INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-1

EVIDENCE REFERENCE:

Exhibit 1, Tab 2, Schedule 5, pp. 16, 31-37, 39, 43

QUESTION(S):

a) (P. 16) With respect to the wood pole price trend, please provide the equivalent analysis based on Canadian data.

b) (P. 31) Please confirm that the OEB's labour escalation rate over-compensated Hydro Ottawa during the period 2021-2025 relative to the actual labour costs incurred.

c) (P. 32-34) Please provide the detailed spreadsheets that support the price analysis shown in Tables 25-30.

d) (P. 35) Please provide the detailed spreadsheets that support the price analysis shown in Table 31. As part of the response, please also provide detailed summaries of the outside services contracts reflected in the analysis.

e) (P. 36) Please provide the specific annual labour increases applied to the OM&A and capital program budget. As part of the response, please provide a detailed calculation that shows how the currently negotiated collective agreement, and bank/government forecasts were incorporated.

f) (P. 36) Please provide the specific inflation adjustments (within the range of 2.1% and 5.0%) that were applied to the various categories of equipment and materials. As part of the response, please provide the detailed spreadsheets and input assumptions applied to derive the inflationary adjustments. Please also highlight which capital programs these inflation adjustments are relevant to.

g) (P. 36) For ratemaking purposes, please provide the weighted-average inflation rate applied to each of the proposed OM&A budget (2026) and the proposed capital budget (2026-2030) as reflected in the various program budgets.

h) (P. 36) Please explain the basis for the assumption that "some of the inflationary trends noted in the previous Sections are expected to continue for the 2026-2030 period..."

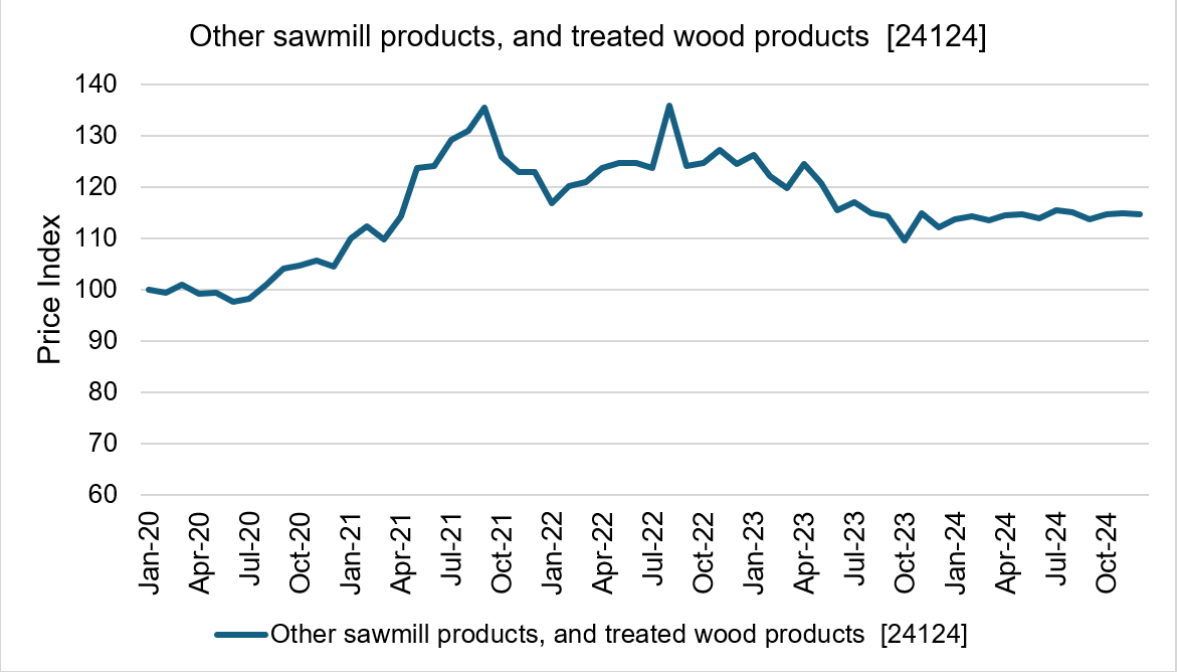
i) (P. 39) Please confirm that the 6.851% utilities machinery and equipment inflation is approximately 66% higher than the overall machinery and equipment inflation of 4.125%. Assuming an overall inflation rate of 2.0%, please confirm that the resulting utility inflation would be 3.32% not 4.7% as calculated by Hydro Ottawa (when holding the incremental inflation applicable to utilities machinery and equipment on a percentage basis constant).

j) (P. 43) Please provide an update to the foreign exchange analysis using the best available information.

RESPONSE(S):

a) Hydro Ottawa uses treated wood poles. Statistics Canada does not produce an equivalent index for treated wood poles. Statistics Canada includes "*Treated wood poles*" (NAPCS 2412422) within the following index, "*Other sawmill products, and treated wood products*" (NAPCS 24124). "*Other sawmill products, and treated wood products*" includes shingles, wood siding, wood ties, fence posts and other treated and untreated wood products. The NAPCS 24124 price index trend is provided as follows:

Figure A - NAPCS 24124 Other Sawmill Products, and Treated Wood Products (2020 to 2024)



Hydro Ottawa primarily uses western red cedar poles whose price trend is more consistent with the Poles price index from the US Federal Reserve Economic Data source. This is demonstrated with the high unit cost increases in Table 28 of Schedule 1-2-5 - Impacts of Inflationary Pressure.

b) The assumption made related to Table 24 - Labour Rate Increases on Page 31 of Schedule 1-2-5 Impacts of Inflationary Pressure is not accurate.

Hydro Ottawa manages its OM&A as an overall envelope over a rate period. The OEB established escalator uses two parameters to inflate rates, labour and non-labour. In Hydro Ottawa's Custom IR approach rebased OM&A was escalated by the combined escalator while capital costs, which also include a labour component, did not have any inflation factored and was additionally subject to a stretch factor. This was also noted on page 31 of Schedule 1-2-5 - Impacts of Inflationary Pressure, "while the escalation of Hydro Ottawa's OM&A labour costs reflected in rates were aligned with the OEB's escalation, planned capital expenditures were not escalated by inflation. This was done to ensure implicit productivity was built in; instead of

including inflation and then decreasing for productivity, Hydro Ottawa did not apply inflation to begin with."

Table 24 compares the Hydro Ottawa's Labour rate increases in comparison to the OEB's Labour escalator and does not translate this to a dollar value. However, as noted on page 31 Table 24 demonstrates "wage increases as per the collective agreement described in Attachment 4-1-3(A) - Employee Compensation Strategy as well as the increases for management employees which "are materially in line with the OEB labour component, as such, are not a significant contributor to higher actual 2021-2025 OM&A." This demonstrated Hydro Ottawa is effectively managing wage increases. However as described above, inflation was not incorporated into capital labour and contributed to the overspend in capital and as such Hydro Ottawa was not overcompensated.

Lastly as noted on page 35 of the same schedule "In addition to its own labour force, Hydro Ottawa engages outside services to support executing OM&A and Capital work programs." and that "Hydro Ottawa procures, negotiates and secures these contracts on an on-going basis and a number of them are multi-year contracts with defined annual escalation rates." And concluded that "Over the 2020-2024 period, the price of some of the most commonly procured outside services increased at a rate of 2% to 11% per year, some of these significantly exceeding the OEB inflation parameters."

c) A detailed spreadsheet was not created to support the price analysis shown in Tables 25-30. The figures presented were derived through a targeted sampling approach, with the tables themselves representing the output of that analysis.

To perform this analysis, the most frequently purchased SKUs were identified within each category (cables, transformers, switchgear, poles, and meters). For each of these representative SKUs, Hydro Ottawa used our ERP system to extract and calculate the average purchase price for 2020 and 2024. The percentage increases were then determined by comparing these average prices.

The data presented in Tables 25-30 of the evidence is the detailed information that resulted from this process. For example for Table 30 (Vehicles), the only additional information that is missing from the table is the actual invoice, purchase order, or quotation numbers. No further or more detailed spreadsheet was generated or is available.

d) A detailed spreadsheet was not created to support the price analysis shown in Table 31. To assess the historical price increases for outside services, Hydro Ottawa focused on its top 10 highest-spend vendors. For each of these vendors, contract terms were reviewed to determine the average annual price increase from 2020 to 2024. The ranges presented in Table 31 reflect the collective average increases for the vendors within each of the four identified service categories.

The summaries of the outside services contracts are provided below, organized by the categories in Table 31. These summaries describe the general scope of work and typical contract terms for the services.

i) **Civil & Electrical**:

- Civil: These contracts are for the provision of Civil Construction & Maintenance Services encompassing general maintenance work for new and existing civil underground distribution plants. Services include tasks such as encasing and rebuilding concrete ducts, direct burying ducts, installing and repairing manholes (including core drilling and cleaning), installing grounding systems, providing pole laterals, trenching, and reinstatement of hard and soft surfaces. Contract terms are typically five years, with a possible two-year extension.
- Electrical: These contracts are for the provision of electrical overhead and underground work on new and existing distribution infrastructure. Services include cable installation, removal, and connector work for primary and secondary cables. Contract terms are typically five years, with a possible two-year extension.

ii) **High Voltage Substation Maintenance**: These contracts provide for a combination of preventive, predictive, and corrective maintenance activities in substations. This includes comprehensive inspections, diagnostic testing, and physical upkeep of key equipment such as transformers, circuit breakers, insulators, and control systems.

iii) **Vegetation Management**: These contracts are for the provision of Live Line Clearing Vegetation Management Services. These services include both planned and as-needed vegetation management for Hydro Ottawa's distribution network, involving tasks like trimming trees, removing vines and other climbing vegetation. Contract terms are typically five years, with a possible two-year extension.

iv) **Technology Support**: The contracts are for the provision of various technology services including software development, enterprise management cloud platforms, and data management tools. Contract terms are typically five years, with a possible two-year extension for support services, or up to ten years for software applications.

e) For the 2026 test year, the annual labour increases applied to both the OM&A and capital program budgets are as follows: an increase of 3.25% is used for unionized employees, as specified in the collective agreement referenced in Attachment 4-1-3(A) - Employee Compensation Strategy, Section 2.4. For management employees, an average annual salary increase of 3.75% is assumed, which is also included in the response to interrogatory 4-Staff-166. The same salary increase rates are applied to our internal labour costs, whether they are allocated to the OM&A or capital program budgets. Regarding a detailed calculation that shows how the collective agreement and external forecasts were incorporated, no single, detailed spreadsheet was created. The methodology used to determine these assumptions is outlined in the response to interrogatory 4-Staff-157. This response details the various sources reviewed to determine our salary forecast projections, including published information from the Bank of Canada and Statistics Canada, as well as specific HR forecast data.

f) See Table A below for the specific inflation adjustments that were applied to equipment and materials.

Table A - Equipment and Materials Inflation Adjustments 2026-2030

Asset Type	Inflation Rate		Relevant Programs
	2026	2027-2030	
Transformer Station Equipment >50 kV	**5%**	**5%**	All System Access, System Renewal, and System Service Programs
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)			
Measurement & Testing Equipment			
Power Operated Equipment			
Communications Equipment			
System Supervisor Equipment			
Tools, Shop & Garage Equipment	**3.0%**	**2.1%**	Tools Replacement
Transportation Equipment	**3.5%**	**3.5%**	Fleet Replacement
Buildings	**3.5%**	**3.5%**	Buildings - Facilities
Buildings & Fixtures			
Computer Software	**3.0%**	**2.1%**	Grid Technologies, Meter to Cash, Enterprise Solutions, and Infrastructure and Cybersecurity
Computer Equipment - Hardware			

Detailed spreadsheets and input assumptions were not used to model these estimates. The analysis of historical costs and assumptions for future inflation were completed through a series of internal discussions and consultations with industry professionals. The budget inflation rates were established based on the collective expertise and reasoned agreement of those involved in these discussions.

g) The weighted-average inflation rates applied to the proposed OM&A budget (2026) and the proposed capital budget (2026-2030) are 3.45% and 3.33%, respectively.

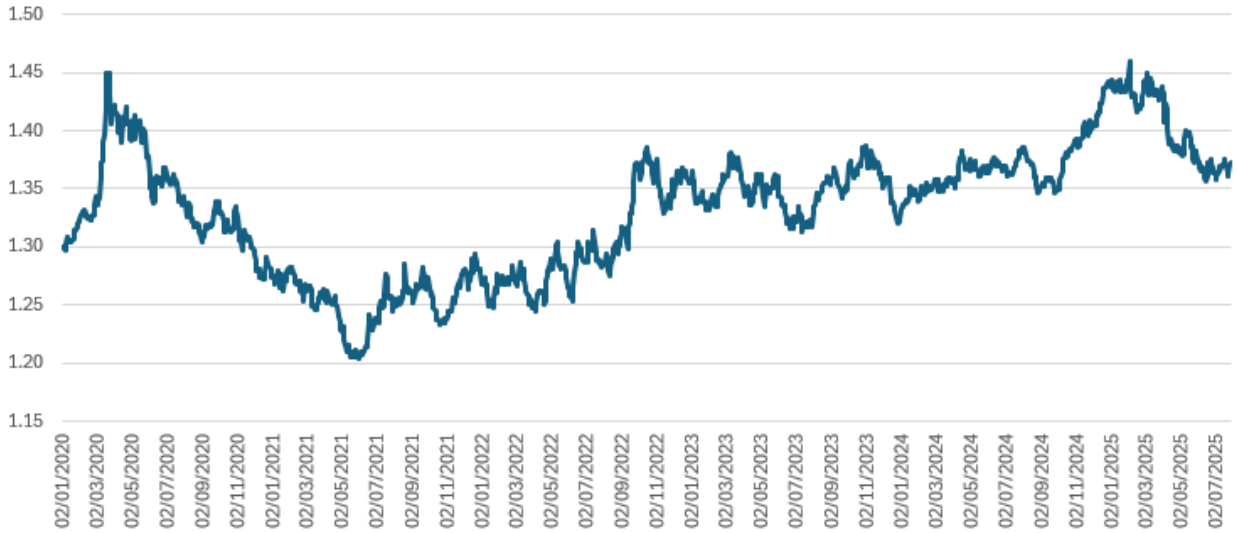
h) Some of the inflationary trends noted in Schedule 1-2-5 Impacts of Inflationary Pressure are general assumptions based on historical trends of Hydro Ottawa's unit costs, as well as the current inflationary economic environment. Increased electrification in Ontario and across North America is creating higher demand for electricity distribution equipment which contributes to driving costs at a higher rate than the overall economy. Discussions with Hydro Ottawa's vendors for certain products and services indicate the recent historical inflation is expected to persist into the future. Statistics Canada's "*Machinery and Equipment*" index shows prices for utilities in January to April 2025 (the latest data available) are 6.0% higher than they were over the same time frame in 2024. Despite lower CPI in 2025, inflation relevant to utilities continues to be higher than general Canadian economic inflation.

i) Confirmed. However, the derivation of the 3.32% figure is based on a proportionate relative calculation and the 4.7% figure in Table 32 is based on an absolute relative calculation. The approach suggested in the interrogatory is an alternate view. The calculation used to derive the 4.7% figure in Table 32 is analogous to the Fisher equation. In the equation detailed in Table 32, the inflation experienced by utilities is the product of overall inflation and utility-specific inflation This calculation is meant to be indicative of the inflation that utilities are experiencing to illustrate that utilities have a higher rate of inflation than other purchasers of machinery and equipment.

j) Figure B below updates Figure 18 included in Schedule 1-2-5 Impacts of Inflationary Pressure.

Figure B - Updated United States Dollar / Canadian Dollar Cross (USDCAD)

January 2020 to July 28, 2025[1]



[1] Bank of Canada, "*Daily Exchange Rates*",https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates-lookup/

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-2

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 1, pp. 13, 15, 16, 23, 29, 32, 34

QUESTION(S):

a) (P. 13) Please advise whether the capital-related revenue requirement shown in Table 2 reflects Hydro Ottawa's proposal with respect to the treatment of the CCA benefit as a capital contribution.

b) (P. 13) Please confirm that the statement that property taxes were included in the capital-related spending as part of Hydro Ottawa's capital-related stretch factor refers to the approved 2021-2025 Custom IR framework methodology.

c) (P. 13) Please confirm, or revise as necessary, the following table which reflects Hydro Ottawa's proposed 2026-2030 revenue requirement (broken out between capital-related revenue requirement and OM&A).

	2026	2027	2028	2029	2030	Total
CRRR	**$ 169.99**	**$ 188.20**	**$ 208.50**	**$ 224.50**	**$ 240.00**	**$ 1,031.19**
Amortization	$67.20	$75.40	$82.30	$88.40	$94.40	$407.70
Income Taxes	$6.60	$6.50	$12.20	$12.70	$15.40	$53.40
Deemed Interest Expense	$36.40	$40.40	$45.30	$49.00	$51.70	$222.80
ROE	$55.20	$61.30	$68.70	$74.40	$78.50	$338.10
PIL Cont.	$ 4.59	$ 4.60				$9.19
Property Taxes						
OM&A	**$ 140.01**	**$ 147.26**	**$ 154.89**	**$ 162.91**	**$ 171.35**	**$776.43**
Service RR	**$ 310.00**	**$ 335.46**	**$ 363.39**	**$ 387.41**	**$ 411.35**	**$ 1,807.62**
Rev. Offset	$ 11.02	$ 10.70	$ 10.86	$ 11.12	$ 11.46	$ 55.16
Base RR	**$ 298.98**	**$ 324.76**	**$ 352.53**	**$ 376.29**	**$ 399.89**	**$ 1,752.46**
CROF	1.0518					

d) Please revise the above table for each of the scenarios discussed below.
   i) Treating the SR&ED tax credits as an offset to PILs (instead of reductions to OM&A and rate base).
   ii) Treating the CCA benefit as it was treated historically (i.e., not as a capital contribution).
   iii) Treating both the SR&ED tax credits and the CCA benefit (i.e., both (i) and (ii) above) as an offset to PILs.
   iv) Including property taxes as a separate line item that forms part of the capital-related revenue requirement.

e) (P. 17) Please provide a specific reference to the 2021-2025 CIR evidence and decision that sets out the previously approved treatment of SR&ED tax credits. Please confirm that Hydro Ottawa's proposed treatment is the same as the previously approved approach. If not, please explain the differences.

f) (P. 17) Please provide reference(s) to the current evidence where the SR&ED credits operate to offset capital and OM&A costs.

g) (P. 23) Please provide the calculation supporting the statement that using quantifiable productivity savings estimated for 2025, the base year OM&A has been reduced by 2.3% which results in a 2027-2030 additional stretch factor embedded in OM&A of 0.61%.

h) (P. 25) Please provide a specific reference within the cost allocation model showing the 54.8% / 45.2% weighting between capacity and customers.

i) (P. 25) Please provide Hydro Ottawa's views on the relationship between capacity/customer growth and OM&A costs.

j) (P. 29) Please confirm that in the 2021-2025 IR term, the costs associated with commercial expansions and capacity upgrades for housing developments were included as part of the scope of the asymmetrical sub-accounts.

k) (P. 32) Please explain how the avoided capital investments resulting from the NWS solutions will be reflected in the NWS Variance Account. As part of the response, please provide an illustrative calculation that shows how the balance in the account will be calculated.

l) (P. 34) With respect the large load requests as reflected in Table 8 of Schedule 3-1-1, please advise whether the Large Load Revenue Variance Account is applicable to all of the demand reflected in the table (given that part of the demand appears to be related to electrification generally instead of large load requests).

m) (P. 34) Please confirm that the Large Load Revenue Variance Account is intended to true-up only the distribution revenue variances resulting from changes in the timing of Large Load connections.

n) (P. 34) With respect to new (or incremental) large load requests beyond those reflected in Table 8 of Schedule 3-1-1, please advise how those will be treated (and whether the associated revenue variance will be included in the Large Load Revenue Variance Account).

o) (P. 34) With respect to revenue requirement changes (between the amount recovered in rates and actual) resulting from variances in the timing of Large Load connections, please advise whether those variances will also be recorded in the Large Load Revenue Variance Account (or any other account).

p) (P. 34) Please provide an illustrative calculation that shows how the balance in the Large Load Revenue Variance Account will be calculated. As part of the response, please provide the proposed baseline to which variances will be measured.

RESPONSE(S):

a) Yes, the capital related revenue requirements in Table 2 of Schedule 1-3-1 - Rate Setting Framework reflects Hydro Ottawa's proposal with respect to the treatment of the CCA benefit as a capital contribution.

b) Property taxes were included in the capital-related spending as part of Hydro Ottawa's approved 2021-2025 capital-related stretch factor, but they are not included in the 2026-2030 proposal.

c) Confirmed.

d) Please see the revised tables below.

   i) Table A below provides the Service Revenue Requirement (SRR) and Base Revenue Requirement (BRR) where SR&ED tax credits are an offset to PILs instead of reductions to OM&A and rate base.

Table A - Treating the SR&ED tax credits as an offset to PILs (instead of reductions to OM&A and rate base) ($'000 000s)

	Test Years					
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
CRRR	**$ 167.5**	**$ 182.9**	**$ 206.9**	**$ 223.5**	**$ 239.5**	**$ 1,020.2**
Amortization	$ 66.2	$ 74.6	$ 82.3	$ 88.4	$ 94.4	$ 405.9
Income Taxes	$ 5.4	$ 2.7	$ 10.4	$ 11.5	$ 14.7	$ 44.6
Deemed Interest Expense	$ 36.1	$ 40.3	$ 45.3	$ 49.1	$ 51.8	$ 222.7
ROE	$ 54.8	$ 61.2	$ 68.8	$ 74.5	$ 78.6	$ 337.9
PIL Cont.	$ 5.1	$ 4.1	-	-	-	$ 9.2
Property Taxes						
OM&A	**$ 140.2**	**$ 147.6**	**$ 155.2**	**$ 163.2**	**$ 171.5**	**$ 777.8**
Service RR	**$ 307.7**	**$ 330.5**	**$ 362.1**	**$ 386.7**	**$ 411.0**	**$ 1,798.0**
Rev. Offset	$ 11.0	$ 10.7	$ 10.9	$ 11.1	$ 11.5	$ 55.2
Base RR	**$ 296.7**	**$ 319.8**	**$ 351.2**	**$ 375.6**	**$ 399.6**	**$ 1,742.8**

ii) Table B below provides the SRR and BRR where they do not include PILS capital contribution funding (i.e. treating the CCA benefit as it was treated historically).

Table B - Treating the CCA benefit as it was treated historically (i.e., not as a capital contribution) ($'000 000s)

	Test Years					
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
CRRR	**$ 163.3**	**$ 180.4**	**$ 208.6**	**$ 225.0**	**$ 240.7**	**$ 1,017.9**
Amortization	$ 66.2	$ 74.7	$ 82.5	$ 88.6	$ 94.6	$ 406.6
Income Taxes	$ 6.2	$ 3.9	$ 11.7	$ 12.5	$ 15.4	$ 49.8
Deemed Interest Expense	$ 36.1	$ 40.3	$ 45.3	$ 49.1	$ 51.8	$ 222.7
ROE	$ 54.8	$ 61.4	$ 69.1	$ 74.7	$ 78.8	$ 338.9
PIL Cont.	-	-	-	-	-	-
Property Taxes						
OM&A	**$ 140.0**	**$ 147.3**	**$ 154.9**	**$ 162.9**	**$ 171.4**	**$ 776.4**
Service RR	**$ 303.3**	**$ 327.6**	**$ 363.5**	**$ 387.9**	**$ 412.0**	**$ 1,794.3**
Rev. Offset	$ 11.0	$ 10.7	$ 10.9	$ 11.1	$ 11.5	$ 55.2
Base RR	**$ 292.3**	**$ 316.9**	**$ 352.6**	**$ 376.8**	**$ 400.6**	**$ 1,739.2**

iii) Table C below provides the SRR and BRR where they do not include PILS capital contribution funding and SR&ED are an offset to PILs instead of reductions to OM&A and rate base.

Table C - Treating both the SR&ED tax credits and the CCA benefit (i.e., both (i) and (ii) above) as an offset to PILs ($'000 000s)

	Test Years					
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
CRRR	**$ 162.6**	**$ 179.4**	**$ 207.5**	**$ 224.2**	**$ 240.2**	**$ 1,013.8**
Amortization	$ 66.2	$ 74.8	$ 82.6	$ 88.7	$ 94.6	$ 406.9
Income Taxes	$ 5.4	$ 2.8	$ 10.5	$ 11.6	$ 14.8	$ 45.1
Deemed Interest Expense	$ 36.1	$ 40.3	$ 45.3	$ 49.1	$ 51.8	$ 222.7
ROE	$ 54.8	$ 61.4	$ 69.1	$ 74.8	$ 78.9	$ 339.1
PIL Cont.	-	-	-	-	-	-
Property Taxes						
OM&A	**$ 140.2**	**$ 147.6**	**$ 155.2**	**$ 163.2**	**$ 171.5**	**$ 777.8**
Service RR	**$ 302.8**	**$ 326.9**	**$ 362.8**	**$ 387.4**	**$ 411.7**	**$ 1,791.6**
Rev. Offset	$ 11.0	$ 10.7	$ 10.9	$ 11.1	$ 11.5	$ 55.2
Base RR	**$ 291.8**	**$ 316.2**	**$ 351.9**	**$ 376.3**	**$ 400.2**	**$ 1,736.4**

iv) Table D below provides the SRR and BRR where property taxes form part of the capital-related revenue requirement and are based on forecast amounts for 2026-2030.

Table D - Including property taxes as a separate line item that forms part of the capital-related revenue requirement ($'000 000s)

	Test Years					
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
CRRR	**$ 168.7**	**$ 184.2**	**$ 208.2**	**$ 224.9**	**$ 240.9**	**$ 1,026.9**
Amortization	$ 66.2	$ 74.6	$ 82.3	$ 88.4	$ 94.4	$ 405.9
Income Taxes	$ 5.4	$ 2.7	$ 10.4	$ 11.5	$ 14.7	$ 44.6
Deemed Interest Expense	$ 36.1	$ 40.3	$ 45.3	$ 49.1	$ 51.8	$ 222.7
ROE	$ 54.8	$ 61.2	$ 68.8	$ 74.5	$ 78.6	$ 337.9
PIL Cont.	$ 5.1	$ 4.1	-	-	-	$ 9.2
Property Taxes	$ 1.3	$ 1.3	$ 1.3	$ 1.4	$ 1.4	$ 6.7
OM&A	**$ 138.8**	**$ 145.9**	**$ 153.5**	**$ 161.5**	**$ 169.8**	**$ 769.5**
Service RR	**$ 307.5**	**$ 330.1**	**$ 361.7**	**$ 386.3**	**$ 410.7**	**$ 1,796.4**
Rev. Offset	$ 11.0	$ 10.7	$ 10.9	$ 11.1	$ 11.5	$ 55.2
Base RR	**$ 296.4**	**$ 319.4**	**$ 350.8**	**$ 375.2**	**$ 399.3**	**$ 1,741.2**

e) Please see Hydro Ottawa's 2021-2025 Custom Incentive Rate-Setting Application EB-2019-0261, specifically Table 4 in Section 8 of Exhibit 4-4-1 - Payments in Lieu of Taxes. Confirmed that Hydro Ottawa's treatment is the same as the previously approved approach.

f) The SR&ED capital tax credits offset capital costs. Further details about these capital offsets can be found in Schedule 2-5-9 - General Plan Investments, specifically Table 26 in Section 8.5. The SR&ED OM&A tax credits offset OM&A costs. Further details about these OM&A offsets can be found in the response to interrogatory 4-CCC-49, specifically Table A in the "Other" row.

g) The 2026 OM&A rebasing amount of $140M was set with assumptions of embedded productivity corresponding to a reduction of 2.3% in the 2026 test year. See Hydro Ottawa's response to interrogatory to 1-Staff-3 for the detailed reconciliation. The 0.61% embedded stretch was calculated by assuming the 2.3% reduction was not applied to the base year, and instead factored into the X factor of the Custom Revenue OM&A Factor (CROF). This calculation results in an OM&A 2026 Test Year of $143M with a X factor of 0.61% larger than what is being proposed. See Table E below for the supporting calculation.

Table E - Supporting calculation of additional stretch factor embedded in OM&A

Test Years	2026	2027	2028	2029	2030
Base OM&A Reduced					
Reduced Base OM&A ($'000s)	$ 140,010	$ 147,257	$ 154,879	$ 162,895	$ 171,326
CROF		5.18%	5.18%	5.18%	5.18%
I+G		5.33%	5.33%	5.33%	5.33%
X		**-0.15%**	**-0.15%**	**-0.15%**	**-0.15%**
Productivity Embedded in X					
Productivity Embedded in X ($'000s)	$ 143,306	$ 149,849	$ 156,691	$ 163,845	$ 171,326
CROF'		4.57%	4.57%	4.57%	4.57%
I+G		5.33%	5.33%	5.33%	5.33%
X'		**-0.76%**	**-0.76%**	**-0.76%**	**-0.76%**
Additional Embedded Productivity (X - X')		**0.61%**	**0.61%**	**0.61%**	**0.61%**

h) The "O5 Details by Class & Accounts" tab (columns F and G) reveals a cost split between Demand and Customer for Operating and Maintenance USofAs. The Demand and Customer split for Administrative and Depreciation USofAs can be determined by analysing the relevant allocator source data on Tab 06 Source Data for E2. The resulting Demand costs total $76,74,276 (54.84%), while Customer costs are $63,226,101 (45.16%).

i) Hydro Ottawa anticipates higher operating and maintenance (OM&A) costs due to an increase in both customer base and the overall capacity of its system due to forecast electrification and organic growth. Therefore, both the station capacity and customer growth has been used to calculate the growth factor to cover anticipated rising costs.

j) Confirmed.

k) As noted in the response to interrogatory 1-Staff-7, the Non-Wires Solutions (NWS) Deferral Variance Account is proposed to capture NWS costs in other revenues and OM&A. As outlined in Section 9.2.1 of Schedule 2-5-4 - Asset Management Process, the NWS proposed within the application are not expected to cause substantial avoidance or deferral of wire capacity investment needs. However in addition the the NWS Deferral Variance Account, Hydro Ottawa proposed to maintain the Capital Variance Accounts (CVA) with modification. If an incremental solution is approved and implemented during this Test period, thereby negating a planned capital project for the same period, any resulting underspending against the approved capital budget would be recorded in Hydro Ottawa's proposed Capital Variance Accounts (CVA). For additional details, please also refer to the response to interrogatory 1-Staff-18. Refer to Section 2.1 in Schedule 9-2-1 New Deferral and Variance Account for the sample journal entries.

l) Refer to the responses to interrogatories 9-Staff-211 and 9.0-VECC–72.

m) Refer to the response to interrogatory 9-Staff-211.

n) Refer to the response to interrogatory 9-Staff-211.

o) Refer to the response to interrogatory 9-Staff-211.

p) The response to interrogatory 9.0-VECC-72 provides the forecasted annual total kW from large load connection requests. This account will record the impact on revenue due to the variance between the actual and forecasted annual kW from large load connections reflected in Table 8 of Schedule 3-1-1 - Revenue Load and Customer Forecast. The revenue requirement impact would be the variance between actual and forecasted annual kW multiplied by the applicable approved vs actual General Service variable rate, net of the return on equity related capital contribution true up. Hydro Ottawa will commence recording into this variance at the earlier of project energized date or actual energization date of the facilities.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-3

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 3, pp. 6-7

QUESTION(S):

a) (PP. 6-7) Please provide rationale for the peer groups used for the various benchmarking metrics as shown in Table 2.

b) Please confirm that the results in Figures 1 & 2 in Exhibit 1, Tab 3, Schedule 3 are not based on the peer groups discussed in Table 2 (and instead are relative to all distributors in Ontario).

RESPONSE(S):

a) Hydro Ottawa assigned peer groups based on an internal assessment of utility characteristics that, in its opinion, appropriately reflected Hydro Ottawa's unique operating conditions. The utility's service territory stands out in Ontario due to its large customer base, its blend of dense urban downtown core and extensive rural peripheries (predominantly residential as opposed to industrial) which are partitioned by its green belt. The utility characteristics that determined peer group eligibility were chosen to capture these characteristics as reflected by customer counts, residential load, and rural/urban ratios.

In regard to how the peer groups were assigned, Hydro Ottawa conducted an informed assessment of the metric being compared and the utility characteristics that would affect the result. For example, the Activity and Program-based Benchmarking (APB) Vegetation Management and Lines Operations and Maintenance metrics were assigned Peer Group 3 because distribution lines that serve rural customers are often overhead and near tree cover,

which increases the risk of damage during extreme weather events and requires more maintenance.

Peer group 1, customer counts, was used for financial metrics because it was assessed that larger utilities are more likely to have similar financial conditions to Hydro Ottawa, given financing costs and capital availability.

Peer group 4 was used for the Scorecard and the APB because the program-level metrics were assessed as being influenced by utility size and residential load mix. Hydro Ottawa included residential load mix because the larger utilities, such as Toronto Hydro and Alectra Utilities, had less residential load, which Hydro Ottawa considered to weaken the suitability of these utilities as comparators.

Finally, the supplemental benchmarking used peer group 1 because relative size of distributors similar to Hydro Ottawa based on customer numbers was considered the most important common factor for the metrics. The economies of scale expected of larger distributors should produce similar results for comparison when measuring labour force sizing, total costs, and financial metrics.

b) Confirmed. The results in Figures 1 and 2 in Schedule 1-3-1 - Benchmarking are based on industry averages (all distributors in Ontario), not peer groups. The reason for displaying industry averages is due to the Ontario Energy Board's Chapter 2 filing requirements, section 2.1.6 Performance Measurement, which stipulates requirements for explanations and plans if unit costs exceed certain industry averages.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-4

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 3, Attachment A, pp. 7-9, 11-13

QUESTION(S):

a) (PP. 7-9) In the context of the very low kilometres of OH secondary lines shown in the early years of the 2008-2023 period, please explain why Hydro Ottawa does not believe that there was missing data in those years. As part of the response, please explain the significant increase in OH secondary lines 63km to 894km between 2008 and 2015.

b) (P. 9) Please confirm that the CAGR used in the extrapolation exercise (Step 4) utilizes the total circuit km (combined primary and secondary cable) in Table 4.

c) (PP. 11-13) Please advise whether the costs of CDM are included in PEG's model (in the absence of Hydro Ottawa's adjustments). Please also advise whether Hydro Ottawa included CDM costs in its adjustments to the PEG model.

RESPONSE(S):

a) Hydro Ottawa acknowledges that overhead secondary lines were underreported between 2008 and 2023, as they were not surveyed in the GIS. The overhead secondary line data was produced based on known quantities for each year. If a secondary line was not surveyed in GIS, it was not counted and could not be adjusted in column C of Table 3 of Attachment 1-3-3(A) - Benchmarking.

Between 2008 and 2023, Hydro Ottawa omitted overhead secondary lines that it reasonably knew existed but had not been surveyed into GIS and had no installation information attached to them. Without installation dates, Hydro Ottawa could not assign a year for when to count the lines with confidence. When the lines were surveyed, they were added in the year the entry into GIS was made. For this reason, the overhead secondary line data grows faster as more lines are surveyed between 2008 and 2023.

b) Not confirmed. The compound annual growth rate is based on the total secondary lines between 2008 and 2023.

c) Hydro Ottawa did not make any adjustments for CDM costs to its PEG model submission other than the alterations to deliveries and peak load (capacity proxy) detailed in Attachment 1-3-3(A) - PEG Benchmarking Analysis.

Provincial CDM programs were not widely adopted between 2002 and 2012, and therefore their effects on deliveries and capacity were minimal during PEG's regression period. As a result, CDM did not impose costs on distributors at that time. As evidenced by Hydro Ottawa's own experience in Attachment 1-Staff-11(A) - CDM Supporting Data, CDM volumes were low in 2011 and began to increase substantially throughout the 2010s and have remained at those levels. This growth or the presence of CDM programs is not modelled in PEG's parameters, nor did PEG implement a variable to model CDM's effect on estimated distributors' costs.

1-INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-5

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 3, Attachment B, pp. 1, 8

QUESTION(S):

a) (P. 1) Please further explain the statement that Hydro Ottawa "does not base its financial forecasts on operation inputs, leaving the denominators unknown." As part of the response, please explain how historical unit costs are reflected in the capital and OM&A forecasts.
b) (P. 8) Please discuss Hydro Ottawa's tree coverage relative to the peer group (which is based on urban/rural split) for vegetation management.

RESPONSE(S):

a) Hydro Ottawa's OM&A and capital forecasts used a top-down and bottom-up approach to forecasting. The top-down approach to forecasting involved business units submitting program-level funding requests, which were prioritized, adjusted, and aggregated to produce a final forecast.

The statement in the original evidence that "Hydro Ottawa does not base its financial forecasts on operation inputs, leaving the denominators unknown" was imprecise and does not accurately reflect the budgeting process, but rather was intended to only discuss the impact on the "denominators" for Activity and Program-Based (APB) benchmarking. With regard to the budgeting process, operational inputs, including the number of units and unit costs where applicable, are a fundamental part of its budgeting. They are used by project and program

managers to inform and justify their financial budgets. This ensures Hydro Ottawa's forecasts are grounded in the expected scope and scale of its operational activities.

The benchmarking analysis is not conducted for bridge and test years because not all inputs for each metric are estimated through the test period. For example, while pole renewal units are forecast as part of the Pole Renewal program, the total number of poles (required for the Poles, Towers, and Fixtures O&M unit cost metric) through 2030 are not estimated. This is due to a lack of detailed project scopes within the System Access, notably the Plant Relocation & Upgrade, Customer Connection, and System Expansion programs. As the final scopes for these projects are still variable and not yet finalized, it is not possible to accurately estimate the number of new units (poles) required.

Furthermore, the industry benchmarking relies on historical data filed by utilities through the Reporting and Record-keeping Requirements (RRR). Since this data is only available for previous years, providing forecast metrics would not allow for any meaningful comparison, as there would be no industry data to benchmark against.

b) Hydro Ottawa's tree coverage in the context of the APB, Vegetation Management O&M unit cost, is a major influence on costs, in addition to major event days. Tree contacts are a cause of power outages, especially during and after storms when trees are weakened, resulting in emergency and ongoing maintenance expenses. Table A summarizes the urban greenness of each utility in peer group 3 - rural/urban ratio.

Table A - Percentage of Land Area Classed as Green by Utility and Geographic Location[1]

Geography	Utility	Average Urban Greenness
Barrie	InnPower	81.3
London	London Hydro	85.1
Ottawa	Hydro Ottawa	87.6
Sarnia	Bluewater Power	82.7
Thunder Bay	Synergy North	88.1
Toronto	Burlington Hydro, Elexicon Hydro	67.7
Welland	Welland Hydro-Electric System	89.7

Table A demonstrates the suitability of the rural/urban peer group for comparing vegetation management costs. Hydro Ottawa has a high average urban greenness, in comparison to its peer group.

Statistics Canada does not stratify its data by a municipality's location within the Greater Toronto Area (GTA). Therefore, Burlington Hydro and Elexicon Hydro's greenness results are skewed by the urban sections of the GTA.

Hydro Ottawa's high average greenness and its recent, more frequent major event days, as evidenced in Section 2.1.3 of Attachment 1-3-3(D) - Supplemental Industry Benchmarking Analysis have resulted in higher vegetation management expenses.

[1] Statistics Canada. Table 38-10-0158-01: Urban greenness and normalized difference vegetation, https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3810015801

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-6

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 3, Attachment E, pp. 12-13, 16-18, 20, 23, 25, 27, 32, 39

QUESTION(S):

a) (P. 12) Please explain what Gartner means by “power recovery” costs.
b) (P. 12) Please confirm that “power recovery” and cost of power are reflected in both Hydro Ottawa’s revenues and costs.
c) (P. 12) Please confirm that power recovery and cost of power are pass-through costs. Please explain why those costs were included in the benchmarking analysis.
d) (P. 12, 32) Please explain what Gartner considers to be operational technology and why that was excluded from the analysis.
e) (PP. 12-13) Please provide the list of 9 companies included in the custom peer group. As part of the response, please provide the information for each company as shown in the “Custom Peer Group Profile.” Please also advise whether power recovery / cost of power and operational technology forms part of the custom peer companies’ revenues and costs in the analysis.
f) (P. 13) Please provide the average USD to CAD exchange rate for the 2022 to 2023 period, which aligns with the data vintage used in the study.
g) (PP. 16-18) As applicable, please provide slides 16-18 showing the same metrics (i.e., IT spend as a % of revenues and operating expenses) with all pass-through costs removed from both Hydro Ottawa and the peers. Please also show the revised “calculation” dollar values (i.e., IT spend $ / revenues or operational expenses excluding pass-through costs).
h) (P. 20, 39) Please explain how Gartner determines whether a type of spending is transform, grow or run. More specifically, what type of information does Gartner receive from Hydro Ottawa and the peers that allows this type of classification to be completed.

i) (P. 23) Please advise whether the data underpinning the analysis of personnel spending on page 23 reflects the 2023 labour disruption.

j) (P. 25) Please provide the supporting documentation (spreadsheets with assumption shown) that supports the real dollar analysis on Slide 25.

k) (P. 27) Please advise whether the data underpinning the analysis of personnel spending on page 27 reflects the 2023 labour disruption. To the extent possible, please provide a revised version that assumes the labour disruption did not occur (i.e., grosses up FTEs to the full-year).

l) (P. 32) Please confirm that the "cash out" basis means that the capital costs reflected in the analysis are expenditures as opposed to in-service additions.

m) (P. 32) Please explain how the costs of facilities related to the IT function were calculated for Hydro Ottawa specifically. Please also explain the implications on total IT budget costs, based on Gartner's methodology, of leased versus owned facilities.

RESPONSE(S):

a) "Including power recovery and cost of power" is language used to illustrate that gross numbers are used for Revenue & Operating Expenses. This is Gartner's standard approach when conducting benchmarking activities for utilities clients. These are noted as power recovery revenue and purchased power in Hydro Ottawa's audited financial statements (Attachment 1-5-1(A) - 2023 Audited Financial Statements) and represent the cost of power recovered from customers through provincially established rates.

b) Confirmed.

c) Confirmed. This is Gartner's standard approach when conducting benchmarking activities for utilities clients. To ensure an "apples to apples" comparison, Revenue & Operating Expenses - including pass-through costs - were collected from Hydro Ottawa, just as they are from all other utilities clients.

d) Operational Technology (OT) is defined by Gartner as hardware and software that detects, reports, and facilitates a change of state in physical assets through direct monitoring and/or control of physical devices, processes, and events. OT systems are designed to monitor and control physical processes and devices, ensuring operational integrity and efficiency. They are often used in industrial settings to manage machinery, production lines, and other critical infrastructure.

While the lines between IT and OT are blurring due to digital transformation and increased connectivity, the traditional reasons for excluding OT from IT spend benchmarks stem from their fundamental differences in purpose, operational context, risk tolerance, and the need to maintain relevant and comparable IT industry benchmarks. Organizations often track OT costs separately, sometimes creating specific budget lines to reflect their unique nature.

As such, Gartner excludes OT from IT Spend benchmarks because OT and IT serve different functions within an organization and often have distinct budgets, management structures, and objectives which can make it difficult to do an apples-to-apples comparison with available peer data. By excluding OT from IT Spend benchmarks, Gartner can provide a more accurate and relevant analysis of IT spending patterns that align with the specific goals and structures of IT departments.

e) Due to client confidentiality agreements, Gartner cannot release the names of the companies included in the custom peer group.

For the 9 organizations in the custom peer group, the distribution is as follows:

i. distribution only utilities = 3
ii. generation only utilities = 1
iii. generation, transmission and distribution = 4
iv. generation and transmission = 1

Power recovery/cost of power and operational technology are included in Revenue & Business Operational Expense for both Hydro Ottawa and the custom peer group companies. However, Operational Technology costs are not included in IT Spend for both Hydro Ottawa and the custom peer group companies.

f) The exchange rate used for the benchmark analysis was $1.00 USD = $1.35 CAD, as stated in the 'Peer Group Profiles' section of Attachment 1-3-3(E) - Hydro Ottawa Enterprise IT Spending & Staffing Benchmark

g) This analysis is not possible as Gartner does not collect Revenue and Operating Expense data points net of pass-through costs from benchmark clients.

h) As part of data collection activities, Gartner provides all benchmarking clients with definitions for what constitutes "Run", "Grow" and "Transform" activities. As clients progress through the data collection phase, they often have Run/Grow/Transform alignment questions which Gartner answers in accordance to the definitions.

The definitions provided to clients are as follows:

Run, Grow, Transform

The distribution of IT spending to run the business, grow the business and transform the business provides a view of the IT investment profile or "portfolio" to support business performance. In some industries, it is not uncommon to see a high "run" focus — typically because organizations in the industry are not planning strong changes in business model growth or high organic growth — which often translates into a more "cost center" role for IT in the industry or niche sector.

Classifying IT spending into categories that show impact on business outcomes or success can aid alignment and quantify underinvestment in IT. Gartner uses the following portfolio spending categories and defines them as follows:

Run the Business

This is an indicator of how much of the IT resource is consumed and focused on the continuing operation of the business. It includes all non discretionary expenses as part of the run-the-business cost. Some businesses call this "business as usual," "keep the lights on" IT spending, or sustain investments. Run expenses do not directly increase revenue or achieve by themselves new or enhanced goals of the enterprise.

Grow the Business

This is an indicator of how much of the IT resource is consumed and focused on developing and enhancing IT systems in support of business growth (typically organic growth). Discretionary investments are more likely to be included in the grow-the-business or transform-the-business cost.

Transform the Business

This is an indicator of how much of the IT resource is consumed and focused on implementing technology systems that enable the enterprise to enact new business models. This is very much a "venture" category and would be represented by activities such as an insurer introducing usage-based insurance products such as telematics or a supermarket combining real time analytic monitoring with in-store task management to provide automated alerts to store staff to perform pre-emptive tasks.

i) Personnel spending in the analysis reflects actual costs for the 12 months ending December 31, 2023 and does, therefore, reflect the labour disruption. Due to the 3-month labour disruption that occurred in 2023, internal personnel costs were lower than originally budgeted, however some of that cost was replaced with Contractor costs.

j) All of the underlying data points used in the analysis on slide 25 can be found on prior slides of the benchmarking report (i.e. slide 18, 20 and 24.). The spreadsheet used to generate the analysis uses basic calculations to calculate the real dollar spend. Please see Attachment 1-CCC-6(A) - Hydro Ottawa - Analysis $100 of OpEx - July 30 2025.

k) The 83 reported IT FTEs does not reflect any impact of the labour disruption, as this was the number of FTEs at year-end (at which point the labour disruption was resolved).

l) Confirmed. The Gartner definition for IT spend includes cash costs associated with IT Operational Expenses and IT Capital Expenses, not in-service additions.

m) Gartner's benchmarking model includes facilities costs associated with data centers only. Office space costs for IT staff are not included in total IT Spend as they are viewed as corporate overhead. Regarding leased versus owned facilities, clients report the "cash cost" associated with leasing (i.e., rent, operational costs) or owning (i.e., principal & interest costs, property tax, operational costs, maintenance). Hydro Ottawa included data center facility costs in their IT spend. Hydro Ottawa owns the building the data center is housed in.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-7

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 3, Attachment F, pp. 6, 8-11

QUESTION(S):

a) (P. 6) Please further explain how Hydro Ottawa/Mercer determined which roles to review in the study. Please provide the overall percentage of Hydro Ottawa's roles that were reviewed as part of the study (i.e., roles in study / total Hydro Ottawa roles). Please also provide the overall percentage of Hydro Ottawa's 2024 FTEs that were reviewed as part of the study (i.e., FTEs in the roles in the study / total FTEs).
b) (P. 8) Please explain why long-term incentives were not included in the study.
c) (PP. 8-11) For each role reviewed in the study, please provide the forecast 2026 base salary and target total cash compensation and the 2026 number of FTEs that are forecast to be in those roles as reflected in Hydro Ottawa's application.

RESPONSE(S):

a) Hydro Ottawa reviewed all current roles. The roles included in the study were representative of Management (including Executives), Union and Non-Union categories of employees. Hydro Ottawa also reviewed the roles from the benchmarking study submitted in its previous rate application. This was to ensure consistency with the benchmarking process. In addition, please note that many of Hydro Ottawa's roles are industry-specific, as such, roles that would have comparators outside of our industry were also included. The roles reviewed represent 32.6% of 2024 total FTEs and 7.1% of total roles.

b) Hydro Ottawa does not have a long-term incentive plan program.

c) Table A below displays the forecast 2026 FTE, average base salary and target total cash for the benchmark roles.

Table A - Base Salary and Total Compensation for Benchmark Roles, 2026

Role	2026 FTE	2026 Forecast Base	2026 Forecast Total Compensation
Billing Service Associate	9.20	$ 79,954.22	$ 79,954.22
Collection Agent	6.44	$ 79,954.22	$ 79,954.22
Communications Officer	0.92	$ 90,614.78	$ 90,614.78
Customer Contact Agent	3.68	$ 83,152.39	$ 83,152.39
Director, Distribution Operations	1.84	$ 169,403.00	$ 203,283.60
Distribution Engineer	10.12	$ 121,927.00	$ 121,927.00
GIS/CAD Technician	10.12	$ 79,954.22	$ 79,954.22
IT Service Desk Technician	3.68	$ 90,614.78	$ 90,614.78
Management Accountant	3.68	$ 102,505.00	$ 102,505.00
Manager, Distribution Operations	2.76	$ 144,586.00	$ 159,044.60
Network Administrator	4.60	$ 115,134.08	$ 115,134.08
Power Line Technician	86.48	$ 110,869.85	$ 110,869.85
IT Systems Support	2.76	$ 100,209.29	$ 100,209.29
Senior Procurement Agent	3.68	$ 98,077.18	$ 98,077.18
Supervisor, Billing	0.92	$ 99,268.00	$ 99,268.00
Supervisor, Distribution Operations	11.40	$ 132,717.00	$ 132,717.00
System Designer	14.72	$ 120,464.36	$ 120,464.36
System Operator	20.24	$ 119,398.30	$ 119,398.30
Warehouse Attendant	7.36	$ 94,879.01	$ 94,879.01
Vehicle and Utility Equipment Technician	4.60	$ 106,605.63	$ 106,605.63

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-8

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 4, pp. 1, 3, 11, 16, 22-24

Preamble:
(PP. 1, 3) Hydro Ottawa states that the productivity initiatives have been incorporated into Hydro Ottawa's capital expenditure forecast and productivity factor applied to OM&A costs.

QUESTION(S):

a) Please provide specific references to the evidence that show where the forecast (2026-2030) productivity savings (Table 1) are directly reflected as offsets to the 2026-2030 capital expenditure budgets, capital in-service additions, and OM&A budgets.
b) Please provide specific references to the evidence that show where the historical (2021-2025) capital-related productivity savings directly offset opening 2026 rate base and the OM&A-related productivity savings reduce the test year OM&A budgets.
c) (P. 1) Please provide the annual revenue requirement reduction reflected in the application resulting from the productivity initiatives for each year 2026 to 2030. Please separate these revenue requirement reduction as between capital-related revenue requirement (and further breakout between depreciation, interest, ROE and taxes) and OM&A.
d) (P. 11) Please explain how capital depreciation was calculated for each sub-category of the labour and supply chain initiatives. As part of the response, please advise whether these are annual depreciation savings.
e) (P. 16) Hydro Ottawa states that improvements realized in the pole renewal program (23.6% decrease in labour hours per pole) serves as a representative model, reflecting the utility's commitment to enhancing efficiency and optimizing resource allocation across all capital

programs (with the exception of station-related programs). Please advise whether the labour savings of 23.6% were reflected in the forecast capital program costs for all capital program (excluding station programs). If not, please explain what Hydro Ottawa means by the pole renewal program-related efficiencies being a "representative model." If yes, please show, with specific reference to the evidence, where these savings are shown in the capital programs.

f) (P. 16) Please advise whether Hydro Ottawa has performed similar impact analysis with respect to its strategic operational and project management enhancements on capital programs other than the planned pole renewal program. If yes, please provide that analysis.

g) (P. 22) Please further explain why Hydro Ottawa could not estimate the 2026-2030 savings resulting from its vendor and supplier engagement practices using historical savings as a proxy.

h) (P. 23) Please explain how capital depreciation was calculated for each sub-category of the innovation and digital transformation initiatives. As part of the response, please advise whether these are annual depreciation savings.

i) (P. 23) Using net metering automation as an example of a productivity improvement that starts accruing savings in the forecast period and impacts only OM&A costs, please explain how the savings of $6.7M are reflected in 2026-2030 rates in the context of Hydro Ottawa's proposed rate framework (and specifically, the CROF).

j) (PP. 24, 32) With respect to the CIS-related reduced managed service costs, please advise whether those cost savings from the 2021-2025 period flow into 2026. If not, please explain what Hydro Ottawa has done to control these costs in the forecast period.

k) (P. 33) Please explain how capital depreciation was calculated for each sub-category of the infrastructure and equipment efficiencies initiatives. As part of the response, please advise whether these are annual depreciation savings.

l) (P. 34) Please confirm that none of "other innovation, productivity, and continuous improvement initiatives" are reflected as offsets to revenue requirement for ratemaking purposes.

m) (P. 36) Please provide the number of outage calls in 2024 handled by agents and the number of outage reports managed through self-service.

RESPONSE(S):

a) As detailed in Section 3.1 of Schedule 1-3-1 - Rate Setting Framework, capital related revenue for 2026-2030 is funded on a forecasted basis. As such, Hydro Ottawa embedded productivity savings assumptions in the capital expenditure plan in its Distribution System Plan. Please see Tables 3 and 4 of Schedule 1-3-1 for an overview of 2026-2030 Required and Proposed Capital Expenditures, and 2026-2030 Capital Related Revenue Requirement Savings, respectively. In addition, please see the response to interrogatory 1-Staff-8 for an annual breakdown of Tables 3 and 4.

As noted in Section 3.2.4 of Schedule 1-3-1 - Rate Setting Framework, the 2026 OM&A budget amount of $140M was set with assumptions of embedded productivity of $3.4M, corresponding to a reduction of 2.3%, which results in a 2027-2030 additional annual stretch already embedded in OM&A of 0.61%. For further details on productivity benefits specific to 2026 OM&A, please refer to the response to interrogatory 1-Staff-3.

b) Please refer to Sections 3.1 and 3.2 of Schedule 1-3-1 - Rate Setting Framework. For further details on productivity benefits specific to 2026 OM&A, please refer also to the response to interrogatory 1-Staff-3 and 1-Sec-24. In addition, references to savings are provided throughout multiple interrogatory responses, particularly in the context of program-level activities and the overall and budgeting framework.

c) Please refer to Table 2 on page 13 of Schedule 1-3-1 - Rate Setting Framework for the 2026-2030 Capital Revenue Requirement, broken out by Amortization/Depreciation, Income Taxes, Deemed Interest Expense, and Return on Deemed Equity for each year 2026-2030. Please also see the response to interrogatory 1-Staff-8.

d) Please see the response to interrogatory 1-SECC-25 for a detailed description of the methodology and supporting calculations used to calculate the specific productivity benefits.

e) Yes, as noted in Section 3.1.2. Capital Productivity of Schedule 1-3-1 - Rate Setting Framework, Hydro Ottawa embedded these productivity savings assumptions in the capital expenditures (excluding station programs) plan in the DSP.

f) As described in Section 3.1.1.2 of Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, Hydro Ottawa has selected the planned pole renewal program as a suitable proxy for quantifying productivity gains across its diverse capital programs. Hydro Ottawa has performed similar analyses using both Switchgear and Transformers, however there are insufficient data points to provide meaningful/statistical results given variations in scope and complexity of these projects. Based on this analysis, only the productivity savings from the pole renewal program were incorporated into the capital programs.

g) As stated in Section 3.1.6. Vendor and Supplier Engagement of Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, it's not feasible to project savings for the 2026-2030 rate term for certain materials. This is because volatile market pricing, combined with persistent inflation, trade uncertainties, tariffs, and potential supply chain disruptions, makes reliable forecasting impossible. Hydro Ottawa's 2026-2030 savings projections rely on stable, probable information, which simply isn't available for this category.

h) Please see the response to interrogatory 1-SEC-27 for a detailed description of the methodology and supporting calculations used to calculate the specific productivity benefits.

i) Hydro Ottawa’s proposed rate framework for 2026-2030 accounts for productivity improvements such as net metering automation by embedding these savings directly into the base OM&A forecast for the 2026 Test year.

Specifically, the anticipated productivity savings from net metering automation, amounting to $6.7M over the 2026-2030 period, have been incorporated into the 2026 OM&A base forecast. This means that these savings are already reflected in the starting point of the OM&A revenue requirement for the new rate term. If these savings had not been embedded, Hydro Ottawa’s

2026 OM&A forecast would be $241K higher, which would then be compounded annually over the subsequent 2027-2030 period due to the formulaic nature of the CROF and the projected increased adoption of net metering enrollment.

j) The Customer Information System (CIS) related savings do not carry forward into 2026. The managed service costs associated with the CIS are structured as fixed fees, which are subject to an annual economic change adjustment factor as stipulated in Hydro Ottawa's agreement with the managed services vendor. Hydro Ottawa's ability to manage these costs is primarily limited to minimizing customizations that extend beyond the defined scope of work in the base product offering.

k) Capital depreciation was calculated by taking the total capital expense and depreciating over an expected useful life of 30 years, starting on the year of expected energization of the related station. The numbers in the table references are for the 5 year period.

l) Regarding the "other innovation, productivity, and continuous improvement initiatives" laid out starting on page 34 of Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, Hydro Ottawa confirms that these are not reflected as offsets to revenue requirement for ratemaking purposes. These initiatives are either not quantifiable or cannot be easily quantified.

m) In 2024, approximately 13,000 outage reports were handled by agents, and approximately 21,000 outage reports were managed through self-service channels.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-9

EVIDENCE REFERENCE:

Exhibit 1, Tab 4, Schedule 1

QUESTION(S):

Please provide a table setting out for each year, 2021-2026, the cost of Hydro Ottawa's customer engagement activities as described in Schedule 1.

RESPONSE(S):

Please see Table A below for a list of programs that align with the ongoing customer engagement initiatives referenced in Schedule 1-4-1 - Customer Engagement Ongoing, along with the related annual costs.

Individual customer engagement activities are not tracked separately in our accounting system. The costs shown in the table reflect the total for relevant accounting codes (e.g., media relations). In this table, a "segment" refers to a functional area within the Customer & Community Relations program that delivers specific types of customer engagement activities.

It should be noted that the costs shown do not include staff compensation, as it is not directly attributable to specific customer engagement activities. Additionally, these costs do not include any software related costs.

Table A - Customer Engagement Activities

Program / Segment	Description of Activities	Annual Costs ($ Thousands)					
		2021	2022	2023	2024	2025	2026
Customer & Community Relations – Customer Contact Segment	Support customer interactions, conduct customer satisfaction surveys	$ 49	$ 86	$ 61	$ 73	$ 73	$ 43
Customer & Community Relations – Communications and Public Affairs Segment	Manage multi-platform communications to inform and engage customers, using feedback and sentiment analysis to shape messaging, guide planning, marketing and communications efforts to keep customers informed and cultivate strong community engagement.	$ 445	$ 455	$ 605	$ 831	$ 596	$ 305
Customer & Community Relations – Key Accounts Segment	Proactive and responsive engagement activities with Key Account customers.	$ -	$ 40	$ 20	$ 81	$ 81	$ 46
Customer & Community Relations – CDM Segment	Reduce electricity use and peak demand through energy efficiency, customer programs, and distributed energy solutions. Hydro Ottawa supports this by delivering local initiatives and contributing to long-term affordability and decarbonization.	$ -	$ -	$ -	$ 12	$ 12	$ 12

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-10

EVIDENCE REFERENCE:

Exhibit 1, Tab 4, Schedule 2, p. 10

QUESTION(S):

a) A large number of letters of comment opposing Hydro Ottawa's proposed rate increase were filed on the record. Please explain how these letters from Hydro Ottawa's customers reconcile with Hydro Ottawa's customer engagement results in Table 2 at page 10.
b) Please confirm that approximately 50% of the responses across all rate classes opposed (or "do not like") the proposed bill increases.

RESPONSE(S):

a) Hydro Ottawa's customer engagement plan on its 2026-2030 rate application is a proactive, in-depth engagement that is specific to this rate application. Customers were provided with information regarding Hydro Ottawa's investment options, enabling them to provide informed input into the development of our proposed plan. Customers were provided with detailed information through a "workbook survey." This survey explained key investment areas, their associated bill impacts, and performance outcomes, allowing them to make informed choices. The inclusion of a dynamic bill calculator gave customers a tangible understanding of how their choices would affect their bills. This process was designed to understand broad customer priorities and preferences before the formal submission of the application.

This proactive approach allowed for a more nuanced understanding of customer needs and preferences, as well as sentiment, which is captured in the "social permission" metric. As defined in the customer engagement, "social permission" is a broader concept than simple support. It includes customers who:

- Believe Hydro Ottawa should accelerate spending beyond the proposed draft plan.
- Support the proposed rate increase.
- Acknowledge the rate increase is necessary to maintain the grid and prepare for the future, even if they personally dislike it.

The results of this survey found in Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application directly informed the direction and proposed investments outlined in the rate application.

The letters of comment filed on the record, while a valuable part of the regulatory process, reflect a different kind of customer input than the customer engagement results presented in Table 2, page 10 of the Customer Engagement Report. The difference between these two sources can be reconciled by understanding the different contexts in which the feedback was gathered.

While the letters of comment may reflect general dissatisfaction with the proposed rate increases, it is unknown whether these respondents were able to review the full rate application linked to the Ontario Energy Board website in the Notice of Hearing email that was sent to them. In addition, if customers were able to access the information, the scale of information may have been overwhelming or customers did not have the time to spend to read through it. This differs from Hydro Ottawa's customer engagement "workbook survey" in which customers, when presented with the necessity of investments for system sustainability and future readiness, acknowledged the proposed rate increase as reasonable and required. Of note, as per page 15 of Attachment 1-4-2(A) - Customer Engagement Report on the 2026-2030 Rate Application, 87% of customers granted 'social permission' to proceed with the plan.

Please refer to response to interrogatory 1-Staf-2 for main themes identified in the letters of comment, along with Hydro Ottawa's response to the matters raised.

b) As noted in Table 2 on page 10 of Schedule 1-4-2 - Customer Engagement on the 2026-2030 Application, 9% of respondents across all rate classes opposed the proposed rate increases, while 87% of customers granted 'social permission' to proceed with the plan as per the definition explained in part (a).

This social permission, as defined by the survey, is a broader category than simple "support." It encompasses customers who actively support the plan, those who want to accelerate spending, and those who accept the increase as necessary despite disliking it. The total respondents in the latter category averaged 43%.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-11

EVIDENCE REFERENCE:

Exhibit 1, Tab 4, Schedule 2, Attachment A, pp. 87-88, 249

QUESTION(S):

a) (PP. 87-88) Please provide a comparison of the demographic information of the residential participants for the Phase 1 online survey relative to Hydro Ottawa's service territory overall.
b) (P. 249) Please provide a comparison of the demographic information of the residential participants for the Phase 2 workbook relative to Hydro Ottawa's service territory overall.
c) Please discuss why different demographic information was collected between the Phase 1 and Phase 2 customer engagement activities.

RESPONSE(S):

a) When conducting both Phase 1 and Phase 2 of its Customer Engagement on the 2026-2030 Rate Application, Hydro Ottawa's primary goal was to ensure participant feedback accurately reflected its residential customer base. As a local distribution company (LDC), Hydro Ottawa does not collect granular demographic data such as age, gender, income level, education, etc. Therefore, a direct demographic comparison of survey participants to Hydro Ottawa's service territory overall using these metrics cannot be provided. Instead, Hydro Ottawa ensured representativeness by weighting survey responses based on the most relevant and comprehensive data it possesses: rate classes, location within its service territory, and electricity consumption. This approach ensures that input from Phase 1, detailed in Attachment 1-4-2(A) -

Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application, proportionally represents its residential customers.

b) Please see the response to part (a) above. The same methodology and data considerations apply to the Phase 2 online survey participants.

c) The difference in demographic questions between Phase 1 and Phase 2 was a strategic decision to maximize value and respect customer time:

- In Phase 1, demographic data, including education and employment status was collected to better understand the make-up of Hydro Ottawa's customers. This helped ensure that the development of Hydro Ottawa's Distribution System Plan considered the needs and preferences of its diverse customer base.
- Since Phase 2 involved a much longer and more comprehensive survey, in order to prevent survey fatigue and encourage thoughtful, complete responses on the core planning questions, Hydro Ottawa made a conscious decision to streamline the demographic section, including only the most essential demographic questions—those directly relevant to informing its planning and analysis—and omitted questions about education and employment status. All other demographic questions asked in Phase 1 that were crucial for their core analysis were carried over to Phase 2.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-12

EVIDENCE REFERENCE:

Exhibit 1, Tab 6, Schedule 1, pp. 2-3

Preamble:
Hydro Ottawa Holding Inc. has a Board of Directors. A separate subsidiary Board of Directors was established to oversee the operations of the utility in accordance with the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters in 2006. The powers and functions of the utility Board are set out in a Shareholder Declaration by its Shareholder, Hydro Ottawa Capital Corporation. On a day-to-day basis Hydro Ottawa Holding Inc. is led by an Executive Management Team comprised of the President and CEO, the CFO and the senior executives of the subsidiaries and critical functional areas.

QUESTION(S):

a) Please file the Shareholder Declaration.
b) Please describe the relationship between Hydro Ottawa Holding Inc.'s Board of Directors and Hydro Ottawa Inc.
c) Please describe what activities are undertaken by Hydro Ottawa Capital Corporation.
d) Please list all "other non-regulated entities" within Hydro Ottawa Capital Corporation.
e) Please indicate whether the Hydro Ottawa Limited's Board of Directors including the CEO and VP Distribution Planning and Asset Management have any responsibilities for Hydro Ottawa Energy Services Inc. and/or the other non-regulated entities.
f) Please describe the responsibilities of the Hydro Ottawa Holding Inc.'s Executive Management Team regarding the unregulated entities under Hydro Ottawa Capital Corporation and Hydro Ottawa Energy Services Inc.

g) Please describe the responsibilities of the Hydro Ottawa Holding Inc.'s Executive Management Team regarding Hydro Ottawa Limited.

RESPONSE(S):

a) Please refer to Attachment 1-CCC-12(A) - Hydro Ottawa Limited Shareholder Declaration.

b) Please refer to the response to Interrogatory 1-CO-1(d).

c) Hydro Ottawa Capital Corporation is a holding corporation that is itself wholly-owned by Hydro Ottawa Holding Inc. Hydro Ottawa Capital Corporation only acts as a vehicle for debt financing and maintains an investment grade credit rating for the purpose of financing. It has no independent business operations or tangible assets of its own. Its credit rating enables Hydro Ottawa Capital Corporation to execute private debt issuances in the Canadian debt market to support financing requirements for Hydro Ottawa Limited. As at June 30, 2025, Hydro Ottawa Capital Corporation is: i) the issuer in respect of an $800 million dollar principal amount of senior unsecured debentures; ii) the issuer under a $450 million dollar commercial paper program; and iii) the borrower under a $500 million dollar senior credit facility.

d) Hydro Ottawa Capital Corporation's subsidiaries are Hydro Ottawa Limited, Envari Holding Inc., 2725163 Ontario Inc. and Telecom Ottawa Holding Inc.

e) The Hydro Ottawa Limited Board of Directors do not have any responsibility for Hydro Ottawa Energy Services Inc. or any other unregulated entity. However, the Executive Management Team, which includes the President and Chief Executive Officer, provides certain services to Hydro Ottawa Energy Services Inc. and the other non-regulated entities as summarized in part (f) below.

The Vice-President, Distribution Planning and Asset Management may provide engineering services to Hydro Ottawa Energy Services Inc. or other unregulated entities from time to time within the confines of the affiliated Service Level Agreements, as further outlined in Schedule 4-2-1 - Shared Services and Corporate Cost Allocation.

f) Members of the Hydro Ottawa Holding Inc.'s Executive Management Team provide certain services to its unregulated subsidiaries as summarized in Table A - Hydro Ottawa Holding Inc. Executive Management Team Members' Responsibilities for Unregulated Entities under Hydro Ottawa Capital Corporation and Hydro Ottawa Energy Services Inc., below.

Table A - Hydro Ottawa Holding Inc. Executive Management Team Members' Responsibilities for Unregulated Entities Under Hydro Ottawa Capital Corporation and Hydro Ottawa Energy Services Inc.

Executive Management Team Member	Responsibility for Unregulated Entities of Hydro Ottawa Capital Corporation	Responsibility for Unregulated Entities of Hydro Ottawa Energy Services Inc.
President and Chief Executive Officer	Management and corporate administration services	Management and corporate administration services
Chief Operating Officer, Distribution and Generation	None	Generation and distributed energy resource operations and management services
Chief Financial Officer	Regulatory, procurement, finance, tax, treasury, investor relations, and building and real estate support services	Regulatory, procurement, finance, tax, treasury, investor relations, and building and real estate support services
Executive Vice-President, People and Culture	Pension, human resources and health and safety services	Pension, human resources and health and safety services
Chief Information and Technology Officer	Information management and information technology services	Information management and information technology services
General Counsel and Corporate Secretary	Legal and corporate administration services	Legal and corporate administration services
Chief Customer Officer	Communications and public affairs services	Communications and public affairs services
Director, Corporate Planning, Risk and Advisory Services, and Head, Internal Audit	Risk management, audit and corporate planning services	Risk management, audit and corporate planning services
Chief Energy and Infrastructure Services	Energy and infrastructure operations and management services	None

g) The Hydro Ottawa Holding Inc. Executive Management Team provides services to the local distribution company within the scope of affiliated Service Level Agreements and as outlined in Table B - Hydro Ottawa Holding Inc. Executive Management Team Members' Responsibilities for Hydro Ottawa Limited, below. Please refer to subsection 4.1 of Schedule 4-2-1 - Shared Services and Corporate Cost Allocation, for a summary of the factors contributing to the projected increase in Hydro Ottawa Holding Inc. service costs to Hydro Ottawa Limited.

Table B - Hydro Ottawa Holding Inc. Executive Management Team Members' Responsibilities for Hydro Ottawa Limited

Executive Management Team Member	Responsibility for Hydro Ottawa Limited
President and Chief Executive Officer	Management and corporate administration services
Chief Operating Officer, Distribution and Generation	Distribution operations and management services
Chief Financial Officer	Regulatory, procurement, finance, tax, treasury, investor relations and building and real estate support services
Executive Vice-President, People and Culture	Pension, human resources and health and safety services
Chief Information and Technology Officer	Information management and information technology services
General Counsel and Corporate Secretary	Legal and corporate administration services
Chief Customer Officer	Communications and public affairs services
Director, Corporate Planning, Risk and Advisory Services, and Head, Internal Audit	Risk management, audit and corporate planning services
Chief Energy and Infrastructure Services	None

SHAREHOLDER DECLARATION OF THE
SOLE SHAREHOLDER OF HYDRO OTTAWA LIMITED dated the 1st day of October, 2024.

BY: **HYDRO OTTAWA CAPITAL CORPORATION/SOCIÉTÉ DE CAPITAUX HYDRO OTTAWA**

a corporation incorporated under the laws of the Province of Ontario

("HOCC")

WHEREAS subsection 108(2) of the *Business Corporations Act* (Ontario) permits all of the shareholders of a corporation to enter into a unanimous shareholder agreement;

AND WHEREAS pursuant to subsection 108(3) of such Act, a written declaration by a sole shareholder of a corporation that restricts in whole or in part the powers of the directors to manage or supervise the management of the business and affairs of the corporation is deemed to be a unanimous shareholder agreement;

AND WHEREAS pursuant to subsection 108(5) of such Act, to the extent that a unanimous shareholder agreement restricts the discretion or powers of the directors of a corporation to manage or supervise the management of the business and affairs of a corporation, a shareholder who is a party to the unanimous shareholder agreement assumes such powers and the related duties and liabilities and the directors are thereby relieved of their duties and liabilities;

AND WHEREAS HOCC is the registered and beneficial owner of all the issued and outstanding shares of Hydro Ottawa Limited/Hydro Ottawa Limitée and desires to make this Declaration with the intent that to the extent that it restricts the discretion and powers of the directors of Hydro Ottawa Limited/Hydro Ottawa Limitée, it shall constitute a unanimous shareholder agreement with respect to only those restrictions;

AND WHEREAS Hydro Ottawa Holding Inc./Société De Portefeuille D'Hydro Ottawa Inc. ("**HOHI**"), together with its subsidiaries Hydro Ottawa Limited/Hydro Ottawa Limitée and Energy Ottawa Inc./Énergie Ottawa Inc., are the successors to the businesses formerly carried on by the Municipal Electric Utilities (as herein defined);

AND WHEREAS HOCC wishes that this declaration show that it is an objective of Hydro Ottawa Limited to provide electricity distribution services to all customers in the geographic area of the City of Ottawa;

AND WHEREAS HOCC wishes to establish certain principles of governance and other fundamental principles and policies relating to Hydro Ottawa Limited/Hydro Ottawa Limitée and its subsidiaries;

NOW THEREFORE, HOCC hereby declares as follows:

ARTICLE I
INTERPRETATION

1.1 Definitions

In this Declaration the following terms will have the meanings set out below:

"Act" means the *Business Corporations Act* (Ontario), as now enacted or as the same may from time to time be amended, re-enacted or replaced;

"Affiliate" means a Body Corporate that is affiliated with Hydro Ottawa Limited/Hydro Ottawa Limitée as such relationship is defined in the Act;

"Board" means the board of directors of Hydro Ottawa Limited/Hydro Ottawa Limitée;

"Body Corporate" means a firm, partnership, unincorporated association, joint venture, corporation, bank, trust, pension fund, union, governmental agency, board, tribunal, ministry of commission or other legal entity of any kind whatsoever, but excludes an individual or natural person;

"Business Day" means a day, other than a Saturday or Sunday, on which the principal commercial banks located at Ottawa, Ontario, are open for business during normal banking hours;

"Energy Legislation" means the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* and all laws, codes, guidelines, orders and regulations created pursuant or in relation thereto that govern the energy sector in Ontario;

"External" means, with respect to a member of the Board, (a) an individual who is not the Mayor, a councilor or employee of the City of Ottawa; or (b) an individual who is not an officer and employee of Hydro Ottawa Limited/Hydro Ottawa Limitée or any Affiliate;

"Hydro Ottawa Limited" means Hydro Ottawa Limited/Hydro Ottawa Limitée, a corporation incorporated under the laws of Ontario;

"Municipal Electric Utilities" means collectively The Hydro-Electric Commission of the City of Ottawa, the Hydro-Electric Commission of the City of Nepean, The Hydro-Electric Commission of The City of Kanata, The Hydro-Electric Commission of the City of Gloucester and Goulbourn Hydro-Electric Commission;

"Person" means an individual, a natural person or a Body Corporate;

"Regulator" means the Ontario Energy Board, the Independent Electricity System Operator, the Ontario Power Authority or any other governmental or regulatory authority having jurisdiction over Hydro Ottawa Limited/Hydro Ottawa Limitée or a Subsidiary;

"Subsidiary" means, any Body Corporate, the incorporation of which has been approved by HOCC as contemplated by subsection 4.2(a) hereof, of which more than fifty percent (50%) of its outstanding securities of any class carrying exercisable voting rights are beneficially owned, directly or indirectly, by Hydro Ottawa Limited/Hydro Ottawa Limitée, and includes any Body Corporate in like relation to a Subsidiary; and

"**Third Party**" means a person who deals at arm's length (as interpreted by subsection 251 (1) of the *Income Tax Act* (Canada)) with Hydro Ottawa Limited/Hydro Ottawa Limitée.

