load	Station level, weather normalized from time of system coincident peak	2013- 2023: weather normalization 2023: starting point
		Equipment Efficiency	N/A - Planning Forecast is completed on a gross basis (excluding efficiency & CDM)	
		Development plans	City of Ottawa Official Plan, City planning circulations, Community Design Plans, developers	Considers non-coincident peak demand requirement per development
		Large Load Requests	Signed offer to connect and submitted load summary	Considers non-coincident peak demand requirement (including reserved capacity) per customer request
3-BOMA-3.1 Reference 2: Cost Allocation Models, Tab I8 Demand Data	Develop monthly coincident and non-coincident peak profiles by customer class that inform the proportionate allocation of demand related costs in the OEB cost allocation models.	Historical load	Weather Normalized	Five years of actual metered hourly load data by customer class, 2020-2024
		Large load and electrification	Signed offer to connect and certain submitted load summary	
		Historical weather data	Environment Canada	Ten years of historical data from two Ottawa weather stations: Experimental Farm and Ottawa Airport

Source	Purpose	Assumption type	Source	Comments
		Historical Averaging Technique	Internal hourly metered data for 2020-2024	Demand profiles modeled by projecting the 5 years of historical results to the test years.
3-BOMA-3.1 Reference 4: Revenue load forecast - System MW Peak	Used to forecast demand related charges in the cost of power estimate for working capital expenses	Population	Conference Board of Canada	Data as of September 2024
		Economic	Conference Board of Canada	Data as of September 2024
		Historical supply load data	Aggregated IESO, Hydro One, and Generation	Ten years of historical data
		Historical load	Billed and unbilled customer load data	Weather Normalized for years 2013 to October 2024.
		Equipment efficiency	NRCan, historical CDM & eDSM	Data as of September 2024 & February 2025
		Electrification hourly load profile	Black & Veatch	
		LDEV	Ministry of Transportation, Zero Emission Vehicle Infrastructure Program (ZEVIP) and customer data	
		Large load and electrification	Signed offer to connect and certain submitted load summary	Considers impact on system coincident peak per customer request, as load is planned to materialize

Please also see response to undertaking JT4.14, which provides additional details regarding large loads embedded in the planning and revenue load forecasts.

<u>System Capacity Planning Information</u>

As outlined in section 9.4 of Schedule 2-5-4 - Asset Management Process, Hydro Ottawa's capacity planning process evaluates the distribution grid's ability to serve current and future customers safely and reliably, using the system load forecast as its foundation. The system load forecast was informed by two types of forecasts: Hydro Ottawa Planning Forecast and the IRRP Forecast. Further, Hydro Ottawa utilized Decarbonization Study's Reference Scenario forecast to inform its IRRP forecast along with the impact of large load requests. Each of these capacity planning forecasts/studies is further discussed below.

Planning Forecast (Section 9.4.1 of Schedule 2-5-4 - Asset Management Process, page 300): The Planning Forecast is designed to project station-level load increases and serves as the primary instrument for assessing and anticipating the immediate needs of the distribution system, ensuring that near-term capacity investments are strategically informed. The planning forecast is a gross model and must consider forecasted non-coincident peak demand without the impacts of equipment efficiency or CDM benefits, to ensure that the system is reliable and capable of serving customers during system, regional and local peaks. As well, assumptions related to equipment efficiency and CDM are only available at the aggregate system level and cannot be appropriately translated to the impacts on the local, station level. Hydro Ottawa currently has limited visibility and control over these assumptions as they relate to behind-the-meter activities. If planning were conducted on a net basis there would be a significant risk that the potential reductions from efficiency and CDM may not materialize as forecasted leaving exposing a risk in meeting the capacity needs of that station and the customers it serves.

Key inputs and considerations for this forecast include:

- Guidance from the City of Ottawa’s Official Plan, City planning circulations, Community Development Plans (CDPs), and consultations with developers.
- Historical weather-normalized load based on the system coincident peak (currently summer) at the station level.
- Planned residential, mixed-use, and employment developments.
- Known large load requests and customer requests currently in the initial planning phases.
- Gross basis - Equipment Efficiency and CDM benefits not applied

It is important to note that while the planning forecast includes known large load requests driven by the electrification of heating and transportation in major institutions, it does not explicitly model the systemic impacts of broader space heating and transport electrification, which were modelled as part of the Reference Scenario from the Decarbonization Study.

As noted in the response to interrogatory 2.5-BOMA-2, and further articulated by the Panel 1 witnesses at the Technical Conference, Hydro Ottawa used the Planning Forecast (rather than Reference Scenario from the Decarbonization Study) to determine the needs of the system in the 2026-2030 rate term based on already constrained regions and areas with immediate investment needs to meet the utility's obligation to serve customers. Hydro Ottawa considered the Reference Scenario from the Decarbonization Study to inform the longer-term IRRP forecast, and to confirm that immediate capacity investments, guided by Hydro Ottawa's planning forecast, strategically support long-term needs, thereby optimizing capital deployment and asset utilization.

Decarbonization Study Reference Scenario (3.1-BOMA-3 Reference 1): As outlined in section 2.1.4 of Schedule 2-5-1 - Distribution System Plan, on page 49, Hydro Ottawa commissioned Black & Veatch in 2023 to conduct a Decarbonization Study, included in this Application as Attachment 2-5-4(F) - Decarbonization Study, to evaluate the potential impacts of societal electrification trends on Hydro Ottawa's distribution system out to 2050 with a scenario-based approach. Through working as part of the IESO's Decarbonization Sub-Working Group Hydro Ottawa identified the need to complete this study as traditional forecasting methods which primarily rely on historical consumption patterns and projected growth based on known and observable trends fail to capture the uncertainties introduced by decarbonization goals and the resulting electrification of building, water heating and transportation. Five scenarios with varying assumptions of decarbonization initiatives on the distribution system are assessed in the Study with refinement from the Decarbonization Sub-Working Group.

The Reference Scenario projects gradual decarbonization in the short term, followed by increasing policy-driven electrification in the mid- to long-term, aiming to meet Canada's 2030 Emissions

Reduction Plan and 2050 decarbonization targets. Hydro Ottawa used the Decarbonization Study's Reference Scenario forecast to inform its Integrated Regional Resource Plan (IRRP) forecast.

IRRP Forecast (Section 9.4.2 of Schedule 2-5-4 - Asset Management Process, page 302): The Reference scenario was instrumental in developing the Integrated Regional Resource Plan (IRRP) forecast for regional transmission planning. Alignment with this Decarbonization Reference Scenario over the medium to long term is crucial for the regional planning process, as transmission-level investments in the provincial grid require lead times exceeding five years. This alignment also enables Hydro Ottawa to confirm that immediate capacity investments, guided by Hydro Ottawa's planning forecast, strategically support long-term needs, thereby optimizing capital deployment and asset utilization. Hydro Ottawa included the impact of Large Load requests received after the creation of the Decarbonization Study within the IRRP Forecast.

Rates and Revenue Forecasting Information

The revenue load forecast and resulting cost allocation demand profiles center on billing consumption, and demand for rate-setting purposes. The assumptions for these forecasts are more aggregated (not location specific), with consideration of economic trends, population growth, energy efficiency initiatives, and the impact of electricity demand-side management (eDSM) programs. Their main purpose is to forecast billing load at an aggregate rate class level and support cost allocation.

Cost Allocation Model (Reference 2 in 3.1-BOMA-3): Reference 2 in 3.1-BOMA-3 refers to the demand profile allocators on Tab I8 Demand Data of the OEB cost allocation model. The demand profile models are developed for the purpose of allocating demand related costs to customer classes based on their modeled proportionate impact on coincident and non-coincident peaks in the test years. The OEB cost allocation model determines whether that impact will be based on one, four or twelve monthly peaks[1]. The model process scales up weather-normalized historical actual hourly load data for the most recent five years, at the customer class level, and then identifies monthly peaks based on those historical load shapes. Five sets of peak data are established for each test year and then a trend methodology[2] is applied to predict the test year peak demand

[1] Table A above reflects the one top month system peak (CP1) for the years presented.
[2] Refer to Attachment 7-1-1(G) - 2026 Demand Allocators for details on the trend method

values. This is a different process than the Itron sales forecast. Demand profiles are built on a bottom-up basis using weather normalized hourly load data without consideration of the other socio-economic factors that inform the sales forecast. Further, the demand factors are created using a historical trending technique rather than multivariate regression. The result is a set of factors that represent proportionate customer class impacts but do not equate to the revenue load forecast.

Itron Revenue Load Forecast (Reference 4 in 3.1-BOMA-3)

Reference 4 of interrogatory 3.1-BOMA-3 refers to the system forecast output from the Itron revenue load forecast and was based on historical data and the impact of electrification and large loads on the system hourly peak.

The main function of the system MW forecast output from Itron is to forecast billing determinate data in order to set distribution rates based on expected customer count and capacity or demand. It also creates a system purchase and peak forecast. This data supports charges in the cost of power estimate for working capital expenses. This historical rate class billed and unbilled data, with consideration of economic trends, population growth, energy efficiency initiatives, and the impact of electricity demand-side management (eDSM) programs support the forecast. The historical purchased data system peak demand (MW) is derived from aggregated hourly commodity purchases data from the IESO, Hydro One and Embedded Generation delivery points. The historical baseline sales (MWh) and demand (kW) are monthly billed amounts aggregated by rate classification. The sales and purchases model validates historical outcomes with past economic trends, population growth, energy efficiency initiatives to support model outcomes for the future forecast.

To forecast the system peak in the revenue load forecast, the baseline system peak is derived through a monthly regression model driven by the rate class level baseline sales (MWh) forecast. The baseline forecast includes the impact of CDM and eDSM, however does not include the impact of electrification. To incorporate electrification, the electrification large load forecast was layered on top of the baseline system peak forecast through the use of hourly profiles for LDEVs, and large loads.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT4.4

EVIDENCE REFERENCE:

1-Staff-1(C)

UNDERTAKING(S):

Provide updated DVA continuity schedule, Tab 2A, that reflects the OEB approved disposition of account 1595, sub account 2020.