1.2 Calculation of Time

In this Declaration, unless otherwise specified, time periods within or following which any payment is to be made or act is to be done shall be calculated by excluding the day on which the period commences and

including the day which ends the period and by extending the period to the next Business Day following if the last day of the period is not a Business Day.

1.3 Regulatory Matters

In the event of any conflict between any approval or direction or other requirement of HOCC and Hydro Ottawa Limited or a Subsidiary under this Declaration and any decision, order or policy of any Regulator, the decision, order or policy of the Regulator shall govern and Hydro Ottawa Limited and a Subsidiary will at all times comply with any decision, order or policy of the Regulator whether or not an approval or direction has first been given in respect thereof by HOCC under this Declaration. For greater certainty, Hydro Ottawa Limited and a Subsidiary will not seek any order from any Regulator for any matter that would require the approval of HOCC under this Declaration without first giving notice of their intention to seek such an order to HOCC.

ARTICLE 2
BUSINESS OF HYDRO OTTAWA LIMITED

2.1 Permitted Business Activities

Subject to its compliance with Energy Legislation, Hydro Ottawa Limited, either directly or through a Subsidiary, may engage in any of the following business activities:

(a) Transmitting and distributing electricity;

(b) providing the standard supply service of electricity to Persons connected to the distribution system of Hydro Ottawa Limited or a Subsidiary;

(c) providing meter installation, repair, calibration and reading services;

(d) providing services related to the promotion of energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources and services to assist the Government of Ontario in achieving its goals in electricity conservation

(e) providing street lighting services;

(f) managing or operating on behalf of the City of Ottawa the provision of a public utility, water or sewage service;

(g) using the real property that Hydro Ottawa Limited or a Subsidiary has the right to use for the purpose of providing telecommunications services for the purpose of electricity transmission or distribution, or entering into agreements with any Third Party, or Subsidiary, authorizing such Third Party or Subsidiary to use such real property for the purpose of providing telecommunications services for the purpose of electricity transmission or distribution;

(h) any other business activities carried on by the Municipal Electric Utilities at the time the assets of the latter were transferred to Hydro Ottawa Limited, the principal purpose of which is to use more effectively the assets of Hydro Ottawa Limited; and

(i) any other business activities permitted, pursuant to provincial legislation, to be carried on by an electricity distributor where the voting securities carrying more than 50 per cent of the voting rights attached to the voting securities of the electricity distributor are owned directly or indirectly by a municipal corporation.

2.2 Other Business Activities with Prior Approval

Subject to compliance with Energy Legislation, and with the prior written approval of HOCC, Hydro Ottawa Limited, either directly or through a Subsidiary, may engage in any of the following business activities:

(a) business activities which Hydro Ottawa Limited is not otherwise permitted to undertake which are not prohibited by section 71 of the *Ontario Energy Board Act, 1998.*

2.3 HOCC Consent

The Board shall have the authority to prepare a business case for consideration by HOCC related to any business activity set out in section 2.2. hereof which business case shall include an assessment of whether or not the new business activity is financially viable or otherwise commercially prudent to be pursued by Hydro Ottawa Limited or a Subsidiary. Upon a review of the business case, HOCC shall advise Hydro Ottawa Limited in writing whether or not the new business activity may be pursued by Hydro Ottawa Limited or its Subsidiary.

2.4 Service Territory

Hydro Ottawa Limited shall have an objective of providing electricity distribution services to all electricity customers in the geographic area of the City of Ottawa.

ARTICLE 3
OPERATION AND CONTROL

3.1 Number of Directors

Hydro Ottawa Limited shall be managed by the Board which shall be comprised of not less than two (2) and not more than three (3) directors, and which initially will consist of three (3) directors elected by HOCC, of whom:

(a) one shall be the President and Chief Executive Officer of HOHI;

(b) one shall be the Chair of HOHI; and

(c) one shall be a member of the management of Hydro Ottawa Limited who is not employed by an affiliate of Hydro Ottawa Limited.

provided that one-third of the Board shall, at all times, be independent from any Affiliate as required by the provisions of subsection 2.1.3 of the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters.

For greater certainty, notwithstanding the fact that the size of the Board may vary within the range specified above, the Board shall at all times be comprised of the director holding the office referred to in paragraph (a) above.

3.2 Term of Office

The term of office for a director shall be:

(a) In the case of the director who is the President and Chief Executive Officer of HOHI for so long as the director holds such office;

(b) In the case of any other directors, for terms, which will be staggered, as may, from time to time, be provided in the by-laws of Hydro Ottawa Limited.

Any director may stand for re-election to the Board at the expiry of his or her term.

3.3 Chair of the Board

The Chair of the Board of Hydro Ottawa Limited shall be appointed by HOL from among the members of the Board of Directors who are also members of the Board of Directors of HOHI.

3.4 Vacancies

If a member of the Board ceases to be a director for any reason, HOCC will fill the vacancy created thereby as soon as reasonably possible having regard to the provisions of section 3.1. If a member of the board of directors of a Subsidiary ceases to be a director for any reason, Hydro Ottawa Limited will cause the vacancy to be filled by another director, as soon as reasonably possible.

3.5 Remuneration

The remuneration of the members of the Board or the board of directors of a Subsidiary for their respective services as directors, will be as determined by HOCC from time to time. For greater certainty, only one annual stipend will be paid where an individual is a director of both Hydro Ottawa Limited and an Affiliate. Notwithstanding the foregoing,

(a) the President and Chief Executive Officer of HOHI will receive no remuneration in his or her capacity as director; and

(c) the member of the management of Hydro Ottawa Limited who is not employed by an affiliate of Hydro Ottawa Limited will receive no remuneration in his or her capacity as a director,

although the individuals described in paragraphs (a) and (b) will, along with all other directors, be reimbursed by Hydro Ottawa Limited for their out-of-pocket expenses upon presentation of supporting receipts therefor.

No amount shall be paid to the Chair, directors, members of their immediate families or entities in which they have a substantive ownership interest over and above the remuneration for directors determined by HOCC from time to time.

ARTICLE 4
SHAREHOLDER MATTERS

4.1 Shareholder Powers

In accordance with the provisions of the Act, Hydro Ottawa Limited will not, without the prior written approval of HOCC:

(a) amend its articles or make, amend or repeal any by-law;

(b) amalgamate (except for an amalgamation with one or more Subsidiaries), apply to continue as a body corporate under the laws of another jurisdiction, merge, consolidate or reorganize, or approve or effect any plan of arrangement, in each case whether statutory or otherwise;

(c) take or institute proceedings for any winding-up, arrangement, reorganization or dissolution;

(d) create new classes of shares or reorganize, consolidate, subdivide or otherwise change its outstanding securities;

(e) change its auditor;

(f) make any change to the number of directors comprising the Board; or

(g) enter into any other transaction or take any other action that requires shareholder approval pursuant to the Act.

4.2 Additional Matters Requiring Shareholder Consent

The powers of the Board, including without limitation any committee thereof, from time to time are herby restricted, in part, such that Hydro Ottawa Limited shall not without the prior written approval of HOCC:

(a) cause a Subsidiary to be incorporated;

(b) make any change in the issued capital of Hydro Ottawa Limited;

(c) implement a business plan other than a business plan approved by HOCC;

(d) incur operating or capital expenditures that exceed the budget approved for Hydro Ottawa Limited;

(e) submit an application to a Regulator for the approval of rates to be charged by Hydro Ottawa Limited that seeks a rate of return on equity other than the rate approved by HOCC;

(f) borrow any money on the credit of Hydro Ottawa Limited other than from HOCC;

(g) grant any security or create an encumbrance on the assets of Hydro Ottawa Limited;

(h) make directly or indirectly loans or advances except advances made to employees to defray expenses to be incurred in the course of the business of Hydro Ottawa Limited;

(i) give security for or guarantee debts;

(j) make donations or contributions to any Person contrary to policies established by HOCC and HOHI;

(k) permit any conduct contrary to codes of conduct or ethical standards established by HOCC and HOHI applicable to directors, officers, employees, contractors or other representatives of Hydro Ottawa Limited;

(l) adopt any governance practices applicable to directors of Hydro Ottawa Limited other than governance practices established by HOCC and HOHI;

(m) make any payment of remuneration to officers or employees of Hydro Ottawa Limited in any form in excess of guidelines or directives established by HOCC and HOHI;

(n) declare any dividend prior to consultation with HOCC or any dividend which is inconsistent with the dividend policy;

(o) appoint any auditor to fill any vacancy in the position of auditor which may occur during a year;

(p) enter into any partnership or any arrangement for the sharing of profits, union of interests, joint venture or reciprocal concession with any Person; and

(q) establish any financial year end of Hydro Ottawa Limited which is not December 31.

4.3 Liability of HOCC

In the exercise of the rights, duties and powers assumed and transferred under this Declaration, HOCC, as-the sole shareholder of Hydro Ottawa Limited, shall be subject to the same obligations and liabilities to which the Board would otherwise have been subject if this Declaration had not been made and the Board is hereby wholly relieved of all powers, duties and liabilities as directors of Hydro Ottawa Limited to the extent HOCC is subject thereto.

4.4 Residual Power of Boards

Without restricting the application of sections 4.1 and 4.2 hereof, the Board and the boards of directors of a Subsidiary shall have, subject to the Act and this Declaration, the full authority to manage the business and affairs of Hydro Ottawa Limited and a Subsidiary, respectively, including the authority to develop and recommend to HOCC decisions with respect to any of the matters specified in sections 4.1 and 4.2 hereof.

4.5 HOCC Power to Consent

The rights, powers and duties vested in HOCC pursuant to the provisions of this Declaration shall be exercised by or pursuant to a resolution or by-law of HOCC.

ARTICLE 5
REPORTING TO HOCC

5.1 Reports

Hydro Ottawa Limited will report to HOCC on any and all matters as requested by HOCC from time to time including reports relating to a Subsidiary. Without limiting the foregoing, Hydro Ottawa Limited shall provide, in a timely manner, to HOCC, an annual financial report containing such financial and other information as HOCC may reasonably request and which information Hydro Ottawa Limited is legally entitled to provide. Hydro Ottawa Limited shall provide to HOCC a report of material facts and material changes as they occur and shall be guided by securities laws applicable to publicly traded corporations when assessing the extent and timing of such disclosure.

ARTICLE 6
GENERAL PROVISIONS

6.1 Reference on Certificates

Hydro Ottawa Limited shall cause a reference to this Declaration to be noted conspicuously on every share certificate issued by Hydro Ottawa Limited. Hydro Ottawa Limited shall cause each Subsidiary to ensure that a reference to the Declaration delivered to it pursuant to subsection 6.4 hereof is noted conspicuously on every share certificate issued by such Subsidiary.

6.2 Termination

This Declaration shall be effective as of the date hereof and shall continue in full force and effect until HOCC has given written notice to the Board of the revocation and termination of this Declaration.

6.3 Amendment of Declaration

This Declaration may be amended from time to time by HOCC as circumstances may require and HOCC will consult with the Board prior to completing any amendments and will promptly provide the Board with copies of such amendments.

6.4 Declaration re Subsidiaries

In the event that, with the approval of HOCC contemplated by subsection 4.2(a) hereof, Hydro Ottawa Limited causes a Subsidiary to be incorporated, and so often as the same may occur, Hydro Ottawa Limited shall execute and deliver a declaration to each such Subsidiary in the form of this Declaration, mutatis mutandis.

6.5 Revocation of Previous Declarations

The Declaration dated August 28, 2014 is hereby revoked and replaced by this Declaration.

6.6 Governing Law

This Declaration shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

6.7 Effective Date

This Declaration shall be effective as of and from October 1, 2024, except as otherwise expressly provided.

IN WITNESS WHEREOF, HOCC has executed this Declaration as a unanimous shareholder agreement pursuant to subsections 108(2) and 108(3) of the Act.

HYDRO OTTAWA CAPITAL CORPORATION/SOCIÉTÉ DE CAPITAUX HYDRO OTTAWA

Per : DocuSigned by: Bryce Conrad 8EDB4595749C4E3...
Name: Bryce Conrad
Title: President & Chief Executive Officer

Per : _____
Name: Geoff Simpson
Title: Chief Financial Officer

IN WITNESS WHEREOF, HOCC has executed this Declaration as a unanimous shareholder agreement pursuant to subsections 108(2) and 108(3) of the Act.

HYDRO OTTAWA CAPITAL CORPORATION/SOCIÉTÉ DE CAPITAUX HYDRO OTTAWA

Per : _____
Name: Bryce Conrad
Title: President & Chief Executive Officer

Per : Signed by: Geoff Simpson 43DC885CF33E43F...
Name: Geoff Simpson
Title: Chief Financial Officer

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

1-CCC-13

EVIDENCE REFERENCE:

Exhibit 1, Tab 6, Schedule 1

QUESTION(S):

Please provide all materials provided to Hydro Ottawa Holding Inc.'s and Hydro Ottawa Limited's Board of Directors regarding this Application. Were the Application and related Business Plans approved by both Board of Directors? If not, which Board granted approvals?

RESPONSE(S):

Please refer to Attachment 1-CCC-13(A) - Rate Application Material provided to the Hydro Ottawa Limited Board of Directors. The same materials were provided to the Hydro Ottawa Holding Inc. Board of Directors.

The application and related business plan were approved by both the Hydro Ottawa Limited and the Hydro Ottawa Holding Inc. Board of Directors.

Annex “A”

Hydro Ottawa Limited
2026 - 2030 Rate Application

Hydro Ottawa Limited Board of Directors

April Barrie – Director, Regulatory Affairs

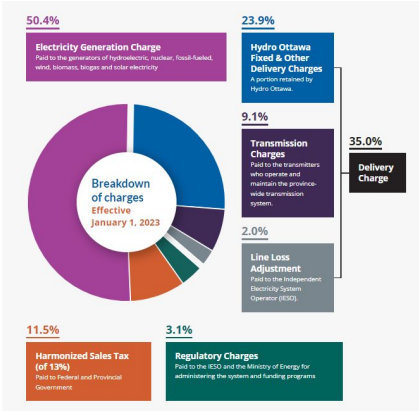
April 23, 2024

HydroOttawa

Agenda

- Regulatory Rate Framework
- Need for a Rate Application
- Planning and Budgeting for 2026-2030 Application Term
- Strategic Considerations
- Revenue Requirement
- Rate Application Schedule
- Policy Consultations
- Questions/Comments

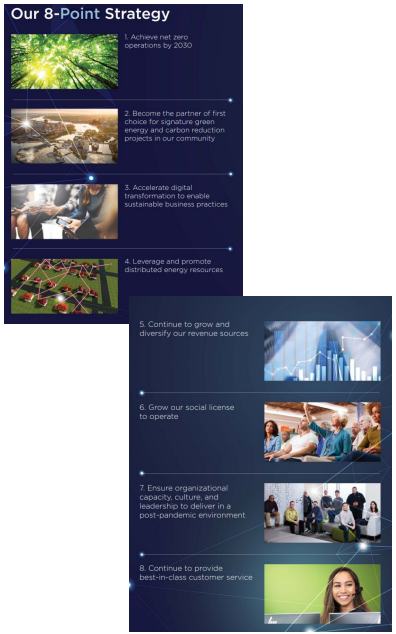
Regulatory Rate Framework



- Regulated by OEB under Electricity Act and OEB Act
- Set rates on a five year cycle
- Hydro Ottawa charges are only a portion of the bill
- Three application types:
  - Custom Incentive Regulation (CIR) - Five year plan, custom to fit the utility, or
  - Price Cap Incentive Rate-setting (Price Cap IR) - one year Cost of Service (COS) rebase followed by four years of inflation minus stretch factor
  - Annual IR Index - No rebasing and set using annual adjustment formula (highest stretch factor)
- Hydro Ottawa files it's fifth/final year update as part of it's 2021-2025 rate cycle in 2024
  - **2025** residential bill high level estimate - $0.20 (0.58%) for distribution only
- Next rebasing application is for 2026-2030

What will this Rate Application provide the Company?

- Sufficient funding and Human Resources to address:
  - Strategic Plan Objectives, and progress on Hydro Ottawa's Roadmaps
  - Installation of new distribution assets to be ready for electrification
  - Preparation for the energy transition, including supporting DERs
  - System upgrades to address large storms and climate change
  - Supply chain, inflation, and resourcing challenges
  - Ability to support evolving customer's needs
  - Increased digitization and IT and OT requirements
  - Financial stability/clarity for 2026 - 2030

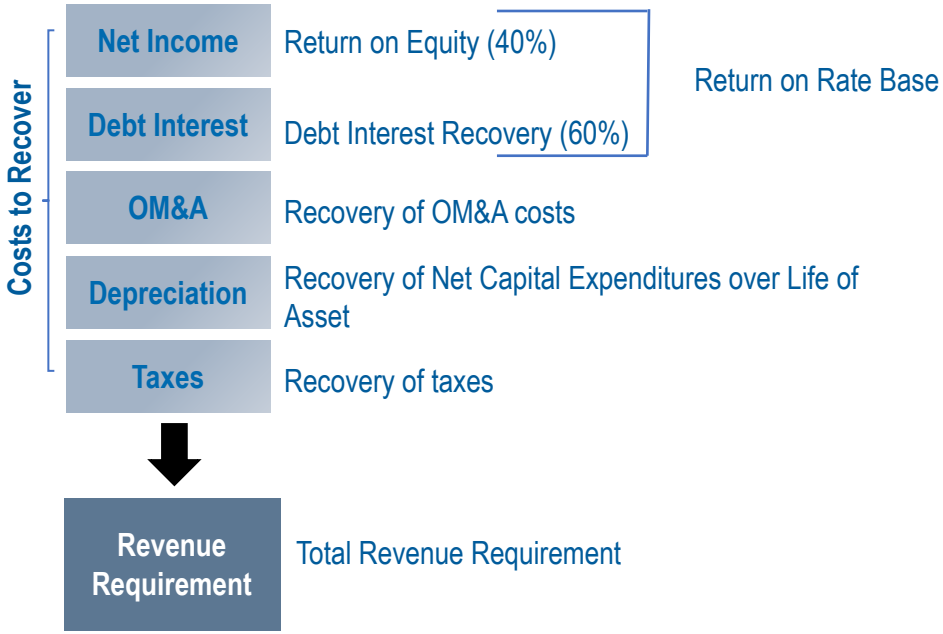


What is the OEB looking for?

- Cost effective and robust plans and projects
  - Focus on outcome not activities
- Continuous improvement
  - Evidence based
  - Benchmarking that demonstrates effectiveness
- Transparency
- True engagement with customers
  - Consideration of affordability
- That we did what we said we were going to do in 2021 - 2025
  - Or the reason why plans changed

Revenue Requirement for Rate Setting

- Customers pay for their use of the electricity grid
- Rates are set to recover an approved dollar amount
- The Approved dollar amount is called “Revenue Requirement”
- The overall cost that a distributor requires to run its business



Early Planning: Significant New Costs and Resourcing

- ***Main Themes Driving Costs***
  - Staffing and Organizational Capacity
  - Electrification & DER
  - Storm Hardening & Strategic Undergrounding
    - Derecho, Tornados & other weather events
  - Grid Modernization - IT and OT enhancements
    - Advanced Metering Infrastructure
  - Net Zero and Climate Change
  - New ERP and Asset Management System
  - Customer needs & preferences

- ***Cost considerations***
  - Capital & OM&A levels in 2021-2025
  - Customer affordability and pacing of investments
  - Customer contributions and building homes
  - Distribution versus grid benefit
  - Non wire versus traditional infrastructure

Ongoing Policy Consultations

- A number of Policy consultations are ongoing and will likely impact plans, for example:
  - Distribution Sector Resiliency, Responsiveness, and Cost Efficiency
  - Reliability and Power Quality Review
  - Cost of Capital/Cloud Computing/Utility Remuneration
  - EV Rate Design
  - Expansion of non wires solutions, including CDM
  - New Housing Developments
  - Ontario's Natural Gas Policy and Bill 165
  - Potential Funding Opportunities
- Despite this …
  - Planning still needs to go forward
  - Plans may need to adjust along the way

2026 - 2030 Rate Application Schedule & Progress to Date

Date	Activity
Q2 2023	Official Start
Summer 2023	Progress on set-up and Foundational Studies
Winter 2023/2024	Planning Memo, Meeting with Owners and Larger Group, Training
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Spring 2025	Evidence Update & Interrogatories
Mid Summer 2025	Technical Conference
Late Summer 2025	Settlement Conference
Fall 2025	Oral Hearing, if necessary
December 2025	Decision
January 1 2026	**Rates Effective**

Additional Comments or Questions

Thank You

HydroOttawa

Annex “A”

2026 - 2030 Rate Application

Hydro Ottawa Limited Board of Directors

April Barrie – Director, Regulatory Affairs

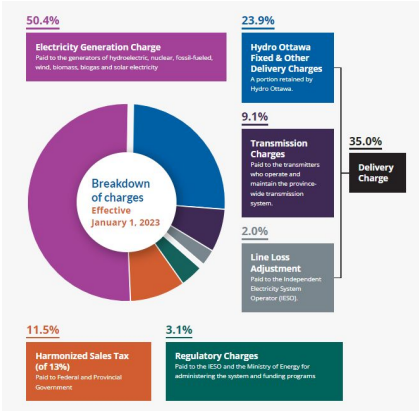
June 13, 2024

HydroOttawa

Agenda

- Regulatory Rate Framework
- Planning
- Affordability Update
  - Capex levels
  - 2026 OM&A level
  - Illustrative Customer Rates
  - Customer Priorities
- Timeline
- Questions/Comments

Regulatory Rate Framework



- Regulated by OEB under Electricity Act and OEB Act
- Set rates on a five year cycle
- Hydro Ottawa charges are only a portion of the bill
- Three application types:
  - Custom Incentive Regulation (CIR) - Five year plan, custom to fit the utility, or
  - Price Cap Incentive Rate-setting (Price Cap IR) - one year Cost of Service (COS) rebase followed by four years of inflation minus stretch factor
  - Annual IR Index - No rebasing and set using annual adjustment formula (highest stretch factor)
- Hydro Ottawa files its fifth/final year update as part of it's 2021-2025 rate cycle in 2024
  - **2025** residential bill high level estimate - $0.20 (0.58%) for distribution only
- Next rebasing application is for 2026-2030

What is the OEB looking for?

- Cost effective and robust plans and projects
  - Focus on outcome not activities
- Continuous improvement
  - Evidence based
  - Benchmarking that demonstrates effectiveness
- Transparency
- True engagement with customers
  - Consideration of affordability
- That we did what we said we were going to do in 2021 - 2025
  - Or the reason why plans changed

Planning: Significant New Costs and Resourcing

- ***Main Themes Driving Costs***
  - Staffing and Organizational Capacity
  - Electrification & DER
  - Storm Hardening & Strategic Undergrounding
  - Derecho, Tornados & other weather events
  - Grid Modernization - IT and OT enhancements
  - Advanced Metering Infrastructure
  - Net Zero and Climate Change
  - New ERP and Asset Management System
  - Customer needs & preferences

- ***Cost considerations***
  - Capital & OM&A levels in 2021-2025
  - Customer affordability and pacing of investments
  - Financial Affordability for restructured company
  - Customer contributions and building homes
  - Distribution versus grid benefit
  - Non wire versus traditional infrastructure

Need vs. Affordability

- In light of the significant new requirements arising from the previous slide, management through a Steering Committee and Working Group, has solicited the 5 year capital and operating needs to maintain reliability, enhance customer service and productivity, and make progress on strategic initiatives
- The needs gathering process has taken time and was impacted by the 2023 strike, but is now substantially completed
- These needs must be measured, and tempered, against affordability, both for the customer and the company
- There are implications to reductions from the need, that may impact reliability, resilience and current and new services to customers

2026 - 2030 Capital Spend Need
New reality = $2B over 5 years

$Millions	2026	2027	2028	2029	2030	Total
Electrification & DER	118	124	86	88	100	**517**
Renewal & Reliability	130	133	143	123	106	**635**
Resilience	34	46	46	46	46	**218**
Grid Modernization	44	45	45	51	44	**229**
Advanced Metering Infrastructure	33	33	33	33	33	**165**
Net Zero	6	5	8	6	3	**29**
IT Systems	7	6	4	6	7	**30**
Customer needs & preferences	3	1	8	2	1	**14**
Third Party Demand	34	33	27	33	27	**154**
Total	**408**	**426**	**401**	**387**	**367**	**1,990**

OM&A Requirements: Current and 2026 Need

($Millions)	Actual 2021	Actual 2022	Actual 2023	Bridge Year 2024	Bridge Year 2025	Rate App Need 2026	Variance 2026 - 2025
OM&A	85	101	113	115	117	160	43
OEB Approved	91	93	97	101	105		
Variance O/(U)	(6)	8	16	14	12		

$43M OM&A increase from 2025 is explained by…

- $19M Compensation including growth; 81 new positions added in 2026
- $13M Cloud implementation costs including first year of the new ERP
- $3M AMI Data Plan
- $8M Others including Underground Locates no longer in deferral variance account, Inflation, Rate App costs amortized over the next 5 years

Need vs. Affordability - Part 1
Financial Affordability

- While the sizeable need is not unexpected, the capital needs analysis is beyond HOL financial capacity to deliver
- In response, management has formulated a draft 5 year capex spend limit of $1.1 Billion, in which all equity remains within HOL
  - Management is striving to prioritize programs to fit within this envelope
  - Even this capex spending envelope contains cost of capital risks and assumptions
  - Other options may need to be considered
- OM&A is being reviewed in light of capex changes and overall affordability
- Currently 2026 distribution rate increases are projected to be 29% (RES), followed by approximately 5% increases each year for 2027 - 2030 (RES & SC)
  - Rate Mitigation must be considered over the 5 year rate plan period
  - Bill impacts include high level cost of capital assumptions

Current State: 5 Year CAPEX Prioritized

$Millions	Full Ask	Prioritized	Reductions	%
Electrification & DER	517	436	(81)	(16%)
Renewal & Reliability	635	409	(226)	(36%)
Resilience	218	11	(207)	(95%)
Grid Modernization	229	79	(150)	(65%)
Advanced Metering Infrastructure	165	99	(66)	(40%)
Net Zero	29	3	(26)	(91%)
IT Systems	30	20	(10)	(32%)
Customer needs & preferences	14	11	(3)	(21%)
Third Party Demand	154	154	-	-
Total	**1,990**	**1,222**	**(768)**	**(39%)**

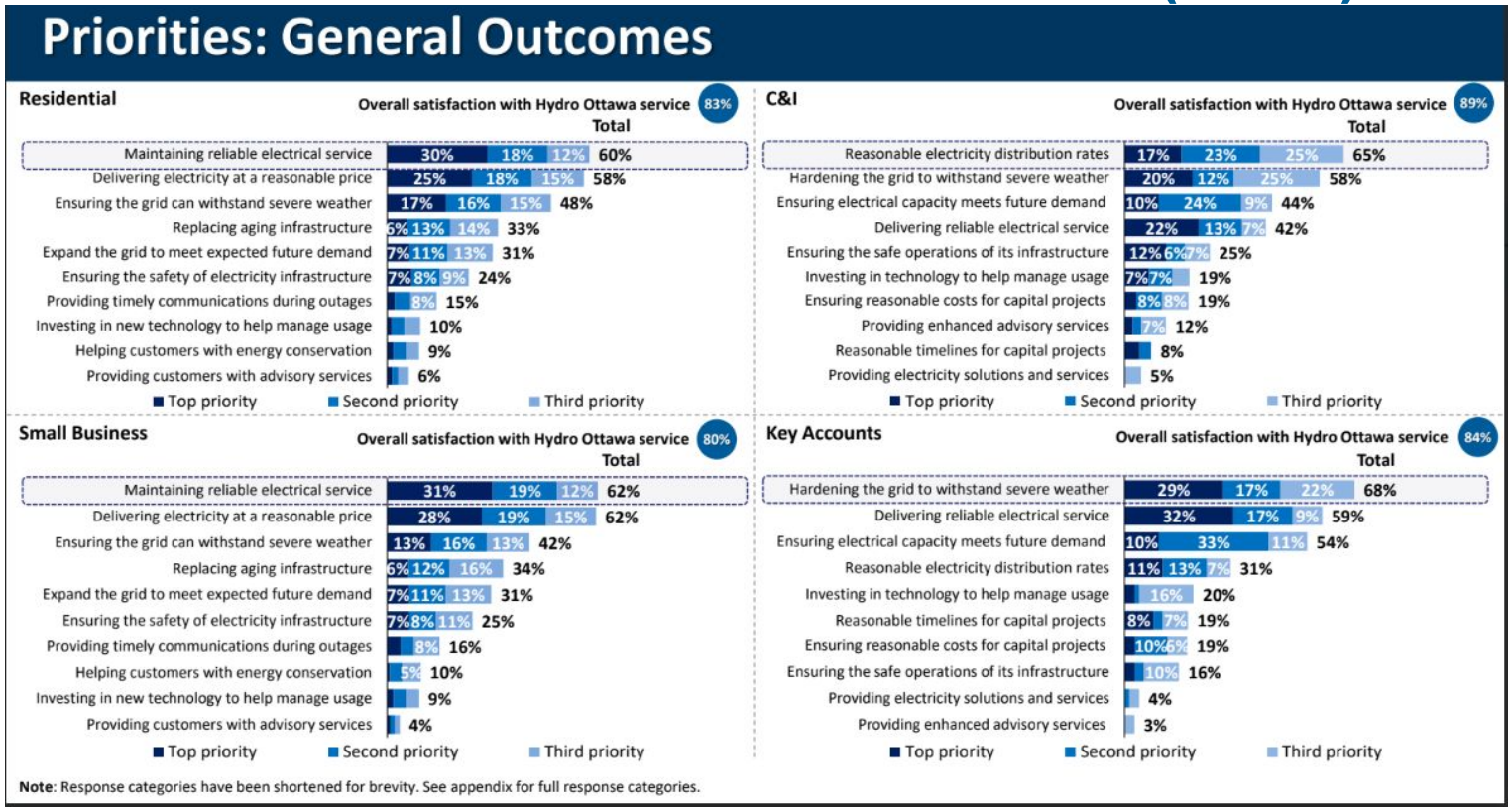
5 Year CAPEX Comparisons - Toronto and Hydro One

($Millions)	2016-2020 Planned	2016-2020 Actual	*Planned vs. Actual*	2021-2025 Planned	2021-2025 Actual/ Forecast	*Planned vs. Actual*	2026-2030 Plan (Affordability Model)	*Change From Previous Rebasing*
Hydro Ottawa	$537.5	$628.7	*17%*	$497.6	$595.2	*19.6%*	$1,100.0	*$504.8 84.8%*
	2015-2019 Planned	2015-2019 Actual	*Planned vs. Actual*	2020-2024 Planned	2020-2024 Actual/ Forecast	*Planned vs. Actual*	2025-2029 Plan	*Change - From Previous Rebasing*
Toronto Hydro	$2,489.5	$2,379.4	*-4.4%*	$2,710.7	$2,841.2	*4.8%*	$3,928.6	*$1,087.4 38.3%*
				2018-2022 Planned	2018-2022 Actual	*Planned vs. Actual*	2023-2027 Planned	*Change From Previous Rebasing*
Hydro One				$3,081.2	$3,255.1	*5.6%*	$5,574.6	*$2,319.5 71.3%*

Residential and Small Commercial Bill Impacts

	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Increase	Average
	2025F	2026F	2027F	2028F	2029F	2030F	Over 2025	5 years
Residential (750 kWh)								
Distribution	$34.39	$44.51	$46.00	$48.36	$50.48	$51.94	$17.55	
Change in Distribution		$10.12	$1.49	$2.36	$2.12	$1.46		$3.51
% Change in Distribution		**29.43%**	**3.35%**	**5.13%**	**4.38%**	**2.89%**	**51.03%**	**9.04%**
% Total Bill Change		6.75%	0.99%	1.55%	1.37%	1.32%		2.40%
General Service <50 kW (2000 kWh)								
Distribution	$85.67	$102.54	$106.67	$112.51	$118.58	$122.76	$37.09	
Change in Distribution		$16.87	$4.13	$5.84	$6.07	$4.18		$7.42
% Change in Distribution		**19.69%**	**4.03%**	**5.47%**	**5.40%**	**3.53%**	**43.29%**	**7.62%**
% Total Bill Change		4.05%	1.08%	1.51%	1.55%	1.05%		1.85%

Customer Priorities Feedback to Date (Draft)



2026 - 2030 Rate Application Schedule & Progress to Date

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January 1 2026	**Rate Effective**

Background Information

Reminder: Revenue Requirement for Rate Setting

- Customers pay for their use of the electricity grid
- Rates are set to recover an approved dollar amount
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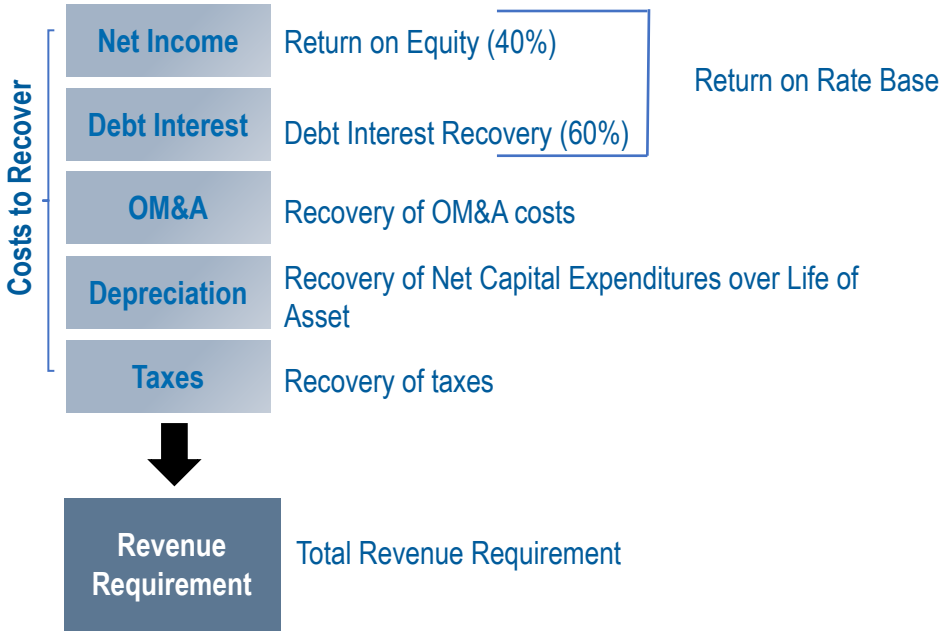


Annex A”

Hydro Ottawa Limited
2026 - 2030 Rate Application

Hydro Ottawa Limited Board of Directors

Julie Lupinacci - Chief Customer Officer
April Barrie – Director, Regulatory Affairs

October 21, 2024

HydroOttawa

Agenda

- What's New
  - Rate Application
  - Other proceedings
- Customer Survey Update
- Timeline
- Questions/Comments

What's New

- Evidence is progressing well
- Training for evidence writing (including Gemini AI)
- Customer Survey Completed (Phase 2)
- OEB Cost of Capital Proceeding is ongoing
  - Experts recommendations range from 7.05% to 11.08%
- Toronto Hydro Settlement complete on all but one item
  - Not yet approved - Presentation Day for clarifications
  - Residential monthly distribution charge
    - Increases $12.34 over the 5 years (not including temporary rate riders)
    - On average a $2.47 annual increase on the monthly charge
  - Toronto Hydro Settled For:
    - Reduction in Revenue Requirement of 4.7%
    - Reduction of 9.2% in capital expenditures & 8.49% in additions
    - 8.6% reduction in OM&A

Customer Rate Impact Overview

- Overall Bill Impacts Presented*
- Optionality provided for five key programs with summaries included for each to provide an understanding of the targeted outcomes

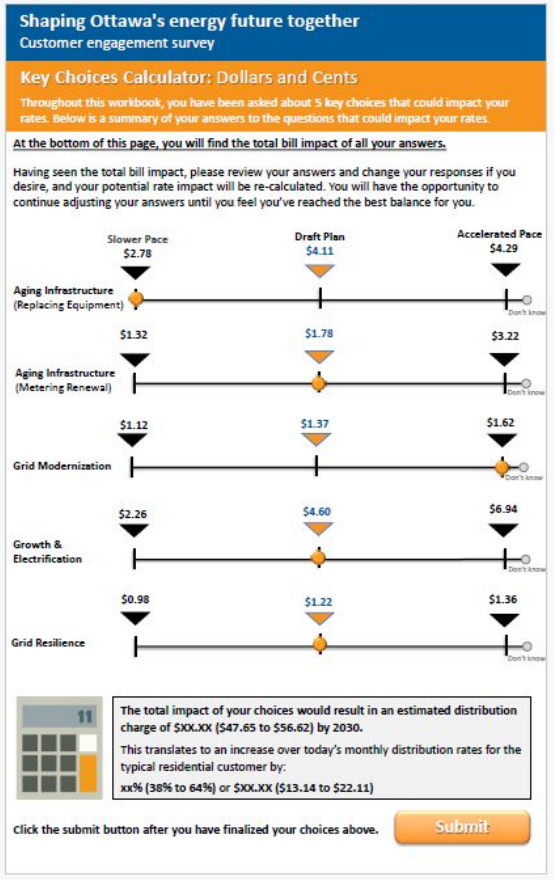
How much will Hydro Ottawa's draft plan cost me?

At the end of the five-year plan (2030), the typical residential customer would see the distribution portion of their monthly electricity bill increase by **$17.76**: from an estimated rate (price) of **$34.51 in 2025** to a proposed rate (price) of **$52.27 by 2030.**

					Hydro Ottawa's Portion	
	Year	Avg. Monthly Bill*	Non-Distribution Component	Distribution Component (Hydro Ottawa's portion)	Annual Increase to Monthly Bill (%)	Annual Increase to Monthly Bill ($)
CURRENT	*2024*	$132.49	$98.30	$34.19	n/a	n/a
BUDGTED	*2025*	$132.06	$97.55	$34.51	1%	$0.32
Rate Period	**2026**	$140.99	$100.41	$40.58	18%	$6.07
	2027	$147.10	$102.28	$44.82	10%	$4.24
	2028	$152.21	$104.25	$47.96	7%	$3.14
	2029	$156.15	$106.31	$49.84	4%	$1.88
	2030	$160.75	$108.48	$52.27	5%	$2.43
	5-yr impact			**$17.76**	**51%**	**$17.76**

Note:

- *Average monthly bill includes taxes and the Ontario Electricity Rate.*
- *These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-use Regulated Price Plan.*
- *Bill projections assume a general inflation increase of 2.1% for other aspects of the electricity bill that are outside of Hydro Ottawa's control (commodity, transmission, government, regulatory fees).*



*The final budget for 2026-2030 will be adjusted to reflect customer feedback collected and any necessary adjustments prior to filing with the OEB.

Once Again Achieved Strong Customer Engagement

	2021-2025 Survey		2026-2030 Survey	
	Completed	% of Customers	Completed	% of Customers
Residential	18,902	6.11%	21,273	6.26%
Small Business	318	1.27%	515	1.92%
Commercial*	13	0.4%	44	1.42%

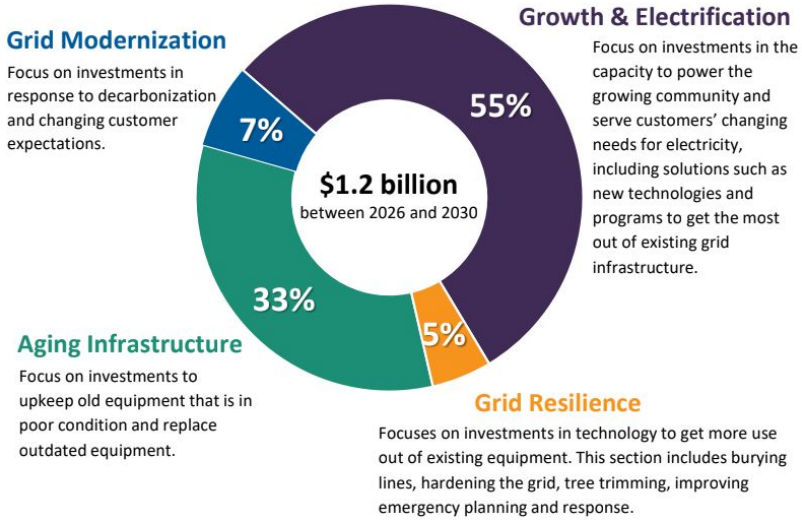
* Includes Key Accounts

Customer Engagement Survey Outreach

- The survey was promoted on the following channels between September 6 and October 6, 2024:
  - Bill insert
  - On-bill message
  - E-blast
  - Corporate newsletters (residential, community, business)
  - Shareholder letter
  - Social media (paid and organic)
  - Website banner and dedicated web section
  - *Ottawa Citizen* print ad
  - *Le Droit* digital ads
  - Google cross-network ads
  - Radio ads

2026-2030 Summary Results*

	Residential	Small Commercial	Commercial**
Social Permission	**84%**	**83%**	**93%**
Go beyond draft plan	**19%**	**19%**	**9%**
Support draft plan	**28%**	**25%**	**31%**
Don't like to pay more, but investments necessary	**37%**	**39%**	**53%**
Oppose, scale back plan	11%	13%	2%
Don't know	5%	4%	4%



* Results are preliminary
** Includes Key Accounts

- Customers continue to indicated reliability was a high priority

2026 - 2030 Rate Application Schedule & Progress to Date

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Additional Comments or Questions

Thank You

HydroOttawa

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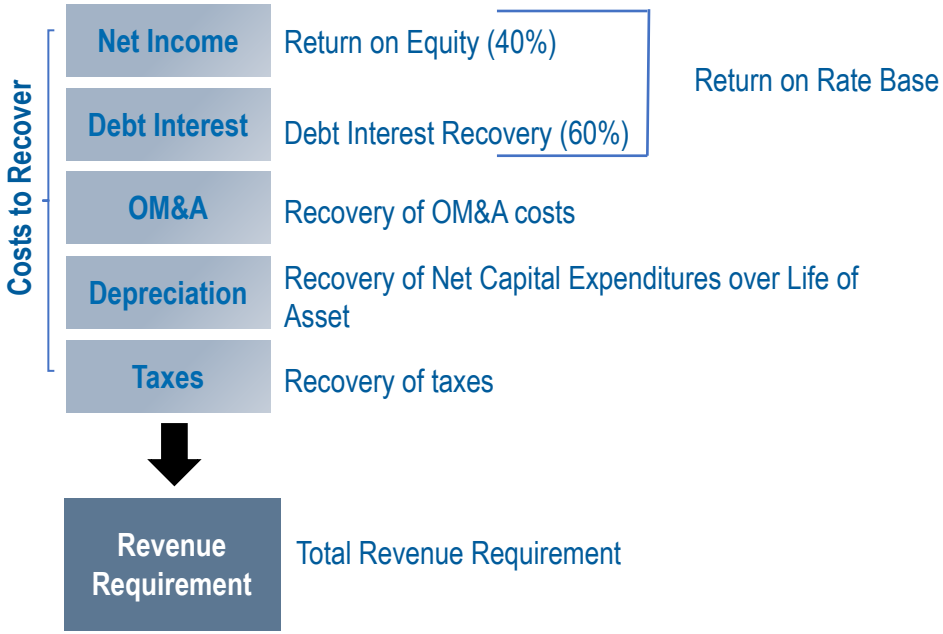


Annex “A”

Hydro Ottawa Limited
2026 - 2030 Rate Application

Hydro Ottawa Limited Board of Directors

April Barrie – Director, Regulatory Affairs

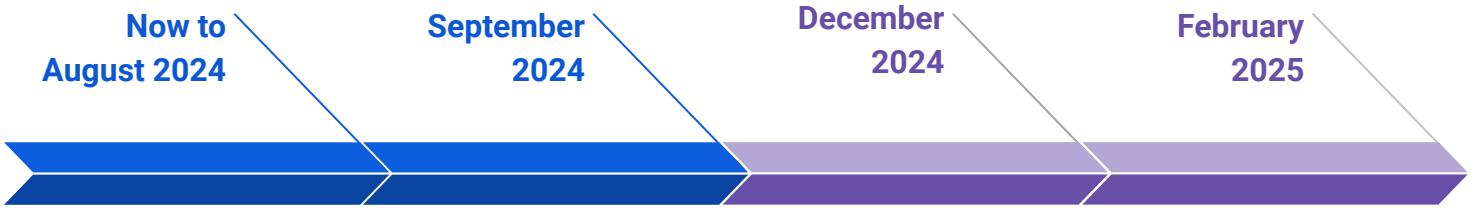
December 5, 2024

HydroOttawa

Agenda

- Timeline
- Industry Update
- Customer Survey Refresh
- Approval Request
- Questions/Comments

2026 - 2030 Rate Application - High Level Schedule



- Complete Special Studies
- Prepare Budgets
- Engage Customers
- Write Evidence

- Customer Survey

- Finalized Budgets and Evidence with Customer Feedback

- File Application

2026 - 2030 Rate Application Schedule & Progress to Date

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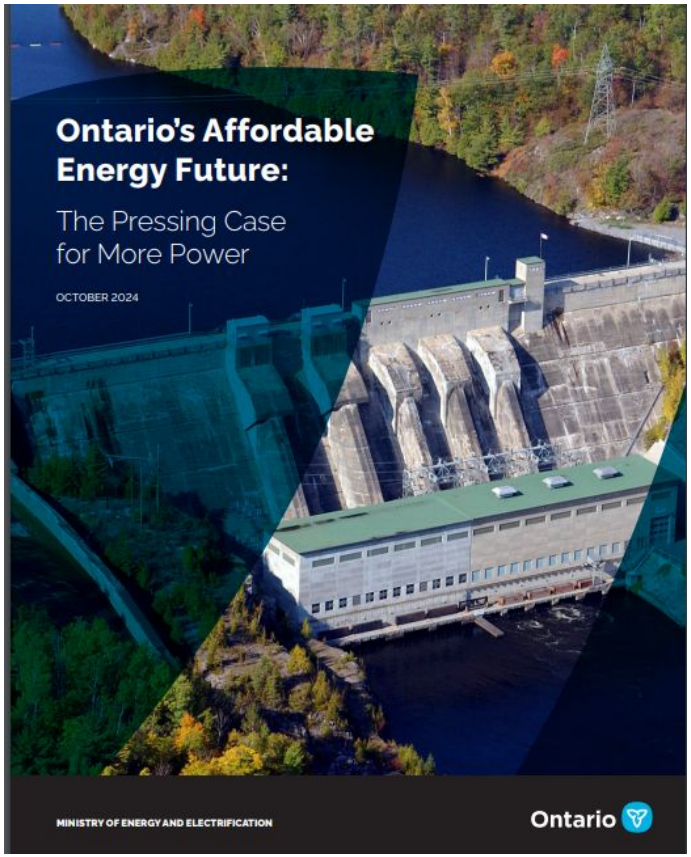
January 1 2026	**Rates Effective**

Industry Update

- Toronto Hydro Received Partial Decision November 12
- Policy has been busy at the Ministry and OEB
  - OEB Housing Report and Implementation
  - Proposed *Affordable Energy Act* (Bill 214)
- Cost of Capital
  - Submission period is complete with decision expected in Q1 2025
  - Experts recommending Return on Equity range 7.05% to 11.08%
    - Currently = 9.25%
- Advanced Performance-Based Approach to Rate Regulation (PBR)
  - Discussion paper in the Spring of 2025, followed by comments
  - Recommendation in the Fall 2025 on any Performance Incentive Mechanisms (PIMs)



Customer Survey Results | Summary

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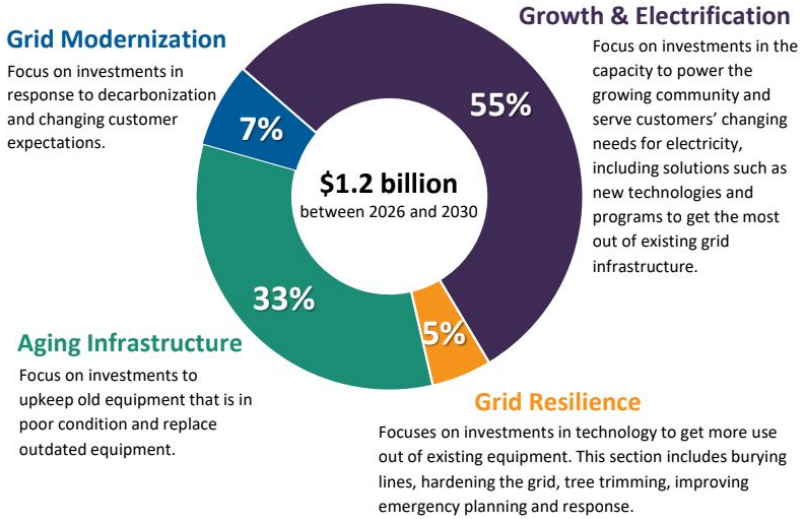
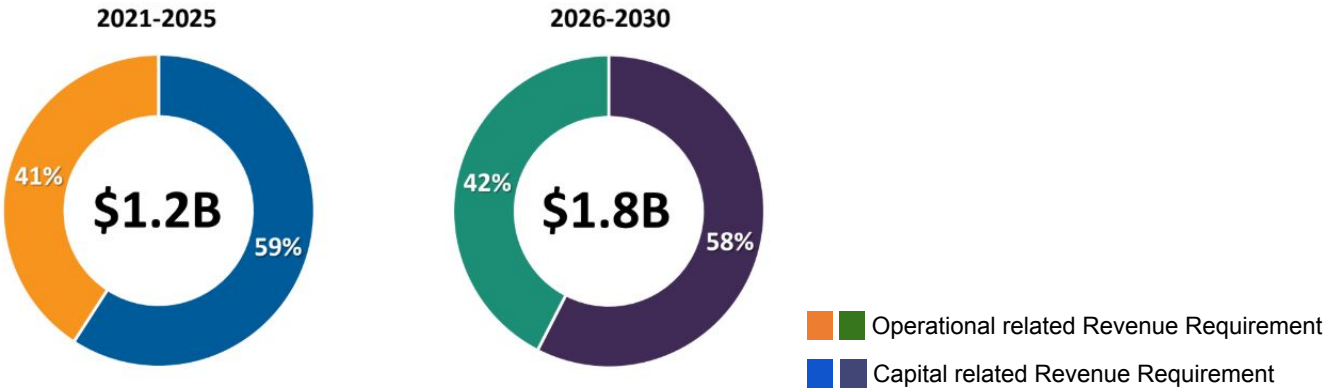


- Customers continue to indicate reliability was a high priority

Updated Revenue Requirement ($000)

	2026	2027	2028	2029	2030	Total
Service Revenue Requirement	**$313,066**	**$341,107**	**$368,801**	**$388,910**	**$412,971**	**$1,824,855**
Revenue Offsets	$11,018	$10,697	$10,859	$11,123	$11,460	$55,157
Base Revenue Requirement	**$302,049**	**$330,410**	**$357,941**	**$377,787**	**$401,511**	**$1,769,698**
Percentage Growth		9.4%	8.3%	5.5%	6.3%	



2021-2025 is after approved annual adjustments

Rate Application Approval Request

- 5 Year Custom Framework for 2026-2030
  - Plan that supports key themes that aligned with customer preferences - reliability, reliance, growth and electrification
    - Including non-wires alternatives
  - 1st year rebasing followed by a formulaic approach that reflects embedded productivity and growth
    - Supported by benchmarking, productivity initiatives and rational of rate framework
  - 5 Year Load Forecast
  - Rate impacts that align with social permission provided through customer survey
    - ***Updated rate impacts to be provided at meeting***
  - Regulatory mechanisms that balance customer and LDC needs and affordability
  - Does not include recently announced policy file implications, but contemplates some
    - May develop over the course of the rate application process

How much will Hydro Ottawa's draft plan cost me?

At the end of the five-year plan (2030), the typical residential customer would see the distribution portion of their monthly electricity bill increase by **$17.76**: from an estimated rate (price) of **$34.51 in 2025** to a proposed rate (price) of **$52.27 by 2030.**

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BUDGTED	*2025*	$132.06	$97.55	$34.51	1%	$0.32
Rate Period	**2026**	$140.99	$100.41	$40.58	18%	$6.07
	2027	$147.10	$102.28	$44.82	10%	$4.24
	2028	$152.21	$104.25	$47.96	7%	$3.14
	2029	$156.15	$106.31	$49.84	4%	$1.88
	2030	$160.75	$108.48	$52.27	5%	$2.43
	5-yr impact			**$17.76**	**51%**	**$17.76**

Note:

- *Average monthly bill includes taxes and the Ontario Electricity Rate.*
- *These estimated rate increases are preliminary and are subject to change based on customer feedback, regulatory approval and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-use Regulated Price Plan.*
- *Bill projections assume a general inflation increase of 2.1% for other aspects of the electricity bill that are outside of Hydro Ottawa's control (commodity, transmission, government, regulatory fees).*

UPDATED Residential and Small Commercial Bill Impacts

	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Increase	Average
		2026F	2027F	2028F	2029F	2030F	Over 2025	5 years
Residential (750 kWh)								
Distribution	$34.51	$41.36	$45.74	$48.97	$51.16	$54.11	$19.60	
Change in Distribution		$6.85	$4.38	$3.23	$2.19	$2.95		$3.92
% Change in Distribution		**19.85%**	**10.59%**	**7.06%**	**4.47%**	**5.77%**	**56.80%**	**9.55%**
% Total Bill Change		6.36%	3.14%	2.25%	1.50%	1.98%		3.05%
General Service <50 kW (2000 kWh)								
Distribution	$85.93	$101.28	$111.13	$119.39	$125.22	$132.43	$46.50	
Change in Distribution		$15.35	$9.85	$8.26	$5.83	$7.21		$9.30
% Change in Distribution		**17.86%**	**9.73%**	**7.43%**	**4.88%**	**5.76%**	**54.11%**	**9.13%**
% Total Bill Change		4.95%	2.75%	2.24%	1.55%	1.89%		2.67%

- Updated for 2025 preliminary Cost of Capital parameter
  - The customer survey used an estimate for 2026 (based on future forecast, is expected to be lower)
- Updated Load Forecast that shows a lower population growth
  - Load Forecast could still have adjustments

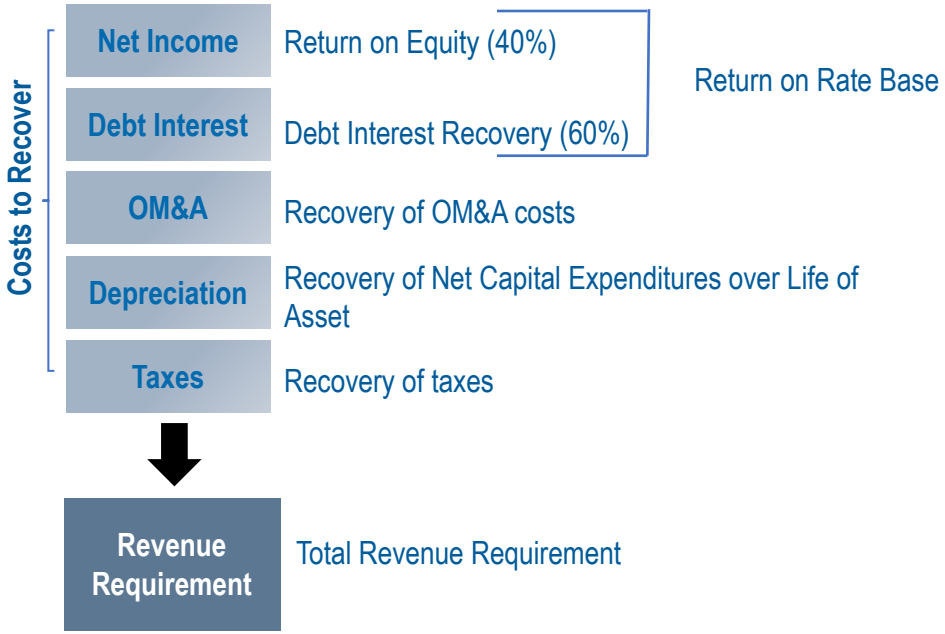
Additional Comments or Questions?

Thank You

HydroOttawa

Reminder: Revenue Requirement for Rate Setting

- Customers pay for their use of the electricity grid
- Rates are set to recover an approved dollar amount
- The Approved dollar amount is called “Revenue Requirement”
- The overall cost that a distributor requires to run its business



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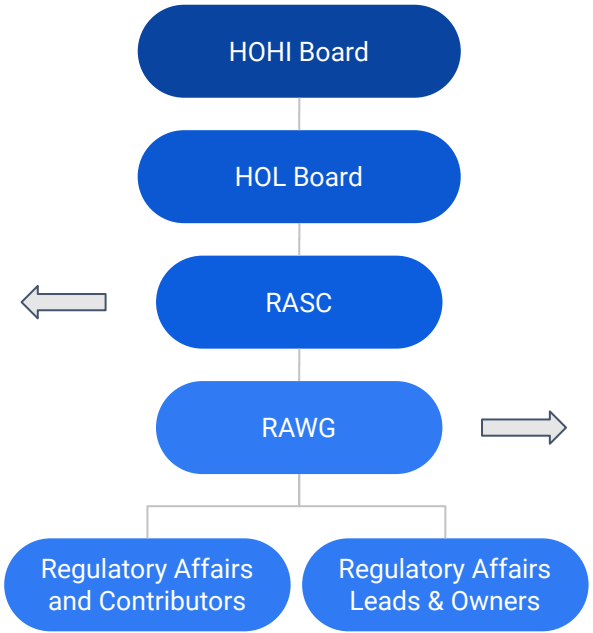

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Annex “A”

Hydro Ottawa Limited
2026 - 2030 Rate Application

Hydro Ottawa Limited Board of Directors

April Barrie – Director, Regulatory Affairs

April 24, 2025

HydroOttawa

Agenda

- Timeline
- Rate Application Submission
- Industry Update
- Summary
- Questions/Comments

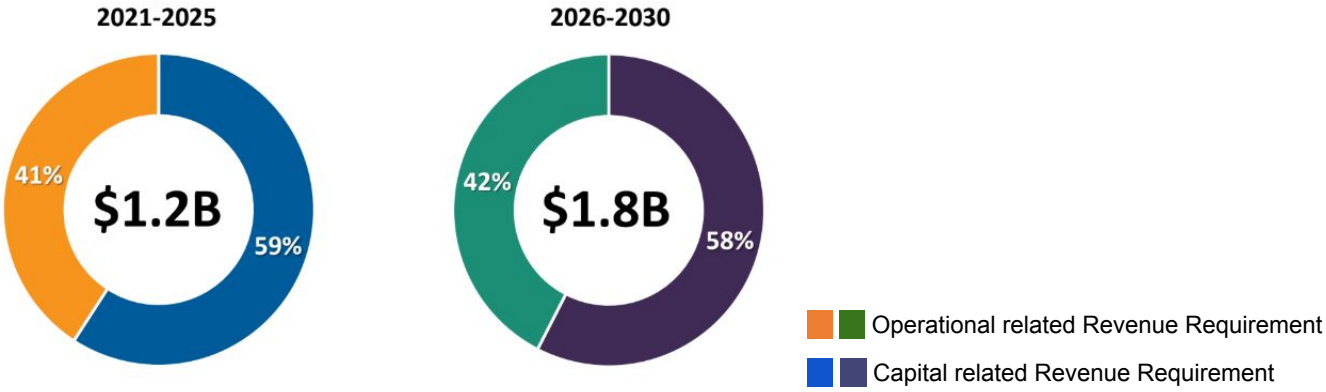
2026-2030 Rate Application Schedule: Progress & Next Steps

Date	Activity
Q2 2023	Official Start
Summer 2023	Progress on set-up and Foundational Studies
Winter 2023/2024	Planning Memo, Meeting with Owners and Larger Group, Training
Spring/Summer	Start Customer Engagement, Complete Special Studies & Prepare Financial Plans
June 2024	First draft of rate increases to the Board
September 2024	Customer Survey Launch, Evidence should have a good first drafts
Mid Fall 2024	Incorporate Customer Feedback & Evidence substantially completed
December 5, 2024	Board Approval of Rate Application
March 2025	Evidence is finalized
April 2025	Final Reviews and Adjustments
April 15, 2025	**Submit Application**
April/May 2025	Completeness Review and OEB Procedural Order #1
Spring/Summer 2025	Evidence Update & Interrogatories
Summer 2025	Technical Conference
Late Summer 2025	Settlement Conference
Fall 2025	Oral Hearing, if necessary
December 2025	Decision
January 1 2026	**Rates Effective**

- 84 Schedules
- 52 Excel Files
- 4,364 Pages

Updated Revenue Requirement, As Filed ($000)

	2026	2027	2028	2029	2030	Total
Service Revenue Requirement	**$309,993**	**$335,440**	**$363,279**	**$387,331**	**$411,392**	**$1,807,436**
Revenue Offsets	$11,018	$10,697	$10,859	$11,123	$11,460	$55,157
Base Revenue Requirement	**298,975**	**324,743**	**352,420**	**376,208**	**399,932**	**$1,752,279**
Percentage Growth		8.6%	8.5%	6.7%	6.3%	



2021-2025 is after approved annual adjustments

Updated Residential and Small Commercial Bill Impacts

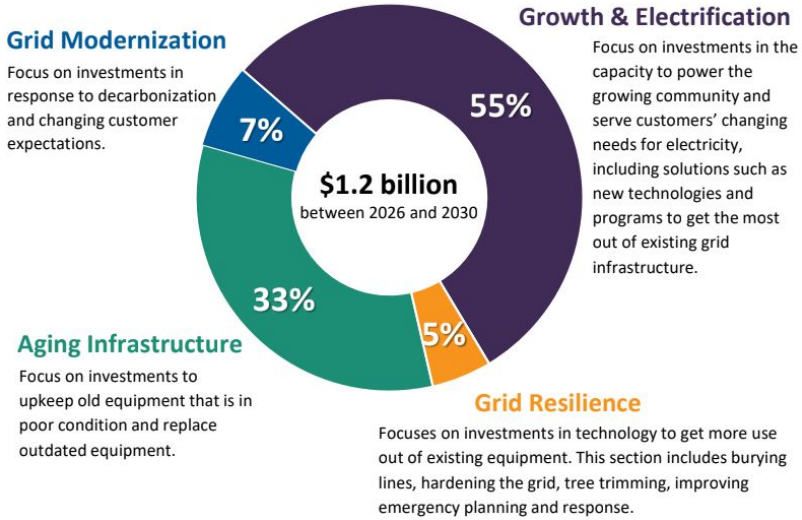
Rate Class		Approved	Proposed					Increase	Average
		2025	2026	2027	2028	2029	2030	Over 2025	5 years
Residential (750 kWh)	Distribution Charge	$34.51	$40.59	$44.38	$47.69	$50.41	$53.15		
	Change in Distribution Charge		$6.08	$3.79	$3.31	$2.72	$2.74	$18.64	$3.73
	% Distribution Increase		17.62%	9.34%	7.46%	5.70%	5.44%	54.01%	9.11%
	% Increase of Total Bill		6.05%	2.73%	2.33%	1.88%	1.85%		2.97%
General Service <50 kW (2000 kWh)	Distribution Charge	$85.93	$100.50	$108.92	$116.42	$123.04	$128.84		
	Change in Distribution Charge		$14.57	$8.42	$7.50	$6.62	$5.80	$42.91	$8.58
	% Distribution Increase		16.96%	8.38%	6.89%	5.69%	4.71%	49.94%	8.53%
	% Increase of Total Bill		4.94%	2.35%	2.05%	1.77%	1.53%		2.53%

- 2025 Final OEB Cost of Capital parameters used (to be updated once 2026 parameters are available)
- Non Distribution portions of the bill, per OEB requirements
  - Transmission rates estimated for 2026 and held constant to 2030
  - All other charges held at 2025 rates (Electricity Generation and Regulatory Costs)

Reminder: Customer Survey Results | Summary

	Residential	Small Commercial	Commercial*
Social Permission	**84%**	**83%**	**93%**
Go beyond draft plan	**19%**	**19%**	**9%**
Support draft plan	**28%**	**25%**	**31%**
Don't like to pay more, but investments necessary	**37%**	**39%**	**53%**
Oppose, scale back plan	11%	13%	2%
Don't know	5%	4%	4%

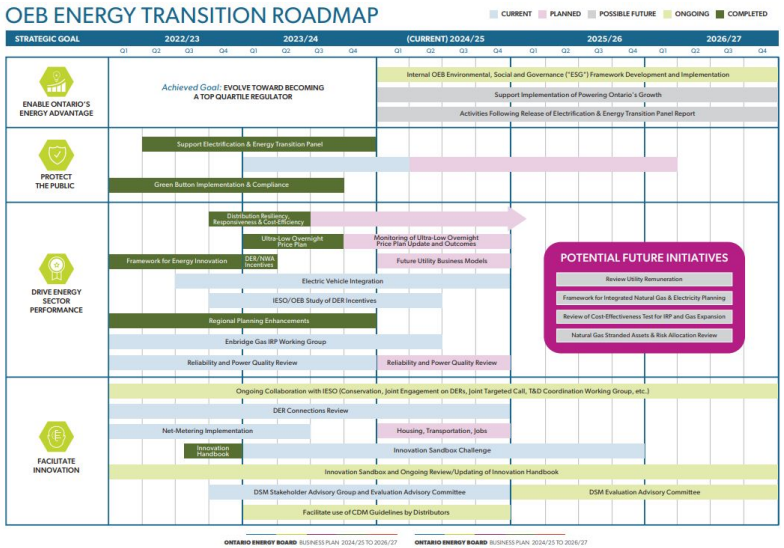
* Includes Key Accounts



- Customers continue to indicate reliability was a high priority

Industry Update - Policy continues to be busy at the OEB

- **OEB Issues Updated Cost of Capital Parameters March 27**
  - Return on Equity 9.00% (was 9.25%)
  - Deemed LT Debt Rate 4.51% (was 4.66%)
  - Deemed ST Debt Rate 3.91%* (was 5.04%)
    - ** disputed by industry as improper methodology*
  - No change in capital structure: 60/40 Debt/Equity
  - ***Rate App Submission updated with all new parameters***
- Total Cost Benchmarking review
- Spending Pattern Analysis Consultation
- Advanced Performance-Based Approach to Rate Regulation
  - Discussion paper in the Spring of 2025, followed by comments
  - Recommendation in the Fall 2025 on any Performance Incentive Mechanisms (PIMs)



Rate Application Summary

- 5 Year Custom Framework for 2026-2030
  - Plan that supports key themes that aligned with customer preferences - reliability, reliance, growth and electrification
    - Including non-wires alternatives
  - 1st year rebasing followed by a formulaic approach that reflects embedded productivity and growth
    - Supported by benchmarking, productivity initiatives and rational of rate framework
  - 5 Year Load Forecast
  - Rate impacts that align with social permission provided through customer survey
  - Regulatory mechanisms that balance customer and LDC needs and affordability
  - Does not include all active policy file implications, but updated with Cost of Capital parameters
    - Others may develop over the course of the remaining process

Typical residential bill

Sample Hydro Ottawa monthly bill
(based on consumption of 750kWh as Jan.1, 2026

Account Number:
000000000
Meter Number:
00000000

Your Electricity Charges

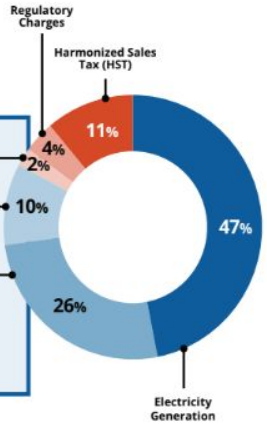
Electricity	
TOU* – Off-Peak @ 7.6 c/kWh	$36.48
TOU* – Mid-Peak @ 12.2 c/kWh	$16.47
TOU* – On-Peak @ 15.8 c/kWh	$21.33
Delivery	$59.56
Regulatory Charges	$6.16
Total Electricity Charges	**$140.00**
HST	$18.20
Ontario Electricity Rebate	($18.34)
Total Amount	**$139.86**

*Time-of-use rates

Delivery: *Line loss and other charges* $2.89

Delivery: *Transmission* (varies based on usage) $16.09

Delivery: *Distribution* Hydro Ottawa's part of the total bill is $40.59. This charge is the same for all residential customers per OEB requirments.

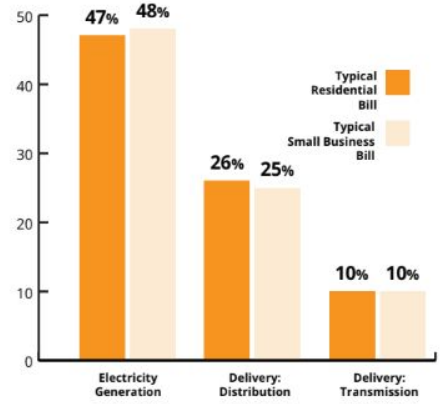


Note: The sample bill above uses an average consumption level of 750kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges. Diagram excludes Ontario Electricity Rebate and may not total 100% due to rounding.

Typical small business bill

	Typical Small Business Bill
TOU* – Off-Peak @ 8.7 c/kWh	97.28
TOU* – Mid-Peak @ 12.2 c/kWh	43.92
TOU* – On-Peak @ 18.2 c/kWh	56.88
Delivery	**148.12**
Regulatory Charges	13.91
Total Electricity Charges	**$360.11**
HST	46.81
Ontario Electricity Rebate	(47.17)
Total Amount	**$359.75**

*Time-of-use rates



Comments or Questions?