RESPONSE(S):

The OEB approved disposition amount for Account 1595 (2020) was incorrectly included in the "Transactions Debit / (Credit) during 2024" column (cells BD35 and BI35) in the Deferral and Variance Account (Continuity Schedule) workform provided in interrogatory 1-Staff-1(C). The 2024 closing principal and interest balances remain correct and do not require modification. A revised Deferral and Variance Account (Continuity Schedule) has been provided showing the OEB-approved disposition amount in the correction columns. Please see Attachment JT4.4(A) - OEB_Workform - 2026 Deferral and Variance Account (Continuity Schedule).

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT4.6

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

Compare proposed PILs contribution methodology by Hydro Ottawa with CCA smoothing mechanism previously approved by OEB in two referenced proceedings and explain impact on rate stability, intergenerational equity and proposed 2026 to 2030 revenue requirement.

RESPONSE(S):

Under the Accelerated Investment Incentive (or Accelerated CCA) rules of Bill C-97 the Budget Implementation Act 2019, Hydro Ottawa was able to deduct up to three times the amount of tax depreciation that would otherwise be available in the year that an asset is acquired and available for use. This is achieved by removing the “half-year” rule and then applying the prescribed CCA rate at 1.5 times on the net qualifying additions for the given year. This Accelerated CCA is available for assets acquired and available for use after November 20, 2018 and before 2024.

A phase-out period will begin for capital assets that become available for use after 2023. For assets acquired after 2023 and before 2028, the “half-year” rule is still not applied and the Accelerated CCA rules will allow Hydro Ottawa to deduct tax depreciation that is two times the amount of tax depreciation that would otherwise apply in the year that an asset is acquired and available for use. The Accelerated CCA rules will no longer be available for assets acquired after 2027.

Accelerated CCA does not change the total amount of CCA that Hydro Ottawa can deduct over the tax life of the eligible capital assets. This Accelerated CCA is only available to be claimed in the first tax year that the eligible capital assets are acquired and available for use. By claiming a larger CCA deduction in the first year, Hydro Ottawa will have smaller CCA deductions available in future years. In general by deducting more CCA in the first year of asset acquisition, taxable income for that first year would decrease. However, less CCA would be available from those assets after the first year and correspondingly taxable income would increase in subsequent years. The assets acquired have long useful lives (weighted average useful life is 36 years for Hydro Ottawa).

Furthermore, on December 16, 2024, the Federal Fall Economic Statement (FES 2024) for 2024 was tabled in Parliament and the FES 2024 proposes to reinstate the Accelerated Investment Incentive (or Accelerated CCA). As previously stated, Bill C-97 which contained the original accelerated CCA legislation was to be gradually phased out starting in 2024 and would not apply to capital property available for use after 2027. The FES retained the 2024 phase out period for Accelerated CCA, but fully reinstates Accelerated CCA from 2025 with a phase out starting in 2030, and will not apply to capital property available for use after 2033. Under the re-instated Accelerated CCA proposals, eligible capital property that would normally be subject to the half-year rule would qualify for a CCA equal to three times the normal first-year deduction if it becomes available for use from 2025 to before 2030. The proposed phase out period will be reinstated from 2030 to 2033 (instead of 2024 to 2027) and would allow eligible capital property that would normally be subject to the half-year rule qualify for a CCA equal to two times the normal first-year deduction. The reinstatement of Accelerated CCA was announced on December 16, 2024 and draft legislation has not yet been introduced nor enacted by Parliament.

During the Technical Conference proceeding, OEB staff requested that Hydro Ottawa compare its CCA PILs contribution method[1] to other CCA smoothing methodologies that have already been approved by the OEB in prior proceedings. The OEB referenced three other prior proceedings. (1) Algoma Power Inc. 2025 cost of service application (EB-2024-0007), (2) PUC Distribution Inc. 2023 cost of service application (EB-2022-0058). Please note that the EB 2022-0058 is the Cost of

[1] EB-2024-0115, Schedule 9-1-4 - Account 1592 PILS and Tax Variance, Section 7, page 7.

Service for Ottawa River Power Corporation, the correct EB number for PUC Distribution Inc. Cost of Service is EB-2022-0059. Furthermore, in the OEB Settlement Submission for Algoma Power Inc. a reference was made to an approved CCA smoothing in the proceeding for (3) Brantford Power Inc. 2022 Cost of Service (EB 2021-0009).

Hydro Ottawa has reviewed these three prior proceedings and compared them to the CCA contribution method proposed by Hydro Ottawa. The three prior proceedings are similar to each other but vastly different from Hydro Ottawa's CCA methodology. The three prior proceedings proposed to smooth the phase out periods of Accelerated CCA by spreading out the increase in taxable income (which increases grossed up PILs) when Accelerated CCA is completely eliminated after 2027 or when Accelerated CCA is reduced from three times to two times regular CCA (from 2024 to 2027). Algoma Power Inc proposed to add an average $212K to taxable income per year over a five year period (from 2025 to 2029) to offset the increase in taxable income in 2028 and 2029 when Accelerated CCA is no longer being available in 2028 and 2029 (Accelerated CCA is eliminated after 2027). Both PUC Distribution Inc. and Brantford Power Inc. proposed to smooth out the Accelerated CCA phase out period of 2024 to 2027 (when Accelerated CCA drops from three times to two times regular CCA) over a five year period. Both PUC Distribution Inc. and Brantford Power Inc. added an average amount to taxable income over a five year period. For PUC Distribution, $197K per year was added to taxable income for the period from 2023 to 2027 and for Brantford Power Inc., $154K per year was added for the period from 2022 to 2026. All five year CCA smoothing proposals were to smooth the phase out of Accelerated CCA in the immediate five year period of their Cost of Service applications.

From Hydro Ottawa's review of the three proposals, the following is observed regarding the smoothing approaches, it:

- Protects the LDC from incorporating a PILs benefit in the base year that is not reflective of a PILs benefit in the entire IR term (without requiring a mechanism to remove it)
- Smooths rates by averaging the benefit in the early years of the rate term over five years (customers do not experience fluctuating rates)
- Provides a greater benefit to new customers past the first year of the 5 year rate term

- Does not address intergenerational issues past the 5 year rate term; current customers receive a larger proportion of the tax benefit of new assets
- No interest (carry charges) appears to be incorporated as a result of the delay of the PILs benefit being provided to the customers over the rate term. However, Hydro Ottawa has not compared the lost interest to the impact of the Price Cap IR formula on the smoothed PILs portion of the revenue requirement to compare the difference to customers.

Should the Federal Government decide to reinstate the Accelerated CCA to 2033 (which also includes a change in the phase out period from 2024 to 2027 to 2030 to 2033) as introduced in FES 2024, then the above three OEB-approved CCA smoothing methodologies would need to be reviewed to see how to incorporate this extension of the Accelerated CCA rules.

Hydro Ottawa's Accelerated CCA methodology is completely different from the three CCA smoothing methodologies previously approved by the OEB. Hydro Ottawa also has larger differences between Accelerated CCA and regular CCA for the 2026 and 2027 Test Years. Please see Updated Tables 3 and 4 below; the original tables are located in Schedule 9-1-4, Section 7. In the response to Technical Conference undertaking JT4.5, Hydro Ottawa has updated the CCA schedules provided in 9-Staff-214 to reflect the updated evidence as provided in the response to interrogatory 1-Staff-1. These supporting CCA schedules can be found in the response to Technical Conference undertaking JT4.5 as Attachment JT4.5(A) - CCA Schedule 2026 & 2027 NO Accelerated CCA and Attachment JT4.5(B) - CCA Schedule 2026 & 2027 Accelerated CCA.

Updated Table 3 - Impact of "Regular" CCA Rules vs. Accelerated CCA Rules for 2026 and 2027 Test Years ($'000s)

Year	Test Year Additions	Prior "Regular" CCA	Accelerated CCA	Difference in CCA	Difference in Grossed up PILS
2026	$ 206,565	$ 89,431	$ 103,321	$ 13,890	$ (5,008)
2027	$ 288,267	$ 109,779	$ 122,891	$ 13,112	$ (4,727)

Updated Table 4 - PILs Contribution ($'000s)[2]

Test Year	Accelerated CCA Grossed Up PILS Difference	2021 Immediate Expensing Grossed Up PILS Difference	Total Grossed Up PILS Difference Included in Revenue Requirement
2026	$ (5,008)	$ (476)	$ (5,484)
2027	$ (4,727)	-	$ (4,727)

Hydro Ottawa is proposing to exclude the impact of the decrease in Grossed Up PILs due to Accelerated CCA for 2026 and 2027 Test Years and the impact in the decrease in accumulated Grossed Up PILs due to the 2021 immediate expensing measure in the proposed revenue requirement for 2026 and 2027. Hydro Ottawa is proposing to record a corresponding amount in the fixed asset subledger (similar to Capital Contributions received from customers) and amortize these amounts over 36 years (the weighted average life of the assets they relate to). This will allow Hydro Ottawa to distribute the Grossed Up PILs difference for both the 2026 and 2027 Accelerated CCA and the 2021 immediate expensing measure over 36 years instead of allocating the entire decrease in Grossed Up PILs to ratepayers in a single year or over five years. Hydro Ottawa's proposal is focused on reducing intergenerational impacts related to Accelerated CCA and immediate expensing while providing the benefit to customers through amortization of the contribution and related cost of capital impacts on rate base. Prior CCA smoothing methods approved by the OEB only smoothed out the phase out of Accelerated CCA over the immediate five year period to accommodate the Price Cap period that is impacted by the PILs calculation and smooth rates. Hydro Ottawa's approach is external to the PILs calculation.

Hydro Ottawa's proposal:

- Smooths rates by removing the PILs impact of Accelerated CCA;
- Returns the impact of Accelerated CCA to customers over 36 years which provides generations of customers the benefit of the tax credit against the cost of the asset;
- Reduces the cost to customers related to the cost of capital, which includes short term and long term debt and return on equity, which in the long term reduces overall costs of rates.

[2] Please note these amounts do not match what has been included in Revenue Requirement, which are from an earlier calculation.