Thank You

HydroOttawa

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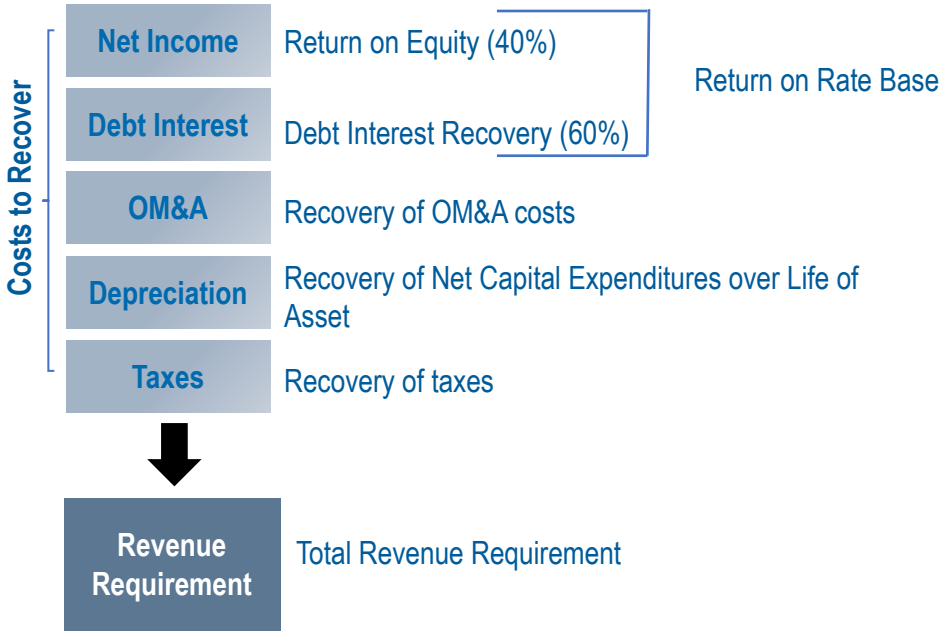

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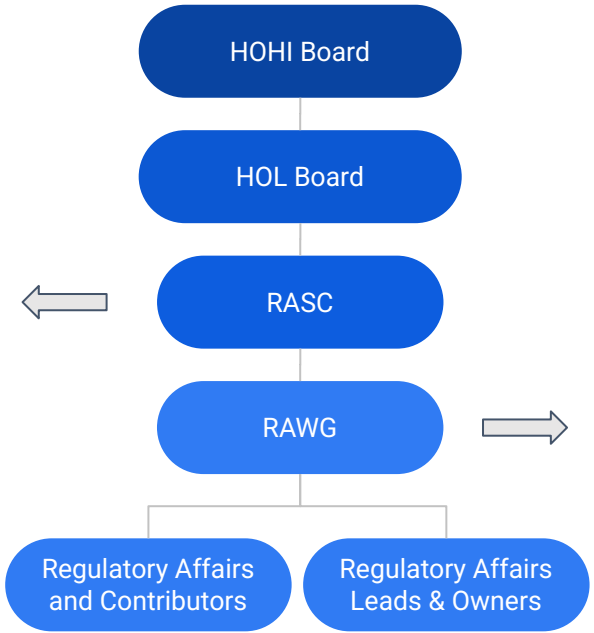

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Annex “A”

Hydro Ottawa Limited
2026 - 2030 Rate Application

Hydro Ottawa Limited Board of Directors

April Barrie – Director, Regulatory Affairs

June 19, 2025

HydroOttawa

Agenda

- Timeline & Progress
- Process Steps
- Other Rate Application Update
- Industry Update
- Questions/Comments

2026 - 2030 Rate Application Schedule & Progress to Date

	Date	Activities in 2025 and 2026
✔	**April 15**	**Submitted Application**
✔	April 16	Letter of Acknowledgement
✔	April	Completeness Review
✔	April 29	Completeness Letter
✔	May 9	Notice of Hearing & Letter of Direction
✔	April to May	OEB Error checking - New process
✔	June 3	Procedural Order No. 1
	June 10	Issues List
	July 22-Aug 12	Evidence Update & Interrogatories
	Fall 2025	Technical Conference **- Dates from here are estimates**
	Q4 2025	Settlement Conference
	Q4 2025	Oral Hearing

Draft Decision for rates effective January 1, 2025 **- OEB timeline puts pressure on this date**

Date set is 24 days beyond OEB Standard

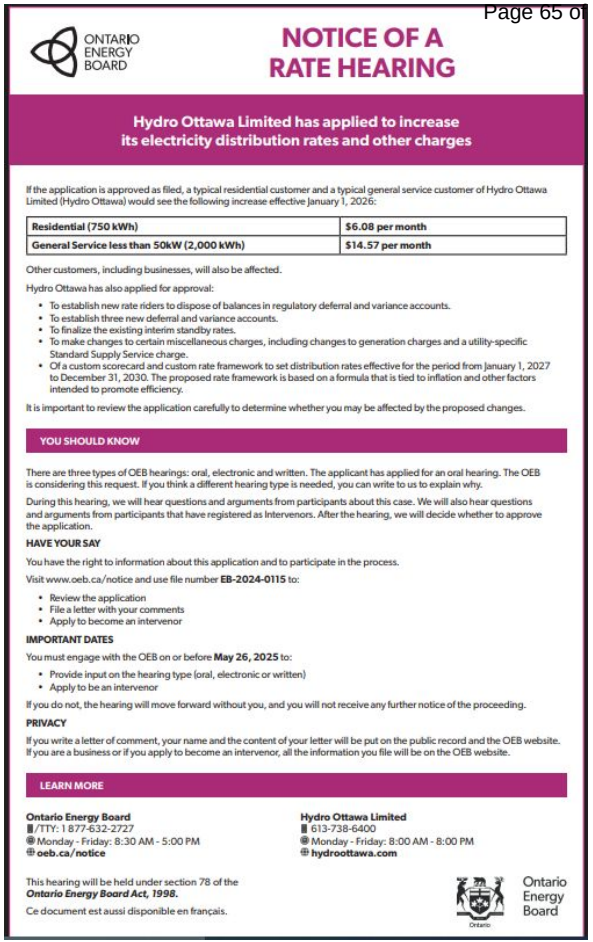
Recent and Upcoming Process Steps Descriptions

- **Completeness Letter**
  - Evidence is considered complete and confirms the OEB has officially begun processing the application
- **Notice of Hearing & Letter of Direction**
  - Sets out the service requirements for the Notice
    - Post Application on our Website, inform previous intervenors & customers
- **Procedural Order No. 1**
  - Provides Decision(s)/Direction(s) on requests for Intervenors, costs eligibility & confidentiality
- **Interrogatories (IRs)**
  - Written questions or requests related to the information/evidence that was filed
  - Utility has 2 to 3 weeks to complete
- **Technical Conference**
  - Hearing where intervenors and OEB staff can seek clarification of the evidence and responses to Interrogatories

OEB Cost of Service June 19, 2024 presentation

Other Rate Application Updates

- The rate application is Public
- 142 Customer letters of comment to the OEB - as of the evening of May 26
- 11 Approved Intervenors:
  - Building Owners and Managers Association Ottawa
  - Coalition of Concerned Manufacturers and Businesses of Canada
  - Community Action for Environmental Sustainability Ottawa
  - Consumers Council of Canada
  - Distributed Resource Coalition
  - Enbridge Gas Inc.
  - Energy Probe Research Foundation
  - Environmental Defence
  - Pollution Probe
  - School Energy Coalition
  - Vulnerable Energy Consumers Coalition



ONTARIO ENERGY BOARD

NOTICE OF A RATE HEARING

Hydro Ottawa Limited has applied to increase its electricity distribution rates and other charges

If the application is approved as filed, a typical residential customer and a typical general service customer of Hydro Ottawa Limited (Hydro Ottawa) would see the following increase effective January 1, 2026:

Residential (750 kWh)	**$6.08 per month**
General Service less than 50kW (2,000 kWh)	**$14.57 per month**

Other customers, including businesses, will also be affected.

Hydro Ottawa has also applied for approval:

- To establish new rate riders to dispose of balances in regulatory deferral and variance accounts.
- To establish three new deferral and variance accounts.
- To finalize the existing interim standby rates.
- To make changes to certain miscellaneous charges, including changes to generation charges and a utility-specific Standard Supply Service charge.
- Of a custom scorecard and custom rate framework to set distribution rates effective for the period from January 1, 2027 to December 31, 2030. The proposed rate framework is based on a formula that is tied to inflation and other factors intended to promote efficiency.

It is important to review the application carefully to determine whether you may be affected by the proposed changes.

YOU SHOULD KNOW

There are three types of OEB hearings: oral, electronic and written. The applicant has applied for an oral hearing. The OEB is considering this request. If you think a different hearing type is needed, you can write to us to explain why.

During this hearing, we will hear questions and arguments from participants about this case. We will also hear questions and arguments from participants that have registered as Intervenors. After the hearing, we will decide whether to approve the application.

HAVE YOUR SAY

You have the right to information about this application and to participate in the process.

Visit www.oeb.ca/notice and use file number **EB-2024-0115** to:

- Review the application
- File a letter with your comments
- Apply to become an intervenor

IMPORTANT DATES

You must engage with the OEB on or before **May 26, 2025** to:

- Provide input on the hearing type (oral, electronic or written)
- Apply to be an intervenor

If you do not, the hearing will move forward without you, and you will not receive any further notice of the proceeding.

PRIVACY

If you write a letter of comment, your name and the content of your letter will be put on the public record and the OEB website. If you are a business or if you apply to become an intervenor, all the information you file will be on the OEB website.

LEARN MORE

Ontario Energy Board
1/TTY: 1 877-632-2727
Monday - Friday: 8:30 AM - 5:00 PM
oeb.ca/notice

Hydro Ottawa Limited
613-738-6400
Monday - Friday: 8:00 AM - 8:00 PM
hydroottawa.com

This hearing will be held under section 78 of the ***Ontario Energy Board Act, 1998.***

Ce document est aussi disponible en français.

Ontario Energy Board

Industry Update - OEB Policy files are active

- Distribution System Operator (DSO) Capabilities discussion paper released
- Code amendments related to Margin on Payments incentives related to third parties
- Waiting on AI Practice Rule to be finalized
- Evaluation of Incremental Capital Module (ICM) Policy
- Staff paper on Performance Incentive Mechanisms (PIMs)
- Stakeholder sessions and Surveys on
  - Cost Benchmarking
  - Spending Patterns
- Proposed System Expansion Capacity Allocation Model
- Exploring options to minimize duplication in interrogatories
- OEB provincial capacity map working group created

Comments or Questions?

Thank You

HydroOttawa

Process Steps - Phase 3, 4 & 5

- **Phase 3 - Settlement Conference**
  - Negotiation/discussion
  - Proceeding is not transcribed
  - If Settlement is reached it becomes part of the evidentiary record
- **Phase 4 - Oral Hearing**
  - Hearing where intervenors, OEB Board Members and staff can seek clarification of the evidence and responses to Interrogatories
    - Evidence is challenged not just tested
  - OEB Board members attend
  - Proceeding is transcribed and becomes part of the evidentiary record
- **Written Submissions**
  - LDC, Intervenors and OEB staff provide positions
- **OEB Board panel renders a Decision & Order**

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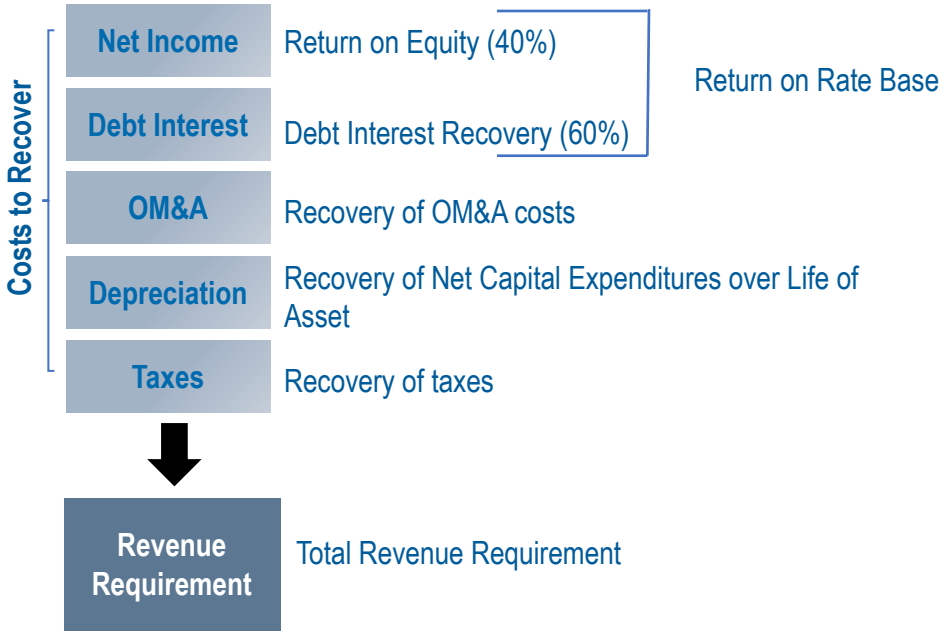

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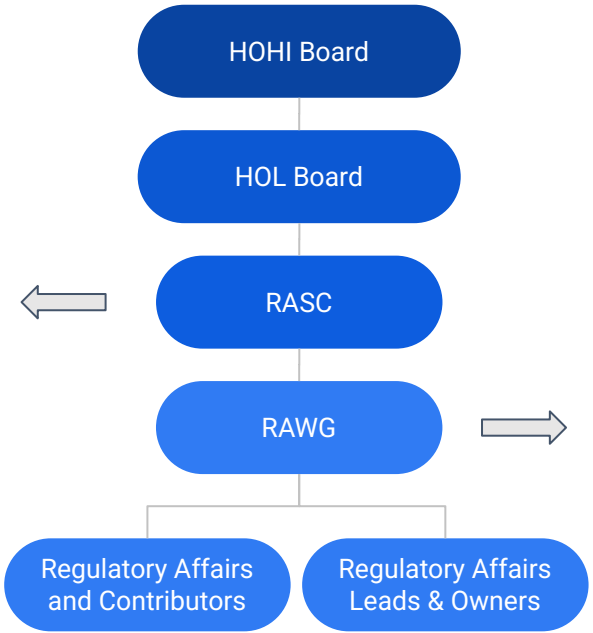

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INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-14

EVIDENCE REFERENCE:

Exhibit 2, Tab 1, Schedule 1, pp. 1, 23, 29
Exhibit 2, Tab 7, Schedule 1, p. 6
Appendix 2-AA
Appendix 2-D

QUESTION(S):

a) Please provide a revised version of Appendix 2-AA that includes an update to the forecast 2024 and 2025 capital expenditures (and 2026-2030 as necessary) using the current best available information. In addition, instead of including the capital contributions only at the major category level (e.g., system access, system renewal, etc.), please also provide the capital contributions at the program level (e.g., Plant Relocation, System Expansion, etc.).
b) Please provide a revised version of Appendix 2-AA on an in-service addition basis (as opposed to capital expenditures). As part of this revised version, please update the forecast 2024 and 2025 in-service additions (and 2026-2030 as necessary) using the current best available information. In addition, instead of including the capital contributions only at the major category level (e.g., system access, system renewal, etc.), please also provide the capital contributions at the program level (e.g., Plant Relocation, System Expansion, etc.).
c) Please advise whether Hydro Ottawa uses the half-year rule for determining rate base with respect to all assets (including both pooled assets and the significant discrete in-service additions shown in Table 19 of Exhibit 2, Tab 1, Schedule 1, p.29).
d) Please confirm that Hydro Ottawa uses the half-year rule for determining depreciation for pooled assets. However, for discrete material projects, it uses the actual or forecasted in-service month.

e) (Exhibit 2, Tab 7, Schedule 1, p. 6) With respect to “discrete material assets” forecast to be placed in-service during the forecast period (2026-2030) and are applied the monthly approach for the determination of depreciation expense, are these the same assets as shown in Table 19 of Exhibit 2, Tab 1, Schedule 1, p. 29?

f) Please explain Hydro Ottawa’s methodology for forecasting the timing of in-service additions. As part of the response, please discuss whether Hydro Ottawa applies a different approach to ongoing capital programs relative to discrete significant capital expenditures. As an example related to an ongoing capital program, how does Hydro Ottawa determine whether an expenditure related to its OH distribution renewal program should be considered in-service in the year that the investment is made or in the following year(s)?

g) Please discuss whether, historically, Hydro Ottawa’s pooled assets were typically placed in-service towards the beginning of the year or towards the end of the year. As part of the response, please advise whether Hydro Ottawa is able to track the month in which a pooled asset is placed in service.

h) (Exhibit 2, Tab 1, Schedule 1, p. 23) With respect to the significant in-service additions shown in Table 16, please revise the planned in-service date column to include the in-service month along with the year that the asset was placed in service.

i) (Exhibit 2, Tab 1, Schedule 1, p. 29) With respect to the significant in-service additions shown in Table 19, please revise the planned in-service date column to include the in-service month along with the year that the asset is forecast to be placed in service.

j) Please provide an illustrative calculation showing Hydro Ottawa’s conversion of capital expenditures to in-service additions to rate base to revenue requirement. As part of the calculation, please use Hydro Ottawa’s proposed cost of capital and a weighted-average depreciation rate (reflecting all of Hydro Ottawa’s assets).

k) (Appendix 2-D) Please explain the decrease (on a percentage basis) of capitalized OM&A between 2021 and 2026.

RESPONSE(S):

a) Please see Attachment 1-Staff-1(A) - Chapter 2 Appendices for a revised Appendix 2-AA showing 2024 full year actuals, 2026-2030 capital expenditures using the current best available information, and June year-to-date actuals for 2025 (along with comparable six month periods for 2024 and 2023). Please note that the June results are subject to year-end adjustments, as certain reclassification and true-up accounting entries are performed annually and are not reflected in these interim figures. An updated 2025 forecast will not be available until October 2025.

For capital contributions by Program, please see Attachment 2-CCC-14(A) - OEB Appendix 2-AA - In-Service Additions and Capital Contributions. One tab provides the capital contributions by program level on the capital expenditure basis (first tab) and one tab provides it on the in-service additions basis (second tab).

b) Please see Attachment 2-CCC-14(A) - OEB Appendix 2-AA - In-Service Additions and Capital Contributions as noted in part (a) above. Also as noted in part a) above, refer to Attachment 1-Staff-1(A) - Chapter 2 Appendices for a revised Appendix 2-AA using the most current information.

c) Confirmed. Total rate base is based on taking the average of opening and closing net fixed assets balance plus working capital allowance.

d) Confirmed.

e) Confirmed. Depreciation expense for the assets shown in Table 19 of Schedule 2-1-1 is forecasted to commence on the month and year the asset is forecasted to be put into service. As an example, the New Kanata Station included in Table 19 of Schedule 2-1-1 Rate Base

Overview is forecasted to be put in-service in March 2028, so depreciation expense for 2028 is forecasted to commence in March.

f) For forecasting purposes, Hydro Ottawa groups its projects into those that are assumed to start and finish in the same year, and those that span multiple years. Projects that are assumed to start and finish in the same year have the half-year rule applied to the capital additions. For projects that span multiple years, the forecasted in-service month and year are used to determine when the capital additions should be forecasted, and the amount of in-service additions is the cumulative forecasted spend up to the forecasted in-service month and year. The total balance is then used to forecast deprecation starting at the in-service month and year. Using the example of OH distribution renewal program, at the time of forecasting, Hydro Ottawa would assume the projects with capital spending forecasted in a given year would all complete within the same year, so the in-service additions total for the forecast year would equal the capital spending total for the same year.

g) On an individual asset basis, Hydro Ottawa does not track the in-service month for pooled assets. Costs are built up on projects and subsequently placed into service for depreciation when the project is flagged as complete. This occurs throughout the year. As noted in Attachment 4-1-1(A) - Transition to Cloud Computing, Hydro Ottawa plans to implement an Enterprise Asset Management (EAM) System over the rate term, which presents an opportunity to enhance its asset data. However as noted in the response to part (f) above, pooled assets that start and finish in the same year, use the half-year rule to forecast depreciation.

h) Table A below has been updated to include the planned in-service date column for the in-service month. The original table is Table 16 of Schedule 2-1-1 Rate Base Overview .

Table A – 2021-2025 Overview of Significant In-Service Additions with Planned In-Service Month and Year ($'000 000s)[1]

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
General Plant	CCRA	Cambrian 28KV Substation	October 2021	$ 50.1	2021-2022	$ 44.6	$ (5.5)
General Plant	CCRA	Riverdale Switchgear Upgrade	Phase 1 December 2024; Phase 2 December 2025	$ 2.4	N/A	-	$ (2.4)
General Plant	CCRA	Piperville Station Capacity Upgrade-New East	December 2025	$ 6.1	N/A	-	$ (6.1)
General Plant	Customer Service	Elster EA-MS Upgrade	Phase 1 June 2021; Phase 2 June 2025	$ 1.6	2022	$ 0.4	$ (1.2)
General Plant	Operations Initiatives	AMI Program	December 2022	$ 1.6	N/A	-	$ (1.6)
General Plant	Customer Engagement Platform	MyAccount	N/A	-	2023-2025	$ 6.8	$ 6.8
General Plant	Enterprise Solutions	ERP Program	December 2025	$ 9.7	N/A	-	$ (9.7)
General Plant	Enterprise Solutions	Service Now	N/A	-	2022-2025	$ 2.7	$ 2.7
System Renewal	Stations and Buildings Infrastructure Renewal	Fisher AK Station Rebuild	Phase 1 December 2022; Phase 2 December 2023; Phase 3 December 2024	$ 9.6	N/A	-	$ (9.6)
System	Stations and	Dagmar Voltage	December	$ 6.0	N/A	-	$ (6.0)

[1] Projects in this table with an asterisk (*) have their capital additions occur throughout the year.

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
Renewal	Buildings Infrastructure Renewal	Conversion	2025				
System Renewal	Stations and Buildings Infrastructure Renewal	Bayswater Transformer Replacement	December 2021	$ 3.4	2021-2024	$ 5.0	$ 1.6
System Renewal	Stations and Buildings Infrastructure Renewal	Bell's Corners Station Rebuild	Phase 1 December 2021; Phase 2 December 2022; Phase 3 December 2023	$ 10.3	2022-2024	$ 13.6	$ 3.3
System Renewal	Stations and Buildings Infrastructure Renewal	Overbrook TO Switchgear Replacement	Phase 1 December 2022; Phase 2 December 2023; Phase 3 December 2024; Phase 4 December 2025	$ 6.7	2021-2024	$ 9.3	$ 2.6
System Renewal	Stations and Buildings Infrastructure Renewal	Lincoln Heights P&C Renewal	Phase 1 December 2021; Phase 2 December 2022	$ 1.1	2021-2024	$ 2.3	$ 1.2
System Renewal	Stations and Buildings Infrastructure Renewal	Rideau Heights DS T1 Renewal	December 2024	$ 3.2	N/A	-	$ (3.2)
System Renewal	Stations and Buildings Infrastructure Renewal	Shillington AD Station Renewal	December 2025	$ 2.5	N/A	-	$ (2.5)

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
System Renewal	Metering Renewal	2.5EL to 3EL*	2021-2025	$ 2.4	2021-2025	$ 1.1	$ (1.3)
System Renewal	Metering Renewal	TR Communications Update*	2021-2025	$ 2.1	2021-2025	$ 1.8	$ (0.3)
System Renewal	Metering Renewal	SC Communications Update*	2021-2022	$ 2.0	2022-2025	$ 2.2	$ 0.2
System Renewal	Metering Renewal	TR Service to 200A SC*	2021-2025	$ 1.1	2021-2025	$ 1.0	$ (0.1)
System Renewal	Metering Renewal	REX 1 Upgrade*	2021-2025	$ 5.0	2023-2025	$ 5.3	$ 0.3
System Service	Capacity Upgrades	Cambrian 28KV Substation	March 2022	$ 26.9	2021-2023	$ 25.6	$ (1.3)
System Service	Capacity Upgrades	Uplands MS Second Transformer	Phase 1 January 2021; Phase 2 December 2021	$ 11.4	2021-2023	$ 14.7	$ 3.3
System Service	Capacity Upgrades	Riverdale Switchgear Upgrade	Phase 1 December 2024; Phase 2 December 2025	$ 11.8	2024-2025	$ 5.5	$ (6.3)
System Service	Capacity Upgrades	Limebank MTS 4th Transformer	Phase 1 December 2021; Phase 2 December 2022	$ 3.0	2021-2022	$ 2.8	$ (0.2)
System Service	Capacity Upgrades	Piperville Station Capacity Upgrade-New East	December 2025	$ 24.6	2024-2025	$ 14.7	$ (9.9)
System Service	Capacity Upgrades	New Mer Bleue Station	N/A	-	2025	$ 6.6	$ 6.6
System Service	Grid Technologies	Advanced Distribution Management System (ADMS)*	2021-2025	$ 5.0	2025	$ 17.9	$ 12.9

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
System Service	Field Area Network	Field Area Network*	2021-2025	$ 5.0	2023-2025	$ 1.0	$ (4.0)

i) Table B below has been updated to include the planned in-service month and year for the projects listed in Table 19 of Schedule 2-1-1 Rate Base Overview.

Table B – 2026-2030 Overview of Significant In-Service Additions with In-Service Month and Year ($'000 000s)[2]

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost ($)
General Plant	CCRA	Riverdale Switchgear Upgrade	March 2026	$ 0.4
General Plant	CCRA	Piperville Station Capacity Upgrade-New East	March 2026	$ 4.7
General Plant	CCRA	New Mer Bleue Station	March 2027	$ 6.3
General Plant	CCRA	Hydro Road Station	December 2027	$ 0.8
General Plant	CCRA	CFIA Greenbank Road New Station	March 2028	$ 4.7
General Plant	CCRA	New Kanata Station	March 2028	$ 5.3
General Plant	CCRA	King Edward Cable Upgrade	December 2029	$ 16.4
General Plant	CCRA	Carling (secondary cable)	November 2026	$ 2.1
General Plant	Meter to Cash	CC&B Upgrade 2028*	2028	$ 6.5
System Access	System Expansion	OC Transpo EBus St. Laurent Road	November 2027	$ 9.7

[2] Projects in this table with an asterisk (*) have their capital additions occur throughout the year.

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost ($)
System Access	System Expansion	DND Dwyer Hill Expansion	Phase 1 December 2026; Phase 2 March 2027	$ 3.1
System Access	System Expansion	DND Dwyer Hill Station Upgrade	March 2027	$ 14.1
System Access	System Expansion	Ottawa Hospital	December 2030	$ 11.5
System Access	System Expansion	Hydro Road Station	December 2027	$ 22.7
System Renewal	Stations and Buildings Infrastructure Renewal	Longfields T2 Transformer Renewal	September 2027	$ 1.6
System Renewal	Stations and Buildings Infrastructure Renewal	Rideau Heights DS Switchgear Renewal	March 2028	$ 5.9
System Renewal	Stations and Buildings Infrastructure Renewal	Parkwood Hills DS Switchgear Renewal	December 2027	$ 4.2
System Renewal	Stations and Buildings Infrastructure Renewal	Hinchey TH Switchgear Renewal	Phase 1 November 2026; Phase 2 November 2027	$ 3.5
System Renewal	Stations and Buildings Infrastructure Renewal	Russell TB Switchgear Renewal	December 2030	$ 9.8
System Renewal	Metering Renewal	Metering Renewal AMI 2.0	Phase 1 September 2026; Phase 2 September 2027; Phase 3 September 2028; Phase 4 September 2029; Phase 5 September 2030	$ 78.2

Investment Category	Capital Program	Project	Planned in-Service Date	Planned Capital Cost ($)
System Service	Capacity Upgrades	Riverdale Switchgear Upgrade	March 2026	$ 8.5
System Service	Capacity Upgrades	Piperville Station Capacity Upgrade-New East	March 2026	$ 27.6
System Service	Capacity Upgrades	New Mer Bleue Station	March 2027	$ 41.2
System Service	Capacity Upgrades	Greenbank Road New Station	March 2028	$ 38.5
System Service	Capacity Upgrades	New Kanata Station	March 2028	$ 44.8

j) Table C below provides an illustrative example of the revenue requirement for a $10M in service capital addition in its second year of being in service. This annual revenue requirement is for year two and includes the impact of accelerated CCA. The calculation assumes Hydro Ottawa's proposed cost of capital outlined in Schedule 5-1-1 - Cost of Capital and Capital Structure, a weighted average depreciation rate of 2.91%, and tax class 47.

Table C – Illustrative Example of Conversion of Capital Expenditures to Revenue Requirement

Capital Related Revenue Requirement	$ ('000)
Amortization	291
Income Taxes	744
Deemed Interest Expense	237
Return on Equity (ROE)	360
Total Revenue Requirement	**1,633**

k) The decrease in the percentage of capitalized OM&A between 2021 and 2026 is due to the growth of OM&A programs that are not eligible for capitalization, which outpaced the increase in total capital spending. The main reasons for this shift are:

- IT Cloud Transition: As noted in Section 3.14 of Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs, Hydro Ottawa moved a larger portion of its IT portfolio to cloud-based solutions. This resulted in an increase in annual subscription costs, which are categorized as operational expenditures (OM&A) rather than capitalized assets.
- Increased Maintenance Spending: Section 3.1 of Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs details increased spending on Testing, Inspection, and Maintenance (TIM) programs. This was a response to deteriorating infrastructure, equipment failure trends, and severe weather events. These maintenance and proactive programs are crucial for system reliability but are largely treated as OM&A and are not eligible for capitalization.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-15

EVIDENCE REFERENCE:

Exhibit 2, Tab 1, Schedule 1, pp. 14-15
Hydro Ottawa, July 4, 2025 Letter re: Grid Technology Program
Exhibit 2, Tab 5, Schedule 5, p. 102

QUESTION(S):

a) (Exhibit 2, Tab 1, Schedule 1, p. 14) Please provide the in-service additions associated with the "Self-Contained Meter Phone Line Elimination project" during the 2021-2025 period (broken out by year).
b) (Exhibit 2, Tab 1, Schedule 1, p. 14) Please further explain the "Gatekeeper solution" for the "Self-Contained Meter Phone Line Elimination project."
c) (Exhibit 2, Tab 1, Schedule 1, p. 14) With respect to the Gatekeeper meters that were installed (assuming there were some installed), please advise whether these will be replaced as part of the AMI 2.0 initiative planned for 2026-2030. If yes, please explain why.
d) (Exhibit 2, Tab 1, Schedule 1, p. 15) With respect to the grid technologies system service capital program, please provide:
    i) The original planning/scoping documents for the ADMS project.
    ii) Any change requests / scope change documents related to the ADMS project that were
    iii) completed at the time of "detailed implementation planning"
    iv) Specifics regarding the significant gaps in the original requirements.
    v) A summary of the key decisions made and the timing of those decisions when significant gaps in the original requirements were recognized.
e) (Hydro Ottawa July 4 Letter) Please confirm that the timing changes for the SCADA/ADMS program result in an approximate $14.5M reduction to opening rate base.

f) (Hydro Ottawa July 4 Letter) Please provide any internal documentation produced related to the comprehensive review of the ADMS program.

g) (Exhibit 2, Tab 5, Schedule 5, p. 102) With respect to the customer engagement platform project, please provide:

i) The original planning/scoping documents from when Hydro Ottawa determined that it was necessary to redesign its customer portal.

ii) Any change requests / scope change documents from when Hydro Ottawa determined that additional functionality related to customer self-service options were necessary.

iii) A summary of the key decisions made and the timing of those decisions when Hydro Ottawa decided to re-design its customer portal.

RESPONSE(S):

a) Please see Table A which provides the in-service additions associated with the "Self-Contained Meter Phone Line Elimination project" during the 2021-2025 period by year.

Table A – Net In-Service Capital Additions - Self-Contained Meter Phone Line Elimination Project ($'000s)

	Historical Years			Bridge Years	
	2021	2022	2023	2024	2025
Self-Contained Meter Phone Line Elimination Project	-	$ 29	$ 35	$ 543	$ 1,613

b) In electricity smart metering, a gatekeeper meter functions as a central collection point for meter readings. It gathers meter reads from surrounding meters within a specific area. These reads are then backhauled to the head-end system at Hydro Ottawa. Since the first implementation of smart meters (completed in 2011), the dominant backhaul communication method has relied on traditional telephone lines, which have low success rates for communication. Meter manufacturers are also discontinuing support and development for meters that utilize telephone

line technology. This requires an alternative solution to our meter communication infrastructure to ensure the continued functionality of metering operations.

A typical meter on a residential home is referred to as a "Self-Contained Meter". The Self-Contained Meter Phone Line Elimination project was a project designed to remove gatekeepers with copper telephone line modem technology from a residential premise and install a cellular modem-enabled gatekeeper on a utility pole.

c) No Gatekeepers were installed. While testing the proposed Gatekeeper solution from the meter manufacturer, Hydro Ottawa identified issues that the metering manufacturer was unable to resolve. As a result, Hydro Ottawa decided not to move forward with the Gatekeeper solution provided by the meter manufacturer and decided to instead address the issue of the telephone line as part of Hydro Ottawa's Advanced Metering Infrastructure (AMI) 2.0 initiative (refer to interrogatory 2-Staff-32 part d) and e) for further details on the cancellation).

d)

i) The original plan/scope for the ADMS project was outlined in Hydro Ottawa's 2021-2025 Rate Application, Exhibit 2-4-3 Distribution System Plan, Attachment 2-4-3(E) - Material Investments, section 2.4. A summary of the plan is as follows:

- 2021 - Upgrade SCADA and DMS foundation with incremental integration to AMI
- 2022 - Implement OMS, with AMI enhancements
- 2023 - Expansion of DMS functionality
- 2024 - Investment in AMI integration for fault identification and map updates
- 2025 - Upgrade to SCADA and DMS

ii) The ADMS detailed implementation plan occurred in 2021/2022. Please see Attachment 2-CCC-15(E) - SESC Portfolio 20210825 where the need for dedicated project resources was identified to support OMS and the expansion of DMS functionality and a revised budget estimate of $19.2M was presented to the steering committee. With steering committee approval for the revised plan, the project moved ahead with the following revised schedule:

- 2022 - Upgrade SCADA and DMS foundation
- 2023 - Implement Schematics
- 2024 - Implement OMS
- 2025 - Implement ADMS advanced applications such as Switch Order Manager, Distribution Powerflow, FLISR and integrate AMI

iii) Please refer to sub part d) ii) as this sub-sub part appears to be a continuation of d ii).

iv) Please see the response to interrogatory 2-Staff-33 part a) and Section 5.3.2 of Schedule 2-5-5 - Capital Expenditure Plan Historical Variances .

v) Please see the response to part d (ii) above.

e) Confirmed.

f) In Schedule 2-5-8 - System Service Investments, Hydro Ottawa explains that the ADMS program was undergoing a comprehensive review, and that updated information and supporting documentation related to the Grid Technology budget program would be filed no later than with responses to interrogatories. Hydro Ottawa filed a letter on July 4, 2025, which provides additional information regarding the outcome of the review. The review process involved a series of meetings and workshops to ensure that the ADMS program aligns with the overarching grid modernization plan. Please see Attachment 2-CCC-15(D) - ADMS Program Charter which documents the outcome of the review process and identifies key capabilities needed to satisfy the evolving energy landscape.

g)

i) Hydro Ottawa's decision to redesign its customer portal known as "MyAccount" is outlined in the attached 2022 charter authorizing the project. Please see Attachment 2-CCC-15(C) - MyAccount Redesign Project Charter Release One SIGNED.

ii) Change requests associated with MyAccount Redesign are captured in the project change register. Please see Attachment 2-CCC-15(B) - MyAccount Redesign Change Register.

iii) Decisions associated with MyAccount Redesign are captured in the project record-of-decision log. Please see Attachment 2-CCC-15(A) - MyAccount Redesign ROD Log.

MyAccount Redesign Project Record of Decision (ROD) Log

ROD #	Description (include "why?")	Decision Date	Communication Mechanism (e.g. meeting, email)	Decision Authorities (Names)
1	Each module / release will follow a set series of events: 1) Internal Hydro Ottawa Customer Experience Committee (HOLCEC) meeting 2) HOCEC meeting with Relevantz 3) Series of workshops between Relevantz and Eric Senechal 4) Module / release review meeting - Relevantz & HOLCEC. If all looks good, HOLCEC to provide sign off 5) Relevantz to conduct internal backlog meetings 6) Relevantz to meet with integrations teams for technical requirements	August 25, 2022	In person meeting	HOLCEC members, Relevantz Scrum Master
2	Eric Senechal to take lead of documenting business requirements for each module / release	7-Sep-22	Google chat	Jennifer Withrow
3	CX Steering Committee meeting to review the future of our engagement with Bidgley. Decision made to not renew the contract at the end of 2022. Mark F and Shawn C to chat with Bidgley representative to see if they will be able to extend the agreement for only Q1. If not, we will terminate at the end of 2022. Strong communications plan will be put together to outline no app for 2 months in 2023.	November 1, 2022	In person and Google Meet	CX Steering Committee members
4	Move forward with the Bidgely contract extension until March 31st as a sole source.	November 24, 2022	CX Steering Committee Meeting	CX Steering Committee members
5	Real time updates in CCB will be pushed to Release Two due to the time required by IBM to make this change (6-8 weeks)	January 27, 2023	HOLCEC meeting	HOLCEC Members
6	Not allow Guest users access to billing/payment at launch until we are able to separate them and control what they can access. We don't want to provide something to the customer at launch which we will then take away.	February 10, 2023	Email from Terry Landry to Relevantz	Seb Oran
7	Terry and Nathalie to assist in creating the BRD for the TOU/ULO project impacts to the MyAccount portal	February 16, 2023	Email	Seb Oran, Jennifer Withrow, Sally Jafari
8	Release one to be pushed from March 20 to March 27 due to the updates for Large Commercial Customers to be updated as well	February 24, 2023	Google Meet	HOLCEC, Seb Oran, Andrew Willis, Sally Jafari
9	Add release three to phase one to include the TOU / ULO rate project requirements and updates	February 24, 2023	Google Meet	HOLCEC, Seb Oran, Andrew Willis, Sally Jafari
10	Rate comparision tool to be built in house by HOL (Aaron Farr)	March 16, 2023	Google Meet	HOLCEC & MTC
11	Mobile App to launch post Release One due to the need for the web to be live in production before the application can be submitted	March 20	Google Meet	HOLCEC
12	After Release One on March 27th, all hotfixes this week have been fixed in high priority. Any new issues that arise will now go through a process of report issue, Relevantz advises fix in which environment to be tested by Terry. Fixes to be deployed in one deployment rather than one at a time. Urgent broken functionality issues will be addressed with higher priority.	March 30, 2023	In person (Edison)	HOLCEC
13	Pre-authorized payment option has been pulled out of the Payments & Billing BRD	April 13, 2023	Google Chat	Jennifer Withrow, Seb Oran
14	Guest and Guest + profiles to be moved to Phase Two due to the heavy admin portal changes required	Emailed HOLCEC May 17, 2023	Email	HOLCEC Replies: Terry - OK Josee - OK Seb - OK Trevor - OK Shawn - OK
15	Remove "Usage" menu in the Whitecap Billing pages rather than updated to point to the new pages. Once we go live with 2.1 in June there is a new Download My Data page integrated into the Usage dashboard.	June 01, 2023	Email	Eric Senechal, Jennifer Withrow
16	Bill prediction calculation tool to be pushed to release 2.2. Users will still be able to see their bill prediction under predict my bill in the current billing and payment module.	June 02, 2023	Email	Jennifer Withrow / Terry Landry
17	The decision to move the Billing & Payments module of the MyAccount Redesign to November/December time frame in lieu of the work required to implement ULO by October 13th has meant that portion of the Whitecap side of MyAccount within Billing is impacted: Electricity bill threshold alert (batch process) Predict My Bill Bill Comparison Decision: Remove/hide/message impacted features from customers electing to ULO, support with messaging that improved tools and experience are coming (very) soon. - The number of customers electing to ULO is expected to be small initially - Early adopters will not be billed until at least November - A high cost and impactful development and UAT effort to update code slated to be replaced within a short time	July 7, 2023	Google Meet	Harold Fudge / Jennifer WIthrow / Sally Jafari / Seb Oran / Trevor Freeman
18	100% focus on Usage and Rates module release scheduled for October 13th, 2023	August 11, 2023	In person meeting	Harold / Tarjit / Jennie
19	Change order to extend project to June 2024 to complete phases one and two. Billing period to be adjusted from the 19th of the month to the 1st of the month starting November.	August 17, 2024	In person meeting	Harold/Tarjit/Jennie
20	Push the deployment of the Outage Reporting module to January of 2024 in order for all resources to focus on the Notifi project deployment	November 15, 2023	In person meeting	CX Steering Committee members
21	Outage reporting UAT and deployment to be pushed to January 2024			
22	Prevent special characters from being entered into the additional details field to prevent special characters from showing up in OMS and potentially causing issues. The only two characters allowed in this additional details field are commas and periods.	January 10, 2024	In person meeting	Hayret, Bryan, Maiss, Eric S, Jennie
23	Allow the 122 special characters that currently exist in the customer name field in CCB when reporting an outage. As per Scott @ Hexagon, "The customer name with accented characters are flowing into OMS production and do not seem to be causing problems."	January 16, 2024	CAB & Email	Hayret, Bryan, Maiss, Ronnie, Santhosh, Todd, Scott M, Shervin, Sarah

MyAccount Redesign Project Record of Decision (ROD) Log

ROD #	Description (include "why?")	Decision Date	Communication Mechanism (e.g. meeting, email)	Decision Authorities (Names)
24	Information displayed for Systems Office includes names, phone number, radio buttons and the additional details. Scott from Hexagon flagged this as a possible issue that Systems Office would not want to see. Meeting with Joseph and Andy Doiron confirms that they are happy with this additional information being received.	January 29, 2024	Google Meet	Jennie, Joseph, Andy
25	ULO rates removed from the requirements outlined for Bill Prediction and the Bill Comparison tool. Per email from Jenn W, "On our end we checked a ULO account and found that they are not presented with the option to see the bill prediction or bill comparison tool on MyAccount, this is good, we will not need an error message. "	February 5, 2024	Email	Jennie, Jenn W
26	All changes from the BRD are to be handled as change requests.	February 21, 2024	In Person meeting	CX Steering Committee
27	EST/EDT - Usage will not be displayed according to EDT starting March 10th, 2024. The usage presentment will be off by one hour. Relevantz effort is approximately 3-4 months (+/-). If we make this change now, it will impact the current project timeline. Business has opted to do nothing for now and wait to see how many customers complain about the presentment. This issue has only been raised by one customer so far last year.	March 07, 2024	In Person meeting & Decision via email from Jenn W	Jenn W, Sally, Terry, Harold, Jennie
28	Estimated target date for EMPP AutoPay in June after Billing & Payments go live.	March 14, 2024	Email	Jennifer W, Terry, Eric, Harold, Sally
29	The scenario described was in the case that the customer signs up for autopay and then EMPP but the EMPP does not go through, the customer will be set up with autopay and the next bill would be paid in full	March 14, 2024	Email	Jennifer W, Terry, Eric, Harold, Sally
30	In the case that the customer signs up for autopay and then EMPP but the EMPP does not go through, the customer will be set up with autopay and the next bill would be paid in full. Per our meeting this morning, Terry confirmed that this is ok. The future state will allow the customer to sign up for one option at a time.	March 14, 2024	Email	Jennifer W, Terry, Eric, Jennie P
31	Prediction option section under Bill Prediction has been removed because collecting that information from the customer has no impact in calculating the bill prediction result	April 10, 2024	Email	Jennifer W, Crispin, Jennie, Harold, Eric, Terry, Ganesh, Vijay, Bagavathy, Deepak
32	Account notifications section on MyAccount was not required as per the business on Feb 1st. On April 19th, the business decided to include this section so that the customers will be able to see the letters that have been sent out to them. Relevantz level of effort would be 7 business days to add this back into scope. Per Jenn W's email May 3rd, they are ok if this feature goes live after Billing & Payments and EMPP/AutoPay. I have asked Harold to add this to a future enhancement list.	May 3, 2024	Email	Jenn W, Jennie, Terry, Harold
33	Remove requirement of impersonation for customers without a MyAccount profile	May 28, 2024	Email	JennW, Harold, Eric, Shawn, Susan, Terry, Trevor, Jennie
34	Postpone deployment of Billing & Payments module to Monday, June 24th due to extreme weather warnings and potential of storms/outages. This deployment would impact the mobile applications and the CE team chose to push the deployment rather than risk having a broken app during outages	June 18, 2024	Google Meet	JennW, Seb, Jennie
35	Billing & Payments deployment sequence of events to be web deployment and then publish ios app. Android app was rejected, therefore, Relevantz would resubmit application and there will be a delay in getting approvals of max 2-3 days. Impact on Android users has been emailed.	June 21, 2024	Email	JennW, Seb, Harold, Jennie
36	IF51 - Daily audit report was only required for the two week hypercare period. Last report was provided on Friday, July 26th. In the future, if there is a need for this reporting, we will use the same audit report request for a temporary timeframe.	July 29, 2024	Email	JennW, Terry, Sally, Seb, Harold, Majid
37	Remaining (7) batch processes to be descoped from the MyAccount project and pushed to 2025. These will be reviewed and managed by the Web Applications team as needed.	August 28, 2024	CX Steering Committee Meeting	Joseph M, Kim T, Julie L, Mark F, Andrew W, Jennie P, Sally J, Harold F, Jennifer W, Odapo, Shawn C, Sarah G, Seb O
38	Descope Large Commercial Customer module from the scope of the MyAccount project. This module requires additional discussions internally to outline business needs and direction before moving forward.	August 28, 2024	CX Steering Committee Meeting	Joseph M, Kim T, Julie L, Mark F, Andrew W, Jennie P, Sally J, Harold F, Jennifer W, Odapo, Shawn C, Sarah G, Seb O
39	following fields be added to the detailed download: Registration Type: (email, social, both) - This is currently displayed on-screen but isn't included in the download. E-bill Type: (enhanced or standard) - This isn't critical but would be helpful. Kishore mentioned this information is available. Impact is 2 days will be added to the Admin portal UAT release date.	September 10, 2024	Email	Jenn W, Terry, Harold, Eric
40	Ability for the agent to self-serve when they have forgotten their own password. This level of effort is not to be sought at this time as the web team and MTC teams help with password resets today and are not permitted to reset their own passwords. This involves a larger discussion with Cyber and is parked as a future enhancement.	September 17, 2024	Email	Terry, Harold, JennW, Jennie, Eric

MyAccount Redesign Project Change Register

Note: IM/IT Project Change Request Forms will contain Change Record # and all details of change

Change #	Request Initiator (Name)	Brief Description	Approved (Yes/No)	Approval Date
1	Jennie Panesar	Phase One / Phase Two Module Breakdown Clarification	Yes	December 2022
2	Sally Jafari	Include development to display Ultra Low Overnight TOU data on MyAccount	Yes	June 2023
3	Sally Jafari	Rejected not displaying on MyAccount - Example - SA in Pending Stop and rejected in CC&B should reflect in MyAccount	Yes	Sept 2023
4	Jennifer Withrow	confirmed rate change requests require an email to be automatically sent to customers indicating that the request was received and highlighting the rate plan effective date.	Yes	Sept 2023
5	Sally Jafari	Functionality the enable Net Metering customers to see their usage/generation, track their credits and request rate option changes within MyAccount	Yes	April 2024
6	Harold Fudge	Real Time updates from MyAccount into CC&B to enhance customer service and reduce manual efforts	Yes	May 2024
7	Jennifer Withrow	EMPP/AutoPay enhancements: **Expanded User Control:** In addition to registration, EMPP users can now: Modify their due date Cancel EMPP Request a review (new feature) Enhanced EMPP Card: The EMPP card will now display both the monthly payment amount and the current EMPP balance for existing EMPP users. Other enhancements	Yes	June 2024

Hydro Ottawa Project Charter Document

MyAccount Redesign

Revision History

Version #	Date (Month, Day, Year)	Author (First and Last Name)	Comment (Summary of Change)
1.0	June 21, 2022	Abdul Meerwali, PM	Initial DRAFT
2.0	August 25, 2022	Jennie Panesar, PM	Edits
3.0	August 30, 2022	Jennie Panesar, PM	Edits
4.0	September 01, 2022	Jennie Panesar, PM	Edits / Circulated for Project Team Review
5.0	September 07, 2022	Jennie Panesar, PM	Business edits
6.0	September 08, 2022	Jennie Panesar, PM	Edits / Circulated for Exec Review
7.0			

1 Project Overview

1.1 Project Description

The Hydro Ottawa customer portal collectively known as "MyAccount" is an interconnected system of multiple web and mobile technologies, services and solutions that have developed organically over the past couple of decades. MyAccount is a significant channel for customer engagement and provides residential and small commercial customers views and self service tools to manage their electricity usage, billing, payment and outage information. The solution has served the company well evolving annually with continued investment to maximize customer value and engagement. However, with the rate of technology change, increasing customer experience demands, a rapidly changing energy industry and continued Hydro Ottawa growth, the current solution is no longer adequate. MyAccount is envisioned to be a key differentiator for Hydro Ottawa serving as the face of the business to the customer populace and a catalyst for increased customer engagement. The solution requires a redesign of the user interface, foundational architecture and a technology refresh. To that end, Hydro Ottawa has selected an experienced implementation partner to assist in the development of a next generation MyAccount offering and delivery of the solution.

In this project, the focus is to address the aging of MyAccount technology, Hydro Ottawa is seeking to centralize the solution, simplify the footprint and update to a modernized technology stack maintaining full control over these digital assets and intellectual property. From a customer perspective, the current site was architected predominantly for residential and small commercial customers whereas large commercial customers who provide Hydro Ottawa with the majority of revenue are not enabled on the platform today. With this redesign, the platform will cater to residential, small commercial and large commercial customers.

As per our commitment to our customers, we are committed to delivering value across the entire customer experience. We are looking to position Hydro Ottawa to be able to handle unforeseen disruption and continually enhance the customer experience and engagement.

- Focus on increasing customer engagement
- Decrease Customer effort
- Redesign of the user interface
- Future HOL needs (system architecture)
- Unified platform, with new futures to better help our customers self-serve their needs.
- Technology refresh

Outage Reporting

- Report outages via text (future)
- Report outage without logging in
- No billing association needed to report outages
- Keep customers informed on their outage resolution status

Alerts, Notifications and Key Highlights

- Alerts that cannot be missed
- Multi-channel
- Notifications and alerts with easy call to action

Customer Support

- Chatbot Integration
- Continuation of chat after navigation

Administration portal

- Seamless operation and consistent interface

1.3 Project Stakeholders

Stakeholder Name (First, Last)	Position & Section	Division - Group
Josee Larocque	Manager, Media and Public Affairs	CCO
Cindy Mckenna	Manager, Customer Care	CCO
Jennifer Withrow	Supervisor, Customer Experience	CCO
Trevor Freeman	Supervisor, Key Accounts	CCO
Meghan Fee	Acting Manager, Meter to Cash	MTC
Shervin Sheidaei	Manager, Data Management, Warehouse and Systems Integration	CITO
Santhosh Jayasankar	Manager, Enterprise Architecture	CITO
Shane Labrash	Supervisor, Energy Conservation, Business Development	CDM
Susan Fekete	Communications Advisor	CCO
Eric Senechal	Customer Experience Agent	CCO
Terry Landry	Customer Experience Agent	CCO

1.4 Project Scope

This project is going to be split into two phases. This charter will outline the scope of phase one only. Once phase two is defined, a new charter will be circulated for review and approvals.

Phase One:

Residential, Small Commercial and New Customer Types to be launched on the new platform (web and mobile)

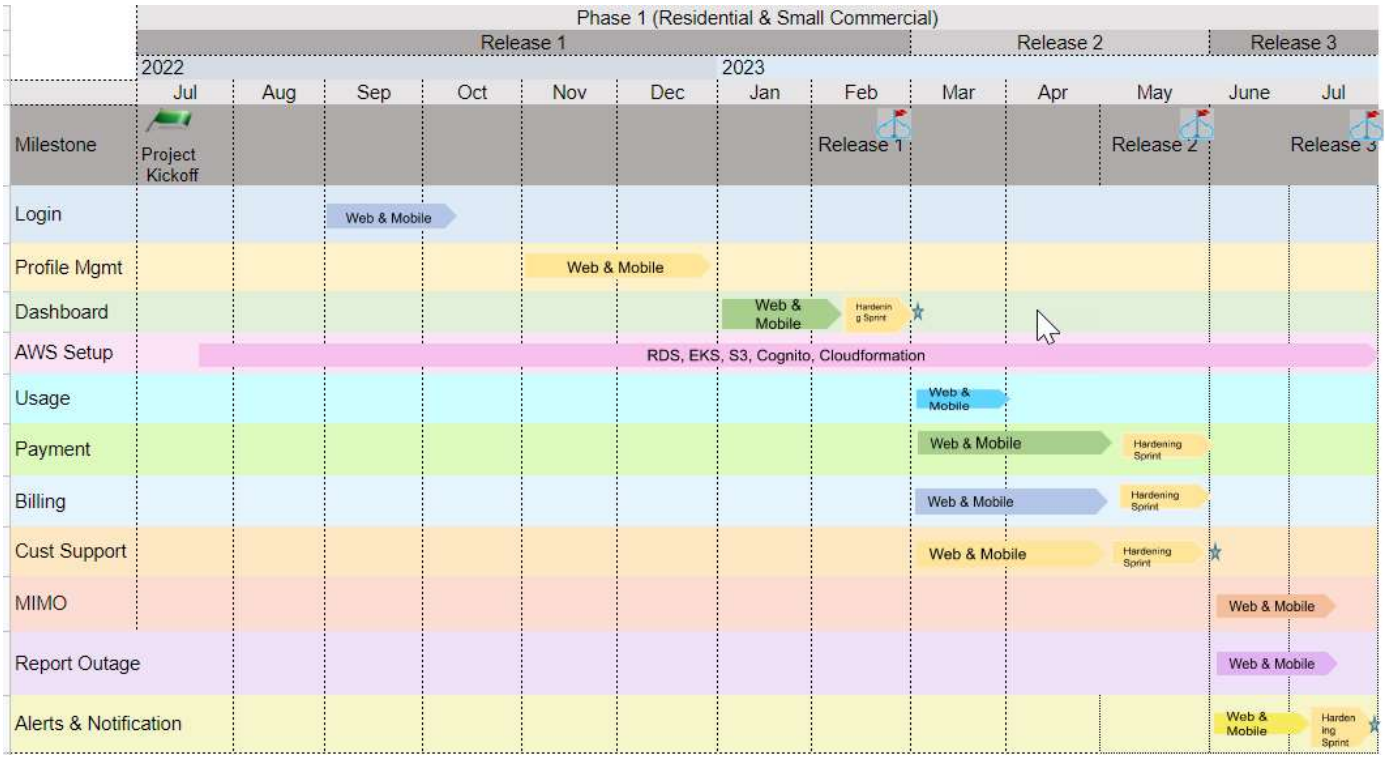
- **Release One: Login**
  - 1.1 - New account types to remove dependency on billing account

1.5 Implementation Timeline

The project will be implemented in two phases. Each phase will start with a review of the business requirements and an alignment with the vendor. Once the requirements are outlined, a dedicated resource from our customer service team will participate in workshops with the vendor to ensure all details of each requirement are captured. Final business sign off will be necessary before moving onto the next module.

- Phase One: Residential and Small Commercial customers
- Phase Two: Larger Commercial customers

Phase One - Residential & Small Commercial



- Vijayabasker, CX Lead

2.1 Key Assumptions

1. The project has full support of the Business Sponsor, stakeholders and all business units.
2. The different groups and committees involved in this project will work in parallel to ensure the project continues to move ahead. The vendor will be working in a very agile project methodology. Hydro Ottawa will work through each module in a structured approach as defined.
3. Significant vendor coordination will be required to perform any changes required.
4. Reuse existing API's for integrations

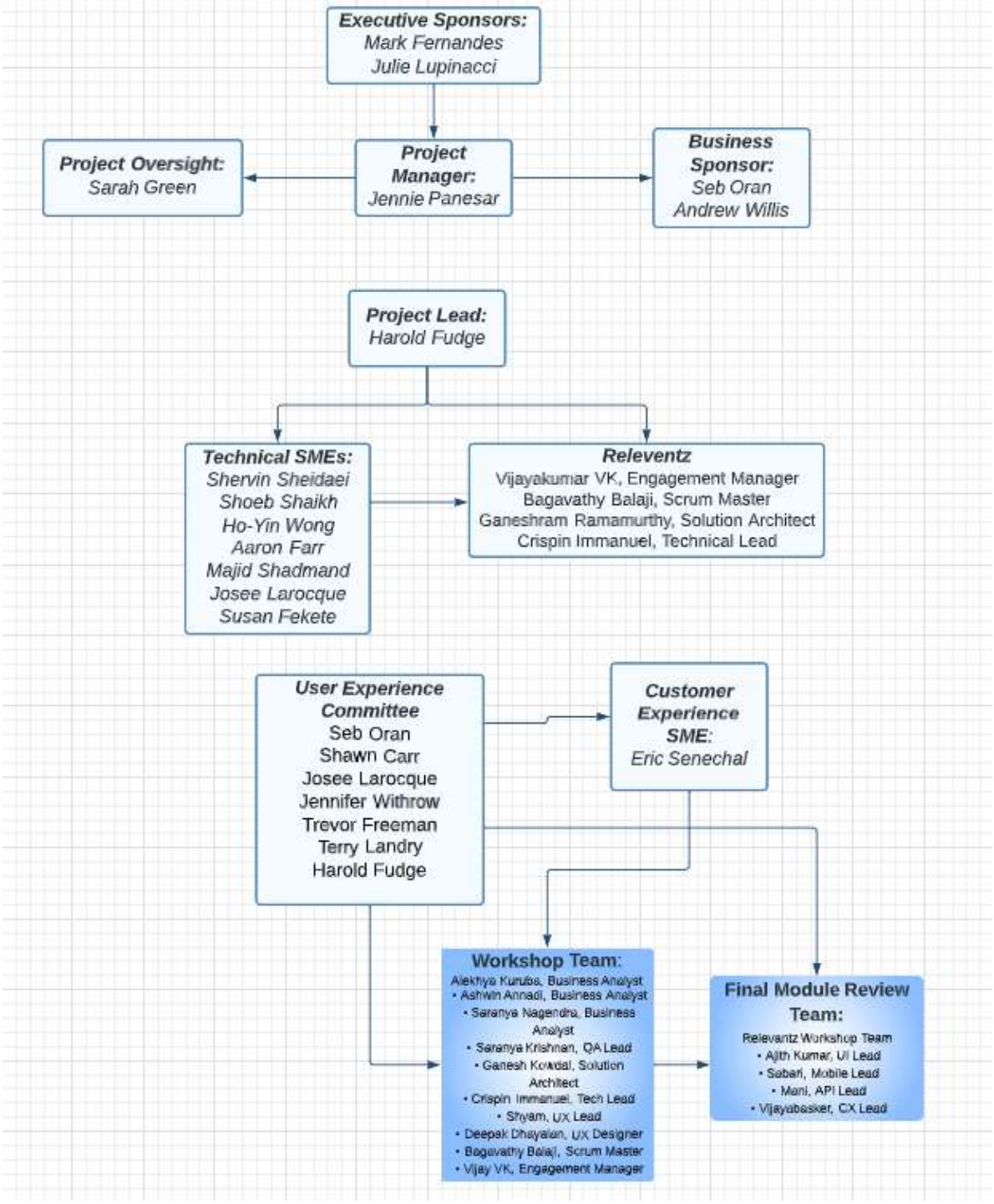
2.2 Constraints

1. Additional time will be required to outline the business requirements before each workshop is scheduled. This will require resource availability from the Hydro Ottawa User Experience Committee as well as the User Experience SME.
2. Third party vendor engagement will be required to perform certain tasks. This may impact project timelines.
3. Relevantz team is located in India, therefore meetings will be difficult to schedule due to time zone constraints

2.3 Key Dependencies

Dependency Description	Contact
API dependency on third party vendors	Internal HO resources knowledge base
Green Button Initiative	Harold Fudge
Hydro Ottawa internal resource availability	Jennie Panesar

3.2 Project Functional Structure



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5 PROJECT FUNDING

This section summarizes the project's general cost components and their estimated costs. Note: As the project progresses, these costs may change as all tasks and requirements become more clear / hardened.

Executive Presentation - MyAccount Redesign

Summary Project Budget			
Item	**Budget / Cost ($000)**	**Funding Source (OM&A, CapEx)**	**BU**
Hardware	0		
Software	0		
Ongoing (e.g. System Maintenance) VM	0		
Resources			
Internal (FTE) Project Manager	$100,000	CapEx	9202015353
Internal (FTE) Customer Experience SME	$200,000	CapEx	9202015353
Internal Labor Hours - Contingency	$207,000	CapEx	9202015353
External Vendor - Relevantz	$2,457,000	CapEx	9202015353
External Vendors - Bidgely & Whitecap	$150,000	OM&A & CapEx	9202015353
External Vendor - French Translation	$50,000		
Contingency	$500,000	OM&A & CapEx	9202015353
Total Funding Required:	**$3,664,000**		

Hydro Ottawa Program Charter Document

ADMS Program

HydroOttawa

Executive Sponsor Approval Signatures

	Date
Mark Fernandes Chief Information & Technology Officer	
	Date
Guillaume Paradis Chief Operating Officer	
	Date
Laurie Heuff Vice President, Distribution System Planning & Asset Management	

Steering Committee Approval Signatures

Note: Signature does not include approval for Program Funding which must be approved by the Executive Sponsors.

	Date
Kristopher Lelliott Director, System Operations and Grid Automation	
	Date
Andrew Willis, Director IT, Enterprise Applications	
	Date
Donna Burnett Vachon, Director, Change and Organization Development	
	Date
Jaime Lawlor, Manager, Control Room	

	Date
Jenna Gillis Director, Asset Management, Distribution Planning	
	Date
Jess Pharand Director, Customer Service	
	Date
Santhosh Jayasankar Manager, Enterprise Architecture	
	Date
Sarah Green Director, IT Planning, Programs, and Grid Technology	

Table of Contents

1. PROGRAM OVERVIEW

A. PROGRAM GOAL

The ADMS Program aims to operationalize the ADMS platform to enhance operational efficiencies, reliability, responsiveness, and grid flexibility, while improving employee and customer experiences. Enable Hydro Ottawa's evolving business model to meet changing energy demands and customer expectations, accommodating more dynamic and bi-directional models.

B. PROGRAM OBJECTIVES

The ADMS Program will enable and prioritize the following strategic objectives, which were developed in alignment with Hydro Ottawa's Grid Modernization Strategy:

Tier 1 Priority

Improve situational awareness, visibility, and safety

- Leverage real-time data processing, intelligent alerts, dynamic symbology, and advanced event detection to drive faster, more accurate decision-making.
- Integrate SCADA, crew management, and simulation-based training to enhance visibility, optimize resource allocation/response, and operational preparedness.
- Align technology, processes, and data to elevate oversight and promote a culture of safety.
- Enhance Power System Model Management by maintaining up-to-date, validated models for operational and planning accuracy.

Improve employee experience

- Simplify workflows and enable user-friendly tools that reduce complexity, empower employees, and streamline business processes to align with future-state operations and new ways of working.
- Provide ongoing training and development opportunities to help staff adapt confidently to new systems and processes.

Improve customer experience

- Deliver transparent, timely communication during outages through customer portals, automated notifications, and clear restoration time updates.

- Minimize outage impacts with better planning and proactive customer engagement.

Enable future energy models

- Develop and implement advanced systems that can accurately simulate and manage the complexities of modern energy grids.
- Enable real-time processing and alerts to manage system constraints, support power systems modeling in a centralized environment, and monitor and analyze the predicted future-state of the distribution system.

Tier 2 Priority

Enhance reliability through improved operability and automation

- Reduce outage durations through improved situational awareness, faster fault detection, and enhanced response coordination.
- Leverage training tools to ensure personnel readiness for emergencies.
- Improve operability and automation through intelligent load shedding and real-time alerts.

Tier 3 Priority

Improve grid efficiency

- Adopt CIM standards to streamline data exchange and interoperability across different systems to enable seamless communication and data sharing between various grid components for improved efficiency.
- Enable a centralized modeling environment to consolidate grid modeling activities and data management.
- Enable Future-State Predictions through advanced forecasting and analytics tools to proactively manage grid operations and optimize resource utilization.
- Reduce losses and support reliable power delivery through Volt-VAR Optimization, Conservative Voltage Reduction and other modernized control strategies.
- Leverage real-time data and predictive analytics to drive proactive maintenance, fault detection, and rapid response to grid disturbances.

Program Guiding Principles

HOL Project Team members will be empowered to implement and execute the ADMS Program Scope in alignment with the ADMS Program Charter and in accordance with the Program Releases.

c. Program Scope

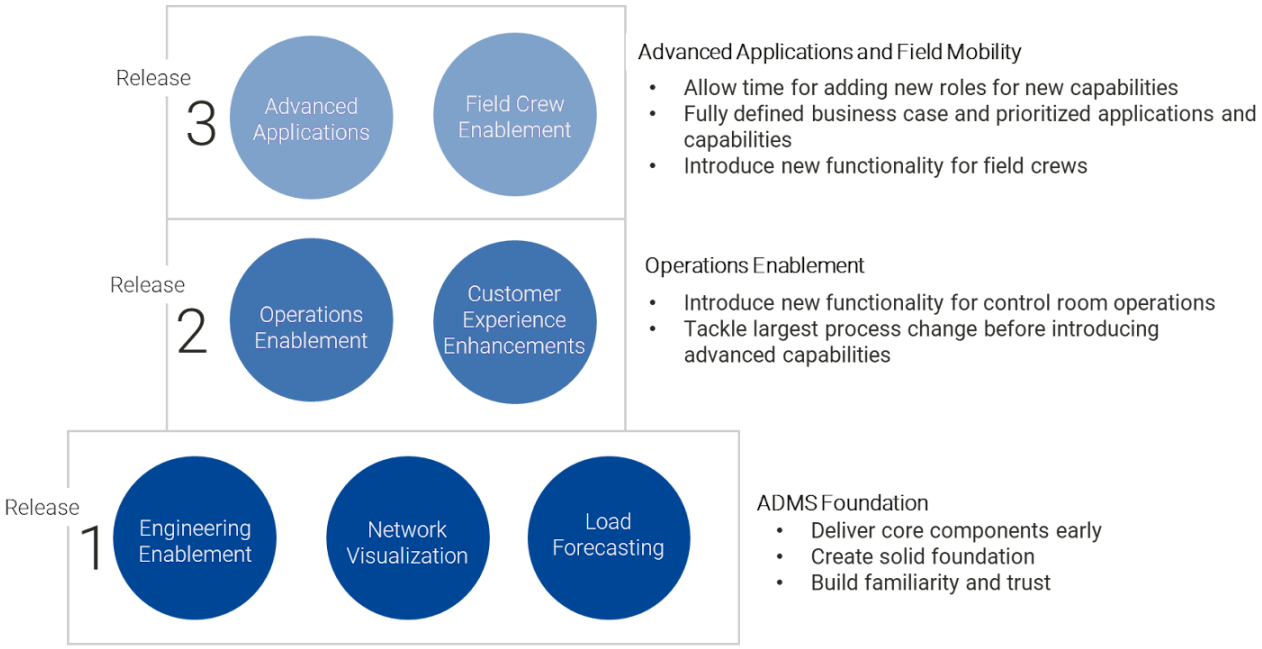
The ADMS Program will enable 49 future ADMS Capabilities aligned to Program Goals and Objectives. To view complete Objective→Capability→Release Mapping, see Appendix A.

Focus for Enablement	**Future Capability**	**Priority**
Customer Communication	Customer outage portal for outage status and reporting	Critical Need
	Customer communication for outages and restoration	Critical Need
	Customer communication for estimated restoration times	Critical Need
	Customer communication for planned outage notifications and updates	Critical Need
	Public outage map and dashboard	Critical Need
DMS	Intelligent load shedding and restoration	Strong Need
	Model based volt var optimization	Nice To Have
	Conservative Voltage Reduction	Nice To Have
	Real-time processing and alerts for calculated system constraints	Critical Need
	Study mode analysis for planned switching orders	Critical Need
	Study mode analysis for emergent switching needs	Critical Need
	Short Circuit Analysis for planned and emergent switching	Strong Need
IT and Cybersecurity	Event detection, event & incident response, configuration management, etc.	Critical Need
Model Management	Switching, tagging and clearance management on the geographic model	Critical Need
	Switching, tagging and clearance management on the schematic model	Critical Need
	Handling and management of GIS/As-Design model errors	Critical Need
	Modeling and management of temporary model features in geographic model	Critical Need
	Modeling and management of temporary model features in schematic model	Critical Need
	Power systems model management, support of Common Information Model (CIM), centralized modeling environment	Critical Need
Operational Awareness	Record grid actions and document events for compliance and analysis	Critical Need
	Crew access to as-switched model and current active tags in field	Critical Need
Outage Management	Wire down detection	Strong Need
	Outage and event prioritization for storms	Critical Need
	Planned outage modeling and reporting	Critical Need
	Planned outage scheduling, management, and coordination	Critical Need
	AMI integration for outage detection and restoration validation	Critical Need
	Damage Assessment integrated with Outage Management	Critical Need
	Streamlined call taking interface for non-operators	Critical Need
	Dynamic symbology to reflect current situational priorities	Strong Need

	Outage and Event Reporting	Critical Need
	Visual playback of all events/alarms/etc., web-based access to data historical info. for report generation	Critical Need
	Real time Storm and Outage Dashboards to provide operational oversight	Critical Need
Resource Management	Crew visibility for normal business availability	Critical Need
	Crew management including contract and external resources during storms	Critical Need
	Crew assignments and management for outages and non-outage emergent events	Critical Need
SCADA	SCADA integration with OMS for unplanned outages	Critical Need
	SCADA integration with logging system for planned and emergent events	Strong Need
Scalability Planning	Automate fault analysis and isolation through FLISR deployment	Strong Need
	Analysis of fault isolation and restoration within the ADMS platform for real-time events	Critical Need
	Ability to monitor and analyze the predicted future-state of the distribution system	Critical Need
Switch Order Management	Mobile integration for field crew switching	Strong Need
	Switching order writing including review and approval process	Critical Need
	Planned switching order schedule management	Strong Need
	Real-time switching analysis and execution	Critical Need
	SCADA integration for switching order execution	Nice To Have
Training	Historic event import for scenario development	Strong Need
	Simulation based training for real-time system operators	Critical Need
	Field personnel training for outage management	Critical Need
	Office personnel training for outage management	Critical Need

Business Release Methodology

Phased releases to deliver value early, manage change, and enable long-term strategic objectives



Release		Timeline for Delivery	Solution Enabled
1	**IGNITE** *(Intelligent Grid Network Integration for Transformative Energy)*	July 2025 December 2025	- Engineering Model Management (DMS) - DPF for Engineering - Network Visualization (Schematics/Geographic) - Load Forecasting
2	**Operations Enablement**	2026-2027	- Operationalized Model Management (DMS) - DPF for the Control Room - Outage Management (OMS) (Including Crew Management System) - Reporting (EpiLog Pro) - SOM for Planned Work - Training Enablement (OTS) - Advisory FLISR (Including Short Circuit Analysis)
3	**Advanced Applications and Field Mobility**	2028+	- DPF for Advanced Applications - Field Mobility (Compass) - SOM for Real-Time Operations - Automated FLISR - Load Shedding and Restoration - Volt Var Optimization (VVO and CVR)

Note: Implementation of a DERMS (Distribution Energy Resource Management System) is currently considered out of scope for the ADMS Program. DERMS capabilities are currently being managed through the ODERA Project and/or through the Grid Modernization Program who will engage the ADMS Program to coordinate ADMS requirements to enable DERMS capabilities.

Release 1: ADMS Foundation

Release 1 is the foundation, focusing on establishing critical and foundational functionalities.

- **Capabilities Enabled:** Foundational elements are in place, but the capability is not yet fully implemented or adopted.
- **Capabilities Realized:** The capability is actively used by the utility to deliver measurable operational or business value, and may be further enhanced by other enabled capabilities.

Engineering Model Management

Enable DMS through Model Management capabilities to support engineering network analysis, enable DPF, link SCADA and DMS, Network Visualization, and Load Forecasting. Enable model management support processes and roles, iteratively working through process improvements that will support future use cases.

Capabilities Realized:

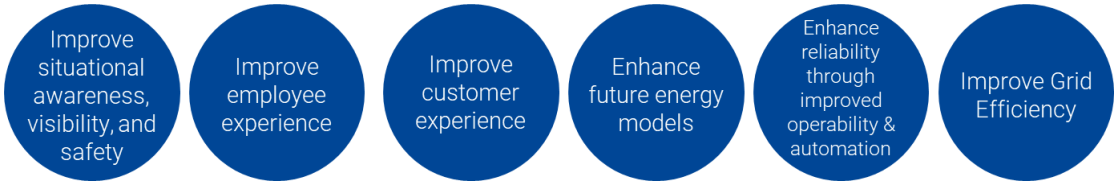
Model Management	1	Handling and management of GIS/As-Design model errors
	2	Modeling and management of temporary model features
Outage Management	3	Dynamic symbology to reflect current situational priorities

Capabilities Enabled:

Model Management	1	Switching, tagging and clearance management on the geographic display
	2	Switching, tagging and clearance management on the schematic display
DMS	3	Intelligent load shedding and restoration
	4	Model based volt var optimization
	5	Conservative Voltage Reduction

	6	Real-time processing and alerts for calculated system constraints
	7	Study mode analysis for planned switching orders
	8	Study mode analysis for emergent switching needs
	9	Short Circuit Analysis for planned and emergent switching
Outage Management	10	Real time Storm and Outage Dashboards to provide operational oversight
	11	Wire down detection
	12	AMI integration for outage detection and restoration validation
Operational Awareness	13	Record grid actions and document events for compliance and analysis
	14	Crew access to as-switched model and current active tags in field
Scalability Planning	15	Automate fault analysis and isolation through FLISR deployment
	16	Analysis of fault isolation and restoration within the ADMS platform for real-time events
	17	Ability to monitor and analyze the predicted future-state of the distribution system
Switch Order Management	18	Mobile integration for field crew switching
	19	Real-time switching analysis and execution
Training	20	Historic event import for scenario development
	21	Simulation based training for real-time system operators

Objectives Achieved: Supports all objectives.



DPF for Engineering

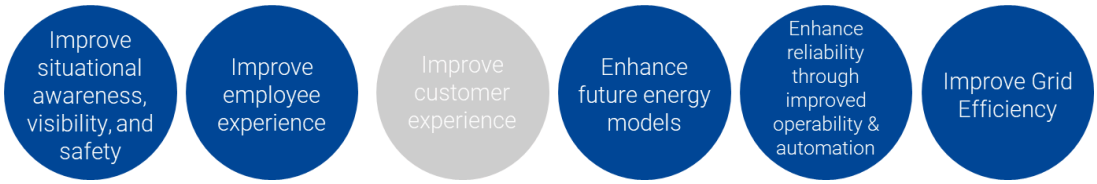
Enable real time powerflow analysis (DPF Distribution Powerflow DMS module) and enhance current steady state engineering analysis (Cyme). Release 1 will limit use of DPF to engineering use cases, while release 2 will bring DPF into real time operations. Distribution Powerflow (DPF) is a prerequisite to enable Advanced Applications in Release 2 and 3 (e.g., FLISR, VVO).

Capabilities Realized: None.

Capabilities Enabled:

DMS	1	Intelligent load shedding and restoration
	2	Model based volt var optimization
	3	Conservative Voltage Reduction
	4	Real-time processing and alerts for calculated system constraints
	5	Study mode analysis for planned switching orders
	6	Study mode analysis for emergent switching needs
	7	Short Circuit Analysis for planned and emergent switching
Outage Management	8	Wire down detection
	9	Planned outage modeling and reporting
	10	Planned outage scheduling, management, and coordination
Scalability Planning	11	Automate fault analysis and isolation through FLISR deployment
	12	Enable analysis of fault isolation and restoration within the ADMS platform for real-time events
	13	Ability to monitor and analyze the predicted future-state of the distribution system
Switch Order Management	14	Mobile integration for field crew switching
	15	Real-time switching analysis and execution
	16	SCADA integration for switching order execution

Objectives Achieved:



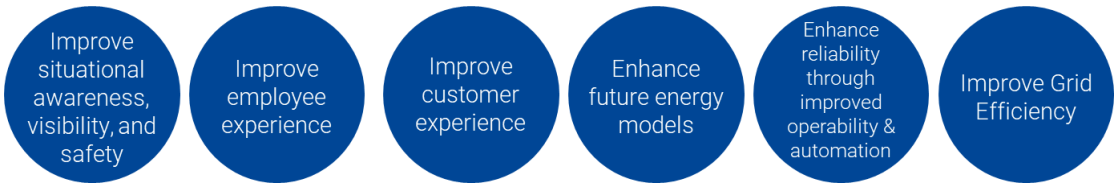
Network Visualization (Schematics/Geographic)
HOL will implement synchronized schematic and geographic model views within ADMS to provide operators with the ability to view and manage the network from either view. Both schematic and geographic views will be imported and maintained from GIS to ensure model alignment. This approach reduces the need for duplicate modeling efforts and manual coordination between teams.