If Hydro Ottawa was to adopt a similar proposal to the others', Hydro Ottawa's revenue requirement would decrease by approximately $10M (please see interrogatory 1-CCC-2 Table B for total 5 year revenue requirement impact), resulting in the continuation of intergenerational issues. Specifically, based on the 36 year methodology, customers will pay for approximately 13% of the asset in the first five years for assets put in service in 2026 while 34% of the tax benefit will be used during the same period. For assets put in service in 2027 approximately 10% of the asset will be paid through depreciation while approximately 28% of the tax relief will be experienced. This is an increase of 2.9% and 3.1% above the normal application of taxes.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT4.7

EVIDENCE REFERENCE:

9-Staff-205

UNDERTAKING(S):

File a copy of the updated drafting accounting order.

RESPONSE(S):

Please see Attachment JT4.7(A) - Hydro Ottawa 2026-2030 Draft Accounting Orders for CCRAs, Tariff (related to JT4.12) and Earning Sharing Mechanism (relation to JT3.19.)

Draft Accounting Order
Hydro Ottawa Limited
EB-2024-0115

Sub-Account 1508 - Other Regulatory Assets - Symmetrical Connection Cost Recovery Agreement (CCRA) Payments Differential Variance Account

Hydro Ottawa shall maintain the use of this 1508 Sub-Account. Effective January 1, 2026, for in-service CCRAs in 2026–2030 that include both new and existing CCRAs, Hydro Ottawa shall record the revenue requirement difference between what Hydro Ottawa has included in base rates and what is actually paid for in both new and true-up CCRA payments made to Hydro One Networks Inc. The Account is symmetrical and any difference will be collected from or refunded to customers.

With respect to new CCRA payments, Hydro Ottawa shall record the difference in depreciation, interest, return, and payment in lieu of taxes ("PILS") components of the revenue requirement impact of new CCRA payments once the assets (to which the CCRA payment relates) provide services to Hydro Ottawa customers and are capitalized. With respect to true-up CCRA payments, Hydro Ottawa shall record the difference in depreciation, interest, return, and PILS components of the revenue requirement impact of true-up CCRA payments once capitalized.

The following is a sample journal entry of the symmetrical account which reflects a balance to be collected as actual CCRA payments are higher than forecasted. Should the actual monthly in-service CCRA capital addition be less, the entries would result in Account 1508 being debited and the other accounts being credited.

The journal entries would continue until Hydro Ottawa's next Custom IR application or rebasing, at which point the residual balances will be requested to be cleared, recovered from, or returned to customers, and the CCRA balance net of accumulated depreciation would be recovered through rate base.

Sample Journal Entries

A) Monthly journal entries to capture the revenue requirement difference to be recovered from customers where the actual monthly in-service CCRA capital addition is more than the forecasted amount.

Account	Debit	Credit
Account 1508 - Sub-Account CCRA - Depreciation	x,xxx.xx	
Account 1508 - Sub-Account CCRA - Interest	x,xxx.xx	
Account 1508 - Sub-Account CCRA - Return	x,xxx.xx	
Account 1508 - Sub-Account CCRA - PILs	x,xxx.xx	
Account 4080 – Distribution Services Revenue		x,xxx.xx

This account would accrue carrying charges at OEB-prescribed rates until final disposition.

The balance will be disposed of as part of the Group 2 Accounts and in accordance with the OEB's direction regarding the disposition of Group 2 accounts.

Draft Accounting Order

Hydro Ottawa Limited
EB-2024-0115

Sub-Account 1508 - Other Regulatory Assets – Tariff impact deferral account

This new 1508 Sub-Account, effective January 1, 2026, is to record the monthly revenue requirements to recover additional costs incurred during the test period directly attributable to imposed global tariffs, including retaliatory tariffs. Amounts related to operation, maintenance and administration (OM&A) would be recorded at the time of expenditure while capital related revenue requirement [depreciation, interest, return, and payment in lieu of taxes ("PILS")] would be recorded at the time the asset is put into service.

Hydro Ottawa shall continue to record variances in this account until the utility's next rebasing period.

This account will accrue carrying charges based on OEB-prescribed interest rates until final disposition.

Sample Journal Entries

To record the additional cost due to global tariffs.

A) To capture the revenue requirement recovered from customers where tariff charges are incurred in capital expenditures, when the assets are put into service.

Account	Debit	Credit
Account 1508 - Sub-Account CCRA - Depreciation	x,xxx.xx	
Account 1508 - Sub-Account CCRA - Interest	x,xxx.xx	
Account 1508 - Sub-Account CCRA - Return	x,xxx.xx	
Account 1508 - Sub-Account CCRA - PILs	x,xxx.xx	
Account 4080 – Distribution Services Revenue		x,xxx.xx

B) To capture the revenue requirement recovered from customers where tariff charges are incurred in OM&A expenditures.

Account	Debit	Credit
Account 1508 - Sub-Account - Tariffs	x,xxx.xx	
Account 4080 - Distribution Services Revenue		x,xxx.xx

The balance will be disposed as part of the Group 2 Accounts and in accordance with the OEB's direction regarding the disposition of Group 2 Accounts.

Draft Accounting Order

Hydro Ottawa Limited
EB-2024-0115

Account 1508 Sub-account Earnings Sharing Mechanism ("ESM") Variance Account

Hydro Ottawa shall maintain this existing account, with modifications effective January 1, 2026. The ESM will be a five-year (2026-2030) cumulative asymmetrical account. The purpose of this account is to record amounts related to any cumulative earnings above Hydro Ottawa's approved Return on Equity ("ROE") to be shared on a 50/50 basis above a dead band of 150 basis points if the utility's efficiency cohort determined by the agreed adjusted PEG Benchmarking Analysis remains constant or reduces over the rate period. Should the utility move to a less efficient cohort within the agreed adjusted PEG model, no deadband would apply and all over earning would be shared on a 50/50 basis. The ratepayer share of the earnings shall be grossed-up for any tax impacts and credited to this account.

For the purpose of earnings sharing, the regulatory net income will be calculated in the same manner as the calculation of net income under the Reporting and Record Keeping Requirements ("RRR") filings. This will exclude revenue and expenses that are not otherwise included for regulatory purposes, such as the following:

- Non-distribution activities, which are not part of revenue requirement;
- The amounts recorded into or disposed through regulatory assets/liabilities (specifically, Group 1 Accounts); and
- Changes in taxes/payments in lieu of taxes ("PILS") to which Account 1592 applies, which will be shared through that account rather than through earnings sharing.

Adjustments may also be required to the ESM calculation to ensure there is an appropriate treatment from amounts recorded and/or recovered by way of deferral and variance accounts.

This account will accrue interest based on OEB-prescribed interest rates.

Sample Journal Entries

A) To record any ESM into the account in any year it is required on a cumulative balance. As a result, previous years' entries could be reversed.

Account	Debit	Credit
Account 4080 – Distribution Services Revenue	x,xxx.xx	
Account 1508 – Sub-Account ESM		x,xxx.xx

The balance will be disposed as part of the Group 2 Accounts and in accordance with the OEB's direction regarding the disposition of Group 2 Accounts.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT4.8

EVIDENCE REFERENCE:

1-SEC-21(B)
4.0-VECC-35

UNDERTAKING(S):

Provide a reconciliation of OM&A and capital numbers provided in the appendices to the main evidence with those in 1- SEC-21, Attachment B, RRR data and why RRR data trial balances differ from the information provided in VECC-35 for OM&A

RESPONSE(S):

<u>OM&A</u>

The Reporting and Record Keeping Requirements (RRR) data, as it appears in the Open Data by the OEB, is grouped in the Income Statement by Operating, Maintenance and Administrative (OM&A) Expense. These include the following Uniform System of Accounts (USofAs) accounts:

- Operating Expense: USofAs 5005-5096
- Maintenance Expense: USofAs 5105-5195
- Administrative Expense: USofAs 5205-5215; 5305-5695; 6105; 6205-6225

Table A below presents a summary-level reconciliation of OM&A values[1] for 2023 between Appendix 2-JC, RRR annual reporting and OM&A value (Line 96) used for Schedule 1-3-3 - Benchmarking. Note that the total OM&A between Appendix 2-JC, JA and VECC-35(A) are the same and therefore used interchangeably. The reconciling items described here explain, at a summary level, the account level differences noted between RRR data and the data provided in Appendix JA/JC and Attachment 4.0-VECC-35(A). They apply to all other years of the historical data.

Reconciliation from Appendix 2-JA and JC to OM&A per RRR 2.1.7 Trial Balance

- **Taxes Other than Income Tax -** Property Tax (USofA 6105 Taxes Other than Income Taxes) is included in the presentation of Appendices 2-JA and 2-JC but is not included in the RRR reporting.
- **Ineligible Donations -** Non LEAP donations in USofA 6205 Donations are not eligible for inclusion in the calculation of Revenue Requirement and are excluded from OM&A in Appendices 2-JA and 2-JC but included in RRR report data.

Reconciliation from OM&A per RRR 2.1.7 Trial Balance to PEG - OM&A cost (Line 96) used in Schedule 1-3-3 Benchmarking

Calculation of the OM&A value for the PEG model features an additional set of inclusions and exclusions detailed in the Model Inputs tab of the model. The OM&A costs[2] adjusted from the calculation of PEG costs are:

- High Voltage costs (2B) in USofAs 5014 Transformer Station Equipment Operations Labour, 5015 Transformer Station Equipment Supplies and 5112 Maintenance of Transformer Station Equipment are removed.
- Administration and General costs for USofAs 5510 Demonstration and Selling, 5335 Bad Debt Expense and 6205 Donations are removed.

[1] Administration and General plus Other Deductions per the RRR Trial balance
[2] See adjustments to OM&A for benchmarking in Excel Attachment JT4.8(A) - Updated OEB PEG Benchmarking Forecast Model.

- Total Other Revenues per Appendix 2-H are deducted, per Hydro Ottawa evidence within Schedule 1-3-3 - Benchmarking.
- A low voltage adjustment (1C), sourced from Hydro One Networks, is added to the calculation.