Capabilities Realized: None.

Capabilities Enabled:

Model Management	1	Switching, tagging and clearance management on the geographic display
	2	Switching, tagging and clearance management on the schematic display
DMS	3	Intelligent load shedding and restoration
	4	Model based volt var optimization
	5	Conservative Voltage Reduction
	6	Real-time processing and alerts for calculated system constraints
	7	Study mode analysis for planned switching orders
	8	Study mode analysis for emergent switching needs
	9	Short Circuit Analysis for planned and emergent switching
Model Management	10	Handling and management of GIS/As-Design model errors
	11	Modeling and management of temporary model features
	12	Power systems model management, support of Common Information Model (CIM), centralized modeling environment
Operational Awareness	13	Record grid actions and document events for compliance and analysis
	14	Crew access to as-switched model and current active tags in field
Outage Management	15	Real time Storm and Outage Dashboards to provide operational oversight
	16	Wire down detection
	17	AMI integration for outage detection and restoration validation
	18	Dynamic symbology to reflect current situational priorities
Scalability Planning	19	Analysis of fault isolation and restoration within the ADMS platform for real-time events
	20	Ability to monitor and analyze the predicted future-state of the distribution system
Switch Order Management	21	Mobile integration for field crew switching
	22	Switching order writing including review and approval process
	23	Planned switching order schedule management
	24	Real-time switching analysis and execution
Training	25	Historic event import for scenario development
	26	Simulation based training for real-time system operators

Objectives Achieved:



Load Forecasting

Implement Short-Term Load Forecasting Module. This tool can predict loads by areas or feeders, enabling distribution planning use cases and DER enablement programs (e.g., integration to DERMS).

Capabilities Realized:

Scalability Planning	1	Ability to monitor and analyze the predicted future-state of the distribution system

Capabilities Enabled:

DMS	1	Intelligent load shedding and restoration
Switch Order Management	2	Mobile integration for field crew switching

Objectives Achieved: Improve situational awareness, visibility & safety, Improve employee experience, Enable future energy models, Enhance reliability through improved operability and automation, and Improve Grid efficiency.

Release 2: Operations Enablement

Release 2 brings foundational functionality tried and tested in R1 into the control room, while introducing new functionality that will streamline real-time operations.

- **Capabilities Enabled:** Foundational elements are in place, but the capability is not yet fully implemented or adopted.
- **Capabilities Realized:** The capability is actively used by the utility to deliver measurable operational or business value, and may be further enhanced by other enabled capabilities.

Operationalized Model Management (DMS)

Implement Operationalized Model Management. This solution builds on the foundation of engineering model management to deliver a validated, trusted network model into daily operations—ensuring operators have confidence in topology, connectivity, and equipment status to support safe, real-time decision-making across ADMS applications.

Capabilities Realized:

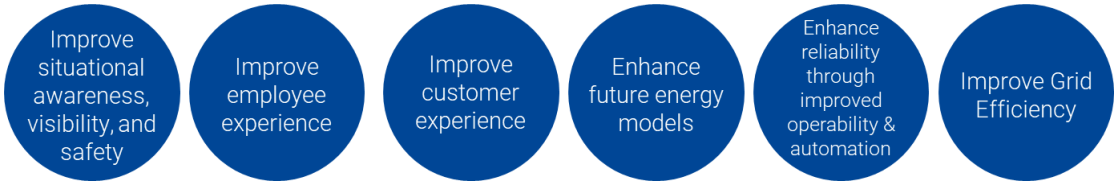
Model Management	1	Switching, tagging and clearance management on the geographic model
	2	Switching, tagging and clearance management on the schematic model
	3	Handling and management of GIS/As-Design model errors
	4	Modeling and management of temporary model features in geographic model
	5	Modeling and management of temporary model features in schematic model
	6	Power systems model management, support of Common Information Model (CIM), centralized modeling environment
Outage Management	7	Dynamic symbology to reflect current situational priorities

Capabilities Enabled:

DMS	1	Intelligent load shedding and restoration
	2	Model based volt var optimization
	3	Conservative Voltage Reduction
	4	Real-time processing and alerts for calculated system constraints
	5	Study mode analysis for planned switching orders
	6	Study mode analysis for emergent switching needs
	7	Short Circuit Analysis for planned and emergent switching
Operational Awareness	8	Record grid actions and document events for compliance and analysis
	9	Crew access to as-switched model and current active tags in field
Outage Management	10	Real time Storm and Outage Dashboards to provide operational oversight
	11	Wire down detection

	12	AMI integration for outage detection and restoration validation
Scalability Monitoring	13	Automate fault analysis and isolation through FLISR deployment
	14	Analysis of fault isolation and restoration within the ADMS platform for real-time events
	15	Ability to monitor and analyze the predicted future-state of the distribution system
Switch Order Management	16	Mobile integration for field crew switching
	17	Real-time switching analysis and execution
Training	18	Historic event import for scenario development
	19	Simulation based training for real-time system operators

Objectives Achieved:



DPF for the Control Room

Implement Operationalized Distribution Power Flow in the Control Room. This solution extends the trusted outputs of engineering-grade DPF into real-time operations, enabling operators to visualize load and voltage conditions across the network, supporting safe switching, outage diagnostics, and overall grid management.

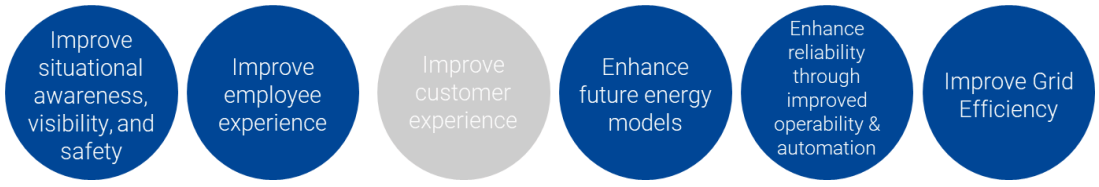
Capabilities Realized:

DMS	1	Real-time processing and alerts for calculated system constraints

Capabilities Enabled:

DMS	1	Intelligent load shedding and restoration
	2	Model based volt var optimization
	3	Conservative Voltage Reduction
	4	Study mode analysis for planned switching orders
	5	Study mode analysis for emergent switching needs
	6	Short Circuit Analysis for planned and emergent switching
Outage Management	7	Wire down detection
	8	Planned outage modeling and reporting
	9	Planned outage scheduling, management, and coordination
Scalability Planning	10	Automate fault analysis and isolation through FLISR deployment
	11	Enable analysis of fault isolation and restoration within the ADMS platform for real-time events
	12	Ability to monitor and analyze the predicted future-state of the distribution system
Switch Order Management	13	Mobile integration for field crew switching
	14	Real-time switching analysis and execution
	15	SCADA integration for switching order execution

Objectives Achieved:



Outage Management (OMS) (Including Crew Management System)

Implement Outage Management System, which centralizes outage detection, tracking, and restoration processes and enables faster response times, improved customer communications, and data integration with systems such as AMI and CIS for enhanced situational awareness. Both operators and crews will be able to access the system on a web platform through their computers, with more field mobility functionality coming in Release 3.

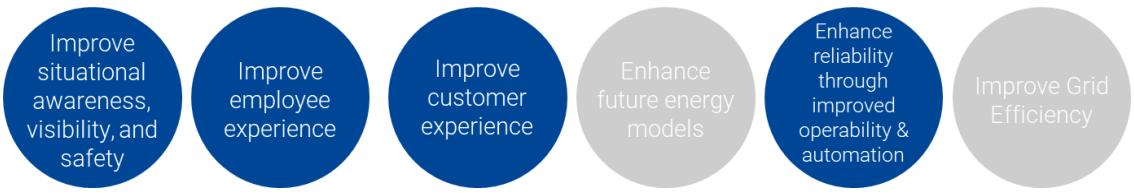
Capabilities Realized:

Customer Communication	1	Customer outage portal for outage status and reporting
	2	Customer communication for outages and restoration
	3	Customer communication for estimated restoration times
	4	Customer communication for planned outage notifications and updates
	5	Public outage map and dashboard
Outage Management	6	Visual playback of all events/alarms/etc., web-based access to data historical info. for report generation
	7	Real time Storm and Outage Dashboards to provide operational oversight
	8	Wire down detection
	9	Outage and event prioritization for storms
	10	Planned outage modeling and reporting
	11	Planned outage scheduling, management, and coordination
	12	AMI integration for outage detection and restoration validation
	13	Damage Assessment integrated with Outage Management
	14	Streamlined call taking interface for non-operators
	15	Outage and Event Reporting
SCADA	16	SCADA integration with OMS for unplanned outages

Capabilities Enabled:

Operational Awareness	1	Crew access to as-switched model and current active tags in field
Outage Management	2	Dynamic symbology to reflect current situational priorities
Resource Management	3	Crew visibility for normal business availability
	4	Crew management including contract and external resources during storms
	5	Crew assignments and management for outages and non-outage emergent events

Objectives Achieved:



Reporting (EpiLog Pro)

Configure EpiLog Pro logging tool to capture and timestamp operator actions and system events, supporting operational transparency, auditability, and post-event analysis.

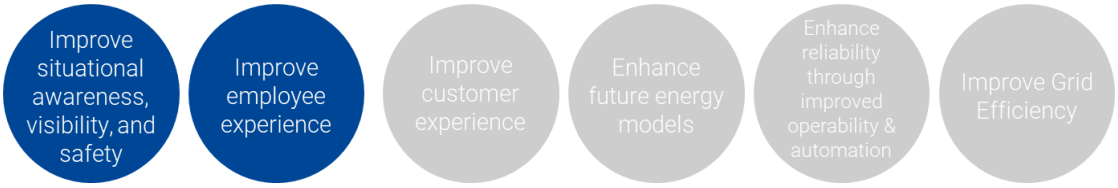
Capabilities Realized:

Operational Awareness	1	Record grid actions and document events for compliance and analysis
SCADA	2	SCADA integration with logging system for planned and emergent events

Capabilities Enabled:

Outage Management	1	Visual playback of all events/alarms/etc., web-based access to data historical info. for report generation

Objectives Achieved:



SOM for Planned Work

Implement Switch Order Management for Planned Work to streamline the planning, approval, and execution of switching operations, enhancing safety, and compliance.

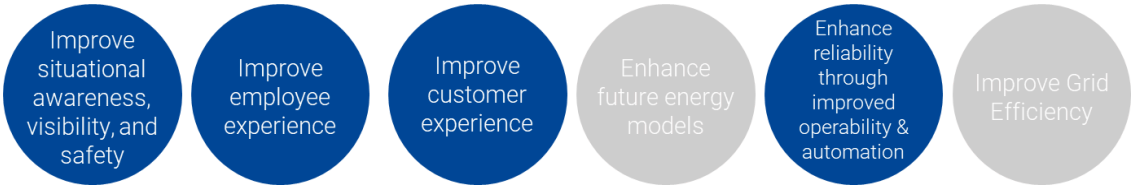
Capabilities Realized:

DMS	1	Study mode analysis for planned switching orders
Switch Order Management	2	Switching order writing including review and approval process
	3	Planned switching order schedule management
	4	Real-time switching analysis and execution
	5	SCADA integration for switching order execution

Capabilities Enabled:

DMS	1	Study mode analysis for emergent switching needs
	2	Short Circuit Analysis for planned and emergent switching
Outage Management	3	Planned outage modeling and reporting
	4	Planned outage scheduling, management, and coordination
Resource Management	5	Crew assignments and management for outages and non-outage emergent events
Switch Order Management	6	SCADA integration with logging system for planned and emergent events
	7	Mobile integration for field crew switching

Objectives Achieved:



Training Enablement (OTS)

Enhances the skills of real-time system operators, field personnel, and office personnel in outage management through simulation-based training and scenario development.

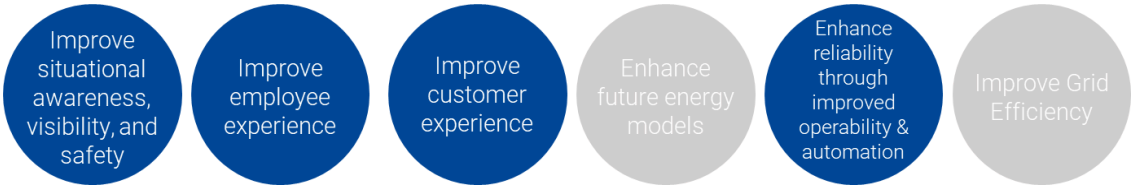
Capabilities Realized:

Training	1	Historic event import for scenario development
	2	Simulation based training for real-time system operators
	3	Field personnel training for outage management
	4	Office personnel training for outage management

Capabilities Enabled:

Outage Management	1	Visual playback of all events/alarms/etc., web-based access to data historical info. for report generation

Objectives Achieved:



Advisory FLISR (Including Short Circuit Analysis)
Implement Advisory Fault Location, Isolation, and Service Restoration (FLISR) to recommend fault isolation and service restoration steps to operators, reducing outage durations and improving reliability.

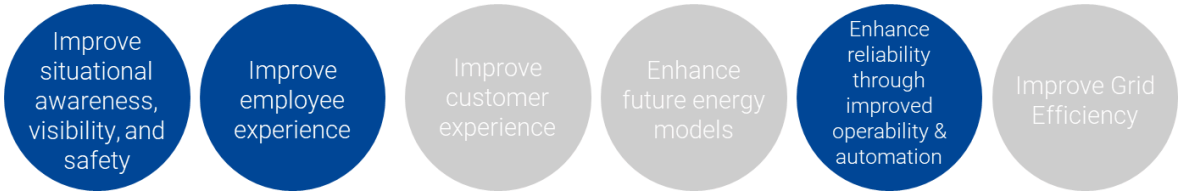
Capabilities Realized:

IT and Cybersecurity	1	Event detection, event & incident response, configuration management, etc.
Scalability Planning	2	Analysis of fault isolation and restoration within the ADMS platform for real-time events
DMS	3	Short Circuit Analysis for planned and emergent switching

Capabilities Enabled:

Scalability Planning	1	Automate fault analysis and isolation through FLISR deployment.

Objectives Achieved:



Release 3: Advanced Applications and Field Mobility

R3 brings advanced functionality to the control room and field crews, while building the groundwork for a scalable system for future grid growth and challenges.

- **Capabilities Enabled:** Foundational elements are in place, but the capability is not yet fully implemented or adopted.
- **Capabilities Realized:** The capability is actively used by the utility to deliver measurable operational or business value, and may be further enhanced by other enabled capabilities.

DPF for Advanced Applications
Enable DPF for Advanced Analytics, to confidently support advanced applications like automatic FLISR and load shedding/restoration.

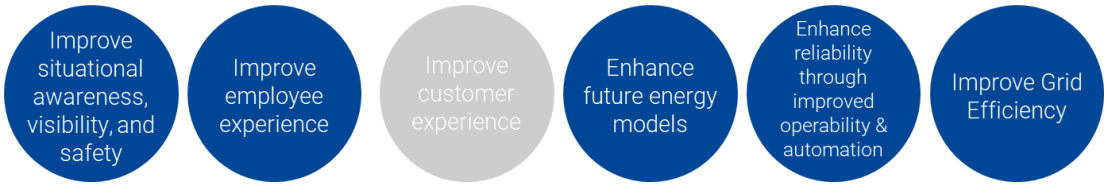
Capabilities Realized:

DMS	1	Real-time processing and alerts for calculated system constraints

Capabilities Enabled:

DMS	1	Intelligent load shedding and restoration
	2	Model based volt var optimization
	3	Conservative Voltage Reduction
	4	Study mode analysis for planned switching orders
	5	Study mode analysis for emergent switching needs
	6	Short Circuit Analysis for planned and emergent switching
Outage Management	7	Wire down detection
Scalability Planning	8	Automate fault analysis and isolation through FLISR deployment
	9	Analysis of fault isolation and restoration within the ADMS platform for real-time events
	10	Ability to monitor and analyze the predicted future-state of the distribution system
Switch Order Management	11	Mobile integration for field crew switching
	12	Real-time switching analysis and execution
	13	SCADA integration for switching order execution

Objectives Achieved:



<u>Field Mobility (Compass)</u>
Deploy Compass to allow field crews to have mobile access to real-time network data, switching orders, and outage information, improving responsiveness and reducing restoration times.

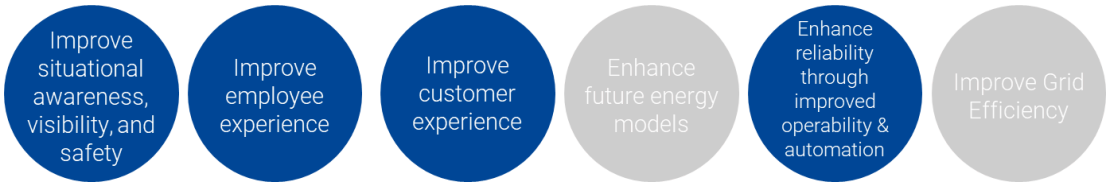
Capabilities Realized:

Operational Awareness	1	Crew access to as-switched model and current active tags in field

Capabilities Enabled:

Customer Communications	1	Customer outage portal for outage status and reporting
	2	Customer communication for outages and restoration
	3	Customer communication for estimated restoration times
	4	Customer communication for planned outage notifications and updates
	5	Public outage map and dashboard
Outage Management	6	Damage Assessment integrated with Outage Management
	7	Dynamic symbology to reflect current situational priorities
Training	8	Field personnel training for outage management

Objectives Achieved:



SOM for Real-Time Operations

Implement Switch Order Management for real time and emergent work to streamline the execution of switching operations, enhancing safety, and compliance.

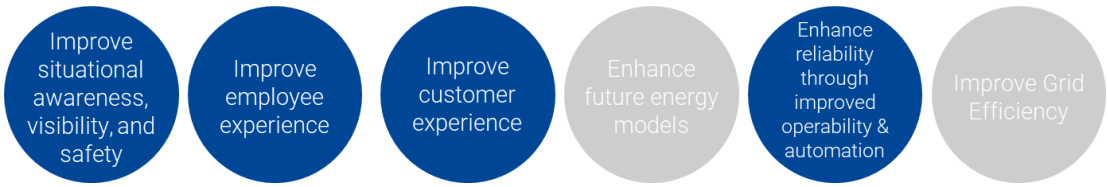
Capabilities Realized:

DMS	1	Study mode analysis for planned switching orders
	2	Study mode analysis for emergent switching needs
	3	Short Circuit Analysis for planned and emergent switching
SCADA	4	SCADA integration with logging system for planned and emergent events
Switch Order Management	5	Switching order writing including review and approval process
	6	Planned switching order schedule management
	7	Real-time switching analysis and execution
	8	SCADA integration for switching order execution

Capabilities Enabled:

Outage Management	1	Planned outage modeling and reporting
	2	Planned outage scheduling, management, and coordination
Resource Management	3	Crew assignments and management for outages and non-outage emergent events
Switch Order Management	4	Mobile integration for field crew switching

Objectives Achieved:



Automated FLISR

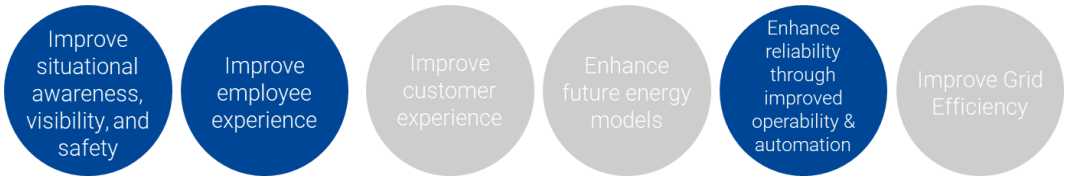
Implement Automated Fault Location, Isolation, and Service Restoration (FLISR) to automatically and confidently execute fault isolation and service restoration actions without operator intervention, reducing outage durations and improving reliability.

Capabilities Realized:

IT and Cybersecurity	1	Event detection, event & incident response, configuration management, etc.
Scalability Planning	2	Automate fault analysis and isolation through FLISR deployment
	3	Analysis of fault isolation and restoration within the ADMS platform for real-time events
DMS	4	Short Circuit Analysis for planned and emergent switching

Capabilities Enabled: None.

Objectives Achieved:



Load Shedding and Restoration

Implement Load Shedding Functionality to automate load reduction strategies during system contingencies, supporting grid stability and adherence to regulatory mandates.

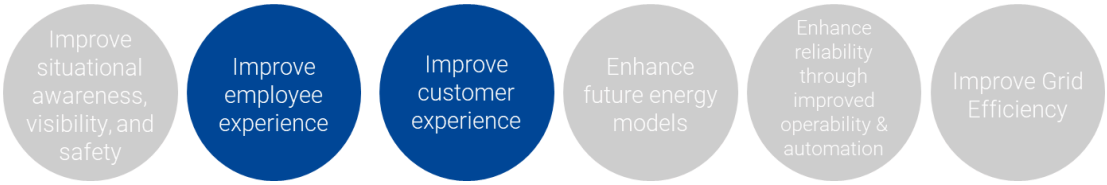
Capabilities Realized:

DMS	1	Intelligent load shedding and restoration

Capabilities Enabled:

Customer Communications	1	Customer communication for estimated restoration times
	2	Customer communication for planned outage notifications and updates

Objectives Achieved:



Volt Var Optimization (VVO and CVR)

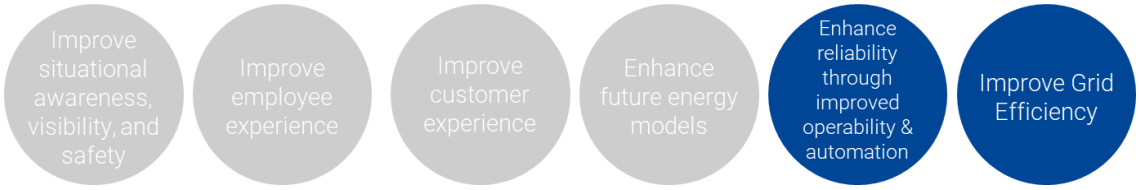
Implement Volt/VAR Optimization and CVR. This solution allows dynamically manages voltage and reactive power on the distribution grid, reducing energy consumption and improving power quality.

Capabilities Realized:

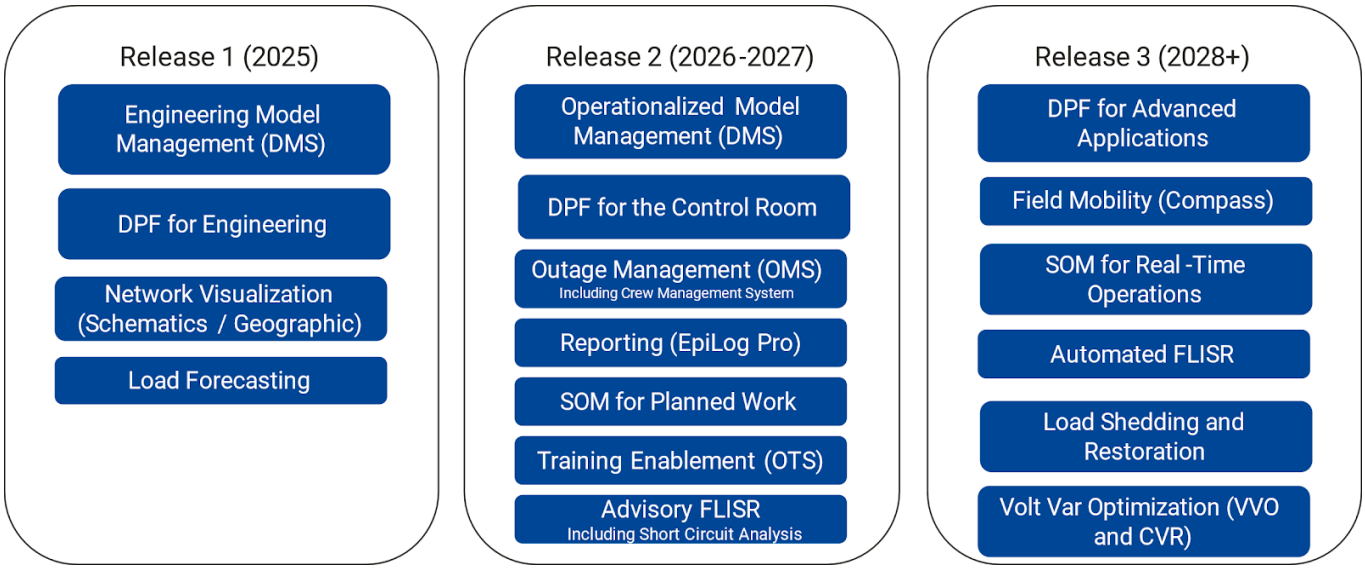
DMS	1	Model based volt var optimization
	2	Conservative Voltage Reduction

Capabilities Enabled: None.

Objectives Achieved:



D. Implementation Timeline



e. Program Stakeholders

The program stakeholders are identified in the following table. The stakeholders are tasked with ensuring alignment to the strategic objectives and overseeing the requirements.

Group
IT, Enterprise Applications
Change and Organization Development
Control Room
Distribution Planning
Customer Service
Enterprise Architecture
IT Planning, Programs, and Grid Technology
Asset Management, Distribution Planning

2. Program Approach

A. Program Governance

An integral part of any successful project is a comprehensive Program Governance Plan. This plan covers critical aspects of the ADMS Project. The Program Governance will guide the PMO workstream who is responsible for the overall delivery and performance of the entire project scope - with delivery leadership provided by the System Integrator (SI), who manages program execution on a day-to-day basis and chairs the PMO.

The purpose of this Program Governance Plan is to provide guidance for a consistent and uniform approach for managing, monitoring, and reporting on project activity. Subcontractors shall comply with the rules and elements within this Plan and with any rules and expectations noted in this document.

This is a living document and will be reviewed periodically, revised, and updated as needed. Revisions will be communicated to all impacted stakeholders following the project communication plan.

The scope of the Program Governance Plan is to define how to manage, monitor, and report on the scope of work for this project as well as the high level roles and responsibilities of the ADMS Program. This includes the following:

- How the ADMS Program will develop and deliver the activities of each workstream (led and coordinated by the SI)
- Communicate specific requirements of the Project and outline reporting procedures (defined and administered by the SI)
- Roles & responsibilities are clearly defined at the program level and within each release to ensure that each stakeholder understands their tasks and contributions to the program's success

I. Program Governance Goals

The goals for PMO governance are transparency, consistency, and clear expectations. The company will achieve its goals by leveraging the following:

PMO Governance Goals		
1	***Transparency***	● Project overall health is clearly measured and reported ● Project leaders and stakeholders have visibility to all project risks, issues, challenges, and successes ● Goal, Objectives, Capabilities, Release Plan, and R1 Scope are understood and signed off on by all directors during replanning effort ● SI provides structured reporting to the Steering Committee and Executive Sponsors
2	***Consistency***	● Recurring meetings have clear structure and agendas ● Project reports follow a standard cadence and format ● Any changes to the ADMS Program Charter or Release 1 Project Charter after replanning effort are escalated and approved through the PMO Governance Process
3	***Clear Expectations***	● All project team members and stakeholders have clear expectations for their participation and performance which are agreed to during Release Scoping ● Open forum for questions and clarification moderated by PMO and SI

II. Schedule Management

Effective schedule management is crucial for the success of the ADMS Program. The table below outlines the key aspects of schedule ownership, management, structure, and reporting. The System Integrator is responsible for owning, maintaining and reporting on the schedule, which is reviewed and updated weekly with inputs from HOL and AspenTech. The schedule includes defining predecessors and dependencies, and a baseline is established to track progress and implement corrective actions. Resources are assigned to each

activity in alignment with the RACI matrix, and schedule extracts are included in both weekly and monthly reports to ensure transparency and accountability.

1	Schedule Ownership	System Integrator owns the integrated master schedule
2	Schedule Management	Schedule is reviewed and updated on a weekly basis with inputs from HOL and AspenTech
3	Schedule Structure	Predecessors / Dependencies are defined in the schedule
4	Baseline Schedule	A schedule baseline is established. The SI will track progress against it to monitor deviations and implement corrective actions.
5	Resource Alignment	Resources are assigned to each activity and align with the RACI
6	Schedule Reporting	Schedule extracts included in weekly and monthly reporting

III. Role Management

Role management involves understanding and assigning the right people to different roles within a project team. Each role has specific responsibilities in guiding the project from conception to completion, managing resources, mitigating risks, and meeting objectives. Specific roles and responsibilities may vary by release depending on the scope and expertise needed, however the standards and approach for project management and role engagement should be consistently applied using the tools and frameworks below.

Role Management Success

The **RACI matrix** is a powerful tool used in project management to clearly define roles and responsibilities. RACI stands for Responsible, Accountable, Consulted, and Informed. This matrix helps ensure that every task and decision within the project is assigned to appropriate groups of individuals, promoting clarity and efficiency. By outlining who is responsible for executing tasks, who is accountable for the outcomes, who needs to be consulted for input, and who should be kept informed of progress, the RACI matrix facilitates effective communication and collaboration among team members. The SI will lead the role coordination across the workstreams, maintaining alignment to the defined RACI matrix.

RACI	Description
R	Responsible to lead/execute the activity
A	Accountable to ensure activity is done
C	Must be consulted to allow the activity to proceed
I	Informed of the activity/results

The RACI Matrix example below provides the structure for the ADMS Program. It will be further developed and refined during detailed scoping. This snapshot services as an initial framework to guide roles and responsibilities.

Key Tasks	Description / Deliverable	Hydro Ottawa						Vendor				SI		
		Role	Role	Role	Role	Role	Role	Role	Role	Role	Role	Role	Role	Role

Summary of Key Project Tasks and Responsibilities	Additional detail, particularly regarding deliverables for which the role is responsible for delivering and/or maintaining.	C						C				A/R		
e.g., Update and Manage Integrated Schedule	*Integrated Project Schedule, Provide Visibility to schedule progress, risks, dependencies, and upcoming activities.*	*C*						*R*				*A*		

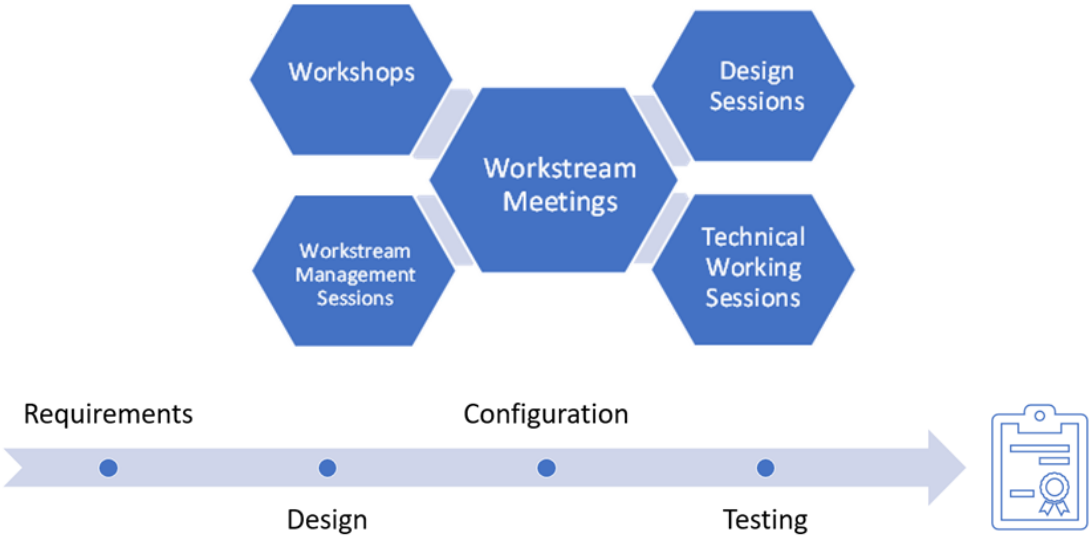
Governance Framework

The Steering Committee is responsible for strategic program governance and making high-level decisions regarding the direction of the program. Additionally, they handle approvals for any changes in the program, ensuring the overall strategy aligns with the ADMS Program's goals and objectives. Steering Committee Meetings occur on a monthly basis led by the SI and includes participation from the vendor and key stakeholders.

Program Management, also referred to as the PMO Workstream (detailed below) is responsible for governance and process standardization to ensure consistency across all workstreams. Chaired by the SI, they manage communication regarding status updates, risks, issues, impact assessments, and solution governance to keep all stakeholders informed and ensure that the ADMS Program progresses smoothly and efficiently. The PMO Workstream meets on a weekly basis to provide integrated oversight of the entire program management process.

Workstreams focus on managing workstream risks while maintaining health checks on the status reports to track progress accurately. Additionally, they are responsible for resource management and deployment, ensuring that all necessary resources are available for successful workstream completion and that the workstream stays on track to meet its objectives. Workstreams are led and coordinated by SI leads, and operate on both a weekly and daily schedule to ensure effective project delivery and day-to-day execution.

Workstreams are a structured approach to managing specific areas of a project, led by a subject expert. Empowered stakeholders are involved to ensure that the scope is clearly defined and decisions are made effectively. The workstream leader guides the design process, ensures quality standards are met, drives actions forward, and maintains the schedule.



The Project Management Office (PMO) Workstream oversees other various workstreams within the ADMS Program, each involving business and technology SMEs (Subject Matter Experts).

Workstreams and Specific Roles will be defined within each Release Charter.

IV. Reporting and Records

The administration of the project health reporting requirements is the responsibility of the SI. Reports pertaining to budget and invoicing is the responsibility of the HOL project coordinator. Reports should outline schedule, quality, cost, and morale updates.

Schedule	Quality	Cost	Morale
• Is the project on-schedule without significant risk of delay?	• Is the project scope being delivered to expected quality standards? • Are project objectives being measured and met?	• Is the project currently within budget? • Are there significant risks that are likely to impact cost	• Are project team members actively participating with positive attitudes? • Are team members working collaboratively and assuming positive intent?

Schedule

Green	Yellow	Red
• On schedule with no significant risk	• Late with mitigation or resolution plan. Or on schedule with minor risk. Mitigations/Resolutions constrain delays to 2 weeks or less.	• Late (2 or more weeks) with no back-to-green plan or mitigations/resolutions in place.

Cost

Quality

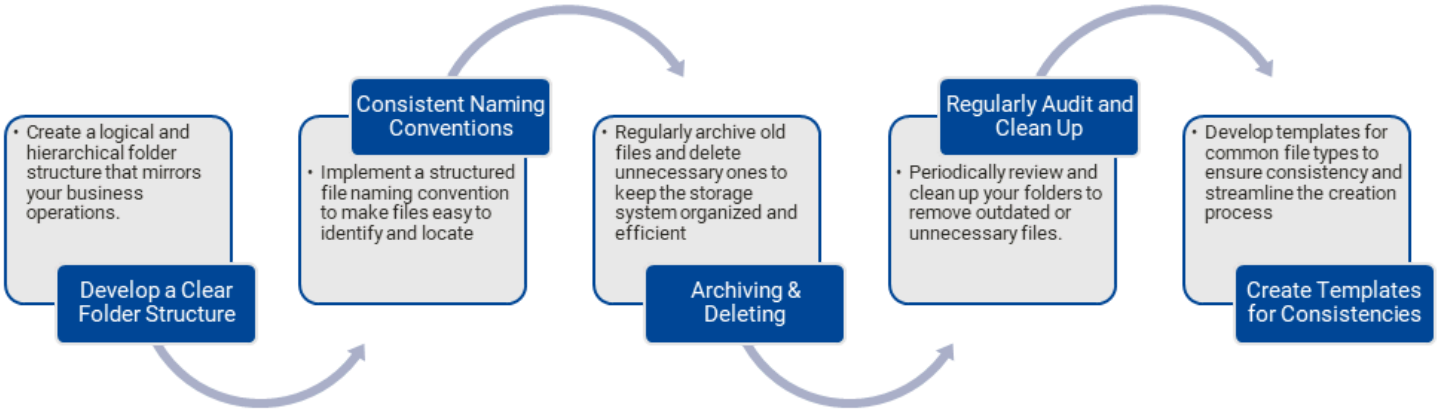
Morale

The PMO Workstream shall, at a minimum, maintain the following reports and records for the project (See Appendix B for Examples):

- Weekly Project Status Reports
- Monthly Project Status Reports
- RAID Log

File Sharing and Retention

All documentation will be made available in the shared document repository or submitted to the Client upon request. Effective file storage is essential for maintaining organization and efficiency for the ADMS Program. All documents should be stored in a shared project drive to ensure easy access and collaboration among team members. It's important to minimize the total number of documents to avoid clutter and confusion. Additionally, developing access controls and implementing document versioning are crucial steps to ensure security and track changes accurately.



v. RAID Management

The SI is responsible for managing the RAID log throughout the project. This log is used to validate the proposed timelines and to record items that could impact the project plan. The SI will maintain and report to the Stakeholders on a regular cadence throughout the duration of the project.

Table 1: RAID Definitions

DEFINITIONS	
Risk	Items that may impact project delivery.
Issue	Item that is or has impacted project delivery.
Action	Task that must be completed
Decision	Decision or selection that must be made.

Risk and Issue Management

1. Risks / Issues are identified and tracked via workstream meetings
    a. Workstream meetings will monitor risks / issues, address any roadblocks, and ensure that the project stays on schedule
    b. Establish a mitigation plan for each risk / issue within the workstreams meetings
2. All project team members have access to manage and update risks in a shared location
    a. SI Workstream Lead is accountable for all risks / issues updates including managing stale items.
3. Review in PMO meeting on a weekly basis
    a. Weekly Progress Updates: provide updates on the status of each risk / issue
    b. Issue Resolution and Adjustments: address any issues or roadblocks encountered with risks / issues
4. Risks / Issues are given severities:

RISK / ISSUE SEVERITIES	
Critical	Significantly impact the project's success immediate attention and resolution
High	Substantially affect the project's progress and outcomes, needing prioritized and close monitoring
Medium	Moderate impact on the project, causing some delays or minor deviations from the plan
Low	Minimal impact on the project, unlikely to cause significant disruptions

Action Management

1. Actions are identified and tracked via workstream meetings
    a. Workstream meetings will monitor the completion of each action, address any roadblocks, and ensure that the project stays on schedule
    b. Establish a due date for each action within the workstreams meetings
2. All project team members have access to manage and update actions in a shared location
    a. SI Workstream Lead is accountable for all action item updates including managing stale actions.
    b. Next action owner can be any team member (AT/HOL/SI) and they report their updates to the workstream lead
3. Review P1 Actions & high-level status of workstreams in PMO meeting on a weekly basis
    a. Weekly Progress Updates: provide updates on the summary workstream status and trends
    b. Issue Resolution and Adjustments: address any issues or roadblocks encountered with action items
4. Actions are given priorities
    a. Workstream Lead is with SI and is accountable for all action item updates including managing stale actions.
    b. Next action owner can be any team member (AT/HOL/SI) and they report their updates to the workstream lead

ACTION PRIORITIES	
P1	Critical to project and require immediate escalation
P2	Significant impact to project, report to management team for immediate review
P3	Identified impact to project, report to Workstream lead for possible escalation and monitor status with regular review
P4	Requires monitoring and periodic check-in, tracking needed for project continuity

Decision Management

1. Decisions are identified and tracked via workstream meetings
    a. Workstream meetings will monitor the timeline of workstream decisions, address any roadblocks, and ensure that the project stays on schedule
    b. PMO manages all decisions to ensure timely and structured decision making process and that decisions are made at the correct level
2. Decisions are reviewed with the PMO leadership team and approved by workstream leaders
    a. Weekly Progress Updates: provide updates on the status of each decision
    b. Pending and made/closed decisions are included in PMO and Steering Committee meetings
3. Decisions are transparent and given deadlines
    a. Pending and made/closed decisions are included in weekly and monthly reporting
    b. Decisions track not only the required decision, but the impact of the decision and required follow-up

DECISION PRIORITIES	
P1	Critical to project and require immediate escalation
P2	Significant impact to project, report to management team for immediate review
P3	Identified impact to project, report to Workstream lead for possible escalation and monitor status with regular review

P4	Requires monitoring and periodic check-in, tracking needed for project continuity

Escalation Process

Risks, Issues, and Decisions requiring Director/Executive input or visibility should be escalated. The process for escalation is shown below:

- **Identification:** Items for escalation can be identified by anyone
- **Documentation:** SI PMO documents and tracks all items for escalation
- **Communication:** The escalation is immediately escalated via workstream, PM leadership, and Steering Committee
- **Decision:** Decision on the escalation (if needed) is made at the lowest level possible
- **Follow-up:** Identifier and impacted stakeholders are notified of decisions and/or resolutions

PRIORITY / SEVERITY	
P1 / Critical	1 business day escalation for PMO and recurring steering committee
P2 / High	Next recurring PMO
P3 / Medium	Monthly reporting
P4 / Low	Monthly reporting & project closeout

b. Assumptions

Identify the key assumptions for the project that are required to move it forward (e.g. Project has full support of the Executive Sponsor, stakeholders and all business units; the IT Ops Manager will provide additional resources as needed; the project will take no more than 6 months to deliver).

Assumption	Description
Executive Sponsorship	The ADMS Program has full executive support across all phases and releases.
Funding Availability	Program funding will be approved and remain consistent with the long-term finances.
Cross-Functional Collaboration	Business units (Operations, IT, Engineering, Customer, etc.) will provide necessary support and SMEs throughout the program lifecycle.
Vendor Commitment	The selected vendor(s) will deliver capabilities on time per the agreed schedule and meet integration requirements.
Change Readiness	The organization will engage in ongoing change management activities to support business adoption.
Change Adoption	Hydro Ottawa will define the requirements and constraints for organization and role change as well as the process for role development and staffing.

No Major Scope Creep	Scope for each release will remain within agreed boundaries unless addressed through governance.
Technology Compatibility	Supporting technologies (e.g., GIS, AMI, CRM) will be compatible or adaptable for required integrations.
Regulatory Stability	No regulatory changes will significantly alter program scope or timeline.
Data Availability	Source systems (e.g., GIS, asset registry) will provide accurate and timely data for modeling and integrations.
Resource Availability	Adequate internal and external resources will be available when needed and retained throughout critical phases.
Change Readiness	Release 2 timeline considers the significant changes involved in, not only technology solutions (including retiring the use of existing ones), but also business processes (current & future) and organizational roles during execution & delivery. The duration of Release 2 will be further validated during R2 detailed planning.

c. Constraints

Identify the constraints for the project as they relate to scope, time/schedule and cost (e.g. all security hardware and software must be compatible with current IT platforms; solution must be implemented by end of 2012; the project resource plan must include 2 IT Specialists and 1 Security Specialist to ensure solution is implemented successfully).

Constraint	Description
Budget	Total program budget will be aligned to Hydro Ottawa financial systems.
Resource Allocation	The maximum number of dedicated internal FTEs as prescribed in the Project Charter (Release 1/2/3).
Integration Limitations	All integrations must align with existing middleware architecture and security protocols.
Infrastructure Dependencies	New functionality must operate within current data center/cloud parameters unless justified in a business case.
Security Standards	All software and hardware must comply with all applicable, internal cybersecurity standards, and corporate IT policies.
Regulatory Timelines	All releases must meet regulatory compliance requirements.

d. Dependencies

Dependencies can be both Internal and External.
Note: Dependencies listed below span all releases and/or affect future releases for which a Project Charter has not been developed. These future release dependencies will be moved into the appropriate Project Charter during the Planning stage of the related release.

Dependency Description	ADMS Functional Impact	ADMS Resource Impact	Change for Operations	Critical Dates
Ongoing and Inflight projects may affect resource availability, requirements for ADMS which should be tracked and managed through PMO	Managed through releases	Managed through releases	Managed through releases	Managed through releases
Workforce expansion should consider ADMS Support/Roles future Planning **across the ADMS Program Releases.**	Medium	Low	Medium	2026-2030
Rate Case Application 2025- Key SMEs from Finance, Regulatory and Operations may be redirected to support development and delivery of application, reducing availability and response for ADMS project	None	Medium	None	Q3-Q4 2025
Change Management				

e. Risks

This section lists the major risks identified for the project, which are those risks that would have a large impact on the project (e.g. Major delay / slippage in the project schedule; major increase in project budget / cost, etc.). Risks that are specific to an individual ADMS release are captured in the specific project charter.

Risk Description	Impact Statement (Budget, Schedule, Scope, Quality)	Mitigation Strategy
Required resources will not be available to the project when required due to competing priorities (Vendor, SI, HOL)	Delays to the project schedule, quality	Ensure project priorities and resource requirements are well defined and communicated to responsible directors / managers to ensure resources are available to the project. Contractual language within SOW and managed through PMO Governance.
Funding	Potential delays or changes to project funding and execution	Being addressed through the 2025 rate case noting updates to be provided later this year.
Volume of hiring in 2026 to 2030	Strain on project resources and potential delays in project staffing as roles are operationalized	Develop a strategic hiring plan and collaborate with HR to mitigate change risk and resource capacity/availability

Regulatory changes impacting project scope	Project delays and increased costs	Stay updated with regulatory changes and engage with legal advisors to ensure compliance
System Upgrades Required	Timing of ADMS Program may require system upgrades to be completed in parallel to or within the ADMS program with potential impacts to ADMS Program resource availability, cost, or schedule	Plan system upgrades in advance and integrate them into the project schedule to minimize disruptions
Stakeholder resistance to change	Delays in project implementation and increased costs	Establish change management - Engage stakeholders early and often, providing clear communication and addressing concerns
Inclusion of cybersecurity IT standards/compatibility with new systems	Schedule and quality impacts if not properly incorporated	Early engagement of IT to validate solution architecture and security posture
Inaccurate budget estimates	Budget overruns and schedule delays	Conduct thorough project planning
Confusion regarding people's roles	Delays and inefficiencies in project execution	Clearly define roles and responsibilities and communicate them effectively to all team members. Leverage Roles and Responsibilities document and maintain throughout
Technical Requirements for Dependent Projects	Dependent projects such as ODERA-DER Accelerator and Sensor Deployment may impact technical requirements for the ADMS program.	As technical requirements are defined across related programs, they must be reviewed collaboratively with all dependent project teams to ensure alignment on data needs and system dependencies. Strong coordination between ADMS leadership and other program leads is essential to minimize misalignment and integration risks.

3. Program Funding

This section summarizes the Estimated ADMS Program Cost (CAD +/-10%).
Note: As the project progresses, these costs may change as all tasks and requirements become more clear.

	HOL	System Integrator	Vendor*	Total*
Release 1 July 2025-December 2025	$754,510	$1,800,000	$1,348,025	$3,902,535
Release 2 (January 2026-December 2027)	$3,299,764	$7,500,000	$2,497,084	$13,296,848

Release 3 (~2028-2030)	$3,162,368	$3,900,000	$1,549,522	$8,611,890
Total Program	**$7,216,642**	**$13,200,000**	**$5,394,631**	**$25,811,273**

* Vendor pricing or cost estimates have not been provided at this time. Estimates are based on previous pricing and industry standards, but should be considered directional until firm estimates are provided by the vendor.

	2025	2026	2027	2028	2029**	Total*
HOL	$754,510	$1,649,882	$1,649,882	$1,581,184	$1,581,184	$7,216,642
System Integrator	$1,800,000	$3,750,000	$3,750,000	$1,950,000	$1,950,000	$13,200,000
*Vendor **	$1,348,025	$1,248,542	$1,248,542	$774,761	$774,761	$5,394,631
Total Program	$3,902,535	$6,648,424	$6,648,424	$4,305,945	$4,305,945	$25,811,273

* Vendor pricing or cost estimates have not been provided at this time. Estimates are based on previous pricing and industry standards, but should be considered directional until firm estimates are provided by the vendor.

** Release 3 is shown as 2028-2029 calendar year, but may go into 2030 dependent upon release planning efforts.

4. APPENDIX

A. Capability Mapping

** A Capability Marked as 'E' in releases following the Realization of the capability indicates the capability is being further enabled or enhanced through future releases.*

Capability			Objective						Release Plan – Capability (E)nabled* or (R)ealized																
									Release 1				Release 2									Release 3					
Focus for Enablement	Future Capability	Priority	Improve situational awareness, visibility & safety	Improve employee experience	Improve customer experience	Enable Future Energy Models	Enhance reliability through improved operability and automation	Improve grid efficiency	Engineering Model Management	Network Visualization	DPF for Engineering	Load Forecasting	Operationalized Model Management	DPF for the Control Room	Outage Management (OMS)	Training Enablement (OTS)	Reporting (EpiLog Pro)	SOM for Planned Work	Advisory FLISR including SCA	DPF for Advanced Applications	Field Mobility (Compass)	SOM for Real-Time Operations	Automatic FLISR	Volt Var Optimization (VVO/CVR)	Load Shedding and Restoration
Customer Communication	Customer outage portal for outage status and reporting	Critical Need			●										R						E				
	Customer communication for outages and restoration	Critical Need		●	●										R						E				
	Customer communication for estimated restoration times	Critical Need		●	●										R						E				E
	Customer communication for planned outage notifications and updates	Critical Need		●	●		●								R						E				E
	Public outage map and dashboard	Critical Need		●	●										R						E				
DMS	Intelligent load shedding and restoration	Strong Need					●	●	E	E	E	E	E	E						E					R
	Model based volt var optimization	Nice to Have					●	●	E	E	E		E	E						E				R	
	Conservative Voltage Reduction	Nice to Have					●	●	E	E	E		E	E						E				R	
	Real-time processing and alerts for calculated system constraints	Critical Need	●	●		●	●	●	E	E	E		E	R						E					
	Study mode analysis for planned switching orders	Critical Need	●	●					E	E	E		E	E				R		E		E			
	Study mode analysis for emergent switching needs	Critical Need	●				●		E	E	E		E	E				E		E		R			
	Short Circuit Analysis for planned and emergent switching	Strong Need	●	●			●		E	E	E		E	E				E	R	E		E	E		
IT and Cybersecurity	Event detection, event & incident response, configuration management, etc.	Critical Need	●	●			●												R				E		
Model Management	Switching, tagging and clearance management on the geographic model	Critical Need	●		●				R	R															

Capability			Objective						Release Plan – Capability (E)nabled* or (R)ealized																	
									Release 1				Release 2									Release 3				
Focus for Enablement	Future Capability	Priority	Improve situational awareness, visibility & safety	Improve employee experience	Improve customer experience	Enable Future Energy Models	Enhance reliability through improved operability and automation	Improve grid efficiency	Engineering Model Management	Network Visualization	DPF for Engineering	Load Forecasting	Operationalized Model Management	DPF for the Control Room	Outage Management (OMS)	Training Enablement (OTS)	Reporting (EpiLog Pro)	SOM for Planned Work	Advisory FLISR including SCA	DPF for Advanced Applications	Field Mobility (Compass)	SOM for Real-Time Operations	Automatic FLISR	Volt Var Optimization (VVO/CVR)	Load Shedding and Restoration
	Switching, tagging and clearance management on the schematic model	Critical Need	●		●				R	R															
	Handling and management of GIS/As-Design model errors	Critical Need	●	●	●				R	E															
	Modeling and management of temporary model features in geographic model	Critical Need	●	●	●				R	E															
	Modeling and management of temporary model features in schematic model	Critical Need	●	●	●				R	R															
	Power systems model management, support of Common Information Model (CIM), centralized modeling environment	Critical Need	●	●	●	●	●	●	R	E															
Operational Awareness	Record grid actions and document events for compliance and analysis	Critical Need	●						E	E			E				R								
	Crew access to as-switched model and current active tags in field	Critical Need	●	●					E	E			E		E						R				
Outage Management	Wire down detection	Strong Need	●	●			●		E	E	E		E	E	R					E					
	Outage and event prioritization for storms	Critical Need	●	●	●		●								R										
	Planned outage modeling and reporting	Critical Need					●				E			E	R			E				E			
	Planned outage scheduling, management, and coordination	Critical Need	●								E			E	R			E				E			
	Real time Storm and Outage Dashboards to provide operational oversight	Critical Need	●	●					E	E			E		R										

Capability			Objective						Release Plan – Capability (E)nabled* or (R)ealized																	
									Release 1				Release 2									Release 3				
Focus for Enablement	Future Capability	Priority	Improve situational awareness, visibility & safety	Improve employee experience	Improve customer experience	Enable Future Energy Models	Enhance reliability through improved operability and automation	Improve grid efficiency	Engineering Model Management	Network Visualization	DPF for Engineering	Load Forecasting	Operationalized Model Management	DPF for the Control Room	Outage Management (OMS)	Training Enablement (OTS)	Reporting (EpiLog Pro)	SOM for Planned Work	Advisory FLISR including SCA	DPF for Advanced Applications	Field Mobility (Compass)	SOM for Real-Time Operations	Automatic FLISR	Volt Var Optimization (VVO/CVR)	Load Shedding and Restoration
	AMI integration for outage detection and restoration validation	Critical Need	●	●	●		●		E	E			E		R										
	Damage Assessment integrated with Outage Management	Critical Need	●	●	●		●								R						E				
	Streamlined call taking interface for non-operators	Critical Need		●	●		●								R										
	Dynamic symbology to reflect current situational priorities	Strong Need	●	●	●				R	E			E		E						E				
	Outage and Event Reporting	Critical Need					●								R										
	Visual playback of all events/alarms/etc., web-based access to data historical info. for report generation	Critical Need	●	●											R	E	E								
Resource Management	Crew visibility for normal business availability	Critical Need	●	●											R										
	Crew management including contract and external resources during storms	Critical Need	●	●			●								R										
	Crew assignments and management for outages and non-outage emergent events	Critical Need	●	●	●										R			E				E			
SCADA	SCADA integration with OMS for unplanned outages	Critical Need	●	●	●		●								R										
	SCADA integration with logging system for planned and emergent events	Strong Need	●	●													R	E				E			
Scalability Planning	Automate fault analysis and isolation through FLISR deployment	Strong Need					●		E		E		E	E					E	E			R		

Capability			Objective						Release Plan – Capability (E)nabled* or (R)ealized																	
									Release 1				Release 2									Release 3				
Focus for Enablement	Future Capability	Priority	Improve situational awareness, visibility & safety	Improve employee experience	Improve customer experience	Enable Future Energy Models	Enhance reliability through improved operability and automation	Improve grid efficiency	Engineering Model Management	Network Visualization	DPF for Engineering	Load Forecasting	Operationalized Model Management	DPF for the Control Room	Outage Management (OMS)	Training Enablement (OTS)	Reporting (EpiLog Pro)	SOM for Planned Work	Advisory FLISR including SCA	DPF for Advanced Applications	Field Mobility (Compass)	SOM for Real-Time Operations	Automatic FLISR	Volt Var Optimization (VVO/CVR)	Load Shedding and Restoration
	Analysis of fault isolation and restoration within the ADMS platform for real-time events	Critical Need					●		E	E	E		E	E					R	E			E		
	Ability to monitor and analyze the predicted future-state of the distribution system	Critical Need				●	●	●	E	E	E	R	E	E						E					
Switch Order Management	Mobile integration for field crew switching	Strong Need	●	●			●		E	E	E	E	E	E				E		E	R	E			
	Switching order writing including review and approval process	Critical Need	●							E								R				E			
	Planned switching order schedule management	Strong Need	●							E					E			R				E			
	Real-time switching analysis and execution	Critical Need	●						E	E	E		E	E				R		E		E			
	SCADA integration for switching order execution	Nice to Have	●								E			E				R		E		E			
Training	Historic event import for scenario development	Strong Need		●	●		●		E	E			E			R									
	Simulation based training for real-time system operators	Critical Need	●	●			●		E	E			E			R									
	Field personnel training for outage management	Critical Need	●	●			●								E	R					E				
	Office personnel training for outage management	Critical Need	●	●												R									

SESC Roadmap

Aug 25, 2021

HydroOttawa

Agenda

1. Strategic objectives
2. Portfolio scope
3. Recommended roadmap
4. 2021 Forecast
5. 2021-2025 Forecast
6. Portfolio health
7. Resource requirements
8. Action items
9. Risks
10. Next Steps

Strategic objectives

Self healing grid

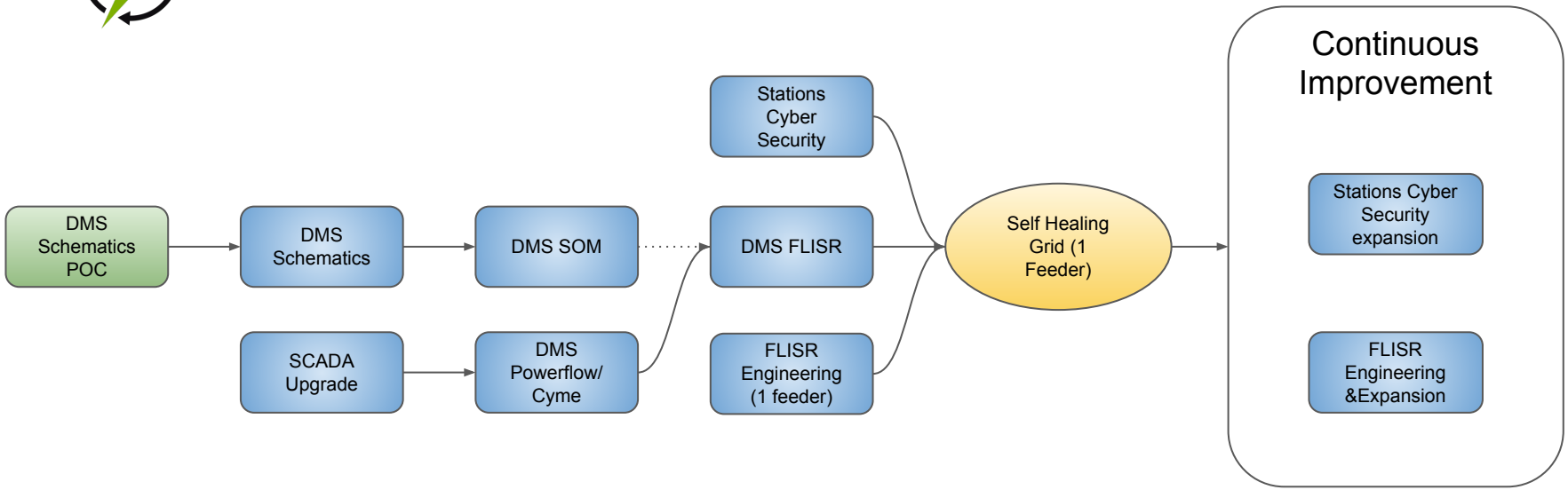
Outage notifications

System Planning Evolution/Adaptation/Innovation

DER Enablement

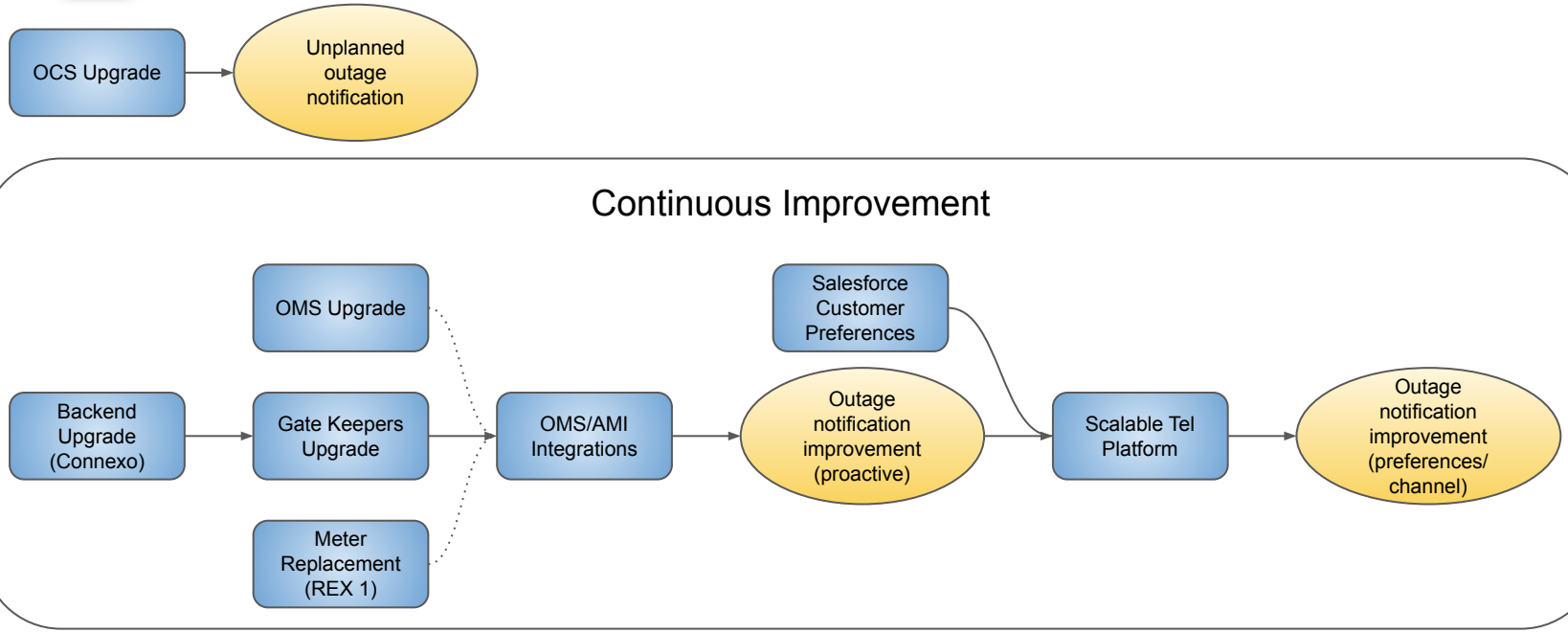
Strategic objectives

Self healing grid



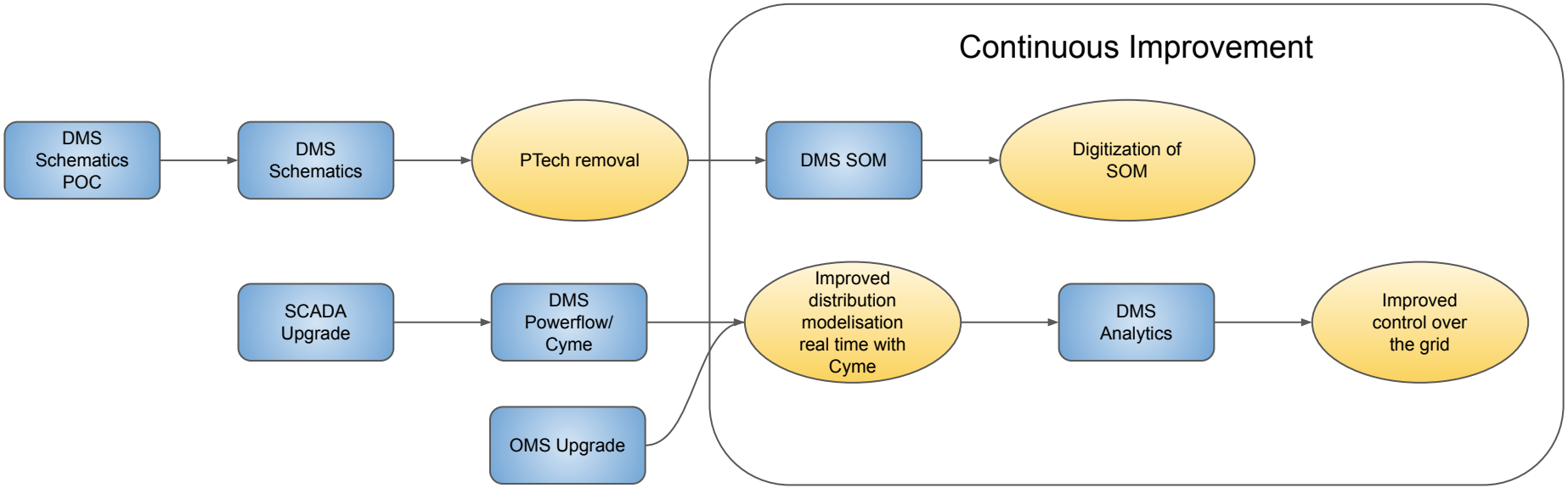
Strategic objectives

Outage notifications



Strategic objectives

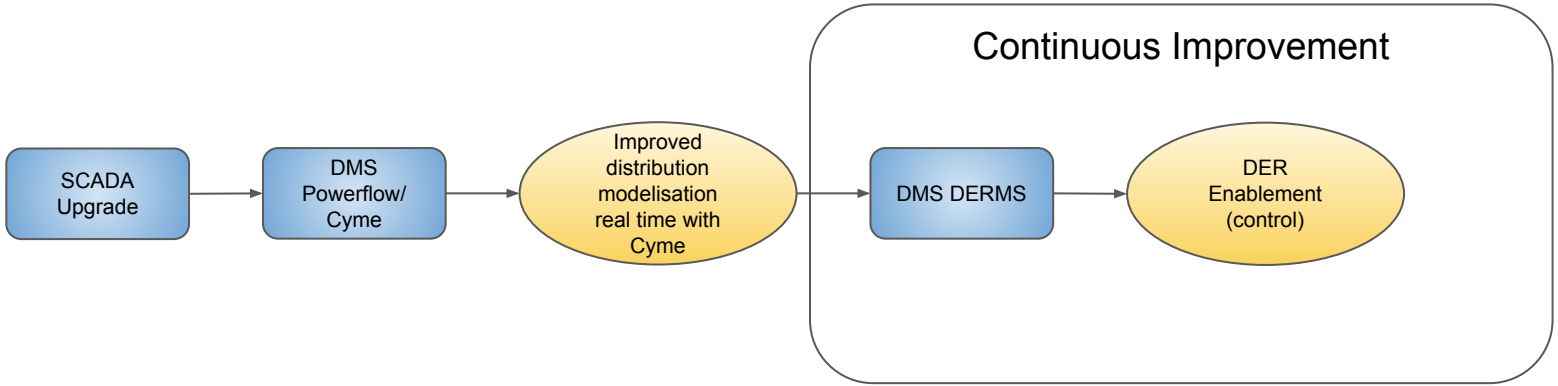
System Planning* Evolution/Adaptation/Innovation



*1) The planning desk within System Office. 2) System Planning within Assets Engineering

Strategic objectives

DER Enablement



Portfolio scope

Core projects
Rate App 2021-2025: $17.9M
	• ADMS Program
	  ○ Outage Communication System replacement
	  ○ DMS modules (Schematics, Powerflow, FLISR, Analytics)
	  ○ OMS upgrade, OMS integration with AMI
	  ○ Device automation deployment for FLISR
	• Stations Cybersecurity
	• REX1 Meter strategic replacement
	• Pole Top Gatekeepers

Supporting project *Rate App 2021-2025: $5.2M*	• Field Area Network • ION Meter Replacement
General grid enhancement projects *Rate App 2021-2025: $11.1M*	• 1.5 EL to 2.5 EL / 2.5EL to 3.5 EL • TR communication update, TR Service to 200A • Low installations • C-Phase Reversal • ION Interval Customer Update • Embedded Generation projects • OTN Equipment replacement
Undefined / Cancelled projects *Rate App 2021-2025: $8.5M*	• New AMI Program (undefined) • Self healing grid (not a project) • Smart Grid Fund initiative (not a project) • MiGen II (cancelled)

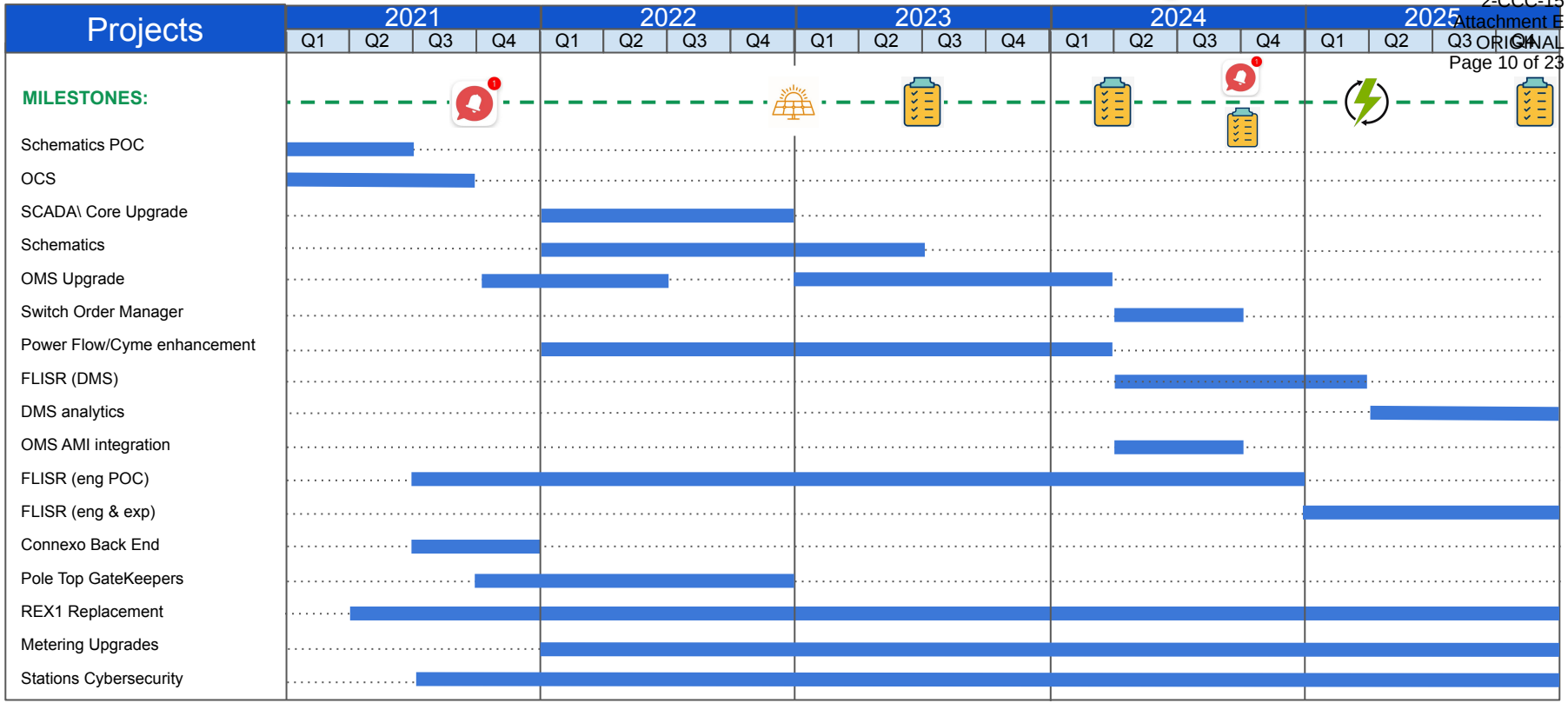
Portfolio scope

Decision		

In scope	**Core projects**
	Rate App 2021-2025: $17.9M
		• ADMS Program
		  ○ Outage Communication System replacement
		  ○ DMS modules (Schematics, Powerflow, FLISR, Analytics)
		  ○ OMS upgrade, OMS integration with AMI
		  ○ Device automation deployment for FLISR
		• Stations Cybersecurity
		• REX1 Meter strategic replacement
		• Pole Top Gatekeepers
		• TR communication update,

In scope	**Supporting project** *Rate App 2021-2025: $5.2M*	• Field Area Network
Out of Portfolio Scope	**General grid enhancement projects** *Rate App 2021-2025: $11.1M*	• 1.5 EL to 2.5 EL / 2.5EL to 3.5 EL • TR Service to 200A • Low installations • C-Phase Reversal • ION Interval Customer Update • ION Meter Replacement • OTN Equipment replacement
Define scope / Redistribute budget	**Undefined / Cancelled projects** *Rate App 2021-2025: $8.5M*	• New AMI Program (undefined) • Embedded Generation projects • Self healing grid (not a project) • Smart Grid Fund initiative (not a project) • MiGen II (cancelled)

Recommended Roadmap



2021 Forecast

Division	Investment Category	Parent Program	2021 Forecast: Q2 Forecast 2021	2021 Forecast: Revised Forecast 2021	2021 Forecast: Budget 2021	2021 Forecast: Revised Forecast vs. Budget
CED	System Renewal	Metering Upgrades	3,384,338	1,656,275	3,452,876	(1,796,601)
CTO	System Service	Communications Infrastructure	-	-	918,508	(918,508)
CTO	General Plant	AMI Program	302	302	504,650	(504,348)
CTO	System Service	Stations Enhancements	305,085	100,000	603,828	(503,828)
CTO	System Service	SCADA Upgrades	771,823	562,582	979,513	(416,931)
CTO	System Service	Distribution Enhancements	105,285	-	311,441	(311,441)
CTO	System Service	RTU Upgrades	-	-	258,224	(258,224)
CED	System Access	Embedded Generation Projects	-	-	141,392	(141,392)
CED	System Service	Distribution Enhancements	161,157	138,177	250,023	(111,846)
CTO	General Plant	CC&B Enhancements	701,042	701,042	701,463	(422)
CED	System Service	Stations Enhancements	-	-	-	-
CTO	General Plant	Web, Mobile, Multi-Channel Comms.	153,339	153,014	120,530	32,485
	System Service		**$ 1,343,351**	**$ 800,759**	**$ 3,321,538**	**$ (2,520,779)**
	System Renewal		**$ 3,384,338**	**$ 1,656,275**	**$ 3,452,876**	**$ (1,796,601)**
	General Plant		**$ 854,683**	**$ 854,358**	**$ 1,326,643**	**$ (472,285)**
	System Access		**$ -**	**$ -**	**$ 141,392**	**$ (141,392)**
TOTAL			$ 5,582,360	$ 3,311,392	$ 8,242,449	$ (4,931,057)

As of Aug 24, 2021

- Pole Top Gatekeepers (SC Comm. Update) deferred from 2021 to 2022 (-$1.8M)
- Field Area Network deferred from 2021 to 2023 (-$0.9M)
- AMI program deferred from to 2022/2023 (-$0.5M)

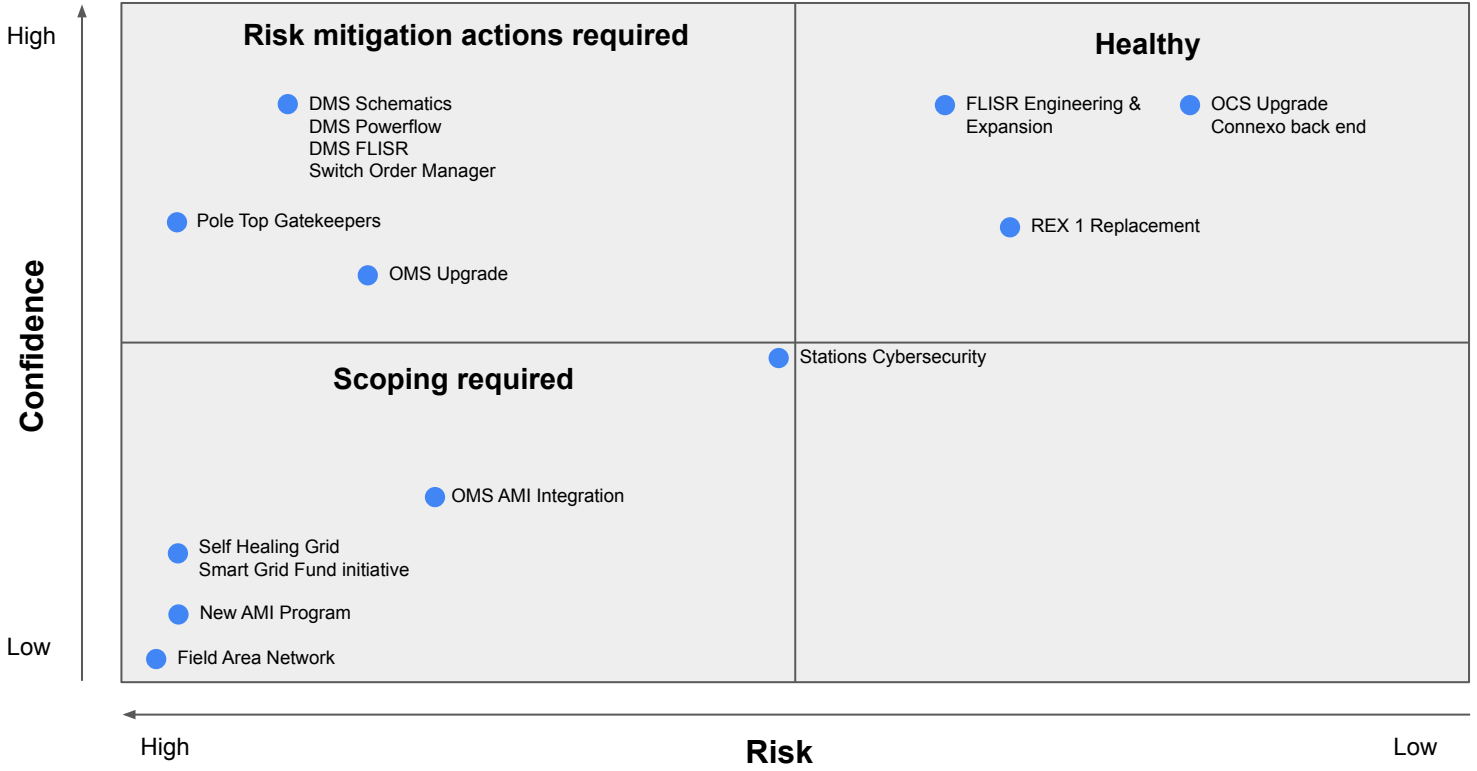
2021-2025 Forecast

Division	Investment Category	Parent Program	Five Year Overview: Forecast 2021 - 2025	Five Year Overview: Rate Application Budget 2021 - 2025	Five Year Overview: Forecast vs. Budget
CTO	System Service	SCADA Upgrades	19,231,602	7,592,134	11,639,468
CED	System Service	Distribution Enhancements	2,717,477	5,356,533	(2,639,056)
CTO	System Service	Distribution Enhancements	-	2,218,536	(2,218,536)
CTO	System Service	Communications Infrastructure	4,123,208	6,069,130	(1,945,922)
CTO	System Service	RTU Upgrades	-	1,267,218	(1,267,218)
CED	System Renewal	Metering Upgrades	12,194,120	13,196,261	(1,002,141)
CTO	General Plant	CC&B Enhancements	701,042	1,612,248	(911,206)
CED	System Service	Stations Enhancements	1,239,834	1,549,792	(309,958)
CED	System Access	Embedded Generation Projects	566,319	710,088	(143,768)
CTO	General Plant	Web, Mobile, Multi-Channel Comms.	153,014	120,530	32,485
CTO	General Plant	AMI Program	1,548,631	1,557,205	(8,574)
CTO	System Service	Stations Enhancements	1,196,092	1,189,579	6,513
	System Service		**$ 28,508,213**	**$ 25,242,923**	**$ 3,265,290**
	System Renewal		**$ 12,194,120**	**$ 13,196,261**	**$ (1,002,141)**
	General Plant		**$ 2,402,687**	**$ 3,289,982**	**$ (887,296)**
	System Access		**$ 566,319**	**$ 710,088**	**$ (143,768)**
TOTAL			$ 43,671,339	$ 42,439,254	$ 1,232,086

As of Aug 24, 2021

- ADMS projects resource cost is factored in (+ $11.6M)
- Smart Grid Fund Initiative non project (- $2.6M)
- MiGen II project cancelled (- $2.2M)
- F.A.N effort deferred from 2021 to 2023 (- $1.9M)

Portfolio Health



Resource requirements

	2021-Q4	2022	2023	2024	2025
Project Structure					
ADMS Project Manager	0.25	2.25	1.5	1	0.5
Metering Project Manager	0.25	0.5	0.5	0.5	0.5
Cybersecurity Project Manager		2*0.3			
FLISR Eng Project Manager	0.2	0.5	0.5	0.75	0.25
ADMS Change Management Lead		1	2	1.75	1
FLISR Eng Change Management Lead	0.1	0.1	0.1	0.5	0.2
ADMS Business Analyst		1.25	2.25	1.25	1
ADMS Data Analyst/Architect	0.5	0.95	0.3	0.1	0.1
System Office					
Business Lead	1	2.25	2.25	2	1
System Planning SME		1.25	0.75	0.25	1
System Operating SME		1.25	1.25	0.75	1
System Dispatcher SME		0.5	0.5	0.5	
Field Operations					
Field Operator SME		1	1.5	1.5	1
Field Crew SME		1	1.5	1.5	1

HOL FTEs
Outsourced FTEs

	2021-Q4	2022	2023	2024	2025
GIS & Distribution Records / Assets					
Data & GIS/CAD Lead		0.85	1.5	0.5	0.25
GIS/CAD Technician		1 + 7	1 + 7	1 + 1	1
Assets Engineer			1	1	
Metering					
Project Manager	0.25	0.5	0.5	0.5	0.5
Technician	3 + 2	5.1 + 4	3.5	3.5	3.5
Electrical Contractor	2	2	2	2	2
Designer	0.2	0.3	0.2	0.2	0.2
Stations					
Station technician		0.5	0.5	0.5	0.5
Grid Technology					
Grid Technology Program Solution Lead	1	1.6	0.85	0.75	0.75
Technology Lead	1	2.2	1.1	0.75	0.5
Engineering Support		2.6	1.85	1.1	0.5
Grid Technology Specialist	1	6	6	4	1
DMI		0.2	1	1	
Web team		0.1	0.5	0.5	
IT PM backfill	1	1	1	1	1

Risks

Risk	Status	Impact	Action	Strategy
Insufficient resources for ADMS project execution		Project delays involving inability to meet strategic objective. Requirement to pay shareholders back for unspent funds	Mitigate	Hire external/internal resources, position internal resources on projects.
Insufficient ADMS budget		Project delays involving inability to meet strategic objective. Requirement to pay shareholders back for unspent funds	Mitigate	Balance the System Service budget 2022-2025
Regulatory requirements		Inability to plan/execute as planned (SOM, FAN)	Mitigate	Estimate and factor in regulatory lead time in planning when possible.

Action items

Action	Timing	Owner
Start resource risk mitigation actions to support the ADMS projects execution	**Now**	Laurie/Joseph/Charles
Update the 2022 budget to include costs related to labour for the ADMS Program	**Now**	Charles

Next steps

- Set up follow-up meeting on resource requirements
  - Launch action to meet resource requirements for 2022 projects

- Subsequent meetings:
  - Present status updates & Q3 forecast
  - Present new projects for approval when required

Questions

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Additional Resources

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Resource requirements

Resource	2022	2023	2024	2025
Change Management Lead	2	2	2.5	1
Business Analyst	2	2.25	2.5	1
CAD technician	8	8 (Q1,Q2)	2	2 (Q1)
System Office Business Lead	2.25	2.25	2.5	1
System Office Planning SME	1.25	1.25	1.75	1
System Office System Operations SME	1.25	1.25	1.75	1
Field Operator SME	0	1	1	1
Field Crew SME	0	1	1	1
IT Project manager (backfill)	1	1	1	1

Resource requirements

Resources to be on boarded by Jan 1 2022

DMS Schematics	• 8 CAD tech • 1 System Office Business Lead • 1 Business Analyst • 1 Change Management Lead
SCADA Upgrade	• 0.75 Business Analyst • 0.5 Change Management Lead • 0.75 System Office Business Lead • 0.5 System Office planning SME • 0.5 System Office system operations SME
DMS Powerflow	• 0.5 System Office Business Lead • 0.5 Change Management Lead • 0.25 Business Analyst • 2x0.75 System Office SMEs
OMS Selection	• 0.25 System Office business lead

Resource requirements

Resources to be on boarded by Jan 1 2022

Resources required for ADMS project execution start in 2022

- 2 Business Analysts
- 2 Change Management Leads
- 8 CAD Technicians
- 2.25 System Office Business Leads
- 1.25 System Office planning SME
- 1.25 System Office system operations SME

In addition, the creation of the Portfolio Manager role involved a requirement to backfill one IT Project Manager position

Resources to be on boarded by Jan 1 2023

Extra resources required for ADMS project execution in 2023

- 1 Field Operator SME
- 1 Field crew SME

Role	Name	Responsibility Highlights
System Office		
Business Lead	Internal Resource	Represents the Product Owner, makes strategic & day-to-day decisions, represents needs of group.
Business Analyst	External Resource?	Re-designs business processes, documents requirements, plans & manages User Acceptance Testing.
Change Management Lead	External Resource?	Performs impact analysis, manages regulatory changes, delivers communications & training.
System Planning SME	Internal Resource	Provides subject expertise, assists in designing processes & system configuration, prepares & participates UAT.
System Operating SME	Internal Resource	Provides subject expertise, assists in designing processes & system configuration, prepares & participates UAT.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-16

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 1, p. 69

QUESTION(S):

Please explain how corrective capital (i.e., reactive replacements) is reflected in Hydro Ottawa's estimate of percentage of assets in degraded condition after investment.

RESPONSE(S):

Hydro Ottawa annually assesses the condition of all its assets as part of its Asset Management Plan. This review uses the latest asset information extract from the Geographic Information System (GIS). When an asset is replaced, it is removed from the existing condition assessment, and its new replacement is automatically given a "Very Good" condition (100% Health Index score). This ensures that any improvement in the overall asset condition profile directly reflects Hydro Ottawa's investments, whether they are reactive or proactive in nature.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-17

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 4, pp. 213, 215, 218, 221, 301-302

QUESTION(S):

a) (P. 213) Please provide the expected timing of the issuance of the final IRRP report. As part of the response, please discuss what actions Hydro Ottawa would take with respect to its system capacity-related investments if there is a material change to forecast capacity requirements resulting from the updated report.

b) (P. 215, 218, 221) With respect to Tables 33, 34 and 35, please advise which tables are showing projects with capital expenditures during the 2026-2030 period.

c) (P. 215) Please provide an expanded Table 33 that includes columns showing:
   i) The in-service date for the solution
   ii) The cost of the solution
   iii) A listing of the specific capital program budget (and evidentiary reference) where the costs are reflected (assuming the work is planned to be completed during the current CIR term).

d) (P. 218) Please provide an expanded Table 34 that includes columns showing:
   i) The in-service date for the solution
   ii) The cost of the solution
   iii) A listing of the specific capital program budget (and evidentiary reference) where the costs are reflected (assuming the work is planned to be completed during the current CIR term).

e) (P. 221) Please provide an expanded Table 35 that includes columns showing:
   i) The in-service date for the solution

ii) The cost of the solution

iii) A listing of the specific capital program budget (and evidentiary reference) where the costs are reflected (assuming the work is planned to be completed during the current CIR term).

f) (P. 229) Please explain why the planning forecast is higher than the IRRP forecast up to 2029.

g) (P. 232) Please explain why the planning forecast is higher than the IRRP forecast for part of the 2026-2030 period.

h) (P. 301) Please provide an update with respect to the preliminary inquiries and formal load summary submissions. As part of the response, please advise how much of this capacity (199 MVA) has moved to the offers to connect stage.

i) (P. 302) Please provide Figure 113 in tabular format.

j) (PP. 301-305) Please provide a summary regarding how the IRRP forecast and the decarbonization study are incorporated as part of Hydro Ottawa's planning forecast.

k) (P. 301-305) Please discuss the implications on Hydro Ottawa's forecast capacity requirements and related capacity expansion-related investments based on the following changes to the underlying assumptions. As part of the response, please provide estimates of the changes to the cost of planned system capacity-related investments.

i) Removal of all the large load requests in the preliminary inquiry stage.

ii) Removal of all the large load requests in the preliminary inquiry and formal load summary stages

iii) Use of the dual-fuel decarbonization scenario.

iv) Use of the low decarbonization scenario.

v) Use of the revenue load forecast (instead of the planning forecast).

l) (P. 305) Based on each of Hydro Ottawa's planning load forecast and revenue load forecast, when does Hydro Ottawa estimate that its system will become winter peaking.

RESPONSE(S):

a) The IESO regional planning process in the Greater Ottawa Area involves collaboration among the IESO, Hydro Ottawa, and Hydro One. Please refer to Section 4 of Schedule 2-5-2 - Coordinated Planning with Third Parties. Hydro Ottawa, as an active member of the Integrated

Regional Resource Planning (IRRP) working group, has ensured that the investment plan presented within the application is in alignment with the needs being identified as part of the IRRP working group and there is no material change to forecasted capacity requirements. The final IRRP report was published on July 31st 2025 and can be found on the IESO website.

b) All three tables show projects with capital expenditures during the 2026-2030 period.

- Table 33 contains the comprehensive list of these projects.
- Table 34 and Table 35 are subsets of Table 33, detailing immediate needs and medium-to-long-term needs, respectively.

While most projects will be completed and energized within the 2026-2030 period, some expenditures will initiate projects that will be energized after 2030.

c) Please see Table A below. The table was slightly altered to be able to accurately show the separate investments and capital program for the region based projects. For clarity, capital expenditures denoted as “TBD” do not have any forecasted expenditures in the rate period. For further detail, please refer to Section 2 of Schedule 2-5-8 - System Service Investments for in-service dates and capital expenditures associated with upgrades listed in Table 33. The column within Table A identifying “Capacity Addition (LTR-MVA)” provides the planning rating for each project/solution.

Note the following evidentiary references for each of the Capital Programs identified within the first column, “Capital Program”, within Table A:

- Station Capacity Upgrades
  - Section 2 of Schedule 2-5-8 - System Service Investments
- Distribution Capacity Upgrades
  - Section 2 of Schedule 2-5-8 - System Service Investments
- Non-Wire Upgrades
  - Section 2 of Schedule 2-5-8 - System Service Investments

- Other Revenue Expense - Non-Wire Solutions
    - Section 2 of Schedule 2-5-8 - System Service Investments
- CCRA
    - Section 7 of Schedule 2-5-9 - General Plant Investments
- EOL Voltage Conversion
    - Section 2 of Schedule 2-5-7 - System Renewal Investments
- System Expansion
    - Section 4 of Schedule 2-5-6 - System Access Investments

1 **Table A - Investment Needs per Planning Region Cost breakdown**

Capital Program	Planning Regions	Wire Solutions	Non-Wires Solutions (NWSs)	Capacity Addition (LTR-MVA)	In Service Date	2026-2030 Capital Expenditure
Station Capacity Upgrades	South 28 kV	Construction of a new 28 kV station (Greenbank MTS) to accommodate overloads in the 8 kV system and large load requests including the Regulatory and Science Main Project		120	2028	$38.5M
	South-East 28 kV	Construction of a new station in the region along the 230 kV transmission corridor (Piperville MTS) to accommodate overloads and support future growth		120	2026	$3.6M
	East 28 kV	Cyrville MTS is proposed to be upgraded to support overload in the East 13 kV and East 8 kV regions and support large load requests including TerraCanada National Capital Area project		70	2028	$35.3M
	East 28 kV	With plans to decommission Bilberry TS and an Orleans feeder, a new 28 kV station is underway (Mer Bleue MTS) to manage existing load from Orleans TS and Bilberry TS		120	2028	$34M
	West 28 kV (North)	Construction of a new 28 kV station to accommodate overloads and support future growth.		120	2028	$44.8M
	West 13 kV and Core 13 kV and Central 4 kV	Conversion of Bronson from 4 kV to 13 kV will help with capacity constraints and support Carling, Lisgar and Riverdale		130	2030 and Beyond	$35.1M
	Core 13 kV	Riverdale switchgear upgrade underway			2027	$0.8M

Capital Program	Planning Regions	Wire Solutions	Non-Wires Solutions (NWSs)	Capacity Addition (LTR-MVA)	In Service Date	2026-2030 Capital Expenditure
	Barrhaven 8 kV	Voltage conversion of 8 kV to 28 kV in the long term supported by Cambrian MTS and the new Greenbank station in the South 28 kV region			2030 and Beyond	TBD
Distribution Capacity Upgrades	South 28 kV	Greenbank Feeder integration plans for new station			2026-2030	$20M
	South-East 28 kV	Piperville Feeder integration plans for new station			2026-2030	$6.0M
	East 28 kV	Mer Bleue Feeder integration plans for new station			2026-2030	$16.6M
	East 28 kV	Cyrville Feeder integration plans for new station			2026-2030	$4.5M
	West 28 kV (North)	New West 28kV Feeder integration plans for new station			2026-2030	$20.7M
Non-Wire Upgrades	West 28 kV		Utility Owned Battery Storage	3	2028	$6.25M
	Core 13 kV		Utility Owned Battery Storage	11	2030	$24.95M
	Bells Corner/ Bayshore 8 kV	None required	Utility Owned Battery Storage	8	2029	$17.5M
	Casselman 8 kV	None required	Utility Owned Battery Storage	6	2028	$12.5M
Other Revenue Expense - Non-Wire	West 28 kV (North) and Core 13kV		Non-Wires Customer Solutions	20-30 MW	2026-2030	$10M

Capital Program	Planning Regions	Wire Solutions	Non-Wires Solutions (NWSs)	Capacity Addition (LTR-MVA)	In Service Date	2026-2030 Capital Expenditure
Solutions			Program			
CCRA	44 kV	Hydro One has plans to upgrade South March TS transformers due to end of life. Installing higher capacity transformers would aid in adding capacity to the region		51	2030 and Beyond	TBD
	West 13 kV	Cable upgrades and remove equipment limitations at Hydro One stations - Carling TS		71.6	2030	$2.1M
	Core 13 kV	Cable upgrades and remove equipment limitations at Hydro One stations - King Edward TS			2030	$16.4M
	Core 13 kV	Cable upgrades and remove equipment limitations at Hydro One stations - Lisgar TS			2029	TBD
	East 13 kV	Hydro One has plans to upgrade Russell TS station transformers due to end of life. Installing higher capacity transformers would aid adding capacity to the region		68	2027	TBD
	East 13 kV	Hydro One has plans to upgrade Albion TS station transformers due to end of life. Installing higher capacity transformers would aid adding capacity to the region			2030 and Beyond	TBD
EOL Voltage Conversion	Central 4 kV	Strategic and phased voltage conversion. Fisher DS is underway and Henderson DS will be initiated.			2026-2030	$64.3M
	East 4 kV	Strategic and phased voltage conversion. Dagmar DS is underway. Church DS and Vaughan DS will be initiated			2026-2030	
TBD	West 12 kV	Strategic and phased voltage conversion			2030 and Beyond	TBD

Capital Program	Planning Regions	Wire Solutions	Non-Wires Solutions (NWSs)	Capacity Addition (LTR-MVA)	In Service Date	2026-2030 Capital Expenditure
	Nepean 8 kV	Voltage conversion of 8 kV to 28 kV in the long term supported by the new Greenbank station in the South 28 kV region			2030 and Beyond	TBD
	West 8 kV	Voltage conversion of 8 kV to 28 kV in the long term			2030 and Beyond	TBD
	East 8 kV	Voltage conversion of 8 kV to 28 kV in the long term supported by the station upgrades in the East 28 kV stations			2030 and Beyond	TBD
System Expansion	West 28 kV	Additional transformer upgrade at Richmond South MTS to meet load requirements of the Department of National Defence Dwyer Hill Training Center. Upgrade and maintain transformer-level redundancy			2027	$22M
	44 kV	A new 44 kV station (Hydro Road MTS) to cater to a specific need for the OC Transpo's Zero Emission Buses		120	2027	$39M

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d) As all of the projects listed within Table 34 are contained with Table 33, please see response to part (c).

e) As all of the projects listed within Table 35 are contained with Table 33, please see response to part (c).

f) As explained in Section 9.4.1 of Schedule 2-5-4 - Asset Management Process, the Hydro Ottawa Planning forecast assesses station-level load increases based on known load growth information and is updated annually. In comparison, the Integrated Regional Resource Planning (IRRP) forecast, detailed in Section 9.4.2 of Schedule 2-5-4 - Asset Management Process, leveraged the Decarbonization Study's Reference Scenario. Since the Decarbonization Study, dated 2022, utilized 2022 actuals with a forecast starting from 2023, newer load forecast information has been incorporated into the annual update of Hydro Ottawa's Planning forecast, but is not reflected within the IRRP forecast. Due to this difference in data recency, the Planning forecast is higher than the IRRP forecast in some instances.

Specifically, the inclusion of new small commercial and residential developments in the South 28kV system drove the planning forecast above the IRRP forecast.

g) The same general explanation, as described in part f) applies in this case. Specifically, the identification of a new commercial customer in the South-East 28kV system drove the planning forecast above the IRRP forecast.

h) Since the original submission provided on page 301 and illustrated in Figure 113 of Schedule 2-5-4 - Asset Management Process, Hydro Ottawa has received an additional 51 MVA of new inquiries and 35 MVA of newly submitted load summaries. Of the original inquiries, 9 MVA have proceeded to submission of load summary and none have moved to Offer to Connect.

i) Please see Table B for the tabular format for Figure 113 of Schedule 2-5-4 - Asset Management Process.

1 **Table B - Tabular Form of Figure 113 (*All values in MVA*)**

Year	Connected	Signed Offer to Connect	Submitted Load Summary Form	Inquiries
2010	0			
2011	0			
2012	8			
2013	33			
2014	33			
2015	49			
2016	57			
2017	57			
2018	62			
2019	69			
2020	80			
2021	105			
2022	105			
2023	110	0	4	0
2024	110	13.1	5	0
2025	110	13.9	7	10.1
2026	110	47.9	24.9	47.4
2027	110	75.5	29.2	86.2
2028	110	113.2	61.3	91.7
2029	110	113.2	62.4	91.7
2030	110	113.2	71.3	128.2
2031	110	113.2	85.8	128.2
2032	110	113.2	115.8	128.2
2033	110	113.2	116.9	128.2
2034	110	121.5	127.1	130.4
2035	110	130.9	128.2	170.4
2036	110	130.9	128.2	170.4
2037	110	130.9	128.2	170.4
2038	110	132.6	165	170.4
2039	110	132.6	165	170.4
2040	110	132.6	176	176.4

j) The Hydro Ottawa Planning Forecast and the Integrated Regional Resource Planning (IRRP) Forecast are distinct forecasts, each derived through different methodologies, as explained in Section 9.4 of Schedule 2-5-4 - Asset Management Process. These forecasts are also utilized in varied ways to inform Hydro Ottawa's capacity needs assessment, as detailed in Section 9.1 of Schedule 2-5-4 - Asset Management Process.

k) As outlined in Section 9.1 of Schedule 2-5-4 - Asset Management Process, the Hydro Ottawa Planning Forecast was used to assess immediate needs of the system and associated capacity related investments focused on already constrained regions and areas with immediate, confirmed, and committed load requirements. In addition, the IRRP forecast, informed by the Decarbonization Study's Reference Scenario, was used to align investment decisions, for mid to long term, for efficient capital deployment and optimized asset utilization. Please see the interrogatory response 2.5-BOMA-2 part (a) for further details.

i) Since only confirmed and committed load requirements were used to inform the capacity needs, removing large load requests in the preliminary inquiry stage would not alter Hydro Ottawa's capacity expansion-related investments.

ii) As mentioned in part (i) above, removal of large load requests in the preliminary inquiry stage would not alter the investment plans. Six large load projects in the load summary stage are included in the planning forecast and impact five planning regions. Removing the large load requests from the load summary stage would not impact the investment plan for three of the five regions, as these requests constitute only a portion of the forecasted station demand driving the upgrades. For the remaining two regions, the large loads in the load summary stage are: i) The TerraCanada National Capital Area project located at the National Research Council of Canada facilities[1] and ii) The Regulatory and Security Science Main (RSS Main) Project's new laboratory facilities.[2] While these large loads are the primary drivers for the Greenbank MTS and Cyrville

[1] Government of Canada,"Government of Canada announces milestones for new science facilities in National Capital Area"
https://www.canada.ca/en/public-services-procurement/news/2024/07/government-of-canada-announces-milestones-for-new-science-facilities-in-national-capital-area.html
[2] Government of Canada, "Government of Canada invests in laboratories to support science in Canada."
https://www.canada.ca/en/public-services-procurement/news/2024/03/

MTS projects, other system limitations, detailed in Section 2.3.2.1 of Schedule 2-5-8 - System Service Investments, also necessitate a new station in the region. Therefore, their exclusion would not eliminate the need for upgrades entirely but would instead defer the investment. A consequence of this deferral is that Hydro Ottawa would be unable to fulfill its service obligations to customers and deliver power within requested timelines.

iii) Please refer to the interrogatory response 2.5-BOMA-2 part b.

iv) Hydro Ottawa assumes the low decarbonization scenario is referring to the Low Case Sensitivity scenario in the Decarbonization Study. Similar to part (iii) above, since the Low Case Sensitivity scenario was not employed in the capacity needs assessment, its impact on capacity needs and associated capital expenditures cannot be furnished.

v) Similar to part (iii) and (iv) above, since the revenue load forecast was not employed in the capacity needs assessment, its impact on capacity needs and associated capital expenditures cannot be furnished. In addition, revenue load forecast is not used for capacity needs assessment for reasons detailed in Section 9.4.3 of Schedule 2-5-4 - Asset Management Process.

l) Please refer to Section 9.4.2.1 of Schedule 2-5-4 - Asset Management Process. Hydro Ottawa anticipates that the system will shift to a winter peak by 2030. This estimate is based on the Integrated Regional Resource Planning (IRRP) forecast, which leverages the Reference Scenario of the Decarbonization Study. The Planning forecast and the revenue load forecast did not make any assumptions on when the system would become winter peaking.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-18

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 5, pp. 8, 20, 23, 26

QUESTION(S):

a) (P. 8) Please confirm that when a program has changed between the 2021-2025 DSP and the 2026-2030 DSP (e.g., Customer Connections Program was previously three separate programs), the relevant program(s) in the historical period and the forecast period have been presented on the same basis for ease of comparison. As part of the response, please identify any programs that have not been presented in this manner.

b) (P. 20) With respect to the Mer-Bleue MTS, please reconcile the statement that this project resulted in $13.8M of unbudgeted expenditures with the $6.6M shown in Table 16 (Exhibit 2, Tab 1, Schedule 1, p. 25).

c) (P. 20) With respect to the Piperville MTS, please reconcile the statement that this project experienced cost overruns with the information provided for this project in Table 16 (i.e., $14.7M actual cost relative to $24.6M planned cost) (Exhibit 2, Tab 1, Schedule 1, p. 24).

d) (P. 23) Please explain the reason for the difference between the $102M CAPEX variance (between $498M approved and $600M actual) and the $45M ISA variance (between $555M approved and $600M actual). As part of the response, please provide a reference to the 2021-2025 CIR application/settlement/decision where the $555M of approved ISAs can be found.

e) (P. 26) Please reconcile the Fisher AK station and Dagmar station deferred budget amounts discussed at p. 26 to the amounts shown in Table 16 (Exhibit 2, Tab 2, Schedule 1, pp. 23-25).

RESPONSE(S):

a) Confirmed; when a program has changed between the 2021-2025 DSP and the 2026-2030 DSP, the relevant program(s) in the historical period and the forecast period have been presented on the same basis for ease of comparison.

b) The stated reference to Schedule 2-5-5 - Capital Expenditure Plan refers to planned expenditures, whereas the stated reference in Schedule 2-1-1 - Rate Base Overview refers to in-service additions timing. For Mer-Bleue MTS, a $6.9M land purchase was capitalized in 2024 (originally planned at $6.6M in 2025 in-service additions). The remaining project costs incurred during the 2021-2025 period will be capitalized in 2027 when the station is energized.

c) The stated reference to Schedule 2-5-5 - Capital Expenditure Plan refers to planned expenditures, whereas the stated reference in Schedule 2-1-1 - Rate Base Overview refers to in-service additions timing. The statement that the project experienced cost over-runs is with respect to the forecasted capital costs for the project in totality versus the original budget submitted according to the 2021-2025 rate application. The initial project budget, as was submitted in the 2021-2025 application was $24.6M versus the updated budget of $38.7M, hence the statement that the project experienced cost over-runs. The 2024 and 2025 $14.7M of project costs expected to be capitalized are for land purchase and completion of civil construction only and not for the full station energization that was originally planned for 2025, hence the ($9.9M) cost variance. The remaining $24.1M of project costs incurred during the 2021-2025 period will be capitalized in 2026 when the station is energized. Though the project experienced cost overruns, the updated energization timing has resulted in a decrease of in-service additions (formerly expected to energize in 2025, Piperville MTS will now energize in 2026).

d) Hydro Ottawa wishes to note that the CAPEX variance has been revised to $99M, and in-service additions has been revised to $30.4M as per ADMS Timing Update submitted on July 4, 2025. Please refer to Interrogatory 1-Staff-1 for details.

The difference between the $99M capital expenditure variance and the $30.4M in-service additions variance is attributed to project timing, whereby spending on projects has started in 2021-2025, however, the associated in-service additions will not occur until 2026-2030. The concept is generally described in Section 1 of Schedule 2-1-1 - Rate Base Overview

Please refer to Section 4, pages 17-22, in Schedule 2-5-5 -Capital Expenditure Plan for details on the $102M variance (revised to $99M as noted in response to Interrogatory 1-Staff-1) to the OEB-Approved Capital Expenditures. The variances can generally be summarized to the following categories:

- Unprecedented Supply Chain Disruption
- Customer Connections Volume, Complexity, and Cost
- Unforeseen Externally-Driven Projects
- Increased Emergency Renewal Work due to Major Storms and Equipment Failure
- New Stations Investments to Address Growing Electricity Demand

Please refer to Section 3 In-Service Capital Additions Variance in Schedule 2-1-1 - Rate Base Overview for details on the $45M variance (revised to $30.4M as noted in response to Interrogatory 1-Staff-1) to the OEB-Approved Capital Additions. The variances can generally be summarized to the following categories:

- Unprecedented Supply Chain Disruption
- Customer Connections Volume, Complexity, and Cost
- Unforeseen Externally-Driven Projects
- Increased Emergency Renewal Work due to Major Storms and Equipment Failure

The $555M of approved in service additions for the 2021 - 2025 rate application can be found in Section 3.1 of the Decision and Order in EB-2019-0261, dated November 19, 2020. Please see Table A below for the yearly breakdown of the 2021-2025 approved in-service additions.

Table A - 2021-2025 Approved In Service Additions ($'000s)[1]

Year	In Service Additions
2021	$ 152,798
2022	$ 122,471
2023	$ 77,776
2024	$ 82,772
2025	$ 119,235
TOTAL APPROVED IN SERVICE ADDITIONS	**$ 555,052**

e) Hydro Ottawa assumes the reference is Schedule 2-1-1 - Rate Base Overview pages 23-25. The Fisher AK station rebuild was budgeted to incur net capital expenditures of $9.6M during the 2021-2025 period, $9.6M of which were budgeted to capitalize during the 2021-2025 period. As a result of the project deferral and transition to a voltage conversion, actual costs incurred during the 2021-2025 period were $3.9M resulting in a $5.7M deferral of budgeted capital investment. The remaining voltage conversion project costs will occur between 2026 and 2029, with capitalization occurring between 2026 and 2029.

Dagmar station rebuild was budgeted to incur net capital costs of $11.9M during the 2021-2025 period, $6M of which were budgeted to capitalize during the 2021-2025 period. Upon project deferral and transition to a voltage conversion, actual costs incurred during the 2021-2025 period were less than $0.1M resulting in a $11.9M deferral of budgeted capital investment. The full project costs for the voltage conversion are expected to capitalize between 2026-2027 when the project is energized.

[1] As per Hydro Ottawa Limited, 2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement - Attachment - Appendix 2-BA - Fixed Asset Continuity Schedule 2019-2025, EB-2019-0261 (September 18, 2020).

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-19

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 6, pp. 9-10

QUESTION(S):

a) (P. 9) Please explain what “contributed plant” refers to in Table 2. As part of the response, please advise whether contributed plant is considered gross capital (as provided by a third-party) but is also offset in the contributed capital line (i.e., it has a net impact of zero). Please confirm whether this is true for all capital programs (where there are both contributed capital and contributed plant).

b) (P. 9) Please explain why the 2021-2023 period was selected as the relevant basis for the forecast capital contributions during the 2026-2030 period.

c) (P. 9) Please provide the annual gross plant additions and contributed capital for the 2018-2020 period for the plant relocation and upgrades program.

d) (P. 9) Please provide the annual 2021-2025 gross expenditure cost resulting from the average project volumes (excluding discrete projects).

e) (P. 9) Please provide the forecast costs for each of the three planned projects (2026-2030) listed on page 9 and the year that the expenditure is expected to be incurred.

f) (P. 10) Please advise whether any costs associated with upgrades for system improvement are incorporated in the proposed 2026-2030 budget for the plant relocation and upgrade program. As part of the response, please provide the annual cost related to system improvements in the plant relocation and upgrade program for the forecast period (2026-2030) and the historical period (2021-2025).

RESPONSE(S):

a) Contributed Plant refers to "in-kind" contributions or non-cash assets, which are constructed by developers and subsequently transferred to Hydro Ottawa. As these assets are provided without direct cash outlay from the utility, their treatment is distinct from cash contributions and is not directly governed by specific OEB-prescribed contribution rates. Contributed Plant is not considered gross capital; it is only included in the Capital Contributions line. This is true for all capital programs.

b) All System Access Capital Programs forecasted capital contributions and volumes are based on historical averages from 2021-2023 (with the exception of System Expansion Demand where a historical contribution average from 2018-2022 has been applied, reflecting specific characteristics or data availability pertinent to that program). This methodology ensures that forecasted contributions are reasonable and reflective of actual experience of recent and relevant completed projects.

c) Table A provides the annual gross plant additions and contributed capital for the 2018-2020 period for the plant relocation and upgrades program.

Table A – Historical Plant Relocation Gross Additions and Contributed Capital ($'000 000s)

	Historical Years		
	2018	**2019**	**2020**
Plant Relocation & Upgrades - Gross Additions	$ 4.8	$ 8.5	$ 17.8
Contributed Capital	$ (2.4)	$ (4.3)	$ (12.0)
Plant Relocation & Upgrades - Net Additions	**$ 2.4**	**$ 4.2**	**$ 5.7**

d) Table B below provides the annual 2021-2025 gross expenditure cost resulting from the average project volumes (excluding discrete projects).

Table B - Plant Relocation 2021-2025 Gross Expenditure Cost Resulting from Average Projected Volumes (Excluding Discrete projects) ($'000 000s)

	Historical Years			Bridge Years	
	2021	2022	2023	2024	2025
Plant Relocation & Upgrades - Gross Expenditure Cost Resulting from Average Projected Volumes (Excluding Discrete projects)	$ 5.1	$ 4.7	$ 4.0	$ 4.9	$ 5.1

e) As mentioned in Section 2.1 Program Summary of Plant Relocation & Upgrade of Schedule 2-5-6 - System Access Investments, projects are entirely dependent on third-party plans and schedules. However, Hydro Ottawa collaborates with the City of Ottawa to understand their infrastructure plans and develops a Plant Relocation and Upgrade program forecast that aligns with those plans, though it is important to note that those plans regularly change. Of the three listed example projects, Bank Street has progressed to a point where the Hydro Ottawa scope and forecasted capital expenditure is projected (please see Table C below). Please note Prince of Wales Drive and Preston Street projects have not been fully scoped by the City of Ottawa, and therefore the forecasted expenditures and specific timing are unknown.

Table C - Gross Capital Expenditure Forecast of Discrete Projects ($'000 000s)

	Test Years				
	2026	2027	2028	2029	2030
Bank Street	$ 1.6	$ 1.2			

f) Yes, as mentioned in Section 3.1 of Schedule 2-5-1 - Capital Expenditure Plan, the Plant Relocation & Upgrade program aims to improve system efficiency (system improvement). The 2026-2030 program is budgeted based on planned road widening projects outlined in the City of Ottawa's Transportation Master Plan. Where an upgrade or lifecycle improvement yields a benefit or efficiency, Hydro Ottawa will contribute capital towards the relocation project costs.

For more information on the program's process and evaluation of projects, please refer to Section 2 of Schedule 2-5-6 System Access Investments.

Tables D and E below provide historical and forecasted system improvement costs embedded in the Plant Relocation & Upgrade Program.

Table D – Annual Cost Related to System Improvements 2021-2025 ($'000 000s)

	Historical Years				Bridge Year
	2021	2022	2023	2024	2025
Plant Relocation & Upgrades Gross Expenditure - System Improvement	$ 2.9	$ 2.6	$ 2.0	$ 4.4	$ 2.4

Table E – Annual Cost Related to System Improvements 2026-2030 ($'000 000s)

	Test Years				
	2026	2027	2028	2029	2030
Plant Relocation & Upgrades Gross Expenditure - System Improvement	$ 1.4	$ 1.4	$ 1.5	$ 1.5	$ 1.6

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-20

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 6, p. 27

QUESTION(S):

a) (P. 27) Please explain why the 2021-2025 period was selected as the relevant basis for the forecast capital contributions during the 2026-2030 period.
b) (P. 27) Please provide the gross plant additions and contributed capital for the 2018-2020 period for the residential subdivision program.
c) (P. 27) Please explain why the 2021-2023 period was selected to determine the average connection volume underpinning the 2026-2030 forecast.
d) (P. 27) Please provide the 2021-2025 average connection volume for the residential subdivisions program.
e) (P. 27) Please provide details, including the relevant calculations, that show the 2021-2023 average connection volume being escalated by the City of Ottawa's residential development growth for the 2026-2030 period that results in the forecast costs for the residential subdivision program for the forecast period.
f) (P. 27) Please advise whether costs per connection are used as part of the forecasting methodology for the 2026-2030 period in the residential subdivision program. As part of the response, please provide historical (2021-2025) cost per connection and forecast (2026-2030) cost per connection data in tabular format.

RESPONSE(S):

a) Hydro Ottawa would like to correct this by stating that 2021-2025 was not used for forecasting capital contributions during the 2026-2030 period for Residential Subdivision Program. As per Section 3.5.1 Residential Subdivisions, “Contributed capital payments are assumed to remain at 69% of total gross cost in line with the average contribution capital portion of gross costs in the Historical Years.” This methodology ensures that forecasted contributions are reasonable and reflective of actual experience of recent and relevant completed projects.

b) Table A provides the gross plant additions and contributed capital for the 2018-2020 period for the residential subdivision program.

Table A – Historical Residential Subdivision Gross Additions and Contributed Capital ($’000 000s)

	Historical Years		
	2018	**2019**	**2020**
Residential Subdivision - Gross Additions	$ 11.2	$ 16.1	$ 27.9
Contributed Capital	$ (7.0)	$ (8.0)	$ (20.8)
Residential Subdivision - Net Additions	**$ 4.2**	**$ 8.1**	**$ 7.1**

c) System Access Capital Programs base historical volumes on average expenditures from 2021-2023. This methodology ensures that forecasted expenditures are reasonable and reflective of actual experience of recent and relevant completed projects.

d) The average connection volume for residential subdivision developments for the 2021-2025 period is 5,870. In this context, this is the average number of units or homes connected per year within these developments.

e) The 2026-2030 forecasted costs can be calculated by taking the 2021-2023 average gross expenditures (excluding discrete projects) increased by the year over year housing growth projections percentage from Appendix 6 of the City of Ottawa, ”Growth Projects for Ottawa: 2018-2046” as referenced in Section 3.3.1 of Schedule 2-5-6 - System Access Investments. From this base, an average annual increase ranging from 2.1% to 5.0% for the future cost of

equipment and materials was applied. For more detailed information on inflationary pressures, please refer to Section 5 Impacts on Hydro Ottawa 2026-2030 Budget of Schedule 1-2-5 - Impacts of Inflationary Pressures.

f) No, costs per connection are not used as part of the forecasting methodology for the 2026-2030 period in the residential subdivision program. While costs per connection can be analyzed, they are not a reliable measure for forecasting due to the variability and timing of the individual projects that are customer-driven. Historical spending proves to be a more stable approach to capture these varying factors. Please see Table B below for Cost per Connection for 2021-2025 and 2026-2030.

Table B – Residential Subdivision Cost per Connection 2021-2030

	Historical Years				Bridge Year	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential Subdivision Cost Per Connection	$ 1,331	$ 1,268	$ 1,466	$ 1,024	$ 1,286	$ 1,466	$ 1,519	$ 1,597	$ 1,660	$ 1,725

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-21

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 6, pp. 28-29

QUESTION(S):

a) (P. 29) Please explain why the 2021-2025 period was selected as the relevant basis for the forecast capital contributions during the 2026-2030 period.
b) (P. 29) Please provide the gross plant additions and contributed capital for the 2018-2020 period for the commercial developments program.
c) (P. 29) Please explain why the 2021-2023 period was selected to determine the average connection volume (excluding discrete projects) underpinning the 2026-2030 forecast.
d) (P. 29) Please provide the 2021-2025 average connection volume (excluding discrete projects) for the commercial development program.
e) (P. 29) Please provide details, including the relevant calculations, that show the 2021-2023 average connection volume (with discrete projects removed) being escalated by the City of Ottawa's employment growth projection for the 2026-2030 period that results in the forecast costs for the commercial development program for the forecast period.
f) (P. 29) Please advise whether costs per connection are used as part of the forecasting methodology for the 2026-2030 period in the commercial development program. As part of the response, please provide historical (2021-2025) cost per connection and forecast (2026-2030) cost per connection data in tabular format.

RESPONSE(S):

a) Hydro Ottawa would like to correct this by stating that 2021-2025 was not used for forecasting capital contributions during the 2026-2030 period for Commercial Developments Program. As per Section 3.5.2 of Schedule 2-5-6 - System Access Investments, “Annual contributed capital payments are assumed to remain at 64% of gross cost, in line with the average contribution capital proportion of gross costs in the Historical Years.” This methodology ensures that forecasted contributions are reasonable and reflective of actual experience of recent and relevant completed projects.

b) Table A provides the gross plant additions and contributed capital for the 2018-2020 period for the commercial development program.

Table A – Historical Commercial Development Gross Additions and Contributed Capital ($’000 000s)

	Historical Years		
	2018	**2019**	**2020**
Commercial Developments - Gross Additions	$ 19.4	$ 11.0	$ 10.9
Contributed Capital	$ (11.0)	$ (6.1)	$ (8.2)
Commercial Developments - Net Additions	**$ 8.4**	**$ 4.8**	**$ 2.7**

c) System Access Capital Programs base historical volumes on average expenditures from 2021-2023. This methodology ensures that forecasted contributions are reasonable and reflective of actual experience of recent and relevant completed projects.

d) The average connection volume for commercial developments for the 2021-2025 period is 144. In this context, one unit refers to one commercial service/account or metered service per project.

e) The 2026-2030 forecasted costs can be calculated by taking the 2021-2023 average gross expenditures (excluding discrete projects) increased by the year over year employment growth

projection percentage from Appendix 6 of the City of Ottawa, "Growth Projects for Ottawa: 2018-2046"[1] as shown in Section 3.5.2 of Schedule 2-5-6 - System Access Investments. From this base, an average annual increase ranging from 2.1% to 5.0% for the future cost of equipment and materials was applied. For more detailed information on inflationary pressures, please refer to Section 5 Impacts on Hydro Ottawa 2026-2030 Budget of Schedule 1-2-5 - Impacts of Inflationary Pressures.

f) No, costs per connection are not used as part of the forecasting methodology for the 2026-2030 period in the commercial development program. While costs per connection can be analyzed, they are not a reliable measure for forecasting due to the variability and timing of the individual projects that are customer-driven. Historical spending proves to be a more stable approach to capture these varying factors. Please see Table B for Cost per Connection for 2021-2025 and 2026-2030. It should be noted that specific customer projects with unique requirements can cause year over year fluctuations.

Table B – New Commercial Development Cost per Connection 2021-2030

	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
New Commercial Development Cost per Connection	$ 30,671	$ 36,242	$ 37,942	$ 29,020	$ 38,742	$ 39,113	$ 79,659	$ 64,261	$ 57,946	$ 64,505

[1] City of Ottawa, *Growth Projections for the New Official Plan, Methods and Assumptions for Population, Housing and Employment 2018 to 2016 - Appendix 6 - Household, Dwelling and Employment Details, Medium Scenario*, (November 2019), page 46.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-22

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 6, pp. 30-31

QUESTION(S):

a) (P. 31) Please provide the gross plant additions and contributed capital for the 2018-2020 period for the infill services program.

b) (P. 31) Please explain why the 2021-2023 period was selected as the relevant basis for the forecast capital contributions during the 2026-2030 period.

c) (P. 31) Please explain why the 2021-2023 period was selected to determine the average connection volume underpinning the 2026-2030 forecast.

d) (P. 31) Please provide the 2021-2025 average connection volume for the infill services program.

e) (P. 31) Please provide details, including the relevant calculations, that show the 2021-2023 average connection volume being escalated by the City of Ottawa's residential development growth forecast for the 2026-2030 period that results in the forecast costs for the infill services program for the forecast period.

f) (P. 31) Please advise whether costs per connection are used as part of the forecasting methodology for the 2026-2030 period in the residential infill program. As part of the response, please provide historical (2021-2025) cost per connection and forecast (2026-2030) cost per connection data in tabular format.

RESPONSE(S):

a) Table A provides the annual gross plant additions and contributed capital for the 2018-2020 period for the infill services program.

Table A – Historical Infill Services Gross Additions and Contributed Capital ($'000 000s)

	Historical Years		
	2018	**2019**	**2020**
Infill Services - Gross Additions	$ 2.9	$ 2.5	$ 1.7
Contributed Capital	$ (1.8)	$ (1.8)	$ (1.3)
Infill Services - Net Additions	**$ 1.2**	**$ 0.7**	**$ 0.4**

b) All System Access Capital Programs forecasted capital contributions and volumes are based on historical averages from 2021-2023 (with the exception of System Expansion Demand where a historical contribution average from 2018-2022 has been applied, reflecting specific characteristics or data availability pertinent to that program). This methodology ensures that forecasted contributions are reasonable and reflective of actual experience of recent and relevant completed projects

c) System Access Capital Programs base historical volumes on average expenditures from 2021-2023. This methodology ensures that forecasted expenditures are reasonable and reflective of actual experience of recent and relevant completed projects.

d) The average connection volume for infill developments for the 2021-2025 period is 3,629, In this context, one unit means one service (e.g. rural or urban) installed which was not part of a pre-planned subdivision development.

e) The 2026-2030 forecasted costs can be calculated by taking the 2021-2023 average gross expenditures increased by the year over year housing growth projections percentage from

Appendix 6 of the City of Ottawa, "Growth Projects for Ottawa: 2018-2046"[1] as shown in Section 3.5.3 of Schedule 2-5-6 - System Access Investments. From this base, an average annual increase ranging from 2.1% to 5.0% for the future cost of equipment and materials was applied. For more detailed information on inflationary pressures, please refer to Section 5 Impacts on Hydro Ottawa 2026-2030 Budget of Schedule 1-2-5 - Impacts of Inflationary Pressures.

f) No, costs per connection are not used as part of the forecasting methodology for the 2026-2030 period in the residential infill program. While costs per connection can be analyzed, they are not a reliable measure for forecasting due to the variability and timing of the individual projects that are customer driven. Historical spending proves to be a more stable approach to capture these varying factors. Please see Table B below for Cost per Connection for 2021-2025 and 2026-2030. It should be noted that specific customer projects with unique requirements can cause year over year fluctuations.

Table B – Residential Infill Cost Per Connection 2021-2030

	Historical Years				Bridge Years	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Infill Cost per Connection	$ 187	$ 88	$ 274	$ 212	$ 178	$ 143	$ 147	$ 166	$ 168	$ 172

[1] City of Ottawa, *Growth Projections for the New Official Plan, Methods and Assumptions for Population, Housing and Employment 2018 to 2016 - Appendix 6 - Household, Dwelling and Employment Details, Medium Scenario*, (November 2019), page 46.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-23

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 6, pp. 52-53

QUESTION(S):

a) (P. 53) Please provide a table showing the 2018-2022 gross and contributed capital for the system expansion program that reconciles to the 64% of gross cost capital contribution proportion discussed on page 53. As part of the response, please also explain why the 2018-2022 period was selected as the relevant basis for the forecast capital contributions during the 2026-2030 period.

b) (P. 53) Please explain why the 2021-2023 period was selected to determine the average volume (excluding discrete large load requests) underpinning the 2026-2030 forecast.

c) (P. 53) Please provide the 2021-2025 average volume (excluding discrete large load requests) for the system expansion program.

d) (P. 53) Please provide details, including the relevant calculations, that show the 2021-2023 average volume (excluding discrete large load requests) escalated by the observed increase in complexity/scale and the addition of the discrete large load requests that results in the forecast costs for the system expansion program for the forecast period.

e) (P. 53) Please provide the forecast costs for each of the three discrete projects listed on page 53 and the year that the expenditure is expected to be incurred.

RESPONSE(S):

a) Table A below provides the annual gross direct costs and contributed capital for the 2018-2022 period for the System Expansion program that reconciles to the 64% of gross cost capital

contribution proportion. This timeframe (2018-2022) was chosen given the specific characteristics and data availability pertinent to the program, whereby System Expansion has a smaller data set and requires additional years for validity, and 2023 was deemed invalid due to the limited size of available reference projects.

Table A – Historical System Expansion Direct Costs and Contributed Capital ($'000 000s)

	Historical Years					Average
	2018	2019	2020	2021	2022	2018-2022
System Expansion (Excluding Discrete Projects) - Gross	$ 4.3	$ 0.9	$ 0.9	$ 1.5	$ 0.7	
Contributed Capital (Excluding Discrete Projects)	$ (0.1)	$ (1.0)	$ (0.5)	$ (1.3)	$ (0.5)	
Contribution Rate	3%	108%	50%	83%	76%	64%

b) All System Access Capital Programs base historical volumes on average expenditures from 2021-2023. This methodology ensures that forecasted expenditures are reasonable and reflective of actual experience of recent and relevant completed projects.

c) The average number of in-flight, multi-year system expansion projects per year for 2021-2025 is 17. The projects are in various stages of completion, which is accounted for in the average.

d) The 2026-2030 forecasted costs can be calculated by taking the 2021-2023 average gross expenditures (excluding discrete projects) increased by 25% to address project complexity and scale. From this base, an average annual increase ranging from 2.1% to 5.0% for the future cost of equipment and materials was applied. For more detailed information on inflationary pressures, please refer to Section 5 Impacts on Hydro Ottawa 2026-2030 Budget of Schedule 1-2-5 - Impacts of Inflationary Pressures.

e) Table B below provides the net forecast costs for each of the three discrete projects listed on page 53 and the year that the expenditure is expected to be incurred.

Table B- Net Capital Expenditure Forecast of Discrete Projects ($'000 000s)

	Historical Years				Bridge Years	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hydro Road	-	-	$ 0.1	$ 3.1	$ 6.0	$ 15.9	$ 9.1	-	-	-
Richmond South	-	-	-	$ 4.7	$ 9.4	$ 6.9	$ 1.0	-	-	-
Feeder Expansions	-	-	$ 0.2	$ 0.1	-	-	-	-	$ 11.4	-

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-24

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 7, pp. 28-29, 34, 37

QUESTION(S):

a) (PP. 28-29) Please provide a single table that shows the 2021-2030 costs shown in Table 3 and the number of assets replaced as shown in Table 4. Please also provide a row showing the related unit costs per asset replacement.
b) (PP. 28-29) Please advise whether any of the replacements shown in Table 4 are covered by the budget for the EOL Voltage Conversion program (or is it only the removals that are covered).
c) (P. 34) Please provide a table that further disaggregates the EOL Voltage Conversion program by project (i.e., Fisher, Dagmar, etc.) for both the historical and forecast period. As part of the table, please provide as much detail as possible with respect to the components of each project.

RESPONSE(S):

a) Specific to Schedule 2-5-7, Table 3 and Table 4, please find the requested consolidated information showing the historical, bridge and test year expenditures, unit counts and unit costs per station asset renewal budget in Table A. Hydro Ottawa notes an error on Page 29, Table 4 of Schedule 2-5-7: the Station Switchgear (Replacement) units for 2029 and 2030 should be ”-” and “21” respectively, not "14" and “14”, as noted in Hydro Ottawa’s response to 2-Staff-90.

Table A - Historical, Bridge, and Test Year Expenditures, Unit Count and Unit Costs per OH Distribution Asset Renewal Budget

Budget Program	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Station Transformer Renewal ($'000 000s)	$1.20	$0.60	$0.70	$0.60	$0.10	$0.20	$0.80	-	-	-
Station Transformers (Replacement)	-	2	3	-	-	-	1	-	-	-
Station Switchgear Renewal ($'000 000s)	$3.50	$2.20	$1.40	$0.40	-	$6.00	$7.00	$0.60	$0.60	$9.30
Station Switchgear (Replacement)	10	18	8	2	-	7	8	2	-	21
Station Switchgear Unit Replacement Cost	$197,000					$620,000				
Station Battery Renewal ($'000 000s)	$0.00	$0.00	$0.00	$0.10	$0.10	$0.20	$0.10	$0.10	$0.10	$0.20
Station Batteries (Replacement)	-	2	2	2	3	3	2	2	2	2
Station Batteries Unit Replacement Cost	$60,000					$73,000				
Station P&C Renewal ($'000 000s)	$1.00	$1.10	$0.10	$0.20	-	$2.40	$2.30	$2.10	$1.00	$1.00
Station Relays (Replacement)	-	28	-	7	4	35	55	55	-	-
Station Relays Unit Replacement Cost	$25,000					$28,000				
Station RTUs (Replacement)	-	-	-	-	2	1	1	1	-	-
Station RTUs Unit Replacement Cost	$1,000,000					$1,100,000				
Transfer Trip Unit	-	-	-	-	-	1	1	-	-	-
Transfer Trip	N/A					$700,000				
Station and Building Minor Assets Renewal ($'000 000s)	$0.40	$0.70	$1.10	$0.60	$0.40	$2.00	$1.90	$1.90	$1.90	$1.70
Station Major Rebuild ($'000 000s)	$2.60	$6.40	$1.60	$0.50	$0.10	-	-	-	-	-
EOL Voltage Conversion ($'000 000s)	$0.40	$1.00	$0.50	$1.80	-	$14.70	$11.20	$12.20	$14.30	$11.90

Budget Program	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Station Transformers (Removed through EOL Voltage Conversion)	-	-	-	-	-	3	-	3	2	2
Station Switchgear (Removed through EOL Voltage Conversion)	-	-	-	-	-	13	4	7	8	6
Station Batteries (Removed through EOL Voltage Conversion)	-	-	-	-	-	1	-	-	1	1
Station Relays (Removed through EOL Voltage Conversion)	-	-	-	-	-	39	-	-	38	30
Station RTUs (Removed through EOL Voltage Conversion)	-	-	-	-	-	1	-	-	1	1

b) Only removals from Table 4 are covered in the EOL Voltage Conversion Program.

c) Hydro Ottawa had initiated the EOL voltage conversion projects at Fisher AK and Dagmar AC through 2021-2025, mainly scoping out the voltage conversion plans and completing select pole renewal jobs on the distribution side, as shown in Table B below.

Table B - Scope and Cost for EOL Voltage Conversion Projects (2021-2025) ($000 000s)

Station	Scope	
Fisher AK	Completion of four pole renewal projects required for voltage conversion	$ 3.6
Dagmar AC	Initiation of phase 1 of voltage conversion involving pole renewal projects	$ 0.1

The majority of the completion of EOL voltage conversion activities at these stations and Henderson UN, Vaughan UG and Church AA is scheduled for 2026-2030. Please refer to part (a) of Hydro Ottawa's response to interrogatory 2-Staff-91 for more information on the 2026-2030 plans.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-25

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 7, pp. 67, 70-73

QUESTION(S):

a) (P. 67) Please provide a single table that shows the 2021-2030 costs shown in Table 9 and the number of assets replaced as shown in Table 10. Please also provide a row showing the related unit costs per asset replacement.
b) (P. 70) Please provide the cost associated with the system observability investments in each of the three alternatives.
c) (P. 71) Please explain whether pole refurbishment (e.g., pole reinforcement) was considered as part of Hydro Ottawa's overhead renewal program. If yes, please provide details of that analysis. If no, please explain why not.
d) (PP. 70, 72) Please advise whether the entire $1.6M incremental resilience investment is related to the undergrounding of 30 poles.

RESPONSE(S):

a) Specific to Schedule 2-5-7, Table 9 and Table 10, please find the requested consolidated information showing the historical, bridget and test year expenditures, unit counts and unit costs per OH distribution asset renewal budget in Table A below.

Table A - Historical, Bridge, and Test Year Expenditures, Unit Count and Unit Costs per OH Distribution Asset Renewal Budget

Budget Program	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Pole Renewal ($'000 000s)	$9.10	$8.20	$8.80	$7.30	$8.80	$11.30	$11.30	$11.80	$12.30	$12.50
Number of Poles	370	419	283	330	330	395	395	395	395	395
Number of OH Transformers	85	54	46	62	62	80	80	80	80	80
Unit Cost	Pole: $24,000					Pole: $27,500 Undergrounding: $60,000				
OH Switch / Recloser Renewal ($'000 000s)	$0.20	$0.60	-	$0.10	-	$1.60	$1.70	$1.70	$1.80	$1.80
Number of OH Switches/Reclosers	-	43	-	13	-	68	68	68	68	68
Unit Cost (OH Switches/Reclosers)	Manual Switches: $ 10,000					Manual Switches: $10,000 SCADAmates: $128,000				

b) Table B shows a summary of the system observability investments between the three alternatives considered.

Table B - Summary of System Observability Investments Considered

Program Investments	Alternative 1: Cost Containment	Alternative 2: Short Term Risk Mitigation	Alternative 3: Long Term Risk Mitigation (Preferred)
System Observability Investments	Minor (2/year)	Medium (4/year)	Highest (8/year)
SYSTEM OBSERVABILITY INVESTMENT COST	**$1,280,000**	**$2,560,000**	**$5,120,000**

c) No, pole refurbishment is not a part of Hydro Ottawa's overhead renewal program. The strategy for pole degradation is focused on replacement and upgrades, which allows for resilience improvements to be built into the design of the new infrastructure. While rehabilitation is considered for other overhead assets (e.g., switches, reclosers) based on specific requirements

(as noted in Table 14 of Schedule 2-5-5 - Capital Expenditure Plan), the replacement-focused approach for poles is driven by a risk assessment where reliability is the primary consideration (as noted on page 68, Section 2.3.3 of Schedule 2-5-1 - Distribution System Plan Overview).

d) Hydro Ottawa notes an error on Page 70, Table 11 of Schedule 2-5-7: the incremental resilience investments should be “$1.8M/year”, not "$1.6M/year." Yes, the entire $1.8M incremental resilience investment estimate per year is related to the undergrounding of 30 poles (one lateral line). However, Hydro Ottawa is currently defining the specific annual project scopes for the strategic lateral undergrounding exercise, while also evaluating other options such as line relocation and fortification of critical overhead sections. More information regarding the cost assumptions is provided in Hydro Ottawa’s response to interrogatory 2-Staff-94.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-26

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 7, pp. 104-106

QUESTION(S):

a) (P. 104) Please provide a single table that shows the 2021-2030 costs shown in Table 15 and the number of assets replaced as shown in Table 16. Please also provide a row showing the related unit costs per asset replacement. If Hydro Ottawa is unable to breakout the cable and transformer replacements (as the UG transformers do not have a distinct budget), please further explain why no budget can be estimated.

b) (P. 105) Please provide a detailed calculation (including all assumptions) that shows how Hydro Ottawa estimated the $1.4M/km cost for the 2026-2030 budget.

c) (P. 105) Please explain whether cable refurbishment (e.g., cable injection) was considered as part of Hydro Ottawa's underground renewal program. If yes, please provide details of that analysis. If not, please explain why not.

d) (P. 106) Please advise whether the forecast 2026-2030 vault renewal budget includes any customer-owned vaults. If so, please provide the number of customer-owned vaults where renewal work will be completed and provide an update on the discussions with those customers.

e) (P. 108) Please provide the cost associated with the system observability investments in each of the three alternatives.

RESPONSE(S):

a) Referring to Schedule 2-5-7, Table 15 and Table 16, please find Table A below showing the related unit costs per for UG asset replacement program.

Table A - Historical, Bridge, and Test Year Expenditures, unit costs per for UG Distribution Asset Renewal Budget

Budget Program	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
UG Transformer Renewal ($000 000s)	-	$ 0.1	$ 0.5	-	-	-	-	-	-	-
Number of UG Transformers Replaced	94	62	60	72	72	80	80	80	80	80
UG Switchgear Renewal ($000 000s)	$ (0.1)	$ 0.8	-	$ 0.5	$ 0.8	$ 1.0	$ 1.0	$ 1.1	$ 1.1	$ 1.2
Number of UG Switchgear Replaced	-	6	-	4	5	6	6	6	6	6
UG Switchgear Unit Replacement Cost	Manual Switches: $133,000					Manual Switches: $163,000 Motorized: $218,000				
Cable Renewal ($000 000s)	$ 9.7	$ 15.4	$ 10.4	$ 9.1	$ 9.8	$ 16.4	$ 16.9	$ 17.7	$ 18.2	$ 18.8
Cable Replaced (km)	19.86	20.24	6.89	13.5	13.5	12.28	12.28	12.28	12.28	12.28
Cable Replacement Unit Cost (per km)	$735,000					$1,400,000				
Civil Renewal ($000 000s)	$ 0.5	$ 1.1	$ 1.0	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.2	$ 1.2	$ 1.3
Number of Cable Chambers Replaced	1	6	4	6	6	6	6	6	6	6
Cable Chamber Unit Replacement Cost	$185,000					$197,000				
Vault Renewal ($000 000s)	-	$ 0.5	-	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 1.2	$ 0.6
Number of Vault Transformers Replaced	-	6	-	7	5	18	18	18	18	18
Number of Vault Switchgear Replaced	-	-	-	-	-	6	6	6	6	6
Vault Equipment Unit Replacement Cost	$83,000					$117,000 per 3-phase bank				

Please note that between 2021 and 2025, the replacement of underground (UG) transformers was included as part of the cable renewal program, and therefore, a separate unit cost was not specified. An exception was a single project in 2022-2023, which required the replacement of three kiosk transformers with padmount transformers and associated cables. Table 16 of Schedule 2-5-7 - System Renewal Investments indicates that from 2026-2030, UG transformers are also scheduled for replacement as part of the cable renewal program.

b) Cable Renewal Program: Assumptions for Increased Forecast (2026-2030)

- **Increased Project Complexity and Costs:** Actual costs from 2021-2023 averaged $0.7M per kilometer, with some projects, particularly those involving civil works in the technically complex Ottawa region, reaching $1M per kilometer. This higher rate is assumed to become more common. The 2026-2030 unit rate explicitly accounts for an increase in these specific costs with an embedded risk factor.
- **General Annual Rate Increases:** The unit rate incorporates a year-over-year increase for labor, fleet, and burden rates, applied in accordance with Hydro Ottawa's Capitalization Policy (Schedule 2-6-1).
- **Equipment and Material Inflation:** An average annual increase ranging from 2.1% to 5.0% has been included for the future cost of equipment and materials. For more detailed information on inflationary pressures, please refer to Section 5 Impacts on Hydro Ottawa 2026-2030 Budget in Schedule 1-2-5 - Impacts of Inflationary Pressures.

c) Hydro Ottawa does not consider cable injection as part of the underground cable renewal strategy. For more details, refer to part (a)(i) of the response to interrogatory 2-Staff-104. Hydro Ottawa's cable renewal program addresses cable degradation primarily through replacement. However, the strategy also includes cost-effective refurbishment, such as replacing cable accessories, to extend the life of underground assets, as outlined in Section 2.3.2 of Schedule 2-5-1 - Distribution System Plan Overview.

d) Yes, the 2026-2030 forecast for the vault renewal budget includes customer-owned assets (mainly vault switchgear) in response to the growing risks associated with customer-owned vault equipment. The program aims to address 90 vault transformers and 11 vault switchgear units

owned by Hydro Ottawa, with select customer-owned vault switchgear also to be identified and addressed (in shared vaults) during this period, as specified in Section 4.5.3 of Schedule 2-5-7 - System Renewal Investments.

The final number of customer-owned vaults where renewal work is to be undertaken is not available at this time and will be defined each year as a part of the capital investment planning optimization process. To clarify, the project-level investment planning process involves an annual assessment to refine and optimize the selection of individual projects. This multi-step process uses Copperleaf as the investment optimization software to prioritize projects based on their value, as discussed in Section 5.3.2 Project Level Investment Planning in Schedule 2-5-4 - Asset Management Process. Furthermore, the planned replacement of customer-owned vault switchgear causing a significant reliability impact to Hydro Ottawa, will be contingent on a final agreement with the related customer and this is still in progress.

e) The system observability spending as a part of the UG distribution asset renewal program is shown in Table B.

Table B - Summary of System Observability Spending in the UG Distribution Asset Renewal Alternatives Considered

Program Investments	Alternative 1: Cost Containment	Alternative 2: Short Term Risk Mitigation (Preferred)	Alternative 3: Long Term Risk Mitigation
System Observability Investments	None	10 (2/ year)	20 (4/ year)
TOTAL SYSTEM OBSERVABILITY COST	**None**	**$2,180,000**	**$4,360,000**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-27

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 7, pp. 138-140, 145

QUESTION(S):

a) (P. 138) Please provide a single table that shows the 2021-2030 capital costs shown in Table 21 and the number of meters replaced as shown in Table 22. Please also provide a row showing the related unit costs per asset replacement. As part of the response, please discuss what appears to be very significant unit cost variances year-over-year.
b) (P. 138) Please explain how the derecognition costs in Table 21 were calculated.
c) (P. 140) Please discuss the implications phasing the meter replacement program over a longer period of time. For example, instead of phasing the replacements over 10 years, the meters would be replaced over 15 years. As part of the response, please provide the costs for the 2026-2030 period of a 15-year replacement cycle.
d) (P. 145) With respect to the meter seal expiry dates, please discuss whether Hydro Ottawa's proposed pacing of meter replacement will result in meter replacements in advance of the seal expiry date.
e) (P. 145) Please discuss whether Hydro Ottawa considered meter re-verification/re-sealing as an alternative to replacement. If so, please explain why this approach is not being pursued. As part of the response, please discuss the cost differential between replacement and re-verification/re-sealing.

RESPONSE(S):

a) Please see Table A below, which shows the 2021-2030 capital costs shown in Table 21 and the number of meters replaced as shown in Table 22 in Schedule 2-5-7 - System Renewal Investments. Table A also includes a row showing the related unit costs per asset replacement.

Table A - Unit Cost of Meters ($'000 000s)

Budget Program	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Metering Upgrades ($'000 000s)	$1.5	$0.3	$1.3	$4.6	$4.1	$15.4	$14.6	$16.2	$19.3	$20.9
Metering Replacements	408	1,488	3,764	2,912	1,377	11,000	29,300	32,950	40,250	47,500
Unit Cost	**$3,676**	**$202**	**$345**	**$1,580**	**$2,977**	**$1,400**	**$498**	**$492**	**$480**	**$440**

The unit cost of meter replacements shows significant year-over-year variances due to the differing nature and scale of the metering programs in each period.

- **2021-2023 Period:** In 2021, the unit cost was higher ($3,676) due to a focus on complex projects. These projects, like the 2.5 to 3.0 element metering upgrades, required specialized equipment, including commercial meters with external communication cards, instrument transformers, and cellular modems, as well as more labour for installation. This program was undertaken to ensure Hydro Ottawa's compliance with Measurement Canada's policy *E-24-Policy on approval and use of 2.5 element metering* by upgrading metering to 3.0 elements. Similarly, the transformer-rated communication upgrade program required commercial meters with an external modem to eliminate meters with phone lines.

  The lower costs in 2022 and 2023 were a result of executing simpler programs that used less expensive residential meters and required less time to install.

- **2024-2030 Period:** The unit costs during the Bridge and Test years differ, as these numbers are forecasts based on program-level averages and not actual costs. For the first year of the

new rate, they also include preparatory work needed for AMI 2.0, and the unit cost stabilizes as the implementation continues.

b) The derecognition costs were calculated by taking the remaining average net book value (NBV) per unit of Hydro Ottawa's meter population for each year from 2026-2030 and multiplying by the number of meters forecasted to be replaced under the AMI 2.0 project in each year from 2026-2030.

c) Phasing the meter replacement program over a longer period, such as 15 years instead of the planned 10 years, would have significant implications for Hydro Ottawa, primarily due to the current state of its metering fleet and the rapid evolution of technology as further outlined below.

Currently, 81% of Hydro Ottawa's metering fleet is projected to reach or exceed its Total Useful Life (TUL) of 15 years by 2030, as detailed in Section 5.5.1 of Schedule 2-5-7 - System Renewal Investments. Extending the replacement cycle to 15 years would further exacerbate this issue.

This scenario presents implications similar to the "run to failure" alternative discussed in Hydro Ottawa's application (Section 5.6.2 of Schedule 2-5-7 - System Renewal Investment). The key implications include:

- Deterioration of Service Reliability and Quality;
- Increased Operations and Maintenance (O&M) Costs;
- Compromised Grid Modernization and AMI 2.0 Functionality;
- Heightened Technological Obsolescence Risk; and
- Safety Concerns.

Hydro Ottawa acknowledges the request for the specific costs for the 2026-2030 period under a 15-year replacement cycle. However, consistent with its implementation plan outlined in its application (Section 5.7.1 of Schedule 2-5-7 - System Renewal Investments), Hydro Ottawa's proposed investment plan focuses on a 10-year phased renewal to mitigate the risks associated with an aging fleet and functional obsolescence.

d) Yes, Hydro Ottawa's proposed pacing of meter replacement may result in some meter replacements in advance of the seal expiry date if the benefit is present (refer to Section 5.7.1 of Schedule 2-5-7 - System Renewal Investments). The plan highlights that the meter replacement prioritization will be based on a multi-faceted approach that considers meter age, meter seal date, meter location, critical meters, grid modernization initiatives and customer density (refer to Section 5.7.1 of Schedule 2-5-7 - System Renewal Investments).

e) Yes, Hydro Ottawa did consider meter re-verification and re-sealing as an alternative to replacement. This approach is not being pursued as the primary strategy because:

- It is a core component of the "Run to Failure" alternative, which is not the preferred approach (refer to Section 5.6.1 of Schedule 2-5-7 - System Renewal Investments).
- The re-verification and re-sealing alternative does not account for technology obsolescence.
- Measurement Canada's S-S-06 program, which governs re-verification, does not account for functional or technological obsolescence, the primary driver for the Meter Renewal program.
- The re-sealing process shortens the re-verification period for sampled meters over time.
- Delaying the renewal program risks a more aggressive, capital-intensive replacement program being required in the future to maintain compliance.

While a specific cost differential is not provided, the "Run to Failure" approach is viewed as less financially sustainable. The preferred phased replacement strategy is designed to balance long-term investment with customer affordability, thereby avoiding a future burden of a capital-intensive program.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-28

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 7, pp. 149, 160-163

QUESTION(S):

a) (P. 149) With respect to the various asset types that are covered by Hydro Ottawa's proactive renewal programs and are also replaced reactively, please provide a table, using historical actuals (2021-2023 or 2021-2024 if available), that compares the average unit costs of reactive vs. proactive replacement.

b) (P. 160, 163) Please provide more specific details regarding the methodology applied to forecast the 2026-2030 corrective renewal program. As part of the response, please provide the calculation showing the use of historical actuals (including the years used) and the normalization of the impact of the 2022 Derecho storm. Please also discuss how reactive pole and UG transformer costs were forecast (as it appears that historical actuals were not the basis for forecasting costs for the reactive replacement of these assets).

RESPONSE(S):

a) Table A shows a comparison between the proactive and reactive replacement costs per asset type (based on 2021-2024 actuals).