Table A - Appendix 2-JA/JC to RRR and Rate App PEG 2023

	USoA Code	Total- VECC 35(A)
Appendix 2-JA/JC		**112,777,746**
Taxes Other Than Income Tax	6105	$ (1,657,924)
Ineligible Donations	6205	$ 191,936
RRR 2.1.7 Trial Balance		**$ 111,311,757**
High Voltage Adjustment - 2B	5014	$ (344,572)
	5015	$ (73,191)
	5112	$ (925,408)
Demonstrating and Selling Expense	5510	$ (1,005,041)
Bad Debt Expense	5335	$ (1,733,560)
LV Adjustment - 1 C	HONI	$ 126,267
Donations	6205	$ (468,044)
Other Revenues	Appendix 2-H	$ (8,504,262)
PEG OM&A Values for Schedule 1-3-3 Benchmarking		**$ 98,383,947**

In addition to the item notes above, as indicated during Technical conference and written within Schedule 1-5-5 - Accounting Orders, Hydro Ottawa completed a review of the USofA and noticed some items that could be better reclassified. Please see an overview.

Change in OM&A USofA Categorization

- **Property Insurance -** Property insurance is centrally managed and historically was allocated to USofA 5635 and 5012. In reviewing the mapping Hydro Ottawa noticed some costs are more appropriately mapped to transformer stations (USofA Account 5015). Presentation of Appendix 2-JC reflects the property insurance budget format within Facilities and Corporate Costs.

- **Billing & Collecting Contracts -** Information Technology costs for the billing and collection services are managed centrally with Information Technology. Hydro Ottawa updated the mapping to better reflect the actual cost of Billing and Collecting for USofA purposes. Presentation of Appendix 2-JC reflects the budget within the Customer Billing program.
- **Reallocation of Costs Among Categories -** The presentation in Appendices 2-JC is based on Hydro Ottawa's internal reporting. Other mapping changes were completed to better have costs reflected based on the USofA.
  - In an effort to reduce costs within USofA 5085 - Miscellaneous Distribution Expense, costs were identified that could be mapped to specifically defined USofA codes such as 5005 - Operation Supervision and Engineering Maintenance.
  - Costs that support other functional groups historically maintained Hydro Ottawa's cost structure rather than the USofA, for example Billing and Collections support of distribution rates within Finance have been remapped.

<u>Capital</u>

For the benchmarking calculations provided in 1-SEC-21(B) (tab "Capital - 2.1.5.2 Capital and L"), Hydro Ottawa used the Capital Additions information as reported in RRR 2.1.5.2 (column C), with high voltage capital additions removed (column G). Hydro Ottawa confirms that the reference to "CAPEX" noted in cells V2 and V11 is mislabelled and should read "Sum of Total Capital Additions".

The figures in Appendix 2-AA and 2-AB represent annual capital expenditures (CAPEX) which include construction work in progress. Because CAPEX captures money spent during the year, while Capital Additions captures assets that were energized and capitalized (transferred from CWIP) during the year, the figures do not align with Appendix 2-AA or 2-AB.

The benchmarking calculations correctly reconcile to Attachment 2-SEC-33(A) - Capital Programs In-Service Additions and Attachment 2-SEC-33(B) - Capital Expenditures Summary In-Service Additions. This is because all these attachments are reported on the same Capital Additions (or "In-Service") basis.

PEG Model Updates

As a result of Undertakings, two corrections in the updated PEG model, Attachment 1-3-3(G) - OEB Benchmarking Spreadsheet Forecast Model_20250604, should be noted.

First, a correction was made to the delivery volumes between 2024 and 2030 (tab "Model Inputs", cells H14:N14). As noted in the response to JT1.14-VECC-13.0, the CDM supporting data had underreported values. The correct values were added to Hydro Ottawa's forecasted delivery volume between 2024 and 2030 to account for the effects of CDM. This impact does not change Hydro Ottawa's cohort, however does positively impact the position within the cohort range.

Second, it was discovered that the Ontario Energy Board's PEG model template logic for calculating the circuit kilometer averages in tab "Benchmarking Calculations", cells H156:N156, shortened the averaging period from 23 years to 15. Each year's averaging logic, between 2025 and 2030, had the same flaw. The logic was updated to reflect the correct term for averaging circuit kilometers.

The PEG model was also updated to incorporate 2024 actuals based on the Benchmarking Update Calculation 2025, released by the OEB to its efficiency website.

The impact of the two corrections and the 2024 actuals is summarized in Table B.

Table B - Summary of Annual Efficiency Score Results with Corrections

Year	HOL_Attachment 1-3-3(G) OEB Benchmarking Spreadsheet Forecast Model_20250604		Attachment JT4.8(A) - Updated OEB Benchmarking Spreadsheet Forecast Model	
	% Difference (Cost Performance)	**Stretch Factor (Annual Result)**	**% Difference (Cost Performance)**	**Stretch Factor (Annual Result)**
2024	1.70%	3	1.90%	3
2025	1.20%	3	0.80%	3
2026	6.50%	3	6.10%	3
2027	9.70%	3	9.20%	3
2028	11.80%	4	11.30%	4

Year	HOL_Attachment 1-3-3(G) OEB Benchmarking Spreadsheet Forecast Model_20250604		Attachment JT4.8(A) - Updated OEB Benchmarking Spreadsheet Forecast Model	
2029	12.90%	4	12.30%	4
2030	14.40%	4	13.80%	4

The slight cost performance improvement is a result of actual inflationary values (GDP IPI, and average weekly earnings) for 2024 being higher than forecasted, which affects OM&A index growth.

An updated model has been filed as part of this undertaking as Attachment JT4.8(A) - Updated OEB Benchmarking Forecast Model.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT4.10

EVIDENCE REFERENCE:

UNDERTAKING(S):

Provide impact of residential solar and battery by kilowatt and kilowatt hours on best-efforts basis and estimate units if possible.

RESPONSE(S):

Table A details the Residential MW savings assumption for the Home Renovations Saving Program (HRSP) for the basis of converting the demand savings to kWh savings based on a historical ratio, further described in interrogatory response 2-PP-12 b) and c).

Table A - Estimate Residential MW Savings

	2025	2026	2027	2028	2029	2030
Home Renovation Savings Program	(2)	(2)	(2)	(3)	(3)	(3)

Table B provides the HRSP MWh amounts incorporated into Hydro Ottawa's revenue load forecast.

Table B - eDSM HRSP Annual MWh savings used in Hydro Ottawa's Revenue Load Forecast

	2025	2026	2027	2028	2029	2030
Home Renovation Savings Program	(9,875)	(29,920)	(50,565)	(71,830)	(93,735)	(116,295)

Solar panels and battery storage are part of the HRSP program, however incentives are also available for homeowners to install other measures such as heat pumps, smart thermostats, and insulation. Therefore the forecasted annual energy MWh savings outlined in Table B are not exclusive to residential solar and battery installations. Hydro Ottawa does not have information on how much of the Provincial HRSP budgets or targets are allocated specifically to the solar and battery storage measures, therefore we cannot isolate the impact of these measures independently in the total eDSM MWh included in the revenue load forecast. Furthermore, the information from the IESO on the eDSM Program Plan[1] does not provide details on the number of expected units for annual energy savings targets (GWh) or annual budgets ($M).

Hydro Ottawa notes that the anticipated cumulative saving (MWh) represents approximately 1% of Residential load forecast in 2026. In order to determine the impacts on the system peaks, residential usage would need to be mapped to each feeder and feeder level assumption would need to be made, this effort could not be completed in the timeline of the undertakings.

[1] Independent Electricity System Operator, 2025-2027 Electricity Demand Side Management Program Plan (with Beneficial Electrification), (January 2025), Page 5.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT4.14

EVIDENCE REFERENCE:

2-CO-21

UNDERTAKING(S):

Explain differences and why they exist between table A and large-load forecasts for purpose of revenue load forecast.

RESPONSE(S):

The revenue load forecast includes the impact of the certain large loads (MW) noted in Figure 4 of Schedule 2-5-1 - Distribution System Plan Overview. Please refer to Table A below for the differences.

Table A - Large Load Breakdown Included in Revenue Load Forecast

Forecast	Stage		2025	2026	2027	2028	2029	2030
Planning forecast	Signed offer to connect	*MVA*	13.9	47.9	75.5	113.2	113.2	113.2
Planning forecast	Submitted load summary form	*MVA*	7.0	24.9	29.2	61.3	62.4	71.3
Revenue load forecast	Signed offer to connect	*billed peak MW*	8.1	14.9	22.1	57.5	88.6	95.9
Revenue load forecast	Submitted load summary form	*billed peak MW*	0.0	2.0	6.0	10.0	20.0	28.0
Revenue load forecast % to planning	Signed offer to connect		59%	31%	29%	51%	78%	85%
Revenue load forecast % to planning	Submitted load summary form		0%	8%	21%	16%	32%	39%

The MVA demand from large load requests in the planning forecast is different from the revenue load forecast because the two serve fundamentally different purposes. The planning forecast must ensure the full requested capacity is available to the customer as soon as they energize their facility. This means the system planning must treat the full potential load as a firm commitment. In contrast, the revenue load forecast is an economic planning tool focused on predicting billable energy consumption, which rarely reaches 100% immediately. Load materializes gradually due to real-world factors like phased occupancy, equipment commissioning and testing, and the time needed for business operations to scale up. This gradual materialization is recognized by the Distribution System Code (DSC), which provides customers a connection horizon. Consequently, the percentage of a large project's requested load included in the revenue load forecast is shown to increase over time, reflecting the realistic, slower ramp-up from initial connection to full operational load, accounting for typical delays. Other external factors, such as the project's geographic location and specific industry segment, can also impact the difference between these two forecasts.

In addition, the revenue load forecast excludes any new contractually reserved capacity from customers; the revenue load forecast uses instead the forecasted billing load summary. System planning requires contractually reserved capacity to be factored in, to ensure sufficient system capacity is available should the customer exercise their right to the contractually reserved capacity. Furthermore, 20% of the large load requests were excluded from the revenue load forecast as those specific requests were not yet firmly committed at the time the revenue load forecast was developed.