Table A - Proactive and Reactive Asset Replacement Costs (based on 2021-2024 actuals)

Asset Type	Proactive Replacement Average		Reactive Replacement Average	
	Cost	Scope	Cost	Scope
Station Transformer	Not Applicable	- Engineering design & coordination - Civil containment - Cost is transformer capacity dependent	Not Applicable	- Excludes engineering design - Sub component like for like replacement (such as bushings/tap changers)
Station Switchgear	$197,000	- Engineering design & coordination - Building additions or modifications - Equipment inclusions are switchgear cell, complete with breaker, bus, and low voltage cabinet	$74,116	- Excludes engineering design - Like for like replacement of sub-components within a cell up to maximum of one (1) breaker
Station P&C/Relays	$25,000	- Engineering design & coordination (includes low voltage cell and cabinet redesign) - Wiring upgrades and relay replacement, typically with net new relay cabinets	$22,057	- Excludes engineering design - Like for like and in-situ relay replacement in an existing cabinet
Station Batteries	$60,000	- Engineering design & coordination - Material includes low voltage panel, disconnect, chargers, and battery	$46,142	- Excludes engineering design - Like for like replacement of typically one of chargers or batteries
Poles	$24,000	- Design & coordination - Municipal consent/pre-emptive road cut permit - Pole hole, anchors, pole/framing and accessories	$26,206	- Excludes design - Pole hole, anchors, pole/framing and accessories - Post installation road cut

Asset Type	Proactive Replacement Average		Reactive Replacement Average	
	Cost	Scope	Cost	Scope
Overhead Switches	$10,000	- Design - Manual switch replacement	$10,645	- Excludes design - Like for like manual switch
Overhead Transformers	None (covered under pole renewal)	N/A	$14,070	- No design - Like for like overhead transformer
Underground Transformers	None (covered under cable renewal)	N/A	$44,911	- No design - Like for like underground transformer
Underground Switchgear	$133,000	- Design & coordination - Municipal consent/road cut permit - Civil construction/base - Switchgear replacement	$70,904	- Excludes design - Excludes civil replacement - Like for like switchgear replacement - Post installation road cut
Underground XLPE Cables (per km)	$735,000	- Design & coordination - Municipal consent/road cut permit - Civil works including net new ductbank where applicable - Cable installation, inclusive of underground transformer replacement	$738,928	- Excludes design - Like for like civil - Like for like cable replacement - Excludes transformer replacement - Post installation road cut
Cable Chambers	$185,000	- Design & coordination - Municipal consent/road cut permit - Civil works including net new ductbank connections where applicable - Cable transfer where applicable	Not Applicable	- Excludes design - Scope includes roof or collar rebuilds
Vault Transformers	$83,000	- Design & coordination - Vault transformer replacement	Not Applicable	- Excludes design - Sub component like for like replacement

b) Table 29 under Schedule 2-5-7: System Renewal Investments shows the Corrective Renewal Historical, Bridge and Future Spending Overview. The budgeting approach for the 2026-2030 corrective renewal program (excluding poles and UG transformers) is discussed in Section 6.6.1: Alternatives Considered (Page 163) under Schedule 2-5-7: System Renewal Investments and was based on historical spending (2021-2025) exclusive of once in 50 year events such as the Derecho.

The methodology applied to forecast the number of poles to be replaced under corrective renewal between 2026-2030 is shown in Hydro Ottawa's response to 2-Staff-62 part a) multiplied by the per unit reactive replacement costs of replacing poles as shown in Table A.

Hydro Ottawa notes an error on Page 163, line 6 of Schedule 2-5-7: the number of UG transformers planned for replacement under emergency renewal should be "65 UG transformers," not "40 UG transformers." Hydro Ottawa's corrective renewal program for UG transformers proposes annual replacements of 75 units (emergency and critical renewal) from 2026 to 2030. The quantity of 75 transformers is derived by multiplying Annual Probability of Failure (PoF) value by 1,428 transformers, the number of underground transformers with a health index (HI) value below 65%. The cost of this initiative is calculated by multiplying the number of proposed replacements by the per-unit reactive replacement cost of UG transformers, as detailed in Table A. Further information on this initiative can be found in Section 6.6.1 (Page 163) of Schedule 2-5-7: System Renewal Investments. More context surrounding UG transformer corrective renewal is provided below.

The cause for emergency/critical UG transformer replacements between 2021-2024 is based on the underlying condition-related causes shown in Table B below.

Table B - UG Transformer Replacement - Condition-Related Causes (2021-2024)

Corrective Renewal Failure Cause (Condition Related)	Number of Transformers Replaced (Total)
Electrical Failure	49
Mechanical Failure	31
Oil Leak	256
Safety	3
Thermal	2
Other	1
TOTAL	**342**

Oil leak is the leading cause of corrective renewal replacements for UG transformers, accounting for 75% of such replacements, as shown in Table B above. Hydro Ottawa's UG transformer inspection program primarily gathers visual inspection data, which is then used for condition assessment. Further details on Hydro Ottawa's Asset Condition Assessment (ACA) process can be found in Section 5.1.2.1 Asset Condition Assessment of Schedule 2-5-4 - Asset Management Process.

A potential for oil leaks exists in 1,428 transformers, with a health index (HI) value below 65%. This is primarily due to the impact of corrosion/oil leak parameters on their long-term performance. Remedial work or replacement may be necessary, as per the recommendations in Table 5 of Schedule 2-5-4 - Asset Management Process, with the specific action depending on criticality and degradation patterns. Based on the annual probability of failure approach outlined in Hydro Ottawa's response to parts b) and c) of the response to interrogatory 2-Staff-102, the overall PoF for underground transformers (for HI below 65%) is 0.0538 (λ). For the annual PoF, the time variable (t) is set to 1 year. Applying this to the annual PoF formula, the annual probability of failure can be obtained as shown below:

$$\text{Annual PoF} = 1 - e^{-0.0538} \approx 0.0524$$

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-29

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 8, pp. 16, 49-52

QUESTION(S):

a) (P. 16) When there are large loads (e.g., Ottawa Hospital, OC Transportation buses, etc.) driving the need for system expansion, please explain how Hydro Ottawa determines whether to require a capital contribution. As part of the response, please discuss how Hydro Ottawa determines whether to treat the costs associated with the request as an expansion vs. an enhancement.

b) (P. 49) Please discuss how the capital contributions in 2026-2028 were forecast.

c) (P. 49) Please confirm that all of the capital cost associated with the non-wires solutions is related to the utility owned BESS. Please provide a breakdown of the capital budget between each BESS installation. Please explain how the costs for each BESS was estimated (including a discussion of the RFP process, the technology selected, etc.).

d) (P. 50) For each of the station projects, please explain the methodology applied for estimating the costs. As part of the response, please provide the historical comparator projects that were considered in developing the cost estimates.

e) (PP. 51-52) For each of the distribution capacity upgrades, please explain the methodology applied for estimating the costs. As part of the response, please provide the historical comparator projects that were considered in developing the cost estimates.

RESPONSE(S):

a) When large loads, such as the Ottawa Hospital or OC Transportation buses, drive the need for system expansion, Hydro Ottawa is guided by the Ontario Energy Board's Distribution System Code. This code dictates whether a system expansion or a system enhancement is required. Furthermore, the determination of whether a capital contribution is required from the customer is governed by the economic evaluation methodology detailed in Appendix B of the Distribution System Code.

b) The contributions were determined using the OEB's prescribed economic evaluation methodology in Appendix B of the Distribution System Code, which assesses financial implications and ensures equitable cost-sharing between the utility and the customer. The customer contributions required based on the results of the economic evaluation model represent a percentage of total project costs. That percentage was applied to the annual capital spend for 2026-2028 to forecast contributions for each year.

c) The costs associated with Non-Wire Upgrades in Table 2 of Schedule 2-5-8 - System Service Investments is forecasted for the four utility-owned BESS planned in the 2026-2030 period. The $61.2M is estimated at $2.5M per MW of utility BESS capacity for a total of 24.5 MW. Please see Table A in part (c)(iii) of the response to interrogatory 2-Staff-111 for a breakdown of BESS costs per installation.

Hydro Ottawa conducted a pre-assessment based on the NWS assessment criteria as outlined in section 9.2.1 of Schedule 2-5-4 - Asset Management Process to determine the viability of NWS within the four areas as presented and based on the timing of needs determined that traditional wires investments were not economically feasible. The results of the benefit and cost analysis of the BESS installations are provided in Table C in part (d) of the response to interrogatory 2-Staff-111.

Hydro Ottawa has not yet progressed to the project design stages that would consider aspects of the RFP process, the technology selected, etc. This will be considered as the project progresses to its design stage

d) Hydro Ottawa estimates station projects using a unit cost/element estimation methodology, by breaking down the substation into individual components (transformers, breakers, civil works, control systems, etc.) and applying pre-determined unit costs from extensive databases and previous substation projects. The historical comparator projects that were considered in developing these cost estimates were Cambrian MTS and Piperville MTS station projects.

e) Hydro Ottawa estimates distribution capacity upgrade costs using a unit cost methodology, where project components are quantified and multiplied by established unit prices. This is supported by historical data for early-stage estimates and confirmed by vendor and contractor quotes for major components. Key cost drivers include the choice between overhead and underground installations, the project's location (urban vs. rural), and the complexity of permitting and regulatory compliance. A contingency is also added to account for unforeseen issues.

To develop these estimates, Hydro Ottawa considered historical data from past projects. For example, cost data from pole renewal projects on Winther Avenue, Clementine Blvd, Niagara Drive, and Dahlia Avenue, and cable renewal projects in areas like Beaverbrook and Blackburn, were used as historical comparators.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-30

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 8, pp. 76, 88, 92

QUESTION(S):

a) (P. 76) With respect to third-party poles, please explain how Hydro Ottawa is estimating the cost to purchase these poles. Please discuss whether the company has purchased third-party poles during the historical period (and at what price).

b) (P. 88) Please provide a table showing a more detailed breakdown for each of the distribution enhancement sub-program costs (i.e., Reliability, Enhancement, Observability, Resiliency) under each of the alternatives. For example, please breakout the costs for each of third-party pole ownership transfers, 13kV neutral ties and DER enablement in the system enhancement category.

c) (P. 92) Please advise whether the proposed undergrounding investments in the system resiliency sub-program is incremental to the activities to be undertaken in the pole renewal program.

d) (P. 92) Please reconcile Hydro Ottawa's proposed resilience-related investments of $36.3M with the conclusions of the Resilience Business Case (Exhibit 2, Tab 5, Schedule 4, Attachment E). Please explain specifically what investments Hydro Ottawa intends to make relative to the conclusions of the business case.

RESPONSE(S):

a) Hydro Ottawa has identified operational and reliability risks associated with critical overhead lines on poles not owned or managed by Hydro Ottawa, as outlined in Section 3.3.2 of Schedule 2-5-8 - System Service Investment. Hydro Ottawa would consider high-risk overhead lines due to degraded condition and age, rendering the cost of ownership transfer immaterial. However, these poles would need to be replaced with new ones to meet Hydro Ottawa standards. The unit cost for replacing these poles would align with the Pole Renewal program, as detailed in Table A of the response to interrogatory 2-SEC-50.

Hydro Ottawa confirms that in the past, under System Access and System Renewal, ownership of third-party poles has been transferred. For poles already in a degraded condition and past their useful life, there has been no cost to Hydro Ottawa for the asset transfer.

b) Based on the information in Section 3.6.1 of Schedule 2-5-8 - System Service Investments, please refer to Table A below for a detailed breakdown for each of the distribution enhancement sub-program costs across all three alternatives.

Table A – Distribution Enhancement Sub-Program Costs ($'000 000s)[1]

Budget Program	Sub Program	Alternative 1: Historical Approach	Alternative 2: Accelerated Approach	Alternative 3: Balanced Approach (Preferred)
Distribution System Reliability	Worst feeder betterment	$5.0	$2.5	$2.5
	Worst Feeder Betternent- Minor	$0.0	$0.3	$0.3
	Distribution Phase Balancing	$0.0	$0.1	$0.1
	Feeder exceeding planning capacity	$0.0	$0.8	$0.8
	Specific Feeder Reliability Upgrades	$0.0	$2.2	$2.2
Distribution System Enhancement	Distribution Enhancements Projects	$14.7	$6.5	$6.5
	Third Party Poles Ownership Transfer	$0.0	$6.2	$6.2
	13.2kV Inter-Station Neutral Ties	$0.0	$2.8	$2.8
	Innovation Fund	$2.0	$4.9	$4.9
Distribution System Observability	OH DA Switch	$0.0	$69.2	$13.6
	UG DA Switch	$0.0	$89.6	$15.9
	FCI	$0.0	$7.4	$0.9
	MCB	$0.0	$0.1	$0.03
Distribution System Resiliency	Strategic Undergrounding	$0.0	$115.0	$23.4
	Line Reinforcement	$0.0	$5.0	$1.0
	Feeder Reconfiguration	$0.0	$5.5	$1.1
	Station Egress Undergrounding	$0.0	$42.5	$8.6
	Line Relocation	$0.0	$10.5	$2.1
TOTAL		**21.7**	**370.9**	**92.8**

c) The undergrounding investments within the System Resiliency sub-program are incremental to the activities undertaken in the Pole Renewal program.

While the primary focus of the Pole Renewal program is the planned replacement of aging or deteriorated poles, its scope will now contemplate incremental investments for resilience. As per Section 3.7.1 of Schedule 2-5-7 - System Renewal Investments, the renewal of deteriorated

[1] Totals may not sum due to rounding.

overhead (OH) infrastructure to withstand climatic forces from storm events is key to resilience over the long term for the system. As such, Hydro Ottawa will enhance the impact of the OH distribution renewal program over the 2026-2030 period by evaluating alternative design standards and creating risk-based application guides to further mitigate potential damage in high-risk installations.

While the Pole Renewal program now incorporates some strategic undergrounding and hardening within its renewed design and increased budget, the System Resiliency program represents a distinct and new dedicated investment. As per Section 3.5.3 in Schedule 2-5-8 - System Service Investments, this program reflects a broader strategic focus on enhancing grid resilience through targeted undergrounding projects and other measures identified via specific studies. The efforts are complementary, with System Resiliency providing a dedicated, expanded focus on strategic undergrounding beyond the core asset replacement in pole renewal.

d) Hydro Ottawa's proposed $36.3M investment in the Distribution System Resilience budget program is directly supported by and reconciled with the findings of Attachment 2-5-4(E) - Resilience Investment Business Case Report. The business case identified a range of approximately $27.5 million to $57.3 million for beneficial overhead-to-underground projects, those with a BCR ≥ 1. The proposed $36.3 million falls within this identified range. While the business case highlighted strategic overhead-to-underground conversions, the Distribution System Resilience program adopts a more comprehensive, multi-faceted approach. It considered projects with a BCR > 0.8 for broader evaluation and made adjustments based on expertise, optimizing project costs and consolidating scopes for enhanced benefits. As per Section 5.2.2.4 in Schedule 2-5-4 - Asset Management Process, the Distribution System Resilience program also considered other resilience scores from the report such as vegetation encroachment, asset accessibility and infrastructure orientation.

Specific investment breakdown (2026-2030) as per Section 3.6.1 - Alternative 3 Balanced Approach in Schedule 2-5-8 - System Service Investments:

- Strategic undergrounding of vulnerable overhead sections ($23.4M): directly addressing the core focus of the Resilience Business Case.
- Station egress undergrounding ($8.6M): improving grid resilience at critical supply points.
- Line relocation ($2.1M): relocating lines with high vegetation or improving access.
- Feeder reconfiguration ($1.1M): enhancing system flexibility and redundancy.
- Line reinforcement ($1M): strengthening pole structures and guying/anchoring.

The proposed investment in Distribution System Resilience represents a prudent and strategically informed allocation, directly supported by the Resilience Business Case, and expanded to include a holistic suite of hardening measures essential for long-term grid resilience.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-31

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 9, p. 70

QUESTION(S):

a) To the extent that fewer capacity expansion projects are approved for the CIR term, please confirm that there would be an expected reduction to the CCRA payments.
b) For each of the transmission connection projects, please provide the forecast CCRA payment and explain how the payment was estimated.

RESPONSE(S):

a) Fewer approved capacity expansion projects for the CIR term would lead to a reduction in CCRA payments. This is because CCRA payments directly recover the capital costs associated with expanding existing transmission infrastructure. With fewer projects, there are fewer capital expenditures to recover through these specific customer contributions.

b) For the forecast CCRA payments for each of the transmission connection projects over the 2026-2030 rate period, please refer to Table 19 in Section 7 of Schedule 2-1-1 - Rate Base Overview.

Hydro One estimates CCRA payments for transmission upgrades through a multi-stage process. This process begins with preliminary studies and progresses through detailed engineering and formal agreements. Initial high-level estimates are refined as the project

progresses, leading to a more precise connection cost estimate. Ultimately, the legally binding CCRA outlines payment schedules and the estimated capital contribution, with final payments based on the actual costs incurred for the connection.

It is important to note that the CCRA payments are directly impacted by Hydro One's transmission project cost estimates and the subsequent Discounted Cash Flow (DCF) calculations. Consequently, these payments are subject to change if Hydro One's project cost estimates are revised during project execution.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-32

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 9, p. 81

QUESTION(S):

a) (P. 81) Please provide further details regarding Hydro Ottawa's methodology for forecasting Infrastructure and Cyber Security costs.

b) (P. 81) Please confirm that Hydro Ottawa owns and operates its own data centres. Please provide any analysis completed with respect to alternative options that do not require Hydro Ottawa to own and operate data centres.

RESPONSE(S):

a) Hydro Ottawa's methodology for forecasting Infrastructure and Cyber Security costs is informed by comprehensive technology and vendor assessments. These assessments are conducted through formal procurement processes which adhere to Hydro Ottawa's established Procurement Policy, as detailed in Attachment 4-2-2(A) - Procurement Policy. Leveraging external expertise ensures that cost forecasts are grounded in current market realities and future technological trajectories, leading to prudent, cost-effective expenditures aligned with the utility's strategic objectives and regulatory obligations. This approach uses external market intelligence to build comprehensive and defensible cost forecasts.

b) Hydro Ottawa currently owns and operates both its primary and secondary data centres. In order to satisfy the findings from the Derecho Action Report (see Attachment 2-1-1(A) - May

2022 Derecho - After Storm Report), Hydro Ottawa will migrate its secondary data centre to a hosting environment in the 2026-2030 period where it will lease space physically distant from the primary data centre, but will maintain ownership of the IT assets. Hydro Ottawa weighed the options of a hosting solution and a cloud solution (both Infrastructure as a Service and Platform as a Service). A hosting solution was chosen because it allows Hydro Ottawa to leverage its existing architecture design, reuse hardware, reduce complexities, and reduce the operational costs versus a cloud solution.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

2-CCC-33

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 9, p. 120

QUESTION(S):

a) (P. 120) Please further explain the methodology applied to estimate the number of vehicles that can be reduced through pooling initiatives.
b) (P. 125) In the context of rising vehicle replacement costs, please provide any analysis undertaken by Hydro Ottawa that compares ongoing maintenance costs relative to replacement costs for the vehicles currently owned by Hydro Ottawa.

RESPONSE(S):

a) Information on the fleet pooling initiative can be found on pages 118 and 130 of Schedule 2-5-9 General Plant Investments, with additional details found in Schedule 1-3-4 - Facilities Innovation and Continuous Improvement.

Specifically, the methodology involved Fleet management meeting with each operational group to review vehicles assigned to individual crews or teams. This included an analysis of vehicle utilization using the live telematics dashboards as well as maintenance and fuel records to pinpoint opportunities for increased asset pooling. It's important to note that Hydro Ottawa currently pools vehicles; this initiative represents an expansion of that existing program, partially enabled by an upgrade to our fleet management software later in 2025. This upgrade will facilitate a reservation system for sharing of vehicles across various teams, moving beyond the current practice of primarily sharing vehicles within teams.

b) Hydro Ottawa's Fleet Management team prioritizes an asset condition perspective when evaluating vehicle replacements, especially given the rising costs. The team does not solely base decisions on a vehicle's age or scheduled end-of-life. Instead, it focuses on extending the life of assets through proactive maintenance and strategic repairs where economically feasible. This approach helps to mitigate the impact of increasing replacement costs, though it is recognized that for certain vehicles, particularly beyond 10-12 years of age, obtaining replacement parts can become difficult or parts may become obsolete, impacting the feasibility of continued maintenance.

For example, Figure 6 on page 122 of Schedule 2-5-9 - General Plant Investments indicates that while 82 light-duty vehicles will reach their end-of-life age between 2026 and 2030, Hydro Ottawa is only seeking funding to replace 58 of them. This difference highlights the commitment to prolonging vehicle life through maintenance and upkeep. A recent illustration of this is with two dump truck units. Hydro Ottawa was able to re-fabricate and install new dump boxes on their existing chassis, significantly extending their operational life and avoiding approximately $60,000 in capital expenditures that a full replacement would have incurred.

Conversely, there are instances where maintenance necessitates replacement. The Fleet team makes these decisions daily, analyzing the required work, its cost, and the vehicle's residual value. For instance, one unit was found to have extensive rust and significant material loss due to corrosion, rendering it unsafe for service. In such cases, despite efforts to prolong life, replacement becomes necessary.

Ultimately, the Fleet team continuously assesses all options to extend vehicle life wherever possible.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

3-CCC-34

EVIDENCE REFERENCE:

Exhibit 3, Tab 1, Schedule 1, pp. 2, 11, 21-22
Exhibit 3, Tab 1, Schedule 1, Attachment B, p. 22

QUESTION(S):

a) (PP. 2, 22) Please provide a summary of the differences between the manner in which the revenue load forecast and capital planning load forecast were derived. As part of the response, please provide a table that highlights the outputs of each of these two forecasts in terms of demand for the 2026-2030 period.
b) (P.11) Please provide the kWh and kW impact of growth in residential heat pump installations for each year 2026-2030 (and as reflected in Tables 1, 2, 5, and 6).
c) (P. 11) Please reconcile the electric heat pump saturations shown in Table 9 to Figure 3-5 (Attachment B, p. 22).
d) (P. 11) With respect to new GS<50kW customers, does Hydro Ottawa's revenue load forecast reflect electric space heating?
e) (P. 21) Please explain, in detail how the energy adjustments for the residential rate class were derived. Please include all assumptions. If no eDSM adjustments were applied, how would this impact rates in 2026-2030?

RESPONSE(S):

a) Please refer to Section 9.4.3 of Schedule 2-5-4 - Asset Management Process and the interrogatory response 3.1-BOMA-3 part (a) for a summary of the differences between the manner in which the revenue load forecast and capital planning load forecast were derived.

For the system level capital planning forecast, Hydro Ottawa utilized the IRRP Forecast which leveraged the hourly system coincident peak forecasts from the Decarbonization Study's Reference Scenario as detailed in Section 9.4.2 of Schedule 2-5-4 - Asset Management Process.

Table A provides a comparison of the demand for the 2026-2030 period between the revenue load forecast and the Planning Load Forecast (IRRP Forecast). Note that the IRRP Forecast is defined in 5 year increments therefore values are only provided in 2025 and 2030.

Table A: Demand (MW) Comparison

Year	System Peak Forecast[1]	Planning Load Forecast (IRRP Forecast)[2]
2025	1,541	1,620
2026	1,556	-
2027	1,570	-
2028	1,585	-
2029	1,600	-
2030	1,615	2,357

The kWh impact of growth in residential heat pump installations for each year 2026-2030 is shown in Table B. The kW impact of residential heat pumps was embedded in the saturation variable and their effects on the system peak forecast was not isolated.

Table B - Impact of Residential Heat Pumps 2026-2030

MWh	2026	2027	2028	2029	2030
Heat Pump Impact	4,879	7,308	9,776	12,158	14,589

[1] System peak demand from Table 4-1 of Attachment 3-1-1(B)
[2] Reference Scenario from Figure 114 in Schedule 2-5-4 - Asset Management Process.

b) Table C shows the correct Heat pump saturation percentage.

Table C - Heat Pump Saturation Percentage 2024-2030

Year	Heat Pump Saturation
2024	4.4%
2025	4.6%
2026	4.7%
2027	4.9%
2028	5.0%
2029	5.2%
2030	5.3%

c) As noted in section 8.2 of Schedule 3-1-1 - Revenue Load and Customer Forecast, Hydro Ottawa did not add incremental electricity demand related to heating for GS <50 rate class.

d) For the energy adjustments for the Residential class please refer to Schedule 3-1-1 - Revenue Load and Customer Forecast, Section and Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast. The Residential class is billed distribution based on a fixed monthly charge. Changes to the kWh sales forecast have little impact on the calculated distribution rate as it is determined by the average number of customers. The main impact would be within the cost allocation and demand factor models, however as the residential rate class revenue-to-cost ratio is close to unity it takes a substantial change in kWh to shift costs. Viewed in isolation of the cost allocation implications, increasing load forecast to exclude eDSM would have no impact on the Residential rates. Hydro Ottawa has not, however, reviewed the impact of eDSM on the demand factors used for Cost Allocation purposes. Lastly, it would not be appropriate, given the province's goals of increasing residential eDSM, to assume no adjustments are required.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-35

EVIDENCE REFERENCE:

Appendix 2-JC

QUESTION(S):

a) Please provide a revised version of Appendix 2-JC that includes an update to the forecasted 2024 and 2025 OM&A costs using the current best available information.

b) For each OM&A program listed in Appendix 2-JC, please provide, for each year in the 2021-2026 period, a breakdown of the total labour costs between Hydro Ottawa labour and contracted labour (e.g. contractors, consultants, etc.). Please also provide a discussion of any year-over-year changes in the proportion of work completed by Hydro Ottawa labour relative to contracted labour.

RESPONSE(S):

a) Please see the response to interrogatory 1-Staff-1(A) - Chapter 2 Appendices for a revised Appendix 2-JC showing 2024 full year actuals, and June year-to-date actuals for 2025 (along with comparable six month periods for 2024 and 2023). Please note that the June results are subject to year-end adjustments, as certain reclassification and true-up accounting entries are performed annually and are not reflected in these interim figures. An updated 2025 forecast will not be available until October 2025.

b) Please see Table A below with a breakdown of the total labour costs between Hydro Ottawa labour and contracted labour (e.g. contractors and consultants). The Others category on the bottom of the table is non-labour costs for all programs.

Table A – Summary of Labour Costs by JC Category 2021-2026 ($'000s)[1]

Programs		Historical Years			Bridge Years		Test Year
	Labour Type	2021	2022	2023	2024	2025	2026
Testing, Inspection & Maintenance	Internal	$ 331	$ 253	$ 247	$ 411	$ 622	$ 4,112
	Contracted	$ 1,077	$ 1,111	$ 1,203	$ 1,692	$ 1,998	$ 4,015
Vegetation Management	Internal	$ 559	$ 1,271	$ 966	$ 811	$ 878	$ 747
	Contracted	$ 3,177	$ 5,278	$ 5,169	$ 5,425	$ 4,741	$ 5,148
Underground Locates	Internal	$ 578	$ 482	$ 459	$ 1,075	$ 1,199	$ 555
	Contracted	$ 2,633	$ 3,015	$ 2,885	$ 3,323	$ 3,803	$ 5,399
Stations Maintenance	Internal	$ 1,931	$ 2,082	$ 2,286	$ 2,600	$ 3,076	$ 3,596
	Contracted	$ 565	$ 482	$ 449	$ 544	$ 676	$ 973
Distribution Overhead & Underground Maintenance	Internal	$ 1,549	$ 1,938	$ 1,955	$ 1,959	$ 1,881	$ 1,676
	Contracted	$ 310	$ 367	$ 5,932	$ 532	$ 529	$ 710
Metering	Internal	$ 1,447	$ 1,467	$ 1,307	$ 1,606	$ 1,588	$ 1,542
	Contracted	$ 28	$ 261	$ 108	$ 106	$ 115	$ 147
System Operations & 24/7	Internal	$ 4,275	$ 7,328	$ 5,426	$ 4,764	$ 5,430	$ 5,418
	Contracted	$ 22	$ 1,233	$ 2,087	$ 383	$ 347	$ 373
Engineering & Design	Internal	$ 4,189	$ 4,569	$ 4,760	$ 6,109	$ 5,639	$ 8,328
	Contracted	$ 289	$ 407	$ 532	$ 625	$ 625	$ 1,044
Distribution Support	Internal	$ 3,006	$ 4,062	$ 4,894	$ 8,632	$ 7,352	$ 7,014
	Contracted	$ 365	$ 442	$ 577	$ 613	$ 617	$ 574
Minor Maintenance	Internal	$ 795	$ 767	$ 729	$ 384	$ 518	$ 977
	Contracted	$ 52	$ 62	$ 85	$ 66	$ 62	$ 66
Collections	Internal	$ 726	$ 694	$ 595	$ 676	$ 719	$ 752
	Contracted	$ 30	$ 39	$ 11	$ 38	$ 39	$ 38

[1] The contracted labour costs may include trucking costs which are integrated within the invoices for contracted services

Programs		Historical Years			Bridge Years		Test Year
	Labour Type	2021	2022	2023	2024	2025	2026
Customer Billing	Internal	$ 2,822	$ 2,679	$ 2,547	$ 3,145	$ 3,274	$ 3,554
	Contracted	$ 356	$ 386	$ 418	$ 436	$ 439	$ 349
Customer & Community Relations	Internal	$ 3,939	$ 4,618	$ 3,955	$ 4,758	$ 5,057	$ 5,247
	Contracted	$ 1,722	$ 1,950	$ 2,223	$ 2,566	$ 2,587	$ 2,312
Information Management & Technology	Internal	$ 4,352	$ 4,821	$ 4,769	$ 5,214	$ 6,134	$ 7,123
	Contracted	$ 606	$ 1,010	$ 913	$ 1,327	$ 1,535	$ 1,145
Safety, Environment & Business Continuity	Internal	$ 1,565	$ 1,581	$ 1,819	$ 2,217	$ 2,440	$ 2,903
	Contracted	$ 697	$ 1,157	$ 610	$ 291	$ 304	$ 510
Human Resources	Internal	$ 2,720	$ 3,366	$ 3,459	$ 3,281	$ 3,433	$ 3,833
	Contracted	$ 727	$ 547	$ 1,859	$ 1,047	$ 915	$ 800
Supply Chain	Internal	$ 1,114	$ 807	$ 426	$ 707	$ 745	$ 760
	Contracted	$ 64	$ 131	$ 44	$ 60	$ 60	$ 55
Facilities	Internal	$ 794	$ 927	$ 968	$ 883	$ 879	$ 959
	Contracted	$ 3,097	$ 3,022	$ 7,543	$ 3,720	$ 3,621	$ 3,536
Finance	Internal	$ 3,480	$ 3,420	$ 3,396	$ 3,674	$ 3,811	$ 3,991
	Contracted	$ (25)	$ -	$ 1	$ 45	$ 45	$ 5
Regulatory Affairs	Internal	$ 993	$ 1,152	$ 985	$ 1,091	$ 1,196	$ 1,370
	Contracted	$ 435	$ 406	$ 388	$ 517	$ 517	$ 1,135
Corporate Costs	Internal	$ 987	$ 550	$ 832	$ 1,246	$ 1,278	$ 1,313
	Contracted	$ 34	$ 52	$ 20	$ 40	$ 40	$ 30
Sub-total		**$ 58,413**	**$ 70,190**	**$ 79,839**	**$ 78,638**	**$ 80,767**	**$ 94,136**
Others		$ 26,324	$ 30,346	$ 32,939	$ 36,683	$ 38,155	$ 45,874
TOTAL		**$ 84,737**	**$ 100,536**	**$ 112,778**	**$ 115,320**	**$ 118,922**	**$ 140,010**

For the year-over-year changes in the proportion of work completed by Hydro Ottawa labour relative to contracted labour see Table B below. For all years except for 2023, the ratio of Hydro Ottawa labour is consistent and ranges from 70% to 72% with an average of 71%. For contracted labour, the range is 28% to 30% with an average of 29% for all years except for

2023. During 2023, Hydro Ottawa had an 84-day labour strike which shifted this 70%/30% proportion and 41% of the labour in that year was contracted out.

Table B – Year-over-year Proportion of Work Completed

	Historical Years			Bridge Years		Test Year
Labour Type	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Internal	72%	70%	59%	70%	71%	70%
Contracted	28%	30%	41%	30%	29%	30%

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-36

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 1, Attachment 1, pp. 1, 7, 12-13

QUESTION(S):

a) (P. 1) Please provide a single table that provides a breakdown between the software costs that were or will be capitalized and the software costs that were or will be expensed for each year during the 2021-2030 period.

b) (P.1) Please advise whether any of the cloud solutions implemented (or that will be implemented) have resulted in a direct offset to the capital budget. As part of the response, please discuss whether Hydro Ottawa expects that as it expands cloud computing solutions, the IT capital program will be reduced over time.

c) (P. 1) Other than the EAM and CRM cloud solutions, please provide any analysis completed related to other cloud solutions that were considered but are not proposed as part of the application.

d) (P. 7) Please file the “2022 assessment” that highlighted critical gaps impeding efficient asset management if not already filed with the application. If it is on the record, please provide a reference to this assessment.

e) (P. 12) With respect to the 2025 work related to the EAM program, please provide a status update and advise whether the schedule in Table 3 and the associated timing of the costs to be incurred in Table 4 remain accurate.

RESPONSE(S):

a) The cost of capitalized software is provided in Table A, along with the associated maintenance costs for that software, which is an annual expense that is intrinsically linked to the capitalized assets. Table B shows the annual subscription costs for software that is immediately expensed.

Table A - Software Costs Capitalized and Associated Maintenance Costs 2021-2030[1] ($'000s)

	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capitalized Software	$ 3,039	$ 4,779	$ 6,265	$ 9,679	$ 7,048	$ 9,694	$ 10,588	$ 11,698	$ 8,442	$ 5,737
Non-capitalized Maintenance	$ 7,183	$ 7,349	$ 7,772	$ 8,461	$ 8,695	$ 9,716	$ 10,219	$ 10,749	$ 11,305	$ 11,891

Table B - Software Costs Expensed 2021-2030[2] ($'000s)

	Historical Years			Bridge Years		Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subscription costs[3]	$ 2,754	$ 3,137	$ 4,404	$ 4,447	$ 4,547	$ 10,842	$ 11,403	$ 11,994	$ 12,615	$ 13,269

b) Several cloud-based software solutions have and will offset the capital budget. For example, the cloud-based Google Workspace eliminated the perpetual licenses of the Microsoft Office suite from the capital budget, and the planned cloud contact centre will replace the on-premise IVR solution currently employed.

[1] 2027-2030 Test Years are forecast using the Custom Revenue OM&A Factor discussed in Schedule 1-3-1 Rate Setting Framework.
[2] Ibid
[3] Also includes cloud implementation costs

c) As discussed in the Attachment 1-3-4(B) - Digital Strategy, Hydro Ottawa is shifting as much as practicable to cloud-based solutions and does expect that this will result in a reduction of capital IT investments over time.

d) Hydro Ottawa carefully considered an ERP cloud solution but decided to defer the project. The decision was based on shifting priorities due to the Derecho and a labor disruption, as well as significant inflationary pressures in the technology space that would have led to a project overrun. Furthermore, the company was able to leverage extended support for its current JD Edwards ERP system until at least December 2035, allowing it to focus on other priorities, such as the EAM system. Please see Schedule 2-5-5 - Capital Expenditures Plan, under section 5.4.2 Enterprise Solutions for additional details.

e) The “2022 assessment” is attached to this interrogatory response and includes both a current state study in August of 2021 as Attachment 4-CCC-36(A) - Hydro Ottawa Current State Analysis Final outlining critical gaps in asset management. This was later followed up in 2022 by Attachment 4-CCC-36(B) - Technology Roadmap For Asset Management with recommendations on a path forward.

f) As noted in the EAM evidence referenced above, current status is centered on development of an EAM roadmap in 2025 to inform future scope including evaluation and selection of EAM technology for execution beginning in 2026. The schedule identified in Table 3 is accurate and the associated costs in Table 4 remain the best forecast available at this time. The EAM project “heavy lifting” will occur in 2026 and 2027.

Technology Roadmap for Distribution, Network Planning & Operations Business Functions

Current State Analysis

As of November 2021

Version	Final
Status	Complete
Created	16 Nov 2021
Author	Infosys Limited

DOCUMENT CONTROL

DOCUMENT AUTHORISATION

The following tables indicates the approval, by the key stakeholders, that the current state defined within this document fully and accurately captures what is required by the business. Document signoff indicates agreement with its contents. Once signed off, any changes to this document will be subject to a formal change control process.

Sign Off(s)

Name	Position	Signature	Date
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Stakeholders/Workshop Participants

This section lists the key stakeholders contributing to this document.

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Mithun Das	Account Lead	Infosys Limited	Y
Ramakrishna Chamarthi	Program Lead	Infosys Limited	Y
Saket Kumar	Business Consultant	Infosys Limited	Y
Biswa Ranjan Patra	GIS Consultant	Infosys Limited	N

REVISION HISTORY

Version	Date	Section	Summary of changes	Author
0.1	12/9/21	All	Initial draft version	Saket
0.2	12/16/21	All	Review feedback provided by Margaret F, Michelle C	Saket/ Ramakrishna
0.3	12/22/21	All	Review feedback provided by Margaret F, Michelle C	Saket/ Ramakrishna
0.4	1/10/22	All	Review by Ram R/Surya C	Saket/ Ramakrishna
0.5	1/11/22	All	Review feedback provided by Margaret F, Michelle C	Saket/ Ramakrishna

REFERENCE DOCUMENTS

This section lists all the documents that are referenced or are related to this document.

No	Document Name	Version	Date
1	Hydro Ottawa AS-IS Process Blocks.pptx at PHASE 2 - Asset Management Life Cycle > 7.Infosys deliverables	1.0	3-Dec-21
2	HOL - EAM Roadmap - Data Capture.xlsx at PHASE 2 - Asset Management Life Cycle > 7.Infosys deliverables	1.0	3-Dec-21

CONTENTS

1 Introduction

The key objective of this initiative is to define a robust IT landscape for Hydro Ottawa for its business systems in the domain of asset management, work management, field services management, asset planning, asset construction, operations & maintenance, and GIS. This IT landscape would be complemented with an execution roadmap which would enable a 5-year transformation to ease the transition and set realistic goals and deadlines.

A high-level strategizing, evaluating, and planning journey of the current exercise entails these tasks

1) Review the Strategic Asset Management Plan (SAMP) and Asset Management Plans (AMP) based on the defined Asset Management System (AMS) framework and Asset lifecycle stages.
2) Review and Assessment of the existing business and IT systems, tools and processes used to support the stages of Asset Lifecycle across the Major Asset Classes/Types
3) Rationalization of existing IT application portfolio including – consolidation, enhancement, and replacement opportunities with product/package options for consideration to effectively support the Asset Lifecycle stages
4) Development of the to be application landscape mapped to the Asset Lifecycle stages
5) Development of the Technology Roadmap covering all Asset Lifecycle stages based on business priorities, technical feasibility, lifecycle cost and alignment to the overall Hydro Ottawa IT strategy

The scope of this document is to summarize the gaps and pain-points in the AS-IS processes, which would be fed into the TO-BE design considerations.

The document is a result of the various discovery sessions conducted by Infosys team, and facilitated by Hydro Ottawa Business and IT leads, with various stakeholders from different asset management groups within Hydro Ottawa from Nov 8th, 2021, to Dec 3rd, 2021. This was documented in AS-IS process and data flow maps which was reviewed by the various stakeholders and finalized for conducting the subsequent phase (TO-BE state planning).

2 Approach

2.1 Interview Process

The key goal of the exercise is to identify the pain points with the AS-IS landscape which would be used to define the TO-BE technology landscape for field asset solutions.

In this regard, we started with overlaying the current competencies over the reference architecture. This will enable the team to identify the pain points, system gaps and automation opportunities to help select all technology solutions to align with ISO 55000/55001 goals. A block representation of the Enterprise Asset Management (EAM) reference architecture is outlined below.

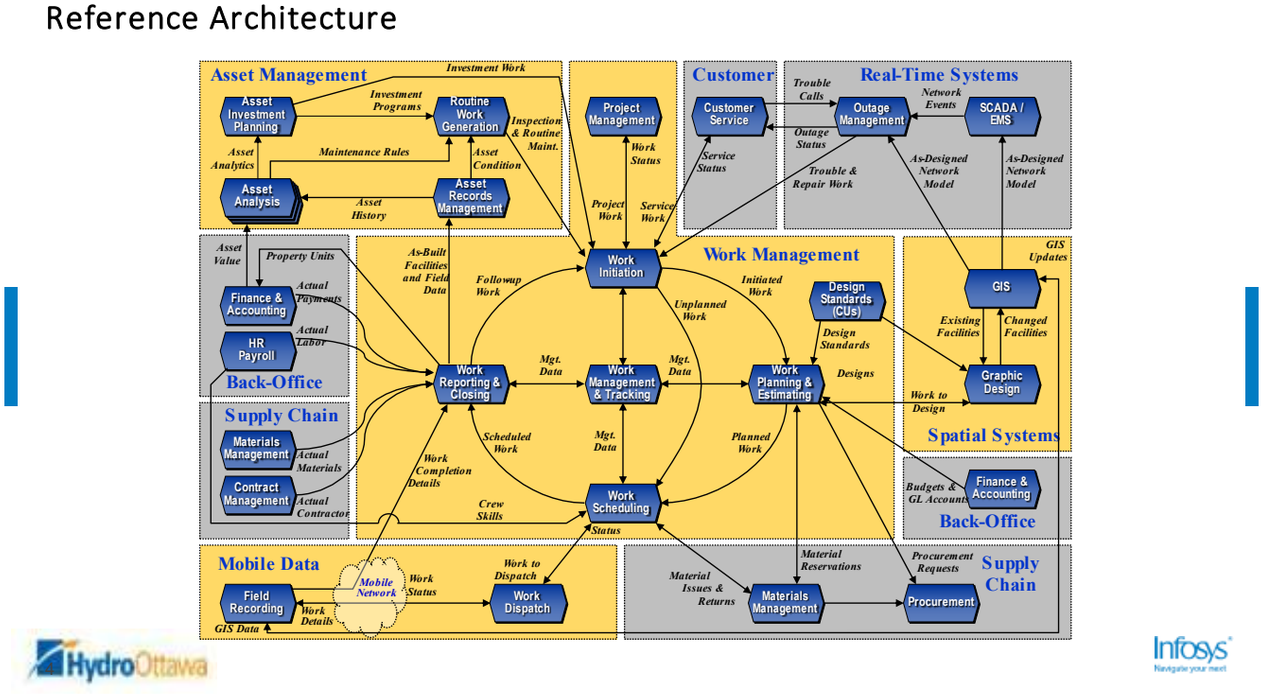


Figure 2-1: Reference Architecture

Figure 3-1 denotes the reference architecture against which all the processes for different Station and Distribution assets were measured.

Furthermore, to facilitate discussion across different groups, the asset types were segregated into different asset groups based on the distinct skills involved to perform field activities on those assets. The asset groups defined for this purpose

1) Underground

Assets that lie below the ground and need additional planning and permitting to perform any work. The assets in this group are Structures (Vaults & Conduits, Manholes), UG Transformers, UG Cables, and Switchgears & Breakers.

2) Overhead

Assets that lie above the ground and can be accessed easily to perform any work. The assets in this group are Structures (Poles, Towers, Fixtures), OH Transformers, OH Conductors, Line Reclosers, and Load Break Switches

3) Stations

Assets that lie within the premises of a substation and involve a thorough knowledge regarding their configuration and setup. The assets in this group are Station Transformers, Station Breakers, and Relays and Protection Equipment. Other station transformers are already covered in other groups., so they are not repeated here.

4) Metering

All metering assets are grouped here. These include Smart Meters and CTs / PTs (Large I&C meters).

5) Telecom

Assets that make up the entire communication infrastructure are covered here. These include the network instruments as well as the equipment. These are not included in the immediate asset management plans but are considered in the long-term plan. The location assets are Fiber optic cable, Station, Jumpers, Splice, Rack, RTU, Fault Indicators, Duct and Conduit, and Manholes. The communication assets are Racking Equipment Information, Router, and Local network accessories like Phone, Radio, Security Cameras.

Along with process and solution discussions, the goal is to also capture interactions among technology solutions to evaluate the overall amount of automation already achieved.

Capturing all these high-level data points would give us a big picture of pain points across the IT landscape and how to address that in the 5-yr roadmap.

2.2 Stakeholder Questionnaire

With the idea to capture all the involved technology solutions in the Hydro Ottawa landscape, the team carried out discussions using the reference architecture on the table along with the following questions.

Function	Details
Work Orders	• Types of work order request that are managed (e.g., reactive, planned, quoted works etc.). • How work order requests are received and processed (including integration). • How planned maintenance is prepared and managed. • Approval process (if applicable). • Work orders created by field operators (if applicable).
Scheduling	• How work is allocated to field operators. • Operational differences between crews and lone operators. • Option for automated scheduling (including scheduling rules). • Use of cyclic schedules for planned maintenance. • Reporting requirements (e.g., performance reports, travel hotspots etc.).
Mobility	• Current capability and available devices. • How health and safety processes are captured. • How status updates are captured and made available to the customer (and whether this is real-time). • Whether the use of On-hold is applicable (with supporting reason codes). • How labor and materials are acquired and accounted for. • How temporary fixes are managed. • Completion process (including the data that is captured). • Billing lines. • Reporting requirements (e.g., productivity).
Asset Management	• Quality and quantity of current asset data. • Which team is responsible for managing asset data and the system that is currently used? • Asset hierarchies (nested assets to support child/grandchild relationships. • Asset details that are captured as part of job management. • Asset lifecycle modelling. • Reporting requirements.
Billing	• How completed transactions are invoiced. • How disputes are dealt with. • Adjustments. • Reporting requirements.
Customer Portal	• Current provision/requirements. • Ability for customers to create and submit work orders. • Approvals process to request customer sign-off before commencing work. • Ability to link to other websites to provide a centralized landing page.
Sub-contractors	• How work is assigned to sub-contractors. • How sub-contractor performance is tracked. • Reporting requirements.

Function	Details
Inventory Management	• How inventory is maintained. • Use of stock-takes, inventory transfers, stock adjustments, returned material authorizations (RMA's) and return to vendor requests (RTV's). • How purchase orders are utilized for materials. • How price lists are used.
Dashboards	• Existing tools and techniques that are in use to monitor performance.
Reporting	• Additional requirements.
Out-of-Hours	• How requests received out-of-hours are managed and which functions they impact.

Table 2-1: Functional Objectives

3 As-Is Landscape

3.1 Underground

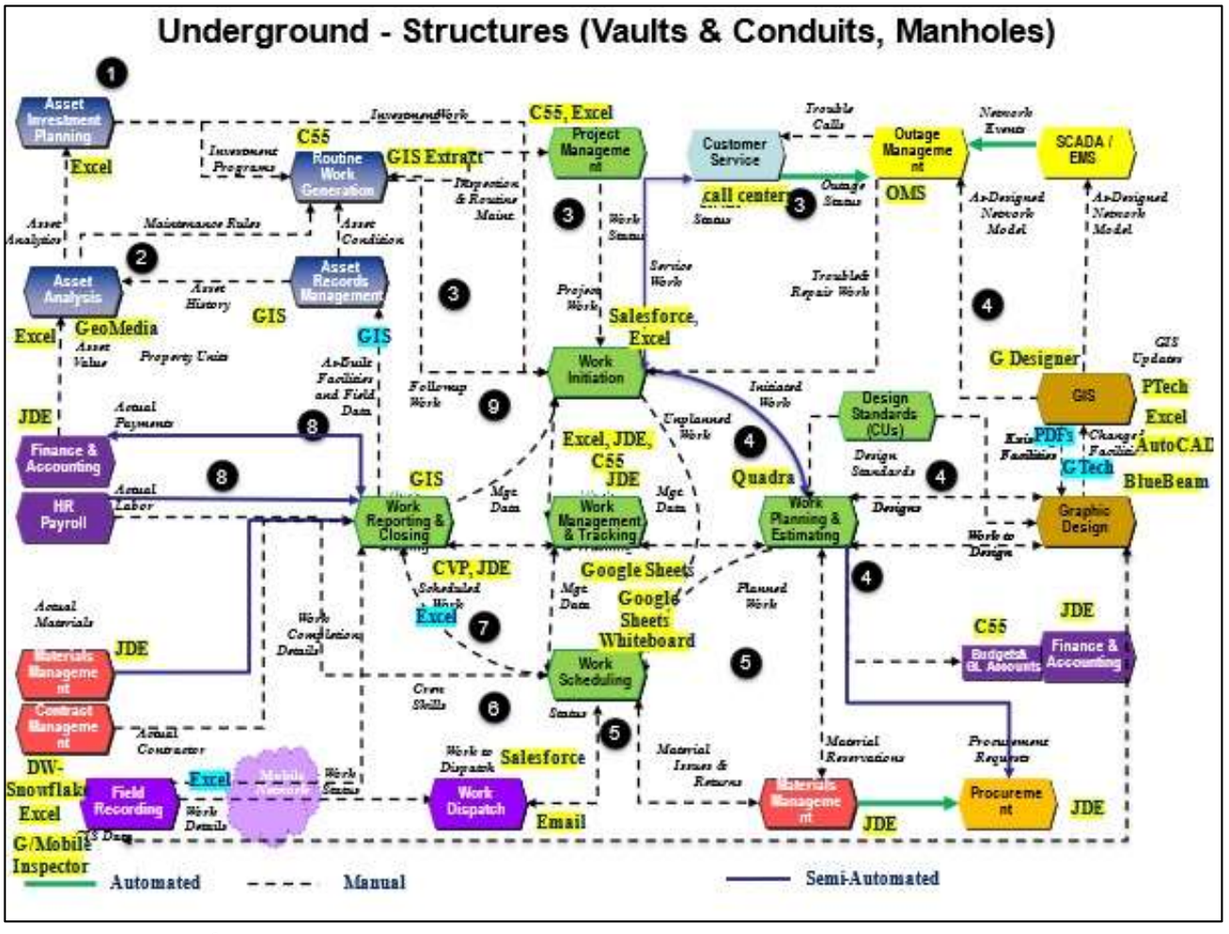
The following assets are categorized as Underground assets

- Structures (Vaults & Conduits, Manholes)
- UG Transformers
- UG Cables
- Switchgears & Breakers

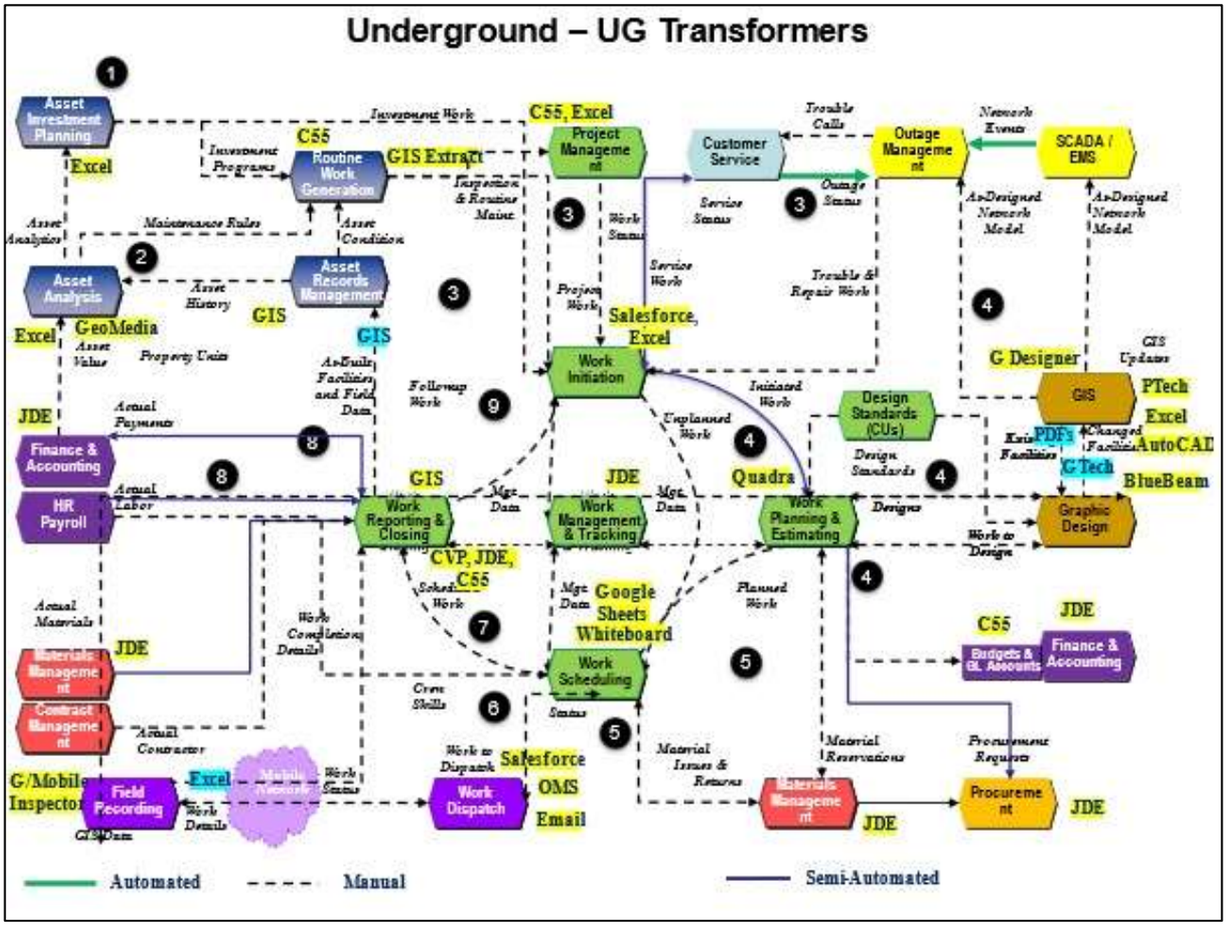
3.1.1 Process Blocks

When we overlay the reference conceptual architecture with the processes for underground assets followed at Hydro Ottawa, we get the following process blocks as results. We will discuss each of the process steps in the next section.

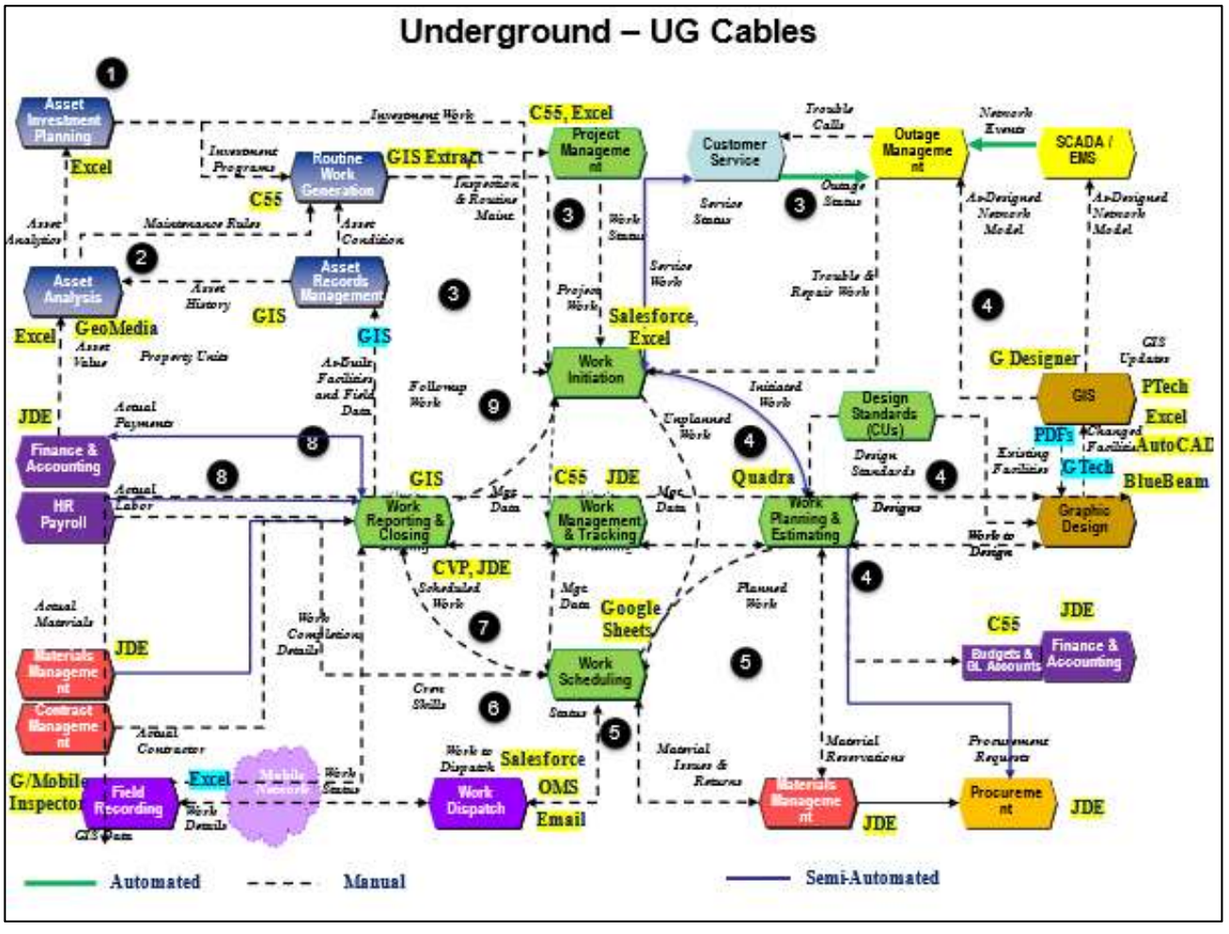
- Structures (Vaults & Conduits, Manholes)



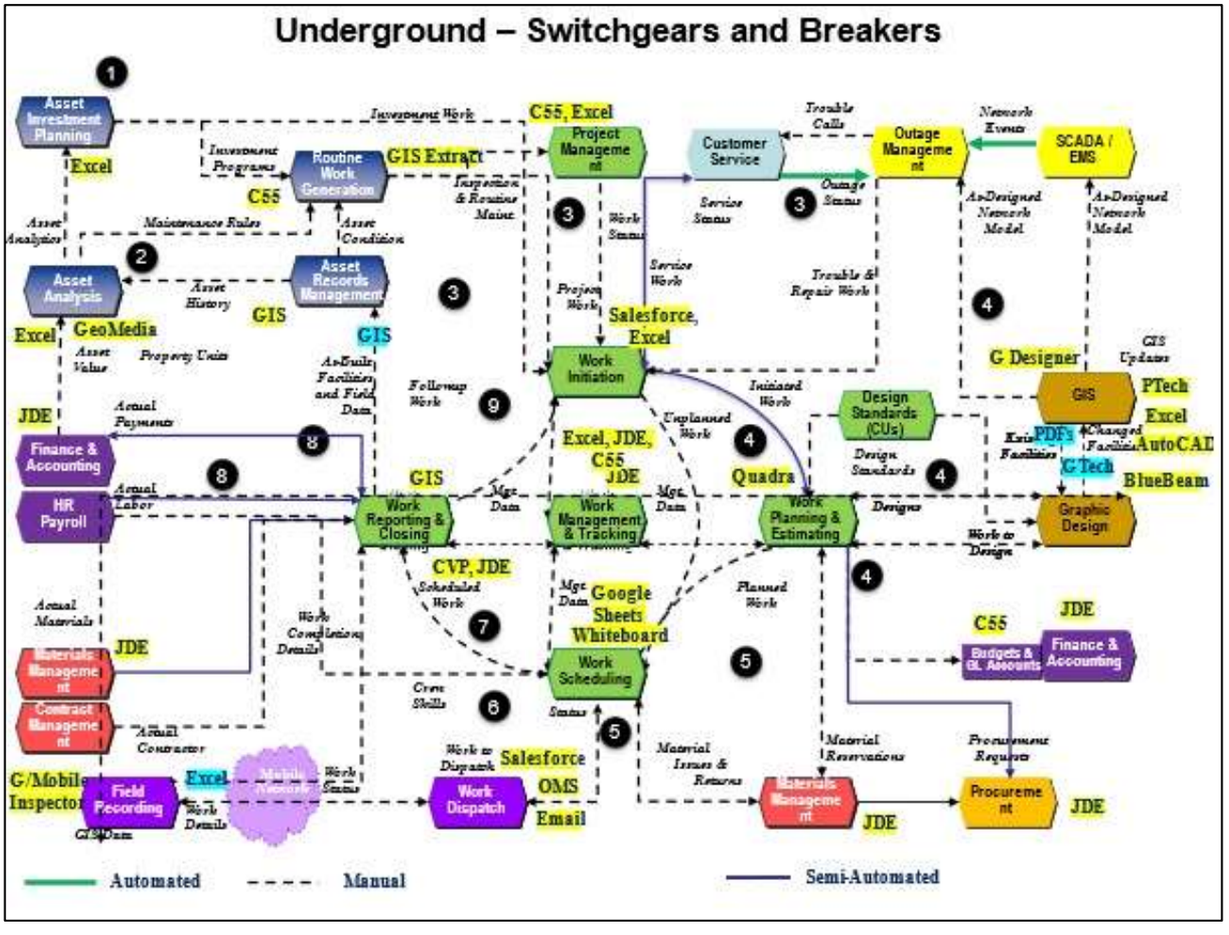
- UG Transformers


Underground – UG Transformers
Asset Investment Planning
Excel
Investment Work
C55, Excel
Project Management
Customer Service
Trouble Calls
Outage Management
Network Events
SCADA / EMS
C55
Investment Programs
Routine Work Generation
GIS Extract
Inspection & Routine Maint
Work Status
Service Status
Outage Status
As-Designed Network Model
Asset Analysis
Maintenance Rules
Asset Condition
Asset Records Management
Asset History
GIS
Service Work
Trouble & Repair Work
Project Work
Salesforce, Excel
Excel
GeoMedia
Asset Value
Property Units
GIS
As-Built, Facilities and Field Data
Work Initiation
G Designer
GIS Updates
GIS
PTech
Excel
AutoCAD
BlueBeam
JDE
Actual Payments
Followup Work
Unplanned Work
Initiated Work
Design Standards (CUs)
Design Standards
Existing Facilities
PDFs
Changed Facilities
G/Tech
Finance & Accounting
HR Payroll
Actual Labor
GIS
Work Reporting & Closing
Mgt. Data
JDE
Work Management & Tracking
Mgt. Data
Quadra
Work Planning & Estimating
Designs
Graphic Design
Work to Design
CVP, JDE, C55
Solved Work
Mgt. Data
Google Sheets
Whiteboard
Planned Work
Actual Materials
Work Completion Details
JDE
Materials Management
Work Scheduling
C55
JDE
Budgets & GL Accounts
Finance & Accounting
Crew Skills
Status
Contract Management
Actual Contractor
Work to Dispatch
Salesforce
OMS
Email
Material Issues & Returns
Material Reservations
Procurement Required
G/Mobile Inspector
Field Recording
Excel
Mobile Network
Work Status
Work Details
GIS Data
Work Dispatch
Materials Management
JDE
Procurement
JDE
Automated
Manual
Semi-Automated

- UG Cables


Underground – UG Cables
Asset Investment Planning
Excel
Investment Work
C55, Excel
Investment Programs
Routine Work Generation
GIS Extract
C55
Inspection & Routine Maint.
Project Management
Customer Service
Trouble Calls
Outage Management
Network Events
SCADA / EMS
Service Status
Outage Status
As-Designed Network Model
Asset Analytics
Maintenance Rules
Asset Condition
Work Status
Asset Analysis
Asset History
Asset Records Management
GIS
Service Work
Trouble & Repair Work
Project Work
Excel
GeoMedia
Asset Value
Property Units
GIS
Salesforce, Excel
G Designer
GIS Updates
As-built, Facilities and Field Data
Work Initiation
Followup Work
Initiated Work
Unplanned Work
Design Standards (CUs)
GIS
PTech
Excel
JDE
Actual Payment
PDFs
Changed Facilities
AutoCAD
Finance & Accounting
Existing Facilities
GTech
BlueBeam
Quadra
Design Standards
Designs
HR Payroll
Actual Labor
GIS
C55
JDE
Mgt Dam
Work Reporting & Closing
Work Management & Tracking
Work Planning & Estimating
Graphic Design
Work to Design
CVP, JDE
Scheduled Work
Mgt Dam
Planned Work
Actual Materials
Work Completion Details
Google Sheets
C55
JDE
JDE
Budgets & GL Accounts
Finance & Accounting
Materials Management
Work Scheduling
Crew Skills
Status
Contract Management
Actual Contractor
Work to Dispatch
Salesforce
Material Issues & Returns
Material Reservations
Procurement Requests
G/Mobile Inspector
Field Recording
Excel
Work Status
Work Dispatch
OMS
Email
Materials Management
Procurement
JDE
JDE
Work Details
GIS Data
Automated
Manual
Semi-Automated

- Switchgears & Breakers



3.1.2 Lifecycle

Process Groups	Business Process(es)	Technology	Pain Points
Capital Projects	*Asset Records Management* GIS houses all the data for UG assets. Spreadsheet is used for cables condition information. *Asset Investment Planning* Spreadsheet is used for Asset investment planning. Spreadsheet is used for determining spending levels/replacement levels. Equipment specific projects are	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets (Google Sheets) • AutoCAD • Copperleaf C55 • PowerDB	• No historical data (once asset is removed from the field, information is lost or may reside in spreadsheets) • Data gaps – missing, incorrect, or unverified • Data Risks – Using formula laden spreadsheets is prone to errors.

	entered in C55-Copperleaf to be scored and optimized. Once the project is added to the project list because of optimization, it is sent to design for detailed estimation. *Asset Analysis* Spreadsheet and GeoMedia is used for Asset Analysis. GMobile Inspector is used to capture inspection data. GIS uses hyperlinks to access the inspection data. Inspection data is exported as a Spreadsheet for analysis. Maintenance and Reliability Unit (MRU) uses dedicated email inbox for Emergency failure, project management and tracking. Quadra is used for Job Costing and Estimation. Salesforce Field Service Lightning (FSL) is used in the field to capture work data. *Project Management* The Major Projects group is only involved with Capital station projects not capital distribution projects. Distribution projects are managed by Design Team for preliminary scope refinement, and estimate. The Asset Planning team approves the final scope and estimate. It is then submitted to the Scheduling group for assigning the labor resources (external/internal). Change requests are submitted monthly in C55 and then extracted in Excel format for upload to JDE. Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) is created in JDE. Contractor management team oversees work initiation of TIM contractors.	• JD Edwards • Microsoft Project • Track-It! • Salesforce FSL • ASPEN Relay Database • Emails • Quadra • Bluebeam Revu • Snowflake • GMobile Inspector	• Currently not Linked to Pi, CYME and JDE Systems

	Work Dispatch Work is manually allocated to field resources using Spreadsheets. Salesforce FSL is used for certain inspections that is manually dispatched currently. *Field Recording* Field data is captured in e-Forms stored on Network drives and PDF documents.		
Small Maintenance Projects	*Asset Records Management* GIS houses all the data for UG assets. Spreadsheet is used for cables condition information. *Asset Investment Planning* Spreadsheet is used for Asset investment planning. Spreadsheet is used for determining spending levels/replacement levels. Equipment specific projects are entered in C55-Copperleaf to be scored and optimized. Once the project is added to the project list because of optimization, it is sent to design for detailed estimation. *Asset Analysis* Spreadsheet and GeoMedia is used for Asset Analysis. GMobile Inspector is used to capture inspection data. GIS uses hyperlinks to access the inspection data. Inspection data is exported as a Spreadsheet for analysis. *Routine Work Generation* Large work generated by design team; residential/commercial work generated by- % not known. Same process followed by separate groups that have different supervisors. Emergency Work Order (WO) is initiated by construction/reliability	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets (Google Sheets)	• Data gaps – missing, incorrect, or unverified • Data Risks – Using formula laden spreadsheets is prone to errors.

	team in Salesforce/Excel. Contractor management team oversees work initiation of TIM contractors. *Project Management* Maintenance and Reliability Unit (MRU) uses dedicated email inbox for Emergency failure, project management and tracking. Quadra is used for Job Costing and Estimation. Salesforce FSL is used in the field to capture work data. For maintenance programs, invoicing is used to track progress. *Work Dispatch* Maintenance work, including inspections are routed to the field using Salesforce FSL. *Field Recording* The work as well as the data for the work is captured in FSL forms.		
Large Maintenance Projects	*Asset Records Management* GIS houses all the data for UG assets. Spreadsheet is used for cables condition information. *Asset Investment Planning* Spreadsheet is used for Asset investment planning. Spreadsheet is used for determining spending levels/replacement levels. Equipment specific projects are entered in C55-Copperleaf to be scored and optimized. Once the project is added to the project list because of optimization, it is sent to design for detailed estimation. *Asset Analysis* Spreadsheet and GeoMedia are used for Asset Analysis. GMobile Inspector is used to capture inspection data. GIS uses hyperlinks to	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets (Google Sheets) • AutoCAD • Copperleaf C55 • PowerDB • JD Edwards • Microsoft Project • Track-It! • Salesforce FSL • ASPEN Relay Database • Emails • Quadra	• No historical data (once asset is removed from the field, information is lost) • Network modelling for stations is not standardized, it does not contain information require by all business units • Data gaps – missing, incorrect, or unverified • Currently not Linked to Pi, CYME and JDE Systems

	access the inspection data. Inspection data is exported to a Spreadsheet for analysis. *Routine Work Generation* Large work generated by design team; residential/commercial work generated by- % not known. Same process followed by separate groups that have different supervisors. Emergency Work Order (WO) is initiated by construction/reliability team in Salesforce/Excel. Contractor management team oversees work initiation of TIM contractors. *Project Management* Maintenance and Reliability Unit (MRU) uses dedicated email inbox for Emergency failure, project management and tracking. Quadra is used for Job Costing and Estimation. Salesforce FSL is used in the field to capture work data. For maintenance programs, invoicing is used to track progress. *Work Dispatch* Maintenance work, including inspections are routed to the field using Salesforce FSL. The work as well as the data for the work is captured in FSL forms. *Field Recording* Field data is captured in e-Forms stored on Network drives and PDF documents.	• Bluebeam Revu • Snowflake • GMobile Inspector	

3.2 Overhead

The following assets are categorized as Overhead assets

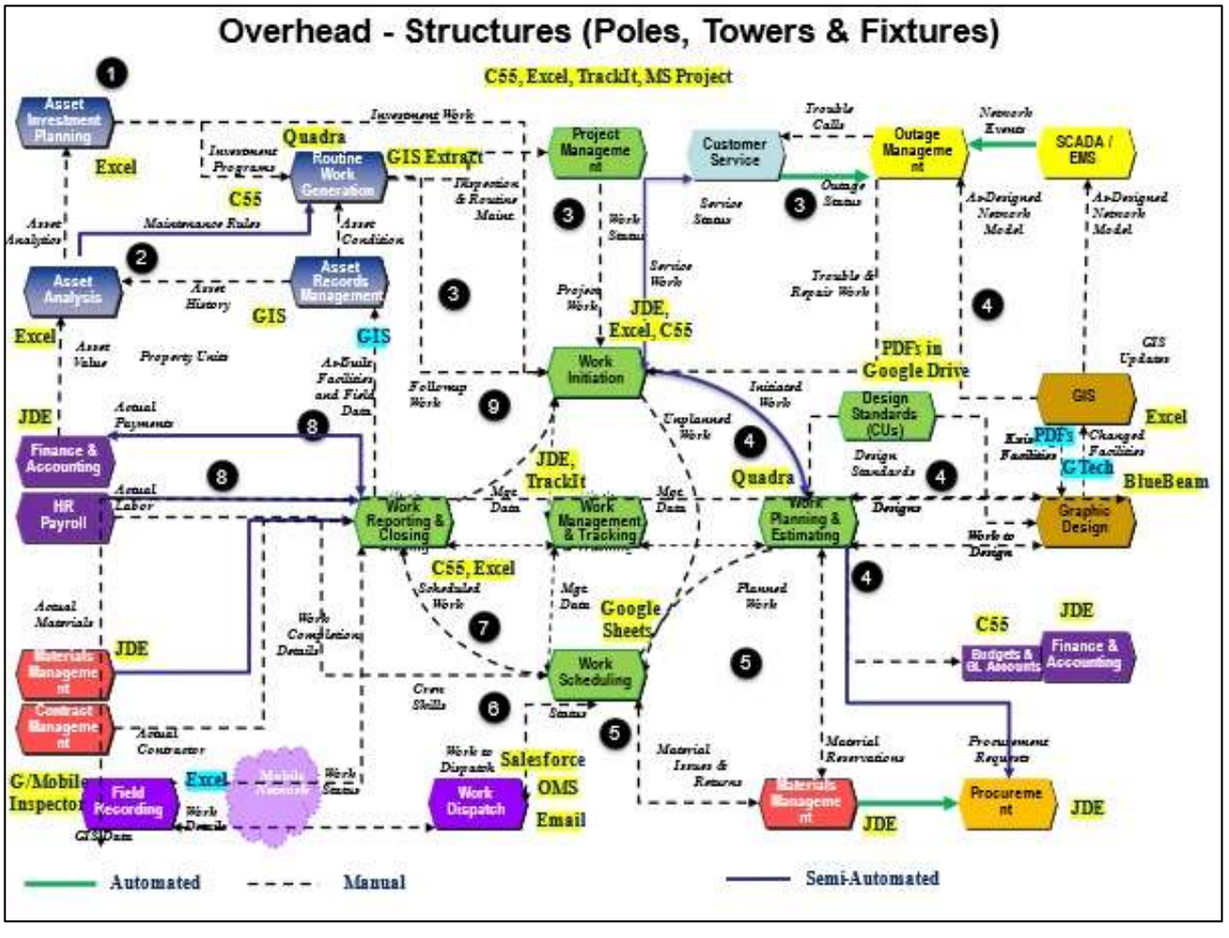
- Structures (Poles, Towers, Fixtures)
- OH Transformers
- OH Conductors
- Line Reclosers

- Load Break Switches

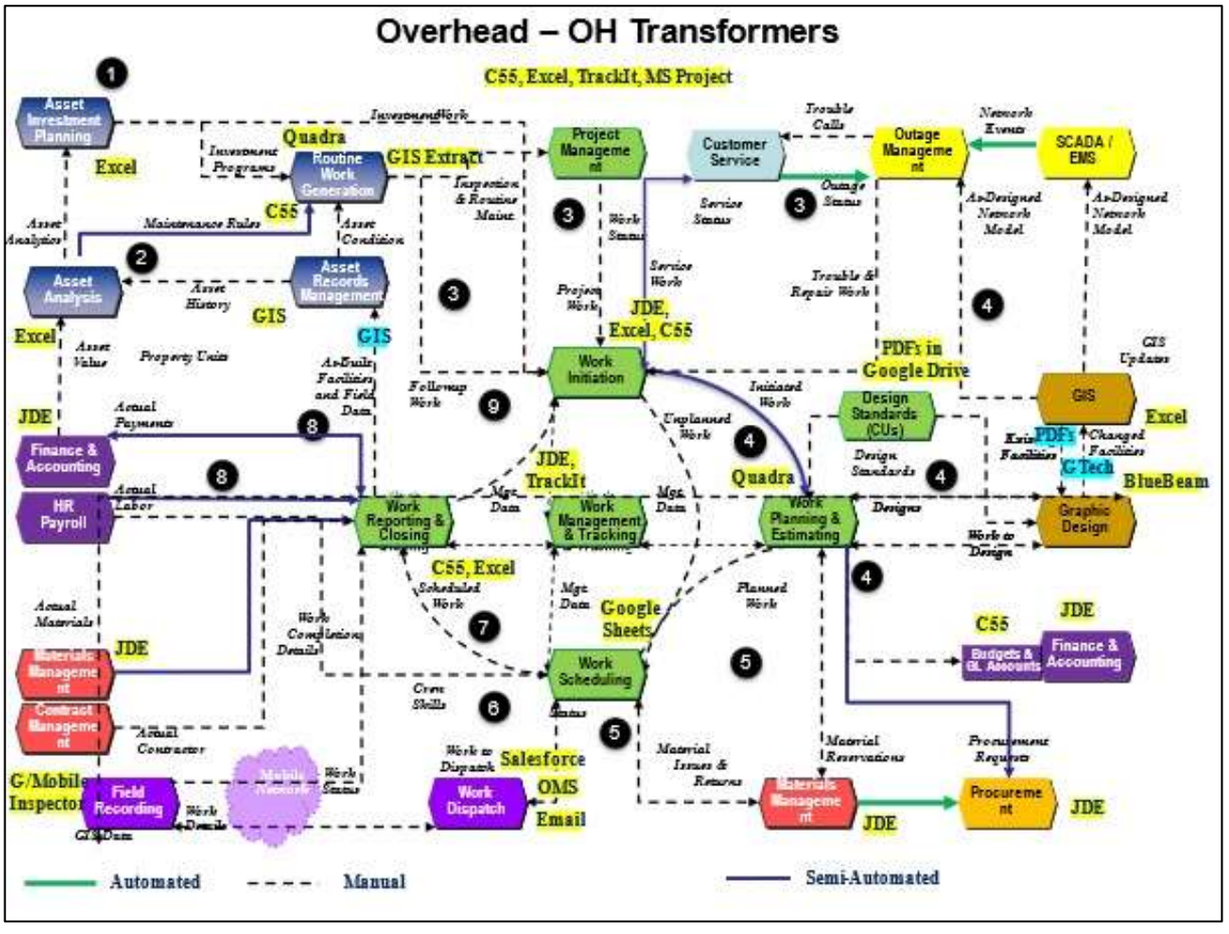
3.2.1 Process Blocks

When we overlay the reference conceptual architecture with the processes for overhead assets followed at Hydro Ottawa, we get the following process blocks as results. We will discuss each of the process steps in the next section

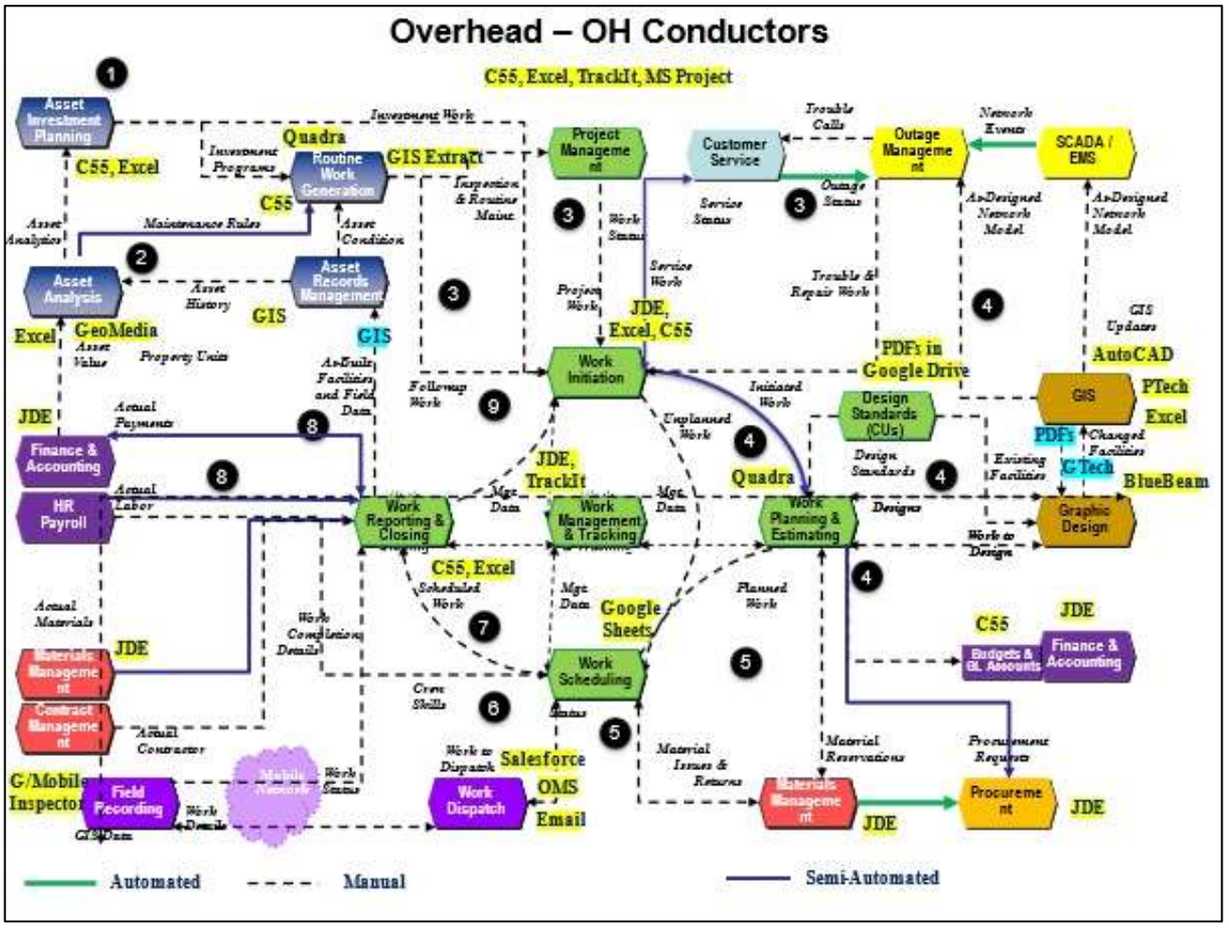
- Structures (Poles, Towers, Fixtures)



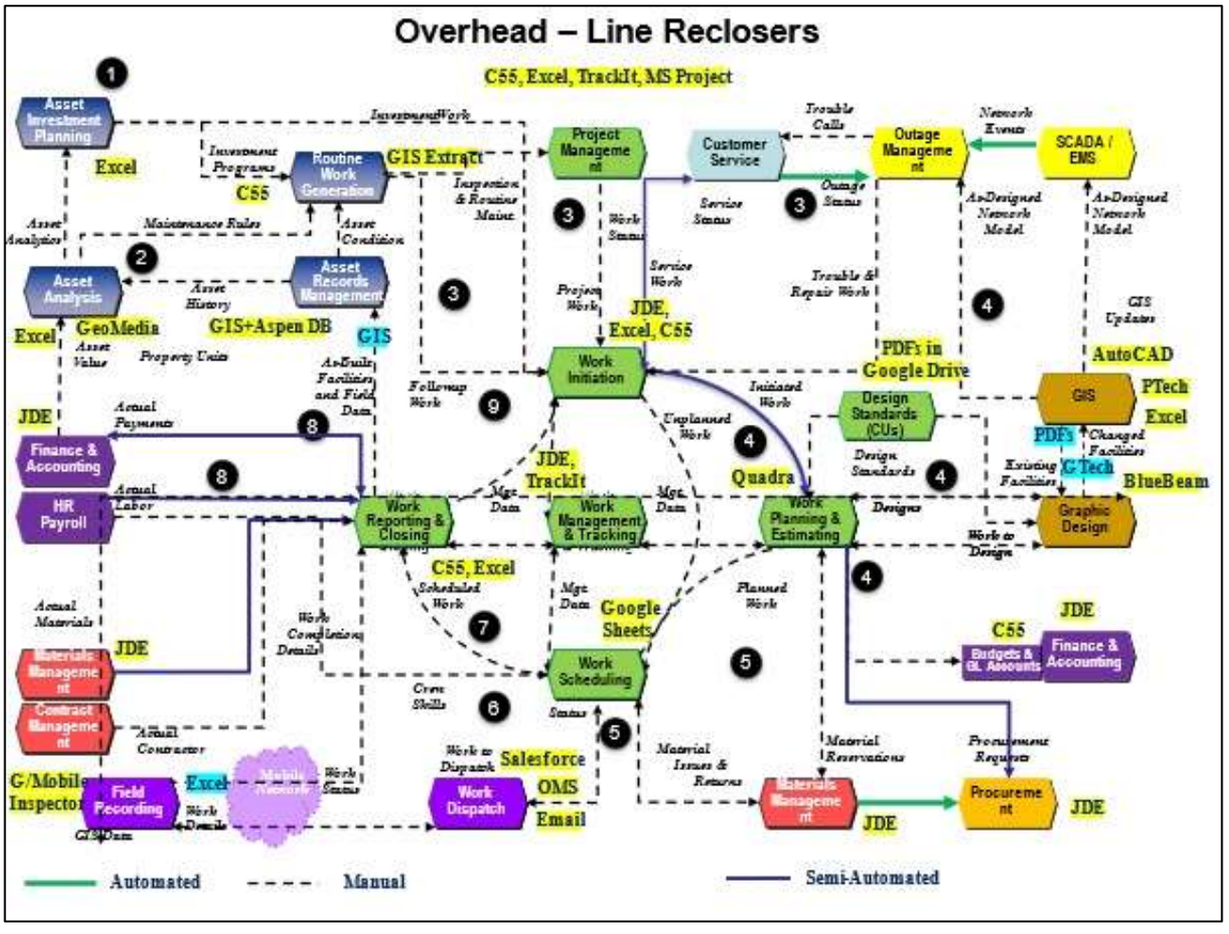
- OH Transformers



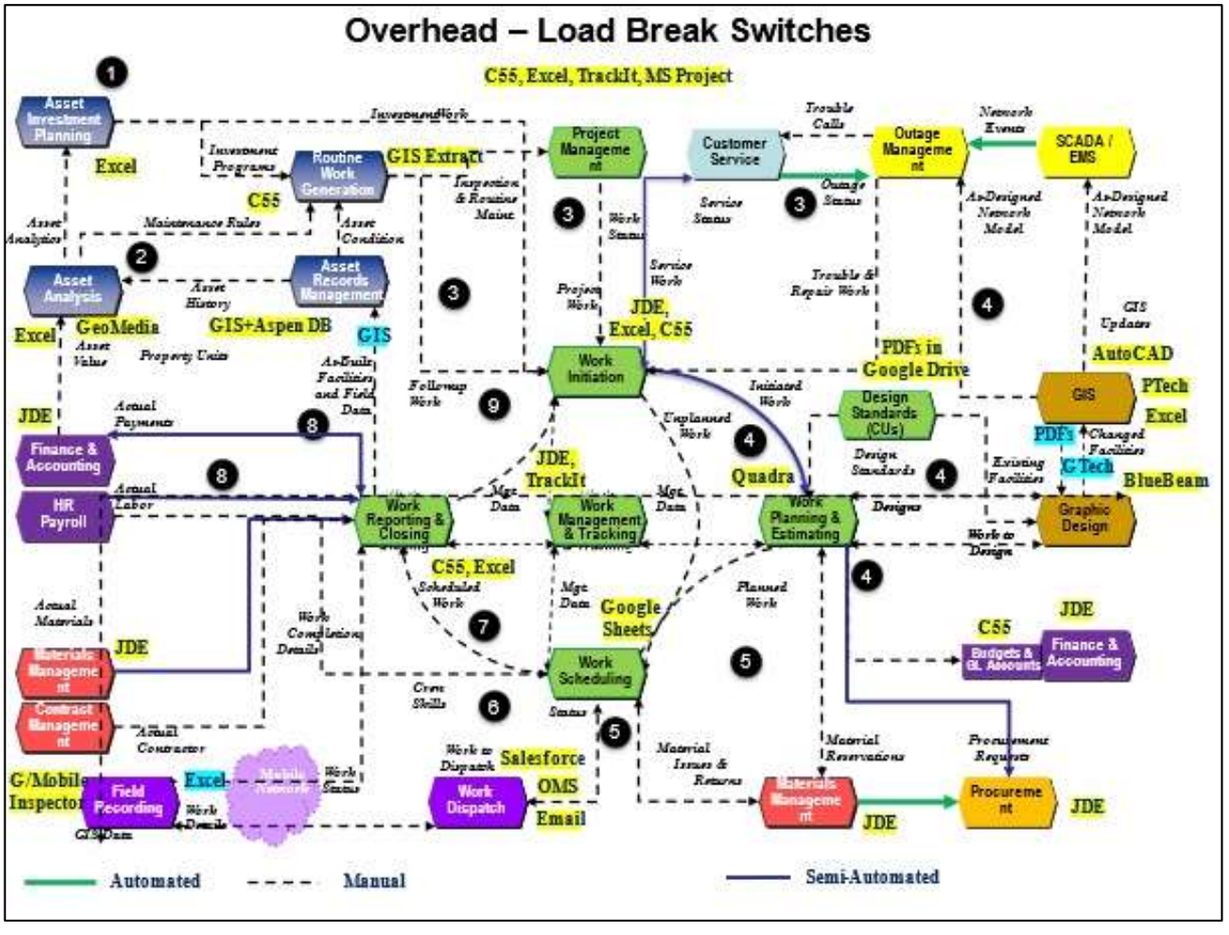
- OH Conductors



- Line Reclosers



- Load Break Switches



3.2.2 Lifecycle

Process Groups	Business Process(es)	Technology	Pain Points
Capital Projects	*Asset Records Management* GIS houses all data for OH Structures. GIS and Aspen DB houses all data for line recloser. There is no integration between the two. *Asset Investment Planning* Spreadsheet is used for Asset Investment planning. Asset investment planning is runs through C55 for Structures (Poles, Towers, Fixtures)	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets • AutoCAD • Copperleaf C55 • PowerDB • JD Edwards • Microsoft Project	• Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or

	Asset planning and budgeting for OH Conductors & Transformers is based on the historical failures, and it gets reconciled monthly. Line Reclosers and Load Break Switches do not have an active investment plan but considered run to failure. *Asset Analysis* Spreadsheet is used for Asset Analysis, initial Investment planning and then sent to Design group. GMobile Inspector is used to perform inspection data. GIS uses hyperlinks to access the inspection data. Inspection data is exported as a Spreadsheet for analysis. Analysis occurs on both Excel and GeoMedia. *Routine Work Generation* GIS data is extracted to Spreadsheet (Structures:10-year inspection cycle, OH Transformers & Conductors: 3-year inspection cycle) and GeoMedia is used for analyzing poles and scoping. *Project Management* PMO uses Track-It! and JDE for project management and tracking. Emails/ITSM are used to track changes in GIS. Quadra is used for Job Costing and Estimation. Data from project work is stored in FSL. Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) is created in spreadsheets and then runs through C55. *Work Dispatch*	• Track-It! • Salesforce FSL • ASPEN Relay Database • Emails • Quadra • Bluebeam Revu • GMobile Inspector	automation for majority of system processes.

	Work is manually allocated to field resources using Spreadsheets. Salesforce FSL is used for certain inspections that is manually dispatched currently. *Field Recording* Data from project work is stored in G/Mobile.		
Small Maintenance Projects	*Asset Records Management* GIS houses all data for OH Structures. GIS and Aspen DB houses all data for line recloser. There is no integration between the two. *Asset Investment Planning* Spreadsheet is used for Asset Investment planning. Asset investment planning is runs through C55 for Structures (Poles, Towers, Fixtures) Asset planning and budgeting for OH Conductors & Transformers is based on the historical failures, and it gets reconciled monthly. Line Reclosers and Load Break Switches do not have an active investment plan but considered run to failure. *Asset Analysis* Spreadsheet is used for Asset Analysis, initial Investment planning and then sent to Design group. GMobile Inspector is used to perform inspection data. GIS uses hyperlinks to access the inspection data. Inspection data is exported as a Spreadsheet for analysis. Analysis occurs on both Excel and GeoMedia. *Routine Work Generation*	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets • AutoCAD • Copperleaf C55 • PowerDB • JD Edwards • Microsoft Project • Track-It! • Salesforce FSL • ASPEN Relay Database • Emails • Quadra • Bluebeam Revu • GMobile Inspector	• Data Governance – System of record is spreadsheets. • Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or automation for majority of system processes.

	GIS data is extracted to Spreadsheet (Structures:10-year inspection cycle, OH Transformers & Conductors: 3-year inspection cycle) and GeoMedia is used for analyzing poles and scoping. *Project Management* Maintenance projects are managed by Phil's and Station maintenance Team in Spreadsheets. The Work Order (WO) is created in JDE PMO uses Track-It! and JDE for project management and tracking. Emails/ITSM are used to track changes in GIS. Quadra is used for Job Costing and Estimation. *Work Dispatch* Maintenance work, including inspections are routed to the field using Salesforce FSL. The work as well as the data for the work is captured in FSL forms. *Field Recording* Data from project work is stored in G/Mobile.		
Large Maintenance Projects	*Asset Records Management* GIS houses all data for OH Structures. GIS and Aspen DB houses all data for line recloser. There is no integration between the two. *Asset Investment Planning* Spreadsheet is used for Asset Investment planning. Asset investment planning is runs through C55 for Structures (Poles, Towers, Fixtures) Asset planning and budgeting for OH Conductors & Transformers is based	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets • AutoCAD • Copperleaf C55 • PowerDB • JD Edwards • Microsoft Project • Track-It! • Salesforce FSL	• Data Governance – System of record is spreadsheets. • Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or

	on the historical failures, and it gets reconciled monthly. Line Reclosers and Load Break Switches do not have an active investment plan but considered run to failure. *Asset Analysis* Spreadsheet is used for Asset Analysis, initial Investment planning and then sent to Design group. GMobile Inspector is used to perform inspection data. GIS uses hyperlinks to access the inspection data. Inspection data is exported as a Spreadsheet for analysis. Analysis occurs on both Excel and GeoMedia. *Routine Work Generation* GIS data is extracted to Spreadsheet (Structures:10-year inspection cycle, OH Transformers & Conductors: 3-year inspection cycle) and GeoMedia is used for analyzing poles and scoping. *Project Management* Maintenance projects are managed by FO and PM group in Spreadsheets. The Work Order (WO) is created in JDE (JDE - > Excel -> C 55) PMO uses Track-It! and JDE for project management and tracking. Emails/ITSM are used to track changes in GIS. Quadra is used for Job Costing and Estimation. *Work Dispatch* Maintenance work, including inspections are routed to the field using Salesforce FSL. The work as well as the data for the work is captured in FSL forms. *Field Recording*	• ASPEN Relay Database • Emails • Quadra • Bluebeam Revu • GMobile Inspector	automation for majority of system processes.

	Data from project work is stored in G/Mobile.		

3.3 Stations

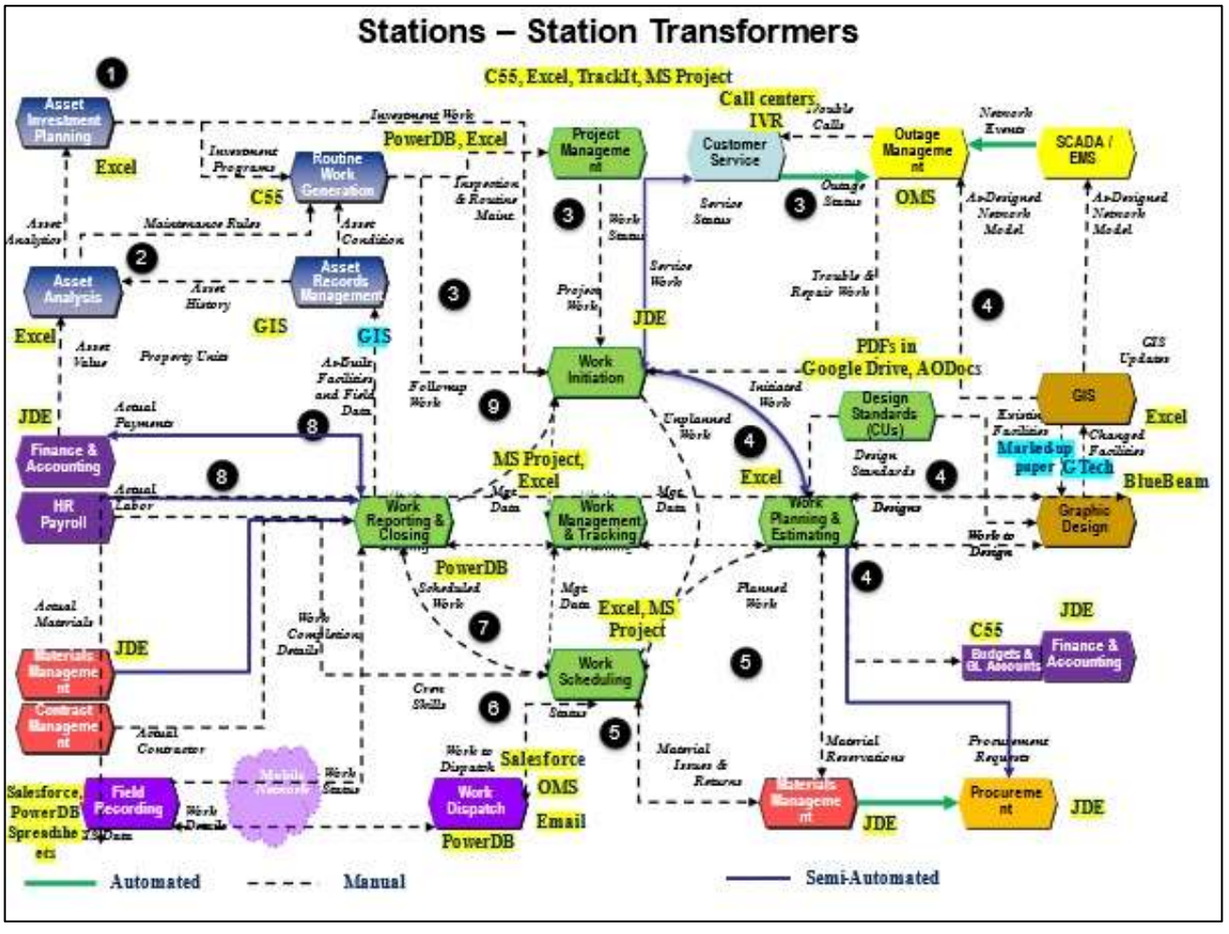
While a station consists of multiple assets, the distinct ones considered for stations business process analysis are

- Station Transformers
- Station Breakers
- Relays and Protection Equipment

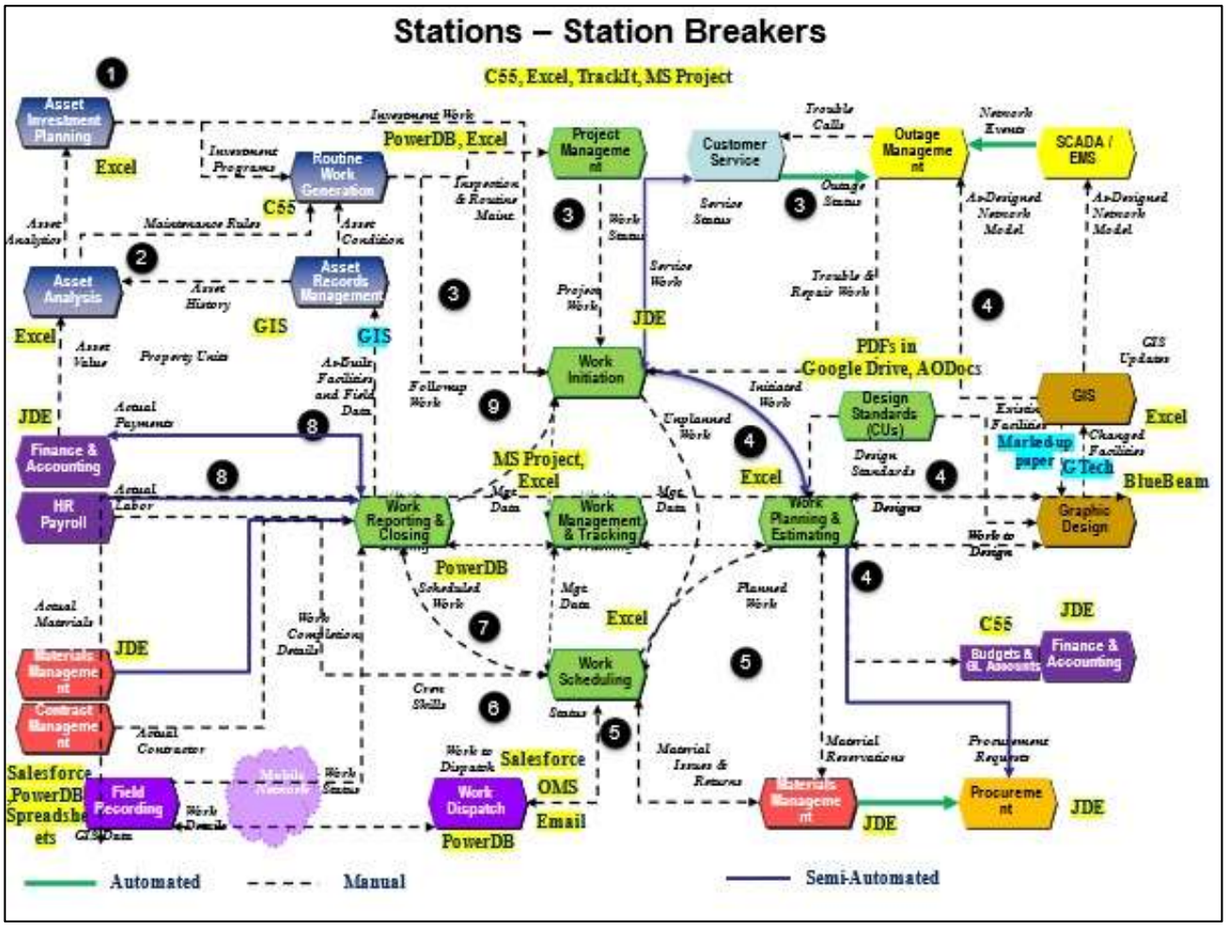
3.3.1 Process Blocks

When we overlay the reference conceptual architecture with the processes for substation assets followed at Hydro Ottawa, we get the following process blocks as results. We will discuss each of the process steps in the next section

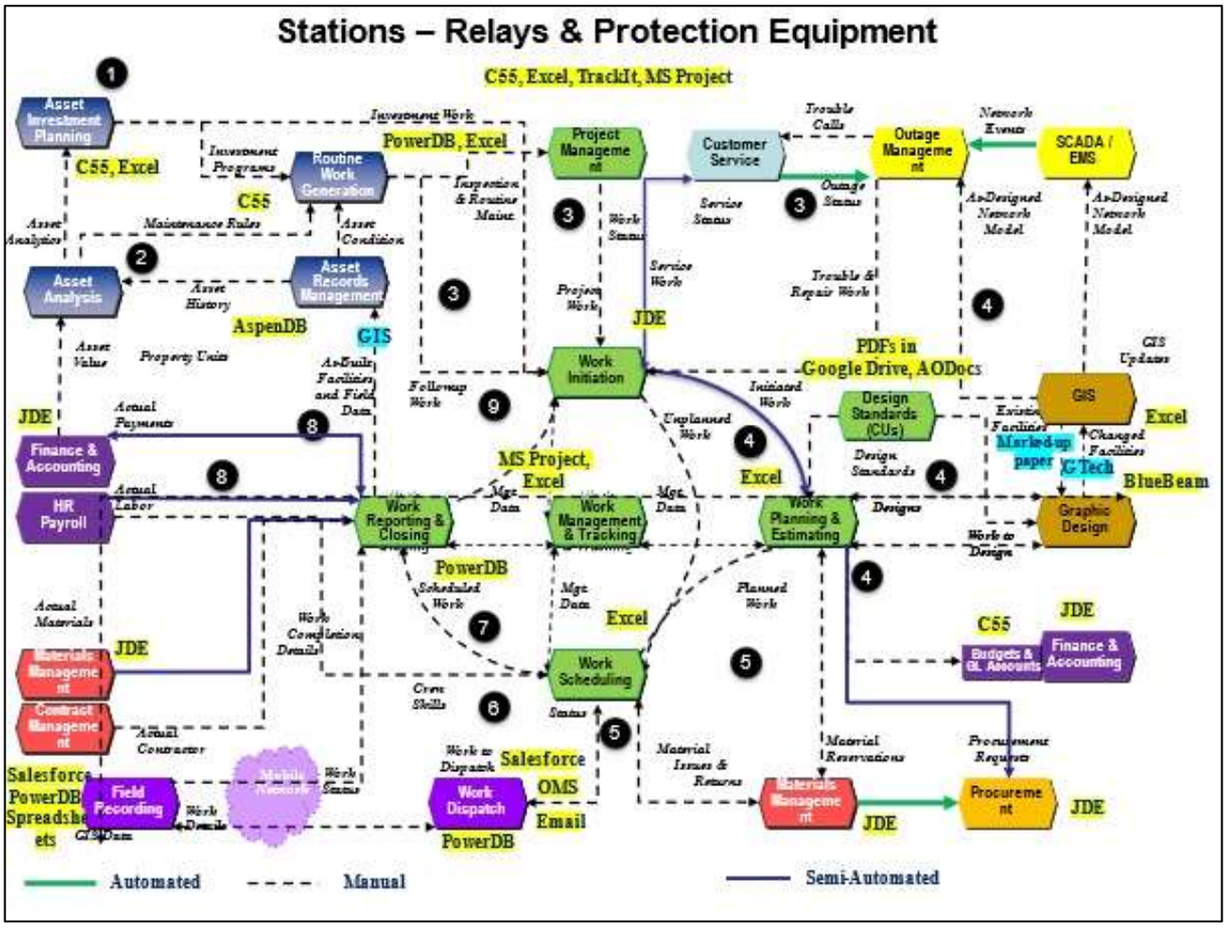
- Station Transformers



- Station Breakers



- Relays and Protection Equipment



The assets in Station are assigned, maintained, and retired using 3 major process groups

- Capital Projects
- Small Maintenance Projects
- Large Maintenance Projects

3.3.2 Lifecycle

Process Groups	Business Process(es)	Technology	Pain Points
Capital Projects	*Asset Records Management* GIS houses all data for station transformers, though not for all station equipment, relays, switchgear and breakers, etc. Single Line Diagrams are stored on Network Drive. Station Diagrams flow from AutoCAD to GIS.	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets (Google Sheets & MS Excel)	• Data Governance – System of record is spreadsheets. • Lack of integrated Document Management System to link up

	Asset Analysis GIS data is extracted to Spreadsheet and complemented with additional data by M&R Unit to create the golden copy to be used for all processes. Spreadsheets are used for calculating health indices, HOL developed HI framework through working with external consultants. A third-party created health index framework is used to evaluate the current health of assets. *Asset Investment Planning* Asset investment planning is triggered, and management finalized in a spreadsheet. This runs through C55 for cost analysis. C55 used for project scoring and optimization of annual project list. *Project Management* Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) is created in JDE PMO uses Spreadsheet/Microsoft Project (MPP) for project management. Emails/ITSM are used to track changes in GIS. *Work Dispatch* Work is manually allocated to field resources using Spreadsheets. Salesforce FSL is used for certain inspections that is manually dispatched currently. *Field Recording* Data from project work is stored in PowerDB and Network folders using e-Forms. For FSL work, data is captured in application forms, along with a few e-forms stored in Network folders.	• AutoCAD • Copperleaf C55 • PowerDB • JD Edwards • Microsoft Project • Track-It! • Salesforce FSL • ASPEN Relay Database • Emails • Bluebeam • AODocs	from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or automation for majority of system processes.

Small Maintenance Projects	*Asset Records Management* GIS houses all data for station transformers. Single Line Diagrams are stored on Network Drive. Station Diagrams flow from AutoCAD to GIS. *Asset Analysis* GIS data is extracted to Spreadsheet and complemented with additional data by Phil's team to create the golden copy to be used for all processes. Spreadsheets are used for calculating health indices, HOL developed HI framework through working with external consultants. *Routine Work Generation* Maintenance work, including inspections are generated using the output of the Spreadsheet. *Work Dispatch* Work is manually allocated to field resources using Spreadsheets. Salesforce FSL is used for certain inspections that is manually dispatched currently. *Field Recording* For FSL work, data is captured in application forms, along with a few e-forms stored in Network folders.	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets • AutoCAD • Copperleaf C55 • PowerDB • JD Edwards • Microsoft Project • Track-It! • Salesforce FSL • ASPEN Relay Database • Emails • Bluebeam • AODocs	• Data Governance – System of record is spreadsheets. • Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or automation for majority of system processes.
Large Maintenance Projects	*Asset Records Management* GIS houses all data for station transformers. Single Line Diagrams are stored on Network Drive. Station Diagrams flow from AutoCAD to GIS. *Asset Analysis* GIS data is extracted to Spreadsheet and complemented with additional data by M&R Unit to create the golden copy to be used for all processes. Spreadsheets are used for calculating health indices, HOL developed HI	• Hexagon G/Technology • Hexagon GeoMedia • Spreadsheets (Google Sheets?) • AutoCAD • Copperleaf C55 • PowerDB • JD Edwards	• Data Governance – System of record is spreadsheets. • Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow

	framework through working with external consultants. A third-party created health index framework is used to evaluate the current health of assets. *Asset Investment Planning* Asset investment planning is triggered, and management finalized in a spreadsheet. This runs through C55 for cost analysis. C55 used for project scoring and optimization of annual project list. *Project Management* Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) is created in JDE PMO uses Spreadsheet/MPP for project management. Emails/ITSM are used to track changes in GIS. *Work Dispatch* Work is manually allocated to field resources using Spreadsheets. Salesforce FSL is used for certain inspections that is manually dispatched currently. *Field Recording* Data from project work is stored in PowerDB and Network folders using e-Forms. For FSL work, data is captured in application forms, along with a few e-forms stored in Network folders.	• Microsoft Project • Track-It! • Salesforce FSL • ASPEN Relay Database • Emails •	across most processes is manual. • Missing system controls and/or automation for majority of system processes.

3.4 Metering

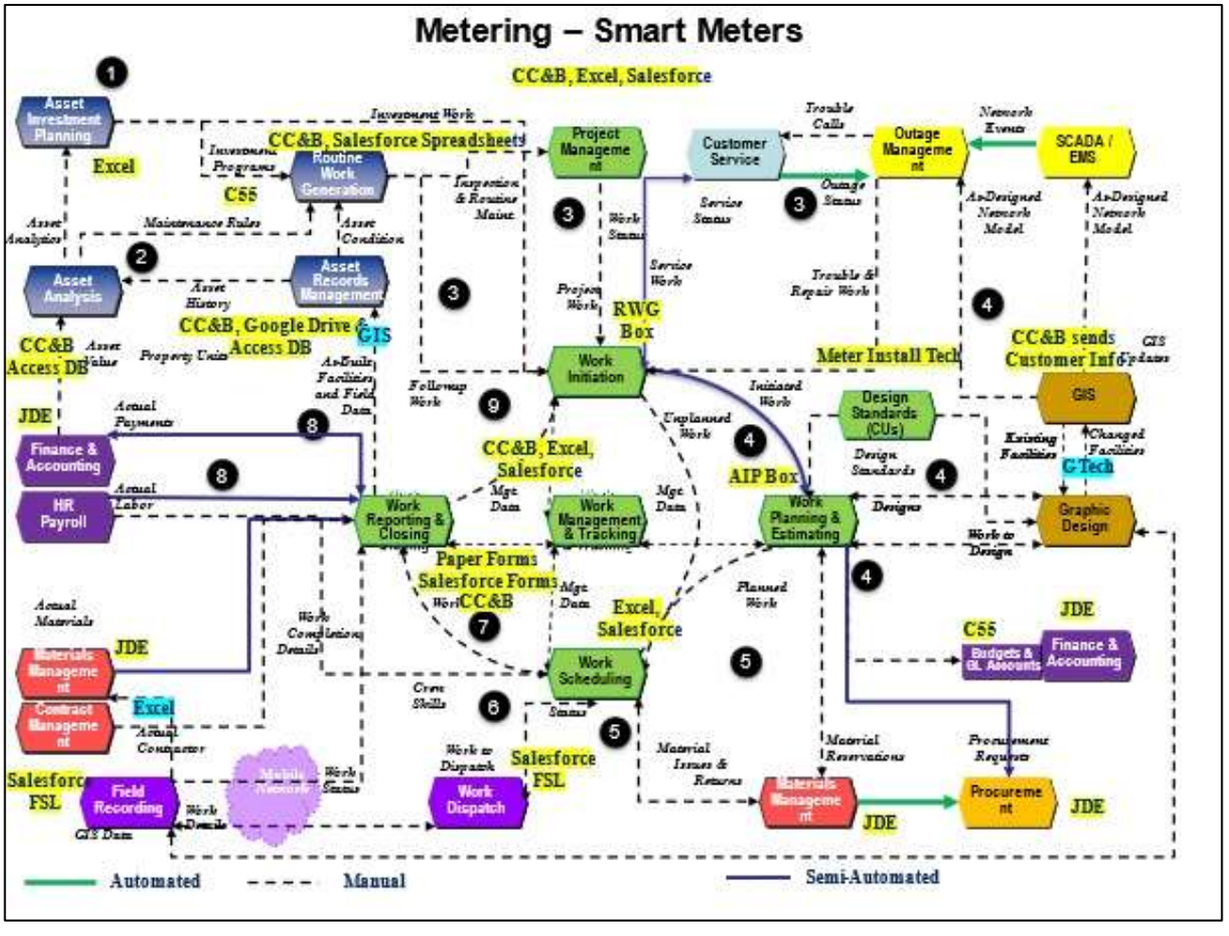
The following assets are categorized under Metering assets

- Smart Meters
- CTs / PTs (Large I&C meters)

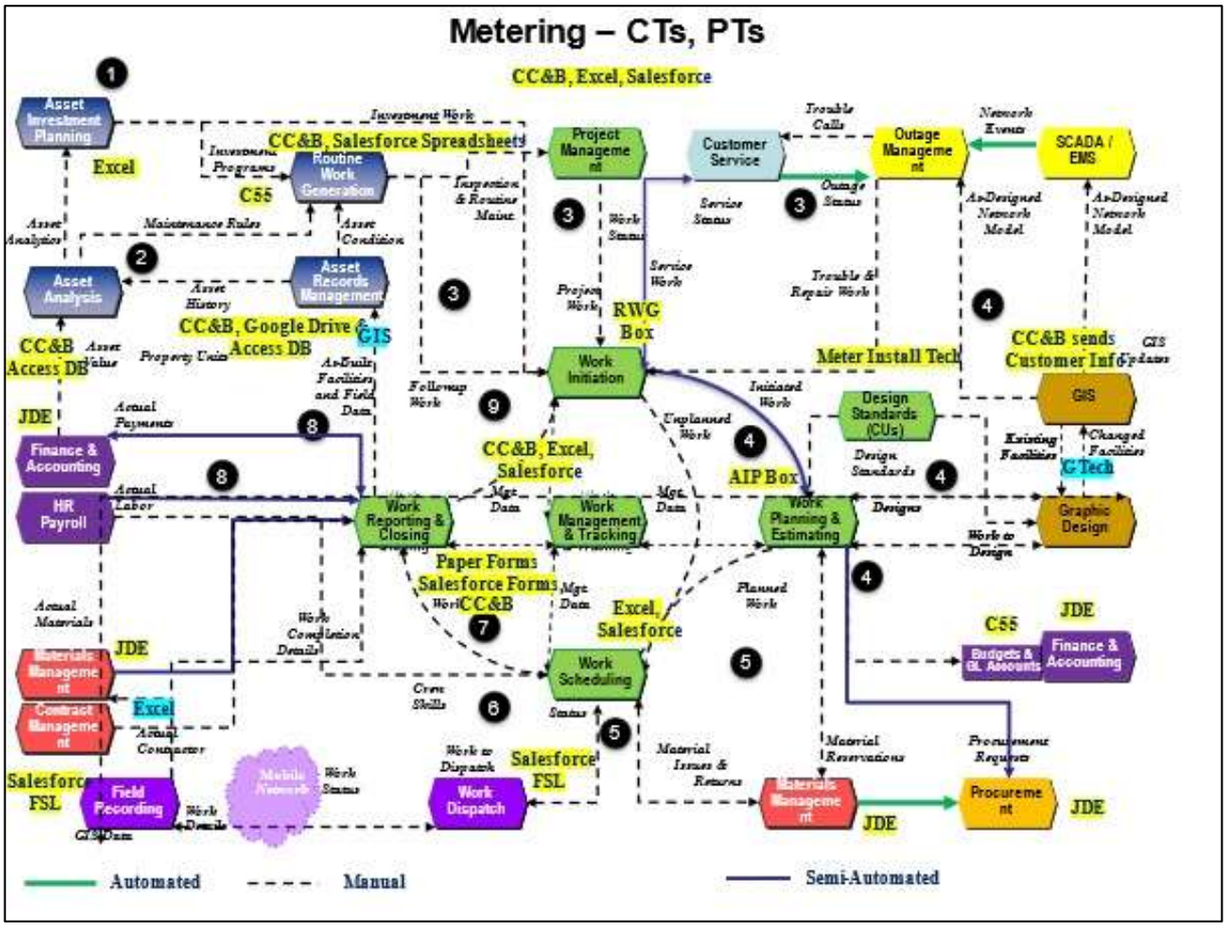
3.4.1 Process Blocks

When we overlay the reference conceptual architecture with the processes for metering assets followed at Hydro Ottawa, we get the following process blocks as results. We will discuss each of the process steps in the next section

- Smart Meters



- CTs / PTs (Large I&C meters)



3.4.2 Lifecycle

Process Groups	Business Process(es)	Technology	Pain Points
Capital Projects	*Asset Records Management* CC&B houses all data for smart meters. Meter Certificates (Pre-test/Sealing certificate) are stored on Network Drive. Non-conformance meters are stored in Access DB. IESO metering registration portal is used to register new wholesale metering installations. The portal also houses all data pertaining to active wholesale meter installations that are registered with the IESO.	• IESO Website • Spreadsheets (Google Sheets) • CC&B • Access DB • Google Drive • JD Edwards • Microsoft Project • Salesforce FSL	• Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow across most processes is manual.

	Asset Investment Planning Meter data is extracted to Spreadsheet from CC&B for Asset investment planning. Inventory is used for investment analysis using Capital and Maintenance programs. *Asset Analysis* Meter data is extracted to Access DB from CC&B for analysis on a weekly basis. Non-conformance process is reactive - either called on field or through automated error messages (MV90 – Industrial & Large Commercial and MDAS – Residential & Commercial). Schneider Electric/Honeywell/Triacta branded meters. *Routine Work Generation* Test data is provided by third party and then the routine order is created in CC&B. *Project Management* Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) are created in JDE. Field activities are created in CC&B/Salesforce PMO uses Spreadsheet for project management. *Work Dispatch* Maintenance works are stored in CC&B and routed to the field using Salesforce FSL. *Field Recording* Data from project work is stored in Salesforce FSL.		• Missing system controls and/or automation for majority of system processes.
Small Maintenance Projects	*Asset Records Management* CC&B houses all data for smart meters. Meter Certificates (Pre-test/Sealing certificate) are stored on	• Spreadsheets (Google Sheets) • CC&B	• Lack of integrated Document Management System to link up

	Network Drive. Non-conformance meters are stored in Access DB Asset Investment Planning Meter data is extracted to Spreadsheet from CC&B for Asset investment planning. Inventory is used for investment analysis using Capital and Maintenance programs. *Asset Analysis* Meter data is extracted to Access DB from CC&B for analysis on a weekly basis. Non-conformance process is reactive - either called on field or through automated error messages (MV90 – Industrial & Large Commercial and MDAS – Residential & Commercial). Schneider Electric/Honeywell/Triacta branded meters. *Routine Work Generation* Test data is provided by third party and then the routine order is created in CC&B. *Project Management* Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) are created in JDE. Field activities are created in CC&B/Salesforce PMO uses CC&B and Salesforce for project management. Maintenance Projects data extracted to Spreadsheets from CC&B and sent back to CC&B after manually processed and then flow from CC&B to Salesforce. *Work Dispatch* Maintenance works are stored in CC&B and routed to the field using Salesforce FSL.	• Access DB • Google Drive • JD Edwards • Microsoft Project • Salesforce FSL	from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or automation for majority of system processes.

	Field Recording Data from project work is stored in Salesforce FSL.		
Large Maintenance Projects	*Asset Records Management* CC&B houses all data for smart meters. Meter Certificates (Pre-test/Sealing certificate) are stored on Network Drive. Non-conformance meters are stored in Access DB *Asset Investment Planning* Meter data is extracted to Spreadsheet from CC&B for Asset investment planning. Inventory is used for investment analysis using Capital and Maintenance programs. *Asset Analysis* Meter data is extracted to Access DB from CC&B for analysis on a weekly basis. Non-conformance process is reactive - either called on field or through automated error messages (MV90 – Industrial & Large Commercial and MDAS – Residential & Commercial). Schneider Electric/Honeywell/Triacta branded meters. *Routine Work Generation* Test data is provided by third party and then the routine order is created in CC&B. *Project Management* Approved projects are managed by assigned Project Managers (PM). The Work Order (WO) are created in JDE. Field activities are created in CC&B/Salesforce	• Spreadsheets (Google Sheets) • CC&B • Access DB • Google Drive • JD Edwards • Microsoft Project • Salesforce FSL	• Lack of integrated Document Management System to link up from multiple processes. • Lack of system integration – information flow across most processes is manual. • Missing system controls and/or automation for majority of system processes.

	Maintenance Projects data extracted to Spreadsheets from CC&B and sent back to CC&B after manually processed and then flow from CC&B to Salesforce. PMO uses CC&B and Salesforce for project management. *Work Dispatch* Maintenance works are stored in CC&B and routed to the field using Salesforce FSL. *Field Recording* Data from project work is stored in Salesforce FSL.		

3.5 Telecom

Hydro Ottawa's fiber optic network provides high performance communications with a dedicated 1 Gigabit connection, it consists of multiple assets and these assets divided into two broad categories - location assets and communication assets. Location asset which has location information, maintained in GIS, and called as OSP – outside plant communication, whereas communication asset helped for network communication and maintained in network management and called as ISP – Inside plant communication.

Location assets

- Fiber optic cable
- Station
- Jumpers
- Splice
- Rack
- RTU
- Fault Indicators
- Duct and Conduit
- Utility access hole

Communication assets

- Racking Equipment Information
- Router
- Local network accessories like Phone, Radio, Security Cameras

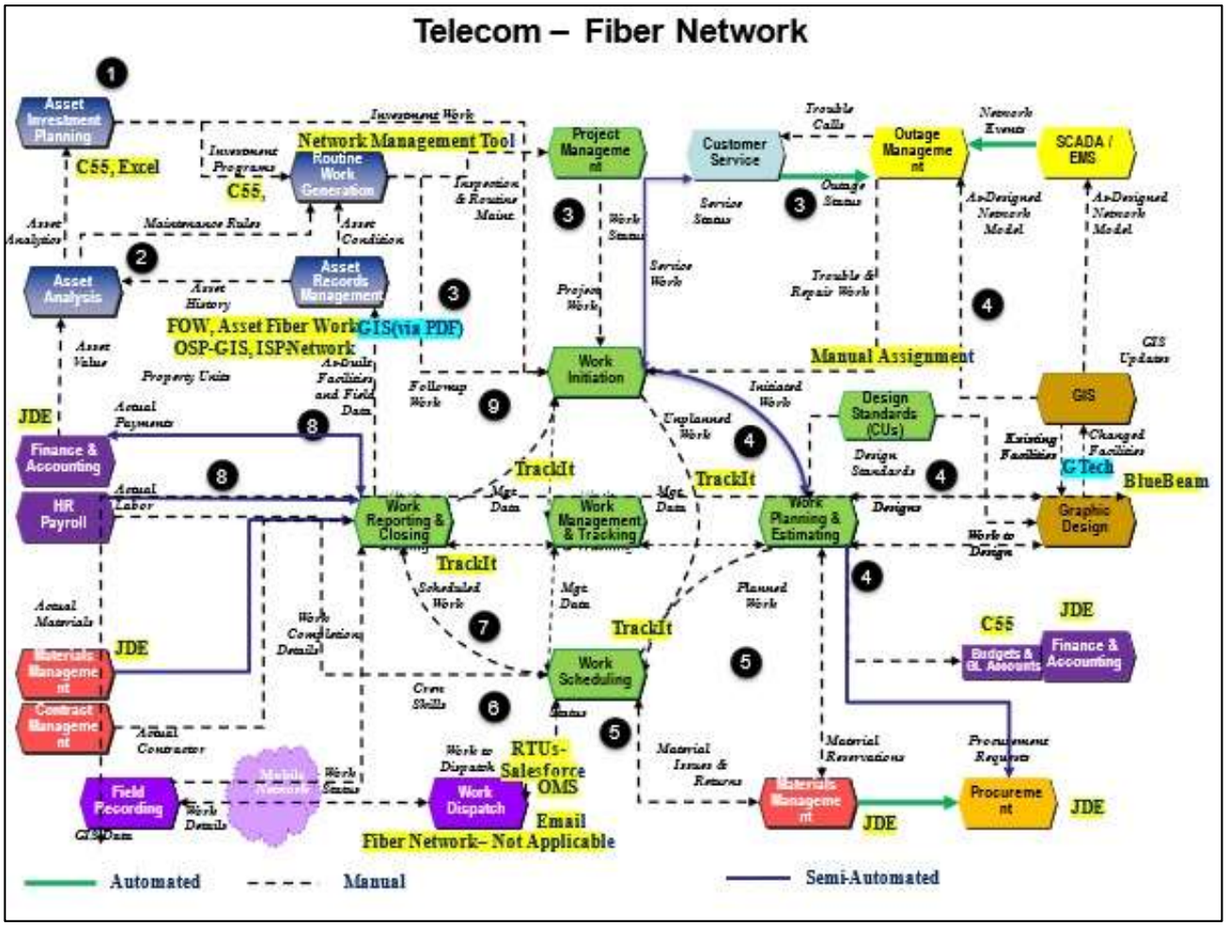
The assets in Fiber optics are assigned, maintained, and retired using 4 major process groups

- Capital Plan: System Access, System Renewal and System Service
- Operation and maintenance plan
- Disposal plan
- Contingency and emergency plan

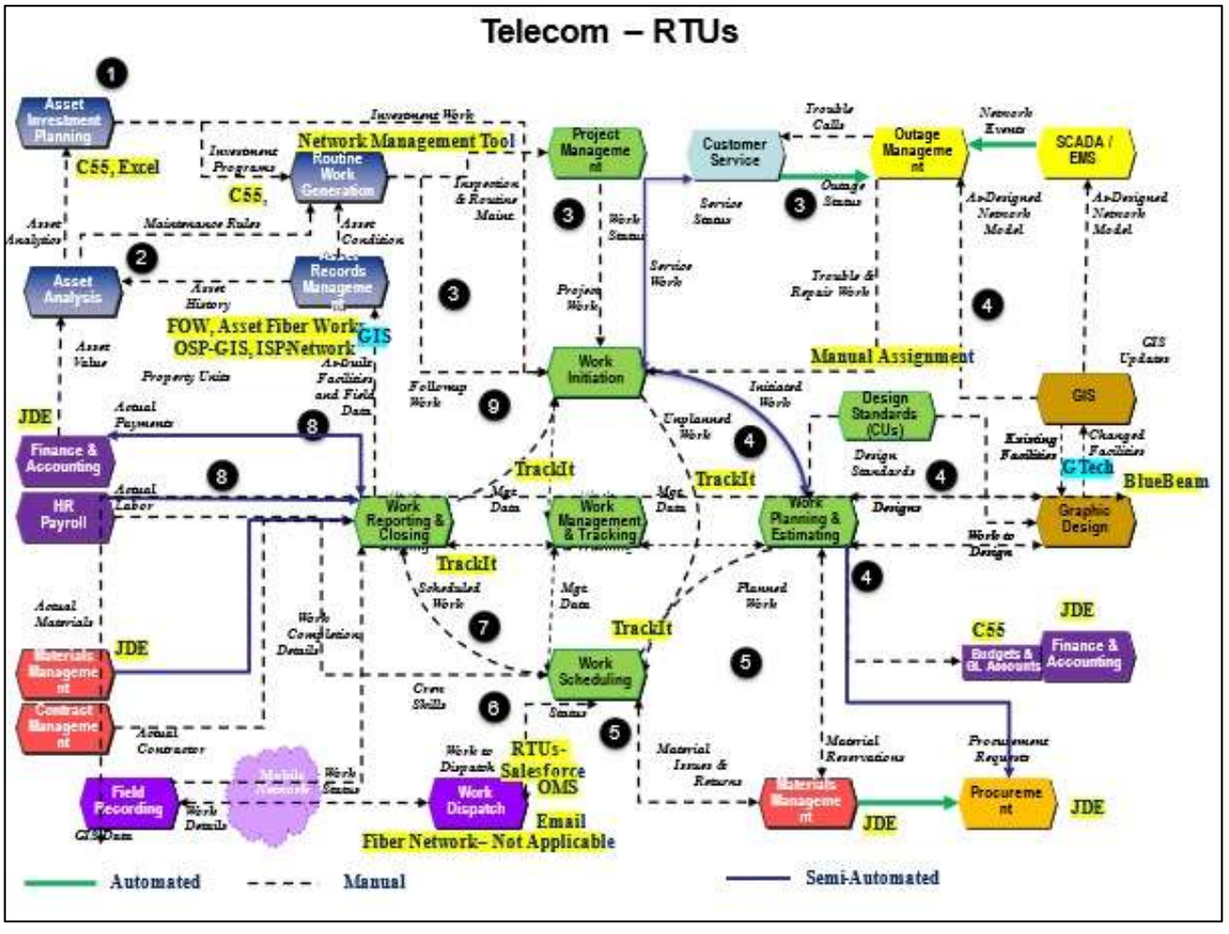
3.5.1 Process Blocks

When we overlay the reference conceptual architecture with the processes for telecom assets followed at Hydro Ottawa, we get the following process blocks as results. We will discuss each of the process steps in the next section

- Fiber Network



- RTUs



3.5.2 Lifecycle

Process Groups	Business Process(es)	Technology	Pain Points
All	System Access: • System Expansion • New/upgraded local network connections System Renewal: • Assets replaced due to failure • Assets installed to maintain or improve network redundancy • Asset damaged by third parties System Service:	• Hexagon G/Technology • Hexagon FOW • Nokia Network Management Tool • PDF Documents • Spreadsheet • ITSM	• No insights into proactive Asset Analysis • Opportunities to bring them under the asset management umbrella with different SOP

	• New or upgraded assets to improve reliability (software) • New or upgraded assets to improve capacity constraints (increase bandwidth) *Asset Investment Planning* All network components are run-to-failure. So, AIP is only applied when a component fails, or vendor retires the equipment. *Asset Analysis* All network components are monitored through network tools which provide real-time state of the network. *Routine Work Generation* The network is managed by Promark-Telecon. For end equipment, work tickets are generated when failure events are triggered. *Project Management* Capital Projects are managed through Microsoft Project/Spreadsheets. Event based work is tracked through ITSM. *Field Recording* All data is captured in ITSM for maintenance work. For capital work, data is captured in e-Forms and PDFs.		

4 Pain Points

A summary of the pain-points of each asset groups and their remediations based on best practices are highlighted in the tables below. These are based on the session discussions and their mappings to the reference T&D conceptual architecture.

4.1 Underground Assets

Key Process	Pain Point(s)	Remediation(s)
Asset Investment Planning	○ Spreadsheets are primarily used ○ Analytics based the asset state is manual.	• Implement predictive analysis through Industry packages.
Routine Work Generation	○ Estimation tool is not used always ○ No integration from C55 with Quadra ○ GIS extract is maintained in Excel and no integration with GIS systems	• Implement Work and Asset management packages to integrate end to end flows.
Work Planning & Estimation	○ Manual process where blue folders, project hours and estimate updated on white board	• Implement Document Management System with smart tagging.
Work Management & Tracking	○ Work management and tracking is done via the Whiteboard/Google Sheet, though the financial aspect is tracked via JDE. ○ No direct linkage exists between the systems	• Implement Work and Asset management packages with compatible units' feature.
	○ Monthly actuals/forecasts and change requests are submitted through C55 and then sent to JDE manually. No direct integration available. ○ A dedicated e-mail inbox is used for emergency failure monitoring	• Implement Work and Asset management packages to integrate end to end flows.
Work Reporting & Closing	○ A closing off meeting is conducted, closures are done manually in each system, data synchronization is unavailable across JDE, GIS etc. ○ Not all assets are treated as discrete in JDE ○ Manual data updates in GIS	• Implement Work and Asset management packages to integrate end to end flows. • Financials can be bundled in the Bill of Materials (BOM) process.
Work Dispatch	○ As on today, only Salesforce used for inspections dispatch. No direct linkage with Field Recording. ○ No skillset driven or automated availability check is functional	• Integrate FSL with EAM packages to trigger automated dispatch. • Implement Resource Management packages
Field Recording	○ No automated process for inspections and emergency work – manual process for planned work using e-mails, Google Sheets ○ Information captured in the field is manual ○ Only visual Inspection done on Switchgears	• Extend Salesforce FSL to meet the needs

Overall	○ At least 60% of the process flows are manual	• Implement Work and Asset management packages to integrate end to end flows.

4.2 Overhead Assets

Key Process	Pain Point(s)	Remediation(s)
Asset Investment Planning	○ Asset Planning and Budgeting is based on the historical failures and is not applicable or not performed ○ Forecasting is done in Excel	• Implement predictive analysis through Industry packages.
Asset Analysis	○ Excel sheets are primarily used for Asset Analysis and Investment planning for Structures and Transformers ○ Ad-hoc analysis is done in Google Sheets & GeoMedia, no specific defined process for Line reclosers and Load Break switches.	
Routine Work Generation	○ GIS extract is maintained in Excel with no backward integration with GIS systems	• Implement Work and Asset management packages to integrate end to end flows.
Project Management	○ Project created is available in C55 and JDE but no direct integration	
Work Initiation	○ WO creation and work assignment is manual process	
Overall	○ At least 60% of the process flows are manual	
GIS	○ Bluebeam markups are manually updated in GIS. Once completed, new PDFs with updated GIS info can be created for further markup.	• Opportunities to integrate Bluebeam with GIS or integrate GIS with a Document Management System.

4.3 Station Assets

Key Process	Pain Point(s)	Remediation(s)
Asset Investment Planning	○ Forecasting and Planning utilizes Excel to an extent	• Implement predictive analysis through Industry packages.
Asset Records Management	○ Updates are made in spreadsheets ○ Asset Info is sent by e-mails to GIS for updates	• Implement Work and Asset management packages to integrate end to end flows
Routine Work Generation	○ PowerDB (maintenance repository) - only stores inspection results, does not generate any work. PowerDB data is manually extracted. ○ PowerDB data is manually extracted for analysis.	

	○ Activities not linked to routine maintenance are managed in a shared drive. ○ Maintenance cycle is maintained through spreadsheets.	
Work Management	○ These key processes related to work initiation, tracking etc. uses spreadsheets throughout the processes with minimal integrations	
Work Reporting & Closing	○ Spreadsheets are used to an extent ○ No data sent to GIS	
Design Standards	○ Mostly available in PDFs and review is done manually	
Overall	○ At least 60% of the process flows are manual	

4.4 Metering Assets

Key Process	Pain Point(s)	Remediation(s)
Asset Records Management	○ Non-Conformance meters are stored in Access DB	• Store this information in CC&B too.
Asset Investment Planning	○ Spreadsheets are used mostly for investment planning	• Implement predictive analysis through Industry packages.
Project Management	○ PMO uses Microsoft Project or Spreadsheets to manage project items.	• Implement Work and Asset management packages to integrate end to end flows.
Work Management	○ These key processes related to work initiation, tracking etc. uses spreadsheets throughout the processes with minimal integrations	• Implement Work and Asset management packages to integrate end to end flows.

4.5 Telecom Assets

Key Process	Pain Point(s)	Remediation(s)
Asset Analysis	○ This is not applicable currently in as-is, there is a need to plan in future.	•

4.6 Summary – Pain Points

The following points summarize the key issues within the current processes followed by Hydro Ottawa team

- ○ Manual Data entry and transfer across key systems
- ○ Integration unavailable between key systems
- ○ Data Synchronization is manual

- Estimations and Forecasting is done through manual operations
- Project Management Tasks are performed in Excel spreadsheets
- Work dispatch, scheduling does not leverage automated functionalities
- At least 60% of the tasks are performed manually across the asset management process stages
- GIS data maintenance, transfer, data posting is manually done

5 Additional Considerations

Along with the major asset groups discussed above, we also discussed secondary and tertiary processes linked to Asset and Work Management processes. A brief review of the processes is

Process Groups	Business Process(es)	Technology	Pain Points
DERMS	Currently this is managed through GIS. All data related to the feed are captured like customer data, capacity, feeder info, controlled or not, any other modelling details. Any analysis on the data is performed through SQL Queries **Adding this capability is being considered in the DMS project.	• Intergraph GeoMedia	• E2E solution missing.
OMS	Outages are reported through a call to the call center, an email to the call center or through the app. A ticket is created in OMS and the work process continues. For Storms work, the prioritization of work is done through Spreadsheets. **A system replacement from Hexagon OMS to ~~OSI~~ a new OMS is planned in DMS project.	• JDE • Intergraph GeoMedia	• Integration with the Enterprise WAM process is missing.
Communication	Customers – While dedicated information is sent via email and letters, mass information relay is also done through company website and social media. Internal – Everbridge is used for mass communication internally.	• Email • Physical Letters (CC&B?) • Website • Social Media • Everbridge	• A dedicated customer engagement module to track all corporate communication.

Locating	The locating work is outsourced to Promark-Telecon. Linked internal processes still need more discovery.	• Intergraph GeoMedia	•
Resource Management	Workday is used for resource management processes. Scheduling team manages technician shifts in Spreadsheets. For projects work, JDE and Workday are integrated. Timesheets are done in Workday and the data flows to JDE. On-call processes are managed through Spreadsheets and on calls are allocated based on least overtime.	• JDE • Workday • Spreadsheets • Salesforce FSL	• Capacity planning and resource planning is still offline and manual. • On-call process is not automated. Need tools for automation as well as auditing. • Integration with work scheduling and dispatch for real-time availability management
Vegetation Management	For distribution lines and equipment areas, vegetation management happens at regular intervals (2 year/3 year based on predefined priority). There are accelerated programs too to target faster vegetation growth areas. For existing customers, Hydro Ottawa undertakes vegetation management for a fee, when serving the area. For non-customers, the process is not defined yet.	•	

6 Summary - Recommendations

Based on the observed and discussed pain points compared against commonly followed industry practices and tools, here are the recommended tools/solution

- Enterprise Asset Management Solution
- Work Management Solution
- Project Management Solution
- Document Management Solution
- Resource Management Solution
- On-Call Management Solution
- Extend Salesforce FSL – Auto Dispatch and Field Data Capture
- Reporting and Analytics Solution esp. Live Dashboards

- Data Governance Policies and Implementation
- Integrations across solutions
- DERMS solution

Technology Roadmap for HOL Asset Management

To-Be Recommendations

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Project Objectives

1. 
   Review HOL's Strategic Asset Management Plan (SAMP) and individual AMPs
2. 
   Identify and document process and systems pain points and gaps
3. 
   Capture future business requirements
4. 
   Formulate To-Be IT Strategy aligned to SAMP
5. 
   IT implementation Roadmap with recommendations for an Integrated Asset Management Platform (IAMP)

Infosys Goal: Assist HOL in deciding and implementing an Integrated Asset Management Platform (IAMP)

Summary of Pain Points

- **Manual Data entry** and **transfer** across key systems
- **Integration unavailable** between key systems
- **Data Synchronization** is manual
- **Estimations and Forecasting** is done through manual operations
- **Project Management Tasks** are performed in Excel spreadsheets
- Work dispatch, scheduling does not leverage **automated functionalities**
- At least **60% of the tasks are performed manually** across the asset management process stages
- GIS data maintenance, transfer, data posting is manually done

** Detailed outline of pain points by asset class listed in appendix section*

Product Selection : Summary

Infosys understands that the following are critical for HOL to deliver incremental business value in 2022 & beyond. These factors will enable a stable, robust IT delivery to achieve the to-be architecture

- **Future Proof Architecture** – 2022 and beyond
- **Leverage on the application offerings** – asset management, CRM, GIS, JDE etc. This will standardize the business processes for asset management
- **Industry standard data model** which caters to the asset management plans defined by HOL. This will help in establish the single source of truth – data and documents
- Defining a **data governance framework** to achieve data integrity and governance
- **Data warehouse maintenance** to extract intelligence on asset data
- **CRM and Mobility driven solutions** – Salesforce, FSL for easy decision making, better customer service
- **Automated processes** to replace manual XLS based data entry resulting in higher productivity and efficiency

Product Selection : Summary

EAM	Weightage	IBM Maximo	Infor CloudSuite EAM	Oracle Utilities WACS	SAP EAM
		Weighted Category Score	Weighted Category Score	Weighted Category Score	Weighted Category Score
VENDOR RATING	15%	2.10	2.10	1.50	2.10
FUNCTIONAL CAPABILITIES	40%	23.20	22.80	18.40	23.20
MOBILITY FEATURES	15%	3.90	3.90	3.00	3.90
REPORTING FEATURES	10%	1.70	1.60	1.30	1.70
TECHNOLOGY FEATURES	10%	3.30	3.30	2.90	3.30
PLATFORM SERVICES	10%	2.70	2.60	2.60	2.80
TOTAL	**100%**	**36.90**	**36.30**	**29.70**	**37.00**

GIS	Weightage	Hexagon(intergraph)	ESRI	GESW
		Weighted Category Score	Weighted Category Score	Weighted Category Score
VENDOR RATING	15%	2.10	1.80	1.50
FUNCTIONAL CAPABILITIES	40%	21.60	20.80	19.60
MOBILITY FEATURES	15%	3.45	4.20	2.25
REPORTING FEATURES	10%	1.50	1.70	1.40
TECHNOLOGY FEATURES	10%	2.80	3.10	2.60
PLATFORM SERVICES	10%	2.30	2.70	1.40
TOTAL	**100%**	**33.75**	**34.30**	**28.75**

**Product Selection for GIS is only for representative purpose as GIS is out of scope*

Product Selection – Why a specific EAM Product?

Infor EAM

- Comparable to leading products in EAM capabilities.
- Hexagon acquisition would lead to GIS and EAM synergy.
- Infor Named 2021 AWS Industry Solution ISV Partner of the Year

IBM Maximo

- Industry leading EAM capability
- AppPoints licensing is a welcome change

SAP EAM

- Industry leading EAM capability
- Unified and integrated Platform for Asset, Inventory & Finance functions
- Well designed Digital Roadmap to align with Industry trends (Ex : Intelligent Asset Management, IoT, Predictive Maintenance)

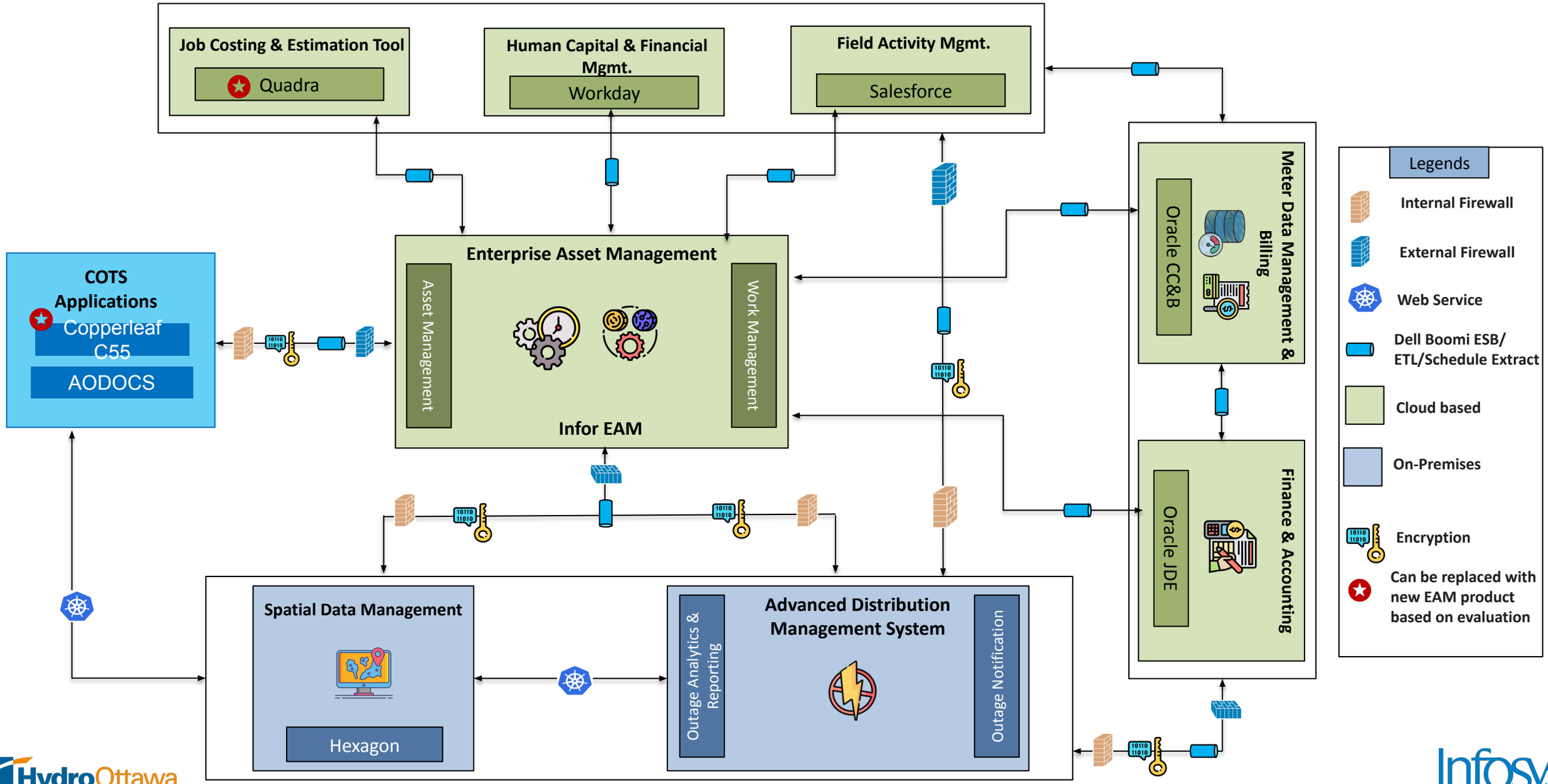
Infor EAM or IBM Maximo

Retain, Retire Matrix

App(s) ↓	Year(s) →	2022				2023				2024				2025				2026			
Business Function	Product Name	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Finance	Oracle JDE 9.2	Y	Y	Y	Y	Y	Y	Y	Y	E											
Procurement	Oracle JDE 9.2	Y	Y	Y	Y	Y	Y	Y	Y	E											
Supply Chain	Oracle JDE 9.2	Y	Y	Y	Y	Y	Y	Y	Y	E											
Metering and Billing	Oracle CC&B	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
CRM	Salesforce CRM	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
HCM	Workday	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Field Service Management	Salesforce FSL	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
GIS	Hexagon Intergraph	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
OMS			E	E	E	T	T	T	T	T	T	T	T	Y	Y	Y	Y	Y	Y	Y	Y
Work Estimation	Quadra	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	E	T	T	N	N	Infor EAM			
Asset Investment Decisions	Copperleaf Portfolio	Y	Y	Y	Y	Y	Y	E	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Infor EAM	
Assets Test Data Management	PowerDB	Y	Y	Y	Y	E	T	T	N	N	Infor EAM										
Assets Maintenance Records	ASPEN Relay Database	Y	Y	Y	Y	Y	E	T	T	N	N	Infor EAM									
Asset Record Management	Infor EAM			T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Asset Management	Infor EAM					T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Work Management	Infor EAM					T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Asset Project Management	Infor EAM							T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Asset Analysis	Infor EAM								T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Asset Investment Planning	Infor EAM										T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y
Document Management	AODocs	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IT Service Management	Trackit!	Y	T	T	N	N															
IT Service Management	ServiceNow		T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

Y	In Use
N	Retired
E	Under Evaluation
T	Transition

Integration Architecture



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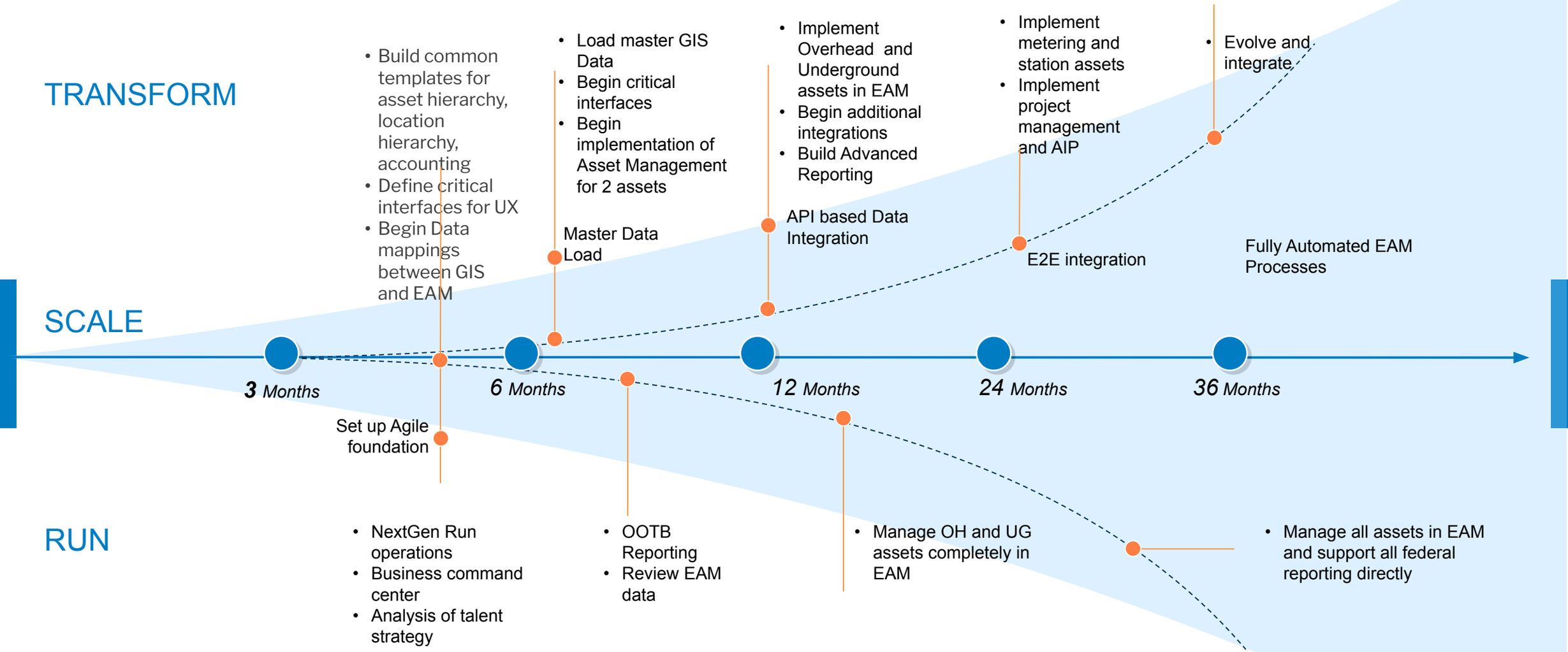
Integrations – To-Be State

Integrations	Business Function	Current Product	Future Product	Hosting Platform	Replacement	Integration Platform
EAM-Job Costing & Estimation	Job Costing & Estimation	Quadra	EAM - Infor/Maximo	Cloud based (SaaS)	Yes	Dell Boomi
EAM - Human Capital Management	Human Capital Management	Workday	Workday	Cloud based (SaaS)	No	Dell Boomi
EAM - Field Activity Management	Field Activity Management	Excel	EAM - Infor/Maximo	Cloud based (SaaS)	Yes	Dell Boomi
EAM - Oracle CC&B	Customer Care & Billing	Oracle CC&B	Oracle CC&B	Hosted on IBM Cloud	No	Dell Boomi
EAM - Oracle JDE	Financial Management	Oracle JDE	Oracle JDE	Hosted on IBM Cloud	No	Dell Boomi
EAM - Copperleaf C55	Asset Investment	Copperleaf	EAM - Infor/Maximo	Cloud based (SaaS)	Yes	Dell Boomi
EAM - Aspen Relay DB	Relay and electric protection equipment repository	Aspen Relay DB	EAM - Infor/Maximo	Cloud based (SaaS)	Yes	Dell Boomi
EAM – PowerDB	Equipment maintenance & inspection	Power DB	EAM - Infor/Maximo	Cloud based (SaaS)	Yes	Dell Boomi
EAM – GIS	Spatial Data Management	Intergraph-Hexagon	Integraph-Hexagon,FME	On-Premise	No	Dell Boomi
EAM – ADMS	Advanced Distribution Management System	Intergraph	To be selected	Cloud based (SaaS)	Yes	Dell Boomi
EAM - Spatial Data Management	Oracle Spatial	Oracle Spatial	Oracle Spatial			
EAM – Salesforce	Field Service	Salesforce	Salesforce	Cloud based (SaaS)	No	Dell Boomi
EAM – AODocs	Document Management	AODocs	AODocs	On-Premise	No	Dell Boomi
Oracle CC&B – Salesforce	Field Service	Salesforce	Salesforce	Cloud based (SaaS)	No	Dell Boomi
Oracle CC&B – GIS	Spatial Data Management	Intergraph-Hexagon	Integraph-Hexagon,FME	On-Premise	No	Dell Boomi
Oracle CC&B – JDE	Financial Management	Oracle JDE	Oracle JDE	Hosted on IBM Cloud	No	Dell Boomi
Oracle JDE – Quadra	Job Costing & Estimation	Quadra	Quadra	Cloud based (SaaS)	No	Dell Boomi
Oracle JDE – Workday	Human Capital Management	Workday	Workday	Cloud based (SaaS)	No	Dell Boomi
Oracle JDE - Salesforce	Field Service	Salesforce	Salesforce	Cloud based (SaaS)	No	Dell Boomi

EAM Roadmap



GIS – Geographic Information System
UX – User Experience
EAM – Enterprise Asset Management

API – Application Programming Interface
AIP – Asset Investment Plan
OOTB – Out of The Box
OH, UG– Overhead, Underground

E2E - End to End Integration

Summary of Deliverables from 2022-2024 (Indicative)

2022: Mar-Jun	2022: Jun-Sep	2022: Sep-Dec	2023	2024
Procurement of EAM software	Asset Templates – Config for OH	Asset Templates – Config for OH	Data Collection & Migration for UG, Stations	Reporting for Telecom, Metering
Project Plan finalization	Data Collection & Migration for 1 asset class (OH)	Data Collection & Migration for 1 asset class (OH)	Asset Templates – Configuration for UG, Stations	Analytics module for UG, Stations, Telecom, Metering
Business Process Analysis & Optimization for 1 Asset Class(OH), Data Mapping	Out-Of-Box reporting for 1 asset class(OH) – 25 reports	Custom reports for 1 asset class(OH) - 10	Maintenance module for UG, Stations	Data Collection & Migration for Telecom, Metering
Base Install of EAM for all asset classes	Assets module for OH	Analytics module for 1 asset class (OH)	EAM Platform configuration for UG, Stations	Asset Templates – Configuration for Telecom, Metering
Build common templates for asset hierarchy, location hierarchy, accounting	Maintenance module, Work Orders module for 1 asset class(OH)	Asset Condition Monitoring app for 1 asset class(OH)	Asset Management – Relationships	Maintenance module for Telecom, Metering
Identify the critical interfaces, screens and reports	Self Service module for OH users	Asset Management – Relationships	Work Orders module for UG, Stations	EAM Platform configuration for Telecom, Metering
System Security	EAM Platform configuration for 1 asset class – OH,	Maintenance module, Work Orders module for 1 asset class(OH)	Assets module for UG, Stations	Asset Management – Relationships
Project Management	Integration: EAM-Salesforce (1)	Integration: EAM-Oracle JDE (4)	Reporting for UG, Stations	Work Orders module for Telecom, Metering
	Integration: EAM-Oracle CC&B (2)	Integration: EAM-Copperleaf C55 (5)	Integration: EAM-Quadra (6) Integration: EAM-Workday (7)	Assets module for Telecom, Metering
	Integration: EAM-GIS (3)	System Security	Integration: EAM-Field Activity management (8)	Integration: EAM-AODOCS (12)
	System Security	Testing, UAT	Integration: Oracle CC&B-Salesforce (9) Integration: Oracle CC&B-GIS (10)	Integration: Oracle CC&B – Oracle JDE (13)
	Project Management	Project Management	Integration: Oracle JDE-Salesforce (11)	Integration: Oracle JDE – Quadra (14) Integration: Oracle JDE – Workday (15)
			Testing, UAT	Testing, UAT

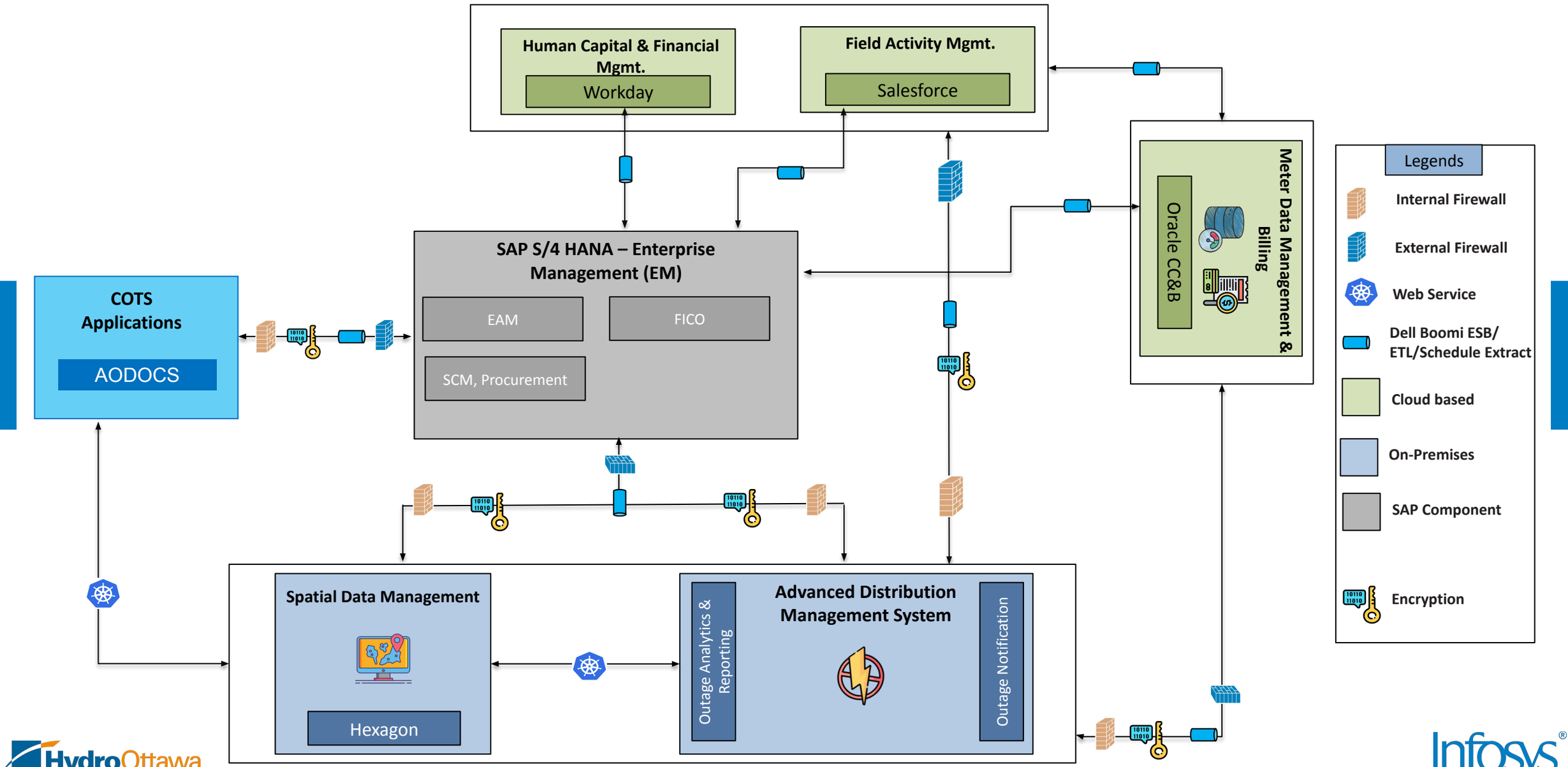
SAP S/4 HANA - EAM

Retain, Retire Matrix

	App(s) ↓		Year(s) →	2022				2023				2024				2025				2026			
	Business Function	Current Product	Future State Product Name	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Phase 1	Finance & Accounting	Oracle JDE 9.2	SAP FICO	Y	E	T	T	T	T	N		SAP FICO (for EAM Focussed)											
	Asset Investment Decisions	Copperleaf Portfolio	SAP EAM, FICO, IM	Y	E	T	T	T	T	N		SAP EAM											
	Assets Test Data Management	PowerDB	SAP EAM	Y	E	T	T	T	T	N		SAP EAM											
	Assets Maintenance Records	ASPEN Relay Database	SAP EAM	Y	E	T	T	T	T	N		SAP EAM											
	Asset Record Management		SAP EAM		E	T	T	T	T	N		SAP EAM											
	Asset Management		SAP EAM		E	T	T	T	T	N		SAP EAM											
	Work Management		SAP EAM		E	T	T	T	T	N		SAP EAM											
	Asset Project Management		SAP EAM		E	T	T	T	T	N		SAP EAM											
	Asset Analysis		SAP EAM		E	T	T	T	T	N		SAP EAM											
	Asset Investment Planning		SAP EAM		E	T	T	T	T	N		SAP EAM											
	Work Estimation	Quadra	SAP EAM, PS, PPM	Y	E	T	T	T	T	N		SAP EAM											
	Procurement	Oracle JDE 9.2	SAP MM, Ariba+	Y	Y	Y	Y	Y	Y	Y	E	T	T	T	N	SAP MM, Ariba							
	Supply Chain	Oracle JDE 9.2	SAP MM, Ariba+	Y	Y	Y	Y	Y	Y	Y	E	T	T	T	N	SAP MM, Ariba							
Phase 2	Field Service Management	Salesforce FSL	SAP FSM+ , Asset Manager+	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	E	T	T	N	SAP FSM, Asset Manager			
	HCM	Workday	SAP HCM*, Successfactors+	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	E	T	T	N	SAP HCM, Successfactors			
	Metering and Billing	Oracle CC&B	SAP ISU+	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	E	T	T	T	T	T	N	SAP ISU
	CRM	Salesforce CRM	SAP CX+, SAP ISU CR&B+	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	E	T	T	T	T	T	N	SAP ISU
Other Projects	GIS	Hexagon Intergraph	Hexagon Intergraph	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
	OMS	Hexagon Intergraph	Hexagon Intergraph	Y	Y	T	T	N	N	ADMS OMS													
	OMS	ADMS	ADMS			T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Document Management	AODocs	AODocs	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
	IT Service Management	Trackit!	Trackit!	Y	T	T	N	N	ServiceNow ITSM														
	IT Service Management	ServiceNow	ServiceNow		T	T	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

* SAP S4 HANA EM license + Additional license Y In Use N Retired E Under Evaluation T Transition

Integration Architecture – Post Phase 1 deployment



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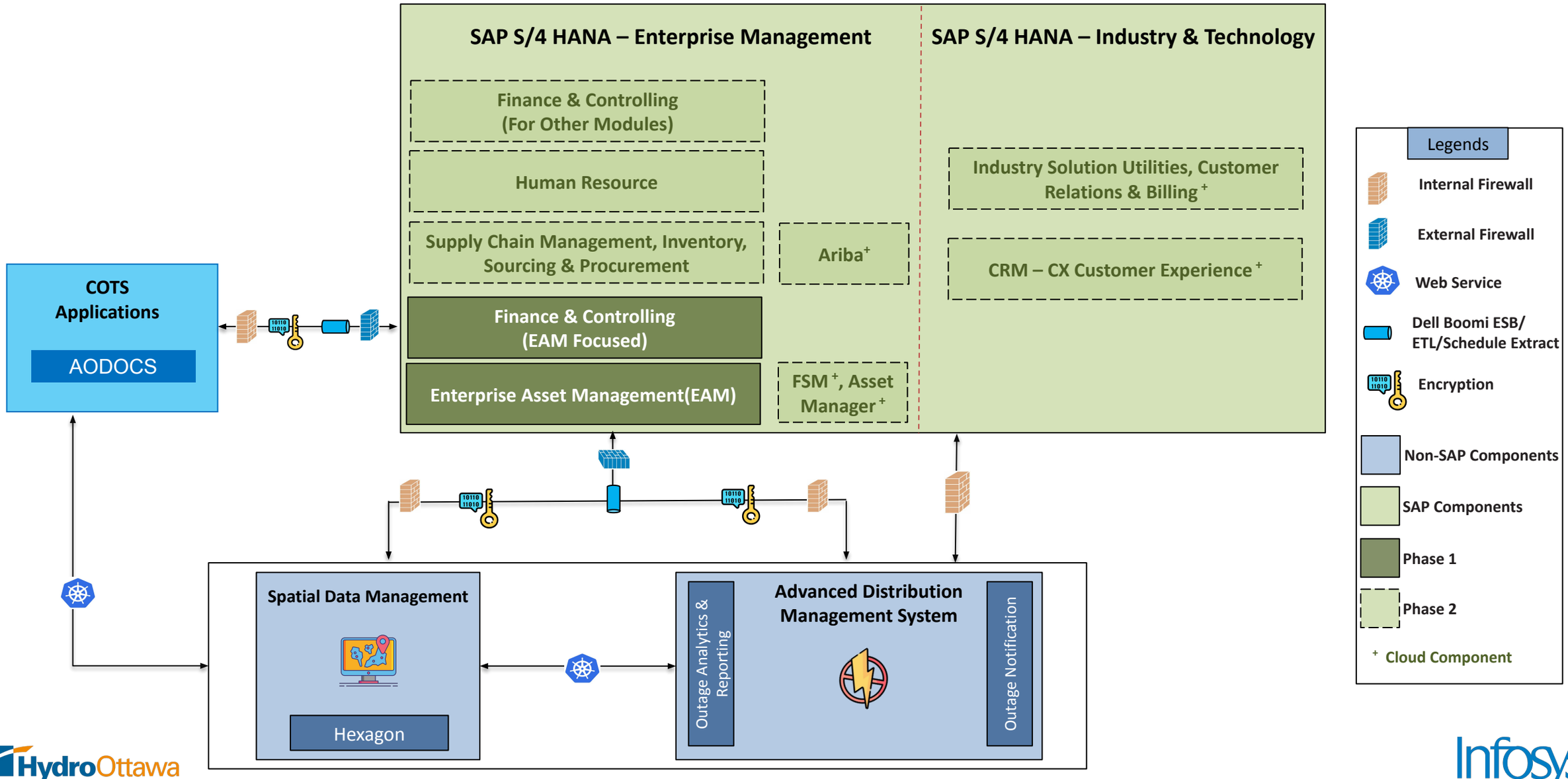
Integrations – To-Be State

Integrations	Business Function	Current Product	Future Product	Hosting Platform	Replacement	Integration Platform
EAM-Job Costing & Estimation	Job Costing & Estimation	Quadra	SAP EAM , PS, PPM, MM, Ariba	S4 HANA On-Prem	Yes	Dell Boomi
EAM - Human Capital Management	Human Capital Management	Workday	SAP HCM	S4 HANA On-Prem	Yes	Dell Boomi
EAM - Field Activity Management	Field Activity Management	Excel	SAP Field Service Management, Asset Manager	S4 HANA On-Prem Cloud based (SaaS)	Yes	Dell Boomi
EAM - Oracle CC&B	Customer Care & Billing	Oracle CC&B	SAP ISU CR&B	S4 HANA On-Prem Cloud based (SaaS)	Yes	Dell Boomi
EAM - Oracle JDE	Financial Management	Oracle JDE	SAP FICO	S4 HANA On-Prem	Yes	Dell Boomi
EAM - Copperleaf C55	Asset Investment	Copperleaf	SAP FICO, PS, PPM, IM	S4 HANA On-Prem	Yes	Dell Boomi
EAM - Aspen Relay DB	Relay and electric protection equipment repository	Aspen Relay DB	SAP EAM	S4 HANA On-Prem	Yes	Dell Boomi
EAM – PowerDB	Equipment maintenance & inspection	Power DB	SAP EAM	S4 HANA On-Prem	Yes	Dell Boomi
EAM – GIS	Spatial Data Management	Intergraph-Hexagon	Intergraph-Hexagon	On-Premise	No	Dell Boomi
EAM – Salesforce	Field Service	Salesforce	SAP Field Service Management, Asset Manager	On-Premise Cloud based (SaaS)	Yes	Dell Boomi
EAM – AODocs	Document Management	AODocs	AODocs	On-Premise	No	Dell Boomi
Oracle CC&B – Salesforce	Field Service	Salesforce	SAP Field Service Management, Asset Manager	S4 HANA On-Prem Cloud based (SaaS)	Yes	Dell Boomi
Oracle CC&B – GIS	Spatial Data Management	Intergraph-Hexagon	Integraph-Hexagon,FME	On-Premise	No	Dell Boomi
Oracle CC&B – JDE	Financial Management	Oracle JDE	SAP FICO	S4 HANA On-Prem	Yes	Dell Boomi
Oracle JDE – Quadra	Job Costing & Estimation	Quadra	SAP EAM, PS, PPM	S4 HANA On-Prem	Yes	Dell Boomi
Oracle JDE – Workday	Human Capital Management	Workday	SAP HCM	S4 HANA On-Prem	Yes	Dell Boomi
Oracle JDE - Salesforce	Field Service	Salesforce	SAP Field Service Management, Asset Manager	S4 HANA On-Prem Cloud based (SaaS)	Yes	Dell Boomi

Integration Architecture – Post Phase 1 & Phase 2 Deployment



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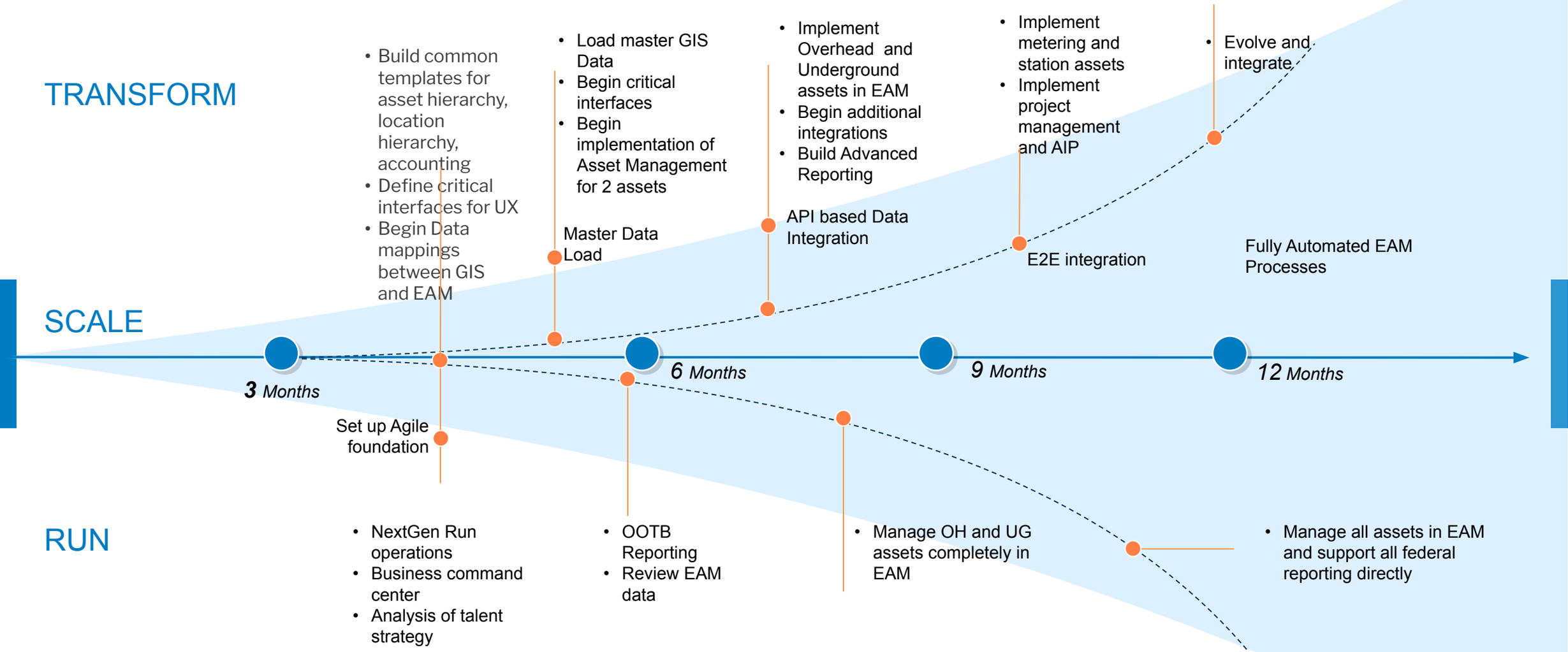
EAM Roadmap



GIS – Geographic Information System
UX – User Experience
EAM – Enterprise Asset Management

API – Application Programming Interface
AIP – Asset Investment Plan
OOTB – Out of The Box
OH, UG– Overhead, Underground

E2E - End to End Integration

Summary of Deliverables from 2022-2024 (Indicative)

2022: Mar-Jun	2022: Jun-Sep	2022: Sep-Dec	2023: Jan-Mar	2023: Apr-June
Procurement of EAM software	Asset Templates – Config for OH	Asset Templates – Config for OH	Data Collection & Migration for UG, Stations	Reporting for Telecom, Metering
Project Plan finalization	Data Collection & Migration for 1 asset class (OH)	Data Collection & Migration for 1 asset class (OH)	Asset Templates – Configuration for UG, Stations	Analytics module for UG, Stations, Telecom, Metering
Business Process Analysis & Optimization for 1 Asset Class(OH), Data Mapping	Out-Of-Box reporting for 1 asset class(OH) – 25 reports	Custom reports for 1 asset class(OH) - 10	Maintenance module for UG, Stations	Data Collection & Migration for Telecom, Metering
Base Install of EAM for all asset classes	Assets module for OH	Analytics module for 1 asset class (OH)	EAM Platform configuration for UG, Stations	Asset Templates – Configuration for Telecom, Metering
Build common templates for asset hierarchy, location hierarchy, accounting	Maintenance module, Work Orders module for 1 asset class(OH)	Asset Condition Monitoring app for 1 asset class(OH)	Asset Management – Relationships	Maintenance module for Telecom, Metering
Identify the critical interfaces, screens and reports	Self Service module for OH users	Asset Management – Relationships	Work Orders module for UG, Stations	EAM Platform configuration for Telecom, Metering
System Security	EAM Platform configuration for 1 asset class – OH,	Maintenance module, Work Orders module for 1 asset class(OH)	Assets module for UG, Stations	Asset Management – Relationships
Project Management	Integration: SAP EAM-Salesforce	Integration: SAP EAM-SAP FICO	Reporting for UG, Stations	Work Orders module for Telecom, Metering
	Integration: SAP EAM-Oracle CC&B	Integration: SAP EAM-SAP FICO, IM	Integration: SAP EAM-SAP PS , PPM Integration: SAP EAM-Workday	Assets module for Telecom, Metering
	Integration: SAP EAM-GIS	System Security	Integration: SAP EAM-Field Activity management	Integration: EAM-AODOCS
	System Security	Testing, UAT	Integration: Oracle CC&B-Salesforce Integration: Oracle CC&B-GIS	Integration: Oracle CC&B – Oracle JDE
	Project Management	Project Management	Integration: Oracle JDE-Salesforce	Integration: Oracle JDE – Quadra Integration: Oracle JDE – Workday
			Testing, UAT	Testing, UAT

Infosys Recommendation – In Conclusion

Based on the overall assessment of Asset Management Processes by Infosys team from Nov 21 to Feb 22, Infosys industry and technical expertise, Infosys team strongly recommends Hydro Ottawa to implement the following key outcomes in 2022

- **An Enterprise Asset Management Platform to gain substantial organizational efficiencies and improve the overall business performance.**
- **Automation enabled Business Process changes**
- **Seamless Integrations across the IT landscape using the EAM platform**

Infosys would like to express our deep appreciation for allowing us to perform the technology roadmap assessment for asset management.

Infosys has a proven track record of helping clients transform from strategy to business enablement. We would very much like to do that for Hydro Ottawa in the near immediate future. Continuity of Infosys resources can also provide ongoing momentum gained from the assessment if that is desired by Hydro Ottawa. Infosys is ready to partner with Asset Management Implementation project at any point in time to help make the vision reality.

From the entire Infosys team and organization, a sincere thanks for this opportunity!

Appendix

Asset Management Process Map vs Pain Points & To-Be - Underground

Key Process	Pain Point(s)	Remediation(s)
Asset Investment Planning	○ Spreadsheets are primarily used ○ Analytics based the asset state is manual.	· Implement predictive analysis through Industry packages.
Routine Work Generation	○ Estimation tool is not used always ○ No integration from C55 with Quadra ○ GIS extract is maintained in Excel and no integration with GIS systems	· Implement Work and Asset management packages to integrate end to end flows.
Work Planning & Estimation	○ Manual process where blue folders, project hours and estimate updated on white board	· Implement Document Management System with smart tagging.
Work Management & Tracking	○ Work management and tracking is done via the Whiteboard/Google Sheet, though the financial aspect is tracked via JDE. ○ No direct linkage exists between the systems	· Implement Work and Asset management packages with compatible units' feature.
	○ Monthly actuals/forecasts and change requests are submitted through C55 and then sent to JDE manually. No direct integration available. ○ A dedicated e-mail inbox is used for emergency failure monitoring	· Implement Work and Asset management packages to integrate end to end flows.
Work Reporting & Closing	○ A closing off meeting is conducted, closures are done manually in each system, data synchronization is unavailable across JDE, GIS etc. ○ Not all assets are treated as discrete in JDE ○ Manual data updates in GIS	· Implement Work and Asset management packages to integrate end to end flows. · Financials can be bundled in the Bill of Materials (BOM) process.
Work Dispatch	○ As on today, only Salesforce used for inspections dispatch. No direct linkage with Field Recording. ○ No skillset driven or automated availability check is functional	· Integrate FSL with EAM packages to trigger automated dispatch. · Implement Resource Management packages
Field Recording	○ No automated process for inspections and emergency work – manual process for planned work using e-mails, Google Sheets ○ Information captured in the field is manual ○ Only visual Inspection done on Switchgears	· Extend Salesforce FSL to meet the needs
Overall	○ At least 60% of the process flows are manual	· Implement Work and Asset management packages to integrate end to end flows.

Asset Management Process Map vs Pain Points & To-Be – Overhead

Key Process	Pain Point(s)	Remediation(s)
Asset Investment Planning	○ Asset Planning and Budgeting is based on the historical failures and is not applicable or not performed ○ Forecasting is done in Excel	· Implement predictive analysis through Industry packages.
Asset Analysis	○ Excel sheets are primarily used for Asset Analysis and Investment planning for Structures and Transformers ○ Ad-hoc analysis is done in Google Sheets & GeoMedia, no specific defined process for Line reclosers and Load Break switches.	
Routine Work Generation	○ GIS extract is maintained in Excel with no backward integration with GIS systems	· Implement Work and Asset management packages to integrate end to end flows.
Project Management	○ Project created is available in C55 and JDE but no direct integration	
Work Initiation	○ WO creation and work assignment is manual process	
Overall	○ At least 60% of the process flows are manual	
GIS	○ Bluebeam markups are manually updated in GIS. Once completed, new PDFs with updated GIS info can be created for further markup.	· Opportunities to integrate Bluebeam with GIS or integrate GIS with a Document Management System.

Asset Management Process Map vs Pain Points & To-Be – Stations

Key Process	Pain Point(s)	Remediation(s)
Asset Investment Planning	○ Forecasting and Planning utilizes Excel to an extent	· Implement predictive analysis through Industry packages.
Asset Records Management	○ Updates are made in spreadsheets ○ Asset Info is sent by e-mails to GIS for updates	· Implement Work and Asset management packages to integrate end to end flows
Routine Work Generation	○ PowerDB (maintenance repository) - only stores inspection results, does not generate any work. ○ PowerDB data is manually extracted for analysis. ○ Activities not linked to routine maintenance are managed in a shared drive. ○ Maintenance cycle is maintained through spreadsheets.	
Work Management	○ These key processes related to work initiation, tracking etc. uses spreadsheets throughout the processes with minimal integrations	
Work Reporting & Closing	○ Spreadsheets are used to an extent ○ No data sent to GIS	
Design Standards	○ Mostly available in PDFs and review is done manually	
Overall	○ At least 60% of the process flows are manual	

Asset Management Process Map vs Pain Points & To-Be – Metering

Key Process	Pain Point(s)	Remediation(s)
Asset Records Management	○ Non-Conformance meters are stored in Access DB	· Store this information in CC&B too.
Asset Investment Planning	○ Spreadsheets are used mostly for investment planning	· Implement predictive analysis through Industry packages.
Project Management	○ PMO uses Microsoft Project or Spreadsheets to manage project items.	· Implement Work and Asset management packages to integrate end to end flows.
Work Management	○ These key processes related to work initiation, tracking etc. uses spreadsheets throughout the processes with minimal integrations	· Implement Work and Asset management packages to integrate end to end flows.

Asset Management Process Map vs Pain Points & To-Be – Telecom

Key Process	Pain Point(s)	Remediation(s)
Asset Analysis	○ This is not applicable currently in as-is, there is a need to plan in future.	Asset Analysis

Secondary Processes Pain Points

Key Process	Pain Point(s)	Remediation(s)
DERMS	1. Partial data for network and feeder data only captured in GIS. **DERMS implementation is already being considered in the DMS program.	○ Implement a DERMS package that integrates with the rest of the technology solutions.
Resource Management	1. No on-call management system present. 2. All resource management steps are manual. 3. Realtime resource availability cannot be determined	○ Implement a resource management package that also supports on-call processes.
OMS	1. Scheduling is done through Spreadsheets 2. Work generation for field is not automated **OMS replacement to OSI is a part of the DMS program.	○ Implement Work and Asset management packages to integrate end to end flows.

THANK YOU

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INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-37

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 12-14, 18-19

QUESTION(S):

a) (PP. 12-14, 18) Please provide a more detailed breakout of the Testing, Inspection and Maintenance program budget for the 2021-2026 period (as shown in Table 6) using the activities set out in Table 5. Please also further describe the methodology applied for forecasting the costs in the test year.

b) (P. 12) Please provide the total number of cable chambers in Hydro Ottawa's service area. As part of the response, please provide a breakout between company-owned and customer-owned cable chambers.

c) (P. 12) Please provide the number of cable chambers that were previously inspected on a 10-year cycle and will now be inspected on a 5-year cycle.

d) (P. 12) Please advise whether Hydro Ottawa bills the specific owner for its maintenance and inspection activities related to a customer's cable chambers. If not, please explain why.

e) (P. 12) Please provide the number of poles that were previously inspected on a 10-year cycle and will now be inspected on a 5-year cycle.

f) (P. 13) Please further explain the operational expenses expected to be incurred related to the installation of FCIs discussed in Exhibit 2, Tab 5, Schedule 8 (p. 93).

g) (P. 16) Please provide any initial results available from the drone inspection pilot in 2025 and whether there are any implications for the 2026 budget. As part of the response, please discuss whether the use of drones is expected to reduce the need for physical inspections of overhead assets in the future.

h) (P. 19) Please confirm that the $2.8M budget for the NWS programming is related to the non-wire customer solutions.

RESPONSE(S):

a) Table A provides a breakout of the actual/forecasted costs in 2021-2026. The activities in Table 5 of the reference have been grouped by category for this table to match the level of granularity present in the budget. The methodology applied for forecasting the costs in the test year is discussed in Hydro Ottawa's response to the interrogatory question 4-Staff-134 (a) (iii).

Table A - Testing Inspection & Maintenance Program Costs ($'000s)

Asset/Systems	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Cable Chambers	$ 161	$ 414	$ 282	$ 309	$ 319	$ 379
Overhead Equipment	$ 268	$ 261	$ 395	$ 712	$ 1,028	$ 1,556
Underground Equipment	$ 795	$ 552	$ 618	$ 898	$ 1,113	$ 1,805
SCADA Devices	$ 227	$ 173	$ 205	$ 179	$ 192	$ 283
Customer Equipment	$ 10	$ 26	$ 40	$ 70	$ 66	$ 56
Third Party Non Wire Alternative Solutions	-	-	-	-	-	$ 2,871
Overall Distribution	$ 10	$ 7	$ 14	$ 53	$ 102	$ 1,945
TOTAL	**$ 1,470**	**$ 1,433**	**$ 1,555**	**$ 2,221**	**$ 2,820**	**$ 8,894**

b) There are 3,904 cable chambers owned by Hydro Ottawa (as stated in Section 7.1.3.6 of Schedule 2-5-4 - Asset Management Process) and 1,173 cable chambers owned by customers.

c) Hydro Ottawa currently inspects all of the Hydro Ottawa owned 3,904 cable chambers on a 10-year cycle. Hydro Ottawa is still evaluating which cable chambers will be moved to a 5-year inspection frequency based on their relative condition assessments.

d) Hydro Ottawa bills the specific owner for its maintenance and inspection activities related to customer-owned cable chambers.

e) Hydro Ottawa currently inspects 46,636 poles on a 10-year cycle. Hydro Ottawa is still evaluating which poles will be moved to a 5-year inspection frequency based on their relative condition assessments.

f) For the installation of FCIs, there are operational expenses associated with inspecting, maintaining and testing the FCIs to ensure they are operational, inclusive of battery replacements.

g) Please refer to 4-Staff-135 f). The use of drones will replace the ground-based inspections of overhead assets performed historically, as a part of Hydro Ottawa's preventative maintenance program. Hydro Ottawa has budgeted for the use of drones as a program enhancement in 2026, as outlined in Hydro Ottawa's response to 4-Staff-134 part a ii). The use of drones is expected to reduce the need for additional physical patrolling or inspections by Hydro Ottawa's field crews. However, Hydro Ottawa will uphold the existing three-year cycle for both visual inspections and IR scanning of overhead equipment via drones. This approach ensures continued adherence to OEB Appendix C: Minimum Inspection Requirements.

h) Confirmed.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-38

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 19-20, 22

QUESTION(S):

a) (P. 22) Please provide a more detailed breakout of the vegetation management program budget for the 2021-2026 period (as shown in Table 7) using the categories of planned trimming, as-needed trimming and emergency vegetation management. Please also further describe the methodology applied for forecasting the costs in the test year.

b) (P. 19-20) Assuming Hydro Ottawa relies on contracted services for its vegetation management activities, please provide the term of its existing vegetation management contract (e.g., 2024-2026, 2023-2027, etc.). Please also explain the process that Hydro Ottawa undertook to enter the tree trimming contract. As part of the response, please provide details about the RFP, the number of bidders, the selection process, etc.

c) (P. 20) Please provide additional details regarding the rotation of planned tree trimming for defined geographical areas on a 5-year cycle. As part of the response, please provide the defined geographical areas, which area(s) were completed in each year of the historical period (2021-2025) and which area(s) are planned for the test year. Please also advise whether different contractors are used for different areas.

RESPONSE(S):

a) Please see the response to interrogatory 4-Staff-139 part e) for the detailed breakout of the program budget. Note this response includes historical figures for 2024, instead of 2024 bridge year figures listed in Table 7 of 4-1-2 - Operations, Maintenance and Administration Programs.

The methodology for forecasting the test year budget was to use the average spending of recent years as a baseline plus an inflationary increase to account for vendor pricing increases.

b) The current vegetation management contract runs from 2019 to 2026 and was awarded following a Request for Proposals (RFP) initiated in 2018, which was issued to three qualified proponents. The selection process was executed following Hydro Ottawa's procurement policy as set out in Attachment 4-2-2(A) - Procurement Policy.

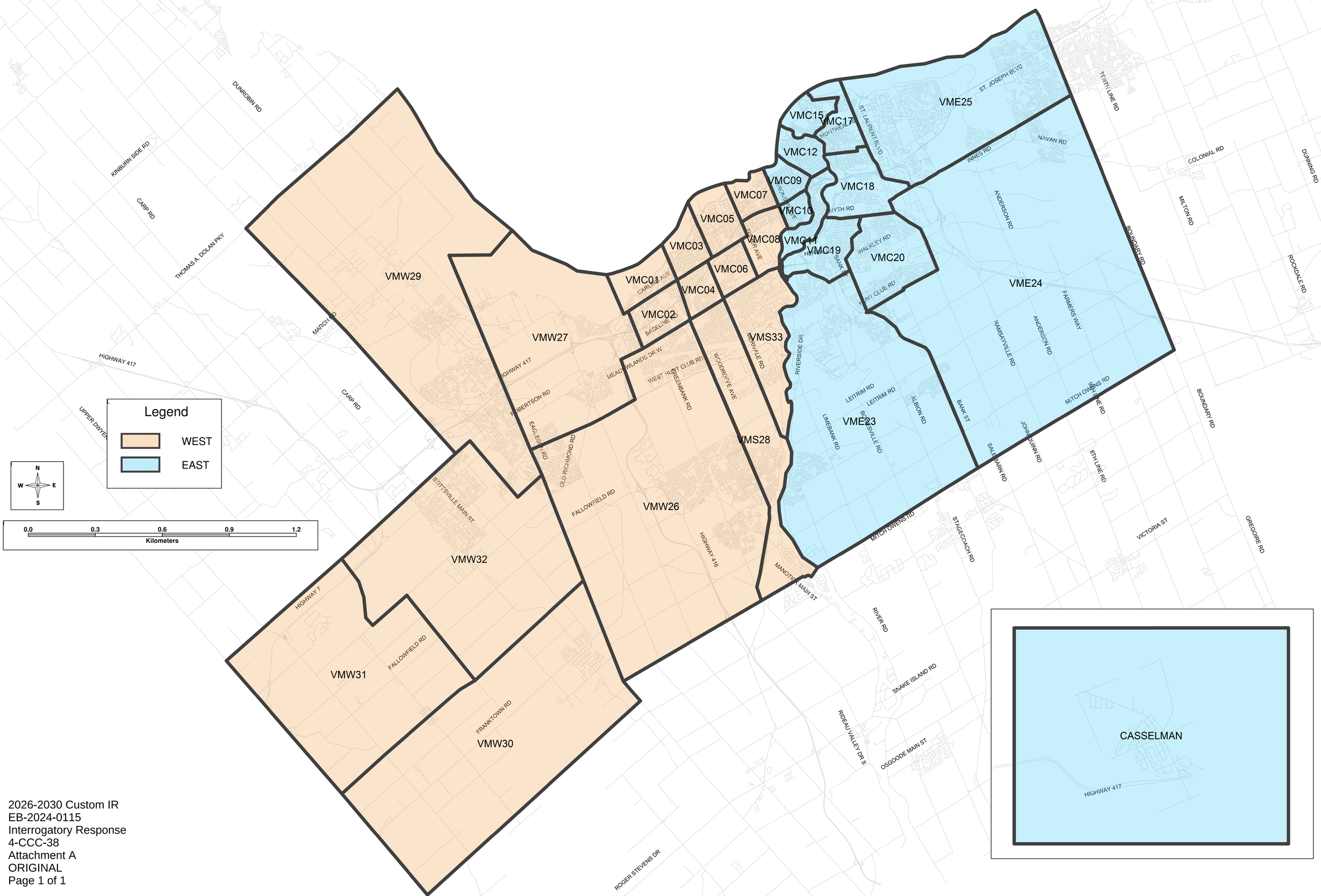
c) Hydro Ottawa's tree trimming program is planned on a five-year cycle for the entire service territory. However, individual geographic areas are actually trimmed on a two or three-year cycle, depending on specific maintenance needs.

Attachment 4-CCC-38(A) - Vegetation Management Map is a map of Hydro Ottawa's service territory split into East and West regions (the former also including the city of Casselman), which are further subdivided into a total of 28 trimming areas.

Table A shows the list of all 28 trimming areas as well as the years within the 2021-2025 period in which each one was trimmed, allowing for easy visualization of the two or three-year trimming cycle of each individual area. One contractor is used to trim all vegetation management zones/areas within Hydro Ottawa's service territory.

Table A - Vegetation Management Geographic Areas by Year Trimmed

	2021	2022	2023	2024	2025	2026
West Area						
VMC01	X		X		X	
VMC02		X		X		X
VMC03		X			X	X
VMC04	X		X		X	
VMC05	X		X		X	
VMC06	X		X		X	
VMC07			X		X	
VMC08	X		X		X	
VMW26		X				X
VMW27	X			X		
VMS28			X			X
VMW29			X			X
VMW30	X			X		
VMW31			X			X
VMW32		X				X
VMS33	X			X		
East Area						
VMC09	50%	X		X		X
VMC10		X			X	
VMC11	X		X		X	
VMC12	X		X		X	
VMC15	X		X		X	
VMC17		X		X		X
VMC18	X		X		X	
VMC19		X		X		X
VMC20		X		X		X
VME23		X			50%	50%
VME24	X			X		
VME25/CASS			X		X	



2026-2030 Custom IR
EB-2024-0115
Interrogatory Response
4-CCC-38
Attachment A
ORIGINAL
Page 1 of 1

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-39

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 22-25
Exhibit 9, Tab 1, Schedule 3, pp. 40-42

QUESTION(S):

a) (Exhibit 4, Tab 1, Schedule 2, p. 24) Hydro Ottawa states that the implementation of Bill 93 has increased operational expenditures for Hydro Ottawa, due to the reliance on external service providers to ensure adherence to the legislated timelines. Please:
   i) Provide the term of the existing contract (e.g., 2024-2026, 2023-2027, etc.)
   ii) Explain the process that Oshawa Power undertook to enter the locates contract. As part of the response, please provide details about the RFP, the number of bidders, the selection process, etc.
   iii) Discuss what happened with respect to the locates contact after Bill 93 was implemented.
   iv) Explain the 5% annual escalation applied during the 2025-2026 period.

b) (Exhibit 4, Tab 1, Schedule 2, p. 25) Please explain what the inspection line item is referring to in Table 9. For the purposes of determining the actual locate costs incurred during April to December 2023 (and as recorded in the GOCA variance account), please explain how inspection costs are treated. Please also advise whether the locate costs recorded in the GOCA are entirely contractor costs or are Hydro Ottawa administrative costs also reflected.

c) (Exhibit 9, Tab 1, Schedule 3, p. 41) Please provide a reference to Hydro Ottawa's 2021 Rates proceeding showing where the OEB approved locate costs of $3M in the 2021 test year.

d) (Exhibit 9, Tab 1, Schedule 3, p. 41) Please provide a table showing the escalation of the approved 2021 locate cost to the 2023 approved locate cost.

e) (Exhibit 9, Tab 1, Schedule 3, p. 41) Please confirm that the actual locate costs incurred between April and December 2023 are based on the actual monthly costs incurred (and not a calculated amount – i.e., 9/12ths factor).

f) (Exhibit 9, Tab 1, Schedule 3, p. 41) Please explain why Hydro Ottawa applied the 9/12ths factor to determine the relevant materiality threshold for 2023.

RESPONSE(S):

a)

i) Hydro Ottawa has five separate contracts with external service providers that support the underground locates program which extend from 2018 to 2029.

ii) Hydro Ottawa notes that this question referred to Oshawa Power. Hydro Ottawa assumes that this was in error and has answered the question as if the question referred to Hydro Ottawa.

Hydro Ottawa is a member of the Locate Alliance Consortium (LAC). The RFP for locate service providers was tendered with all LAC members in the corresponding Geographic Area, Ottawa, in 2018. By tendering the pricing with all LAC members, Hydro Ottawa was able to negotiate pricing as a larger group, with other added benefits such as Quality Assurance and Compliance, overseen by LAC collectively. Three proponents submitted pricing for this RFP in 2018 and the winning proponent was selected. A decision was made by LAC to extend the contract with the successful proponent in 2023 due to uncertainties as a result of Bill 93.

Hydro Ottawa has contracts with several other external service providers to fulfill the other roles required in the Underground Locates program, such as clearing house and mapping software services. The procurement process for these services adhered to Hydro Ottawa's procurement policy as described in Attachment 4-2-2(A) - Procurement Policy.

iii) After implementation of Bill 93, the LAC Locate contract with Promark was extended due to uncertainties in the locates service market. LAC members were uncertain as to the impact of the Bill on all aspects of locates so the decision was made to continue services with the same vendor.

iv) Given the year over year volatility associated with contracted costs for outside services associated with locates, an escalation factor of 5% was chosen for the 2025-2026 period. It should be noted that this indicator varied year over year from -11.5% to 35%, averaging 8%.

b) The inspection line item refers to the costs of third-party site inspectors. These costs are excluded from all calculations to do with the GOCA variance account.

Hydro Ottawa confirms that the balance recorded in the GOCA account is exclusively contractor costs and does not include any internal administrative costs.

c) Reference to Table 3 within UPDATED Exhibit 4-1-4, OM&A Cost Drivers and Program Variance Analysis, in EB-2019-0261 shows underground locate costs were forecasted at $3.1M for 2021. This amount was reduced to $3.0M as part of the Settlement Agreement. The $0.1M reduction represents an overall 3.5% reduction from total OM&A envelope of $93.9M to $90.6M.

d) Table A shows the escalation of the approved 2021 locate cost to the 2023 approved locate cost.

Table A - Escalation of the Approved 2021 Locate Cost to 2023

	$
2021 Forecast in EB-2019-0261	$ 3,114,336
Settlement Reduction of 3.5%	$ 110,174
OEB Approved 2021	$ 3,004,162
OEB Approved 2022 with 3.2% escalation	$ 3,099,994
OEB Approved 2023 with 3.6% escalation	$ 3,211,284
OEB Approved 2023 (April to December)	$ 2,408,463

e) Confirmed.

f) The 9/12ths factor was applied to the materiality threshold for 2023 because Bill 93 came into effect on April 1, 2023. This left nine months of the year for which costs could be applied to the variance account and materiality was likewise reduced to apply to the same period.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-40

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 25-31

QUESTION(S):

a) (P. 31) Please provide a more detailed breakout of the station maintenance program budget for the 2021-2026 period (as shown in Table 11) using the activities described in Table 10. Please also further describe the methodology applied for forecasting the costs in the test year.
b) (P. 30) Hydro Ottawa states that it has allocated additional funds for reactive maintenance to address unanticipated situations. Please provide the amount historically spent (2021-2025) on reactive station repair/refurbishment and the forecast amount for these same activities (2026-2030). Please advise whether these costs are treated as capital or OM&A (and in which specific program budget these amounts are reflected).
c) (P. 27) Please further describe what is involved in the decommissioning support for 4kV equipment and provide the total 2026-2030 cost of this activity.

RESPONSE(S):

a) Table A provides a breakout of the actual/forecasted costs in 2021-2026 by the activities set out in Table 10 of the reference (From Table 10, “station switchgears” and “station relays” were grouped, and “reactive maintenance” was added as a separate category). The methodology applied for forecasting the reactive maintenance costs in the test year is discussed in Hydro Ottawa’s response to the interrogatory question 4-Staff-140 part c) iv). Specific to the preventative maintenance programs, the 2026 maintenance cost for station assets is

determined by multiplying the time-based maintenance schedule by the latest unit cost for each individual asset. There are also some additional program enhancements proposed in 2026 compared to the base program, as discussed in Hydro Ottawa's response to the interrogatory question 4-Staff-140 part a) vi).

Table A - Detailed Station Maintenance Program Cost Breakdown (in $'000s)

Activity	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Station Inspections (Overall)	$ 500	$ 563	$ 425	$ 528	$ 674	$ 771
Station Transformers	$ 258	$ 287	$ 237	$ 463	$ 738	$ 1,081
Station Switchgear + Relays	$ 510	$ 592	$ 648	$ 804	$ 986	$ 1,187
Station Batteries	$ 325	$ 32	$ 97	$ 157	$ 233	$ 460
Reactive Maintenance	$ 1,077	$ 1,236	$ 1,480	$ 1,503	$ 1,536	$ 1,534
TOTAL	**$ 2,670**	**$ 2,710**	**$ 2,888**	**$ 3,454**	**$ 4,167**	**$ 5,033**

b) Table B shows the historical and forecast amounts for the 2021-2026 period for reactive station repair/refurbishment which are treated as OM&A and are budgeted in the Station Maintenance program. The budget for 2027-2030 will be determined by applying the CROF factor as described in Schedule 1-3-1 - Rate Setting Framework. For further information regarding the 2026-2030 reactive maintenance budget forecast methodology, please refer to Hydro Ottawa's response to 4-Staff-140 part c iv).

Table B - Stations Reactive Maintenance 2021-2026 ($'000s)

	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Reactive Maintenance	$ 1,077	$ 1,236	$ 1,480	$ 2,266	$ 1,536	$ 1,534

c) Decommissioning support for 4 kV equipment involves activities such as:

- Site inspections and investigations for planning and execution
- Testing and assessments for capital spare determination
- Relocation needs assessment and actual move and testing of equipment to be retained as capital spares
- Switching for planned feeder cutovers and phased decommissioning planning
- Disposal planning and costs of equipment to be scrapped

Between 2026 and 2030, the total projected OM&A spending for 4 kV station decommissioning support is $3.1M. Additionally, Hydro Ottawa proposes to spend $64.2M on the EOL voltage conversion program under System Renewal to decommission select 4 kV stations by converting their associated 4 kV distribution lines to 13 kV, as shown in Section 2.5.7 EOL Voltage Conversion under Schedule 2-5-7 - System Renewal Investments.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-41

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, p. 33

QUESTION(S):

Please provide a more detailed breakout of the distribution overhead and underground maintenance program budget for the 2021-2026 period (as shown in Table 12) using the activities described in the list on pages 31-32 (or at the level of granularity that is available to Hydro Ottawa). Please also further describe the methodology applied for forecasting the costs in the test year.

RESPONSE(S):

Please see Table A for a breakdown of the 2021-2026 maintenance program budget using the activities described in Section 3.5 of Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs.

Hydro Ottawa's forecasting for the Test Year employs a two-pronged approach for maintenance programs:

- For certain programs, such as testing, inspection, and maintenance, the forecast is determined by multiplying the estimated yearly activity levels by their respective unit costs. This approach is designed to align budgeting with anticipated work volumes.

- For all other maintenance programs, the projection is based on an analysis of historical spending. The company uses an average of recent years' spending to establish a baseline, with adjustments made to exclude any outlier years that may skew the data.

  Additionally, an average annual increase has been incorporated to address the rising future costs of equipment and materials.

Table A - OH & UG Maintenance Program Costs ($'000s)

Activity	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Overhead Maintenance						
Refurbishment/repair of line switches and reclosers	$ 437	$ 738	$ 467	$ 634	$ 541	$ 571
Refusing line cut-outs	$ 9	$ 5	$ 13	$ 12	$ 11	$ 10
Removing temp switching devices	$ 309	$ 654	$ 484	$ 501	$ 522	$ 501
Cleaning insulators/bushings	$ 331	$ 282	$ 6,000	$ 657	$ 676	$ 464
Underground Maintenance						
Repair of UG cable conductors, splices, connections	$ 179	$ 218	$ 240	$ 219	$ 203	$ 242
Repair/relocate junction boxes and potheads	$ 0	$ 14	$ 1	$ 3	$ 4	$ 6
Apply/repair cable fireproofing and supports	$ 0	$ 14	$ 1	$ 3	$ 4	$ 6
Asbestos removal	$ 39	$ 4	-	$ 16	$ 24	$ 17
Fault detection/repair	$ 179	$ 218	$ 240	$ 219	$ 203	$ 242
Vault maintenance	$ 62	$ 6	$ 14	$ 61	$ 69	$ 32
Replenishment of SF6 gas in gas-insulated switchgear	$ 179	$ 218	$ 240	$ 219	$ 203	$ 242
Transformer base repair	$ 110	$ 32	$ 54	$ 103	$ 109	$ 77
Maintenance of drainage and insulation	$ 110	$ 32	$ 54	$ 103	$ 109	$ 77
Maintenance of UG secondary services	$ 163	$ 158	$ 276	$ 319	$ 337	$ 229
TOTAL	**$ 2,110**	**$ 2,591**	**$ 8,085**	**$ 3,070**	**$ 3,016**	**$ 2,714**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-42

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, p. 34

QUESTION(S):

Please advise whether the efficiencies gained from the historical and forecast capital expenditures in AMI are reflected in the metering budget for the test year. If so, please provide the amount of savings reflected.

RESPONSE(S):

Efficiencies that result in capital expenditure savings are expected as a result of the AMI 2.0 program, however the 10-year deployment was used to minimize upfront capital costs (as detailed in Preferred Alternative 2 – Phased Metering Renewal, in Section 5.6.1 of Schedule 2-5-7 – System Renewal Investments). This strategy means that savings are realized later in the deployment period, but there are none in the test year.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-43

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, p. 39

QUESTION(S):

Please provide a more detailed breakout of the Engineering & Design program budget for the 2021-2026 period (as shown in Table 12) using the activities described in the list on pages 37-38 (or at the level of granularity that is available to Hydro Ottawa). As part of the response, please separate EAM platform costs and other software costs from the other line items.

RESPONSE(S):

Hydro Ottawa assumes that the relevant table in the reference is Table 15.

Please see Table A for a more detailed breakout of the Engineering & Design program budget for 2021-2026.

Table A - Engineering & Design Program Costs ($'000s)

Category	2021	2022	2023	2024	2025	2026
Distribution Design	$ 315	$ 425	$ 561	$ 559	$ 599	$ 918
Assets	$ 3,175	$ 3,185	$ 3,356	$ 3,780	$ 3,659	$ 4,976
Standards & Quality Assurance	$ 319	$ 540	$ 467	$ 649	$ 633	$ 1,070
Distribution System Integration	$ -	$ 313	$ 675	$ 913	$ 768	$ 1,033
Program Management	$ 361	$ 361	$ 340	$ 347	$ 340	$ 460
Program Oversight	$ 385	$ 221	$ 173	$ 300	$ 332	$ 361
Grid Technology	$ 979	$ 1,094	$ 979	$ 1,423	$ 1,234	$ 1,668
EAM Platform	$ -	$ -	$ -	$ -	$ -	$ 2,951
Other Software	$ 1,195	$ 1,088	$ 1,275	$ 1,335	$ 1,363	$ 1,787
TOTAL	**$ 6,729**	**$ 7,226**	**$ 7,826**	**$ 9,306**	**$ 8,930**	**$ 15,224**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-44

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, p. 44

QUESTION(S):

Please provide a more detailed breakout of the Collections program budget for the 2021-2026 period (as shown in Table 18) with bad debt shown on a separate line item. Please also further describe the methodology applied for forecasting the costs in the test year (including the forecast for 2026 bad debt).

RESPONSE(S):

Table A below provides a more detailed breakout of the Collections program for the 2021-2026 period by key activity and the methodology applied for forecasting the costs in the test year are described below.

Table A - Collections Breakdown by Key Activity 2021-2026 ($'000s)

	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Labour Costs (Compensation Net of Labour Recovery)	$ 726	$ 694	$ 595	$ 676	$ 719	$ 752
Bad Debt Expense	$ 776	$ 1,972	$ 2,197	$ 2,226	$ 2,387	$ 2,514
External Collection / Credit Checks	$ 182	$ 186	$ 127	$ 190	$ 191	$ 190
Other	$ 3	$ 4	$ 10	$ 8	$ 8	$ 7
TOTAL	**$ 1,687**	**$ 2,856**	**$ 2,929**	**$ 3,099**	**$ 3,304**	**$ 3,462**

The forecast for Labour Costs in the 2026 Test Year assumes an annual increase in compensation.

Please see answer a) response to interrogatory 4-Staff-147 for bad debt forecast methodology.

The forecast for External Collection / Credit Checks in the 2026 Test Year is based on the historical trend with current contract pricing.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-45

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 45-46

QUESTION(S):

Please provide a more detailed breakout of the Customer Billing program budget for the 2021-2026 period (as shown in Table 19) using the activities described in the first full paragraph on page 45 (billing (including postage, etc.), meter-to-cash processes, etc.). Please also further describe the methodology applied for forecasting the costs in the test Year.

RESPONSE(S):

Table A provides a more detailed breakout of the Customer Billing for the 2021-2026 period by key activity and the methodology applied for forecasting the costs in the test year are described below.

Table A - Customer Billing Breakdown by Key Activity 2021-2026 ($'000s)

	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Labour Costs (Compensation Net of Labour Recovery)	$ 2,822	$ 2,652	$ 2,433	$ 3,145	$ 3,274	$ 3,554
CIS Meter to Cash Maintenance Contracts	$ 2,846	$ 2,715	$ 2,623	$ 3,220	$ 3,341	$ 3,425
Postage	$ 1,601	$ 1,662	$ 1,541	$ 1,519	$ 1,503	$ 1,135
Customer Billing Subcontractors	$ 356	$ 386	$ 418	$ 436	$ 439	$ 349
Data Services Telephone	$ 324	$ 396	$ 330	$ 350	$ 350	$ 256
Metering Renewal AMI 2.0	$ -	$ -	$ -	$ -	$ -	$ 696
Other	$ 199	$ 222	$ 607	$ 599	$ 624	$ 638
Total	**$ 8,148**	**$ 8,033**	**$ 7,952**	**$ 9,269**	**$ 9,530**	**$ 10,053**

Labour cost forecasts for 2026 are based on two factors: an annual increase in compensation for existing staff and the addition of one new technical position. This new role will support the ongoing development of technology platforms for the customer billing system. More details can be found in Section 3.2 of Attachment 4-1-3(C) - Workforce Growth.

The forecast for the contracts in 2026 is driven by the IBM Managed Service contract. This contract, which supports the CIS/Billing system, includes monthly fees and yearly economic adjustments. Also included are any change requests to enhance the CIS system due to regulatory requirements.

The postage forecast is a calculation based on the estimated volume of physical mailings and the expected postage rate per item. In 2026 the amount budgeted decreased due to Hydro Ottawa's Percentage of Online Billing Accounts stretch target of 80%.

The forecast for subcontractors is calculated by projecting the total expense for bills and notifications. This is determined by their projected volumes and the cost per item, plus any associated operational and service fees. The net decreased costs in this area is also related to paperless billing and a built in target of 80%.

The forecast for Data Services Telephone is largely related to the metering system and costs are expected to decrease in the forecast period as AMI 2.0 deployment begins.

The forecast for Metering Renewal AMI 2.0 in the 2026 Test Year is driven by preliminary IT costs required to initiate the project.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-46

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 46-47

QUESTION(S):

a) Please provide a more detailed breakout of the Customer and Community Relations program budget for the 2021-2026 period (as shown in Table 20) using the activities described on page 46 (contact centre, administration of provincially-mandated programs). Please also further describe the methodology applied for forecasting the costs in the test year.

b) With respect to the customer contact centre, please discuss whether the contact centre is outsourced to a third-party and if it was outsourced, advise when it was outsourced.

RESPONSE(S):

a) Table A below provides a more detailed breakout of the Customer Billing for the 2021-2026 period by key activity and the methodology applied for forecasting the costs in the test year are described below. Please note that we do not track administration of provincially-mandated programs in our financial system.

Table A - Customer & Community Relations Breakdown by Key Activity 2021-2026 ($'000s)

	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Labour Costs Net of Recovery	$ 3,929	$ 4,510	$ 3,930	$ 4,758	$ 5,057	$ 5,247
Customer Contact Centre	$ 1,620	$ 1,737	$ 1,774	$ 2,038	$ 2,059	$ 2,102
Media/Communication	$ 352	$ 340	$ 480	$ 710	$ 485	$ 250
LEAP Donation	$ 249	$ 263	$ 276	$ 294	$ 315	$ 324
IT Subscriptions	$ 895	$ 517	$ 919	$ 670	$ 611	$ 748
Technology-related projects	$ -	$ -	$ -	$ -	$ -	$ 1,655
Other	$ (189)	$ 62	$ 459	$ 685	$ 687	$ 327
Total	**$ 6,856**	**$ 7,428**	**$ 7,838**	**$ 9,156**	**$ 9,213**	**$ 10,653**

The forecast for Customer and Community Relations program Labour Costs in the 2026 Test Year is based on an annual increase in compensation and one new position in a technical role that supports the ongoing development of technology platforms associated with Customer and Community Relations as described in Section 3.2 of Attachment 4-1-3(C) - Workforce Growth.

The forecast for Customer Contact Centre in the 2026 Test Year is based on projecting the volume of customer interactions across various channels, including phone calls, web chats, and administrative tasks based on historical data, then multiplying these volumes by the per-minute rates established in Hydro Ottawa's agreement with its service provider.

The forecast for Media / Communication costs in the 2026 Test Year is based on projected 2026 media project initiatives and related costs.

Please refer to Section 2 Historical and Forecasted LEAP Contribution of Schedule 4-2-5 - Low-Income Energy Assistance Program for details of the forecast for LEAP Donation in the 2026 Test Year.

The forecast for IT Subscriptions in the 2026 Test Year is based on existing contracts, which either already include pricing for that year or have a renewal option at a stated percentage increase, and vendor quotes for any new subscriptions to be added during the year.

The Technology-related projects are primarily Customer Engagement Platform, Customer Relationship Management System, and MyAccount as described in detail in Schedule 2-5-9 - General Plant Investments as well as in Attachment 4-1-1(A) - Transition to Cloud Computing.

b) Hydro Ottawa's contact centre has been outsourced to a third-party since 2004.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-47

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 48-53

QUESTION(S):

a) (P. 51) Please provide a more detailed breakout of the Information Management & Technology program budget for the 2021-2026 period (as shown in Table 21) using the activities described in the list on page 49. Please also further describe the methodology applied for forecasting the costs in the test year.

b) (P. 52) Please provide the costs of software subscriptions included in the Information Management & Technology program budget for each year of the 2021- 2026 period.

c) (P. 52) Please discuss the extent to which the software licenses include support to Hydro Ottawa for the installation, use, troubleshooting, etc. of the licensed software.

RESPONSE(S):

a) Table A provides a detailed breakout of the Information Management & Technology program budget for the years 2021-2026. The methodology for forecasting costs in this program is a mixture of using specific known costs/increases (e.g. software subscriptions), project estimates (e.g. consulting costs), and an inflationary increase.

Table A - Information Management & Technology Costs by Category, 2021-2026 ($'000s)

	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Planning & Programs	$ 891	$ 997	$ 1,194	$ 1,220	$ 1,634	$ 1,902
Infrastructure Management	$ 4,529	$ 5,046	$ 4,737	$ 5,449	$ 5,666	$ 6,028
Enterprise Applications	$ 3,015	$ 4,263	$ 4,650	$ 5,466	$ 6,178	$ 6,756
Cyber Security	$ 1,226	$ 1,367	$ 1,327	$ 1,567	$ 1,627	$ 2,094
TOTAL	**$ 9,661**	**$ 11,674**	**$ 11,908**	**$ 13,702**	**$ 15,105**	**$ 16,780**

b) Table B displays the costs of software subscriptions for each year of the 2021-2026 period in the Information Management & Technology program.

Table B - Information Management & Technology Subscription Costs, 2021-2026 ($'000s)

	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Subscription costs	$ 1,579	$ 2,322	$ 3,166	$ 3,410	$ 3,570	$ 4,874

c) Hydro Ottawa has two types of software licenses:

i) **Perpetual Licenses:** In the case of on-premise systems, Hydro Ottawa typically pays a one-time fee for indefinite use of the software. A support fee is charged annually that enables Hydro Ottawa to receive updates, security patches, or technical assistance.

ii) **Subscription-Based Licensing:** This is the typical model for cloud-based software. Hydro Ottawa will pay a recurring fee (monthly or annually) for access to the software. Support is almost always bundled into the subscription fee. This is a significant advantage, as it ensures continuous updates, maintenance, and support as part of the service.

It should be noted that implementation of the software is generally not covered under a software license and/or support arrangement. Hydro Ottawa must contract separately with professional services partners to implement on-premise systems or to configure cloud systems.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-48

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 59-60

QUESTION(S):

Please provide a more detailed breakout of the Facilities budget for the 2021-2026 period (as shown in Table 25) using the activities/taxes described in the list on page 59. Please also further describe the methodology applied for forecasting the costs in the test year.

RESPONSE(S):

Table A below provides a more detailed breakout of the Facilities OM&A program as shown in Table 25 of Schedule 4-1-2 - OM&A Program Costs.

Table A - Facilities Costs Breakdown by Key Activities 2021-2026 ($'000s)

Expenditures	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Building Maintenance	$3,677	$3,637	$3,556	$3,897	$3,952	$4,130
Property Tax	$2,979	$3,269	$3,369	$3,453	$3,539	$3,663
Building Insurance	$951	$966	$1,210	$1,680	$1,764	$2,126
Utilities	$561	$583	$571	$622	$637	$627
Others	$249	$855	$4,545	$710	$616	$423
TOTAL	**$8,417**	**$9,311**	**$13,250**	**$10,362**	**$10,509**	**$10,969**

The 2026 Test Year forecast for building maintenance costs is predominantly based on existing contracts with our vendors/suppliers. The forecast incorporates the contractually-obligated price increases for 2026.

The forecast for property tax in the 2026 Test Year is based on the increase observed in 2024 and it also takes into account some increases for new stations under construction.

The forecast for insurance expense in the 2026 Test Year is based on the average historical increases observed over the past three years.

The forecast for utilities is based on historical actuals.

The forecast for the other category is based on historical actuals as well as a reduction for productivity savings and removal of any one-time costs that are not expected to occur in 2026.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-49

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 2, pp. 64-66

QUESTION(S):

a) (P. 65) Please provide a more detailed breakout of the Corporate Costs for the 2021-2026 period (as shown in Table 28) using the activities described in the paragraph at the top of page 64. Please also further describe the methodology applied for forecasting the costs in the test year.
b) (P. 64) Please advise whether Hydro Ottawa's insurance coverage includes provisions for cyber security. If so, please describe those provisions.
c) (P. 64) Please explain the process that Hydro Ottawa undertook with respect to selecting its insurance policy. As part of the response, please provide details about the RFP, the number of bidders, the selection process, etc.

RESPONSE(S):

a) Table A below provides a more detailed breakout of the Corporate Costs for the 2021-2026 period by key activity and the methodology applied for forecasting the costs in the test year are described below.

Table A - Corporate Costs Breakdown by Key Activity 2021-2026 ($'000s)

	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Strategic Direction and Oversight from Hydro Ottawa Holding Inc.	$ 4,017	$ 5,018	$ 6,433	$ 6,893	$ 7,436	$ 7,712
Insurance	$ 3,244	$ 2,042	$ 2,233	$ 2,095	$ 1,973	$ 2,186
Future Employee Benefits	$ 472	$ 55	$ 586	$ 840	$ 857	$ 874
Legal Services	$ 362	$ 359	$ 291	$ 394	$ 405	$ 399
Other	$ 21	$ 53	$ (33)	$ (200)	$ (127)	$ 34
TOTAL	**$ 8,116**	**$ 7,528**	**$ 9,509**	**$ 10,022**	**$ 10,544**	**$ 11,204**

The methodology used to forecast the cost of services provided by Hydro Ottawa Holding Inc. in the 2026 Test Year are outlined in Section 2 of Schedule 4-2-1 - Shared Services and Corporate Cost Allocation, Table 2. Costs are allocated based on a combination of proportionate share of time spent, revenue, headcount, asset values, number of employees and value of outstanding debt, as is most relevant to the management service provided.

The forecast for insurance expense in the 2026 Test Year is based on the average historical increases observed over the past three years. This methodology applies to both property and liability insurance premiums, reflecting a data-driven approach to projecting these costs.

The annual expense for future employee benefits represents the year-over-year change in the actuarial liability as determined by third party actuaries. The 2026 Test Year assumes an increase based on historical average increases.

Legal services includes the expenses associated with in-house legal counsel and the 2026 Test Year assumes an annual increase in compensation.

Other costs include audit fees and similar corporate expenses for which the 2026 Test Year assumes an inflationary increase. SR&ED OM&A tax credits on eligible operating expenses are included in this line as a credit.

b) Yes, Hydro Ottawa has purchased a cyber liability insurance policy to protect against the evolving landscape of digital threats as noted in the 'Cyber Security' portion within Section 2.3.4 of Schedule 2-5-1 - Distribution System Plan Overview. The policy provisions are designed to protect Hydro Ottawa against various financial impacts arising from cybersecurity incidents including privacy breaches, network disruptions and cyber threats.

c) Hydro Ottawa procures its insurance policies through a leading global insurance broker and risk advisor with a significant presence in Canada. They offer a wide range of insurance and risk management services to commercial clients, including many Canadian electricity local distribution companies. The insurance broker, using their expertise of the insurance market and knowledge of Hydro Ottawa's business, in conjunction with input from Hydro Ottawa, procures insurance policies with the objective of maximizing coverage for premium paid. Hydro Ottawa is also a member of the Municipal Electrical Association Reciprocal Insurance Exchange (MEARIE).

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-50

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, pp. 4-5
Appendix 2-JC

QUESTION(S):

a) (P. 4) Please provide the underlying data in tabular format that supports Figure 1.
b) (P. 5) Please provide a revised version of Table 1 that shows for every Appendix 2-JC OM&A program (whether or not there have been FTE additions during the period), the number of FTEs assigned to each program for each year 2021-2030. As part of the response, please also update the FTEs using the current best available information for the 2024 and 2025 bridge years (and update the 2026-2030 forecasts as necessary). Please also show each specific program that underpins “Distribution Operations” on separate lines.

RESPONSE(S):

a) Please see Tables A and B below:

Table A – Underlying Data for Figure 1 Historical Years - 2016 - 2023 ($'000s)

	Historical Years							
	2016	2017	2018	2019	2020	2021	2022	2023
Program Costs	$ 146,927	$ 167,320	$ 214,619	$ 174,863	$ 181,122	$ 170,942	$ 177,907	$ 165,324
FTEs	611	612	605	611	623	585	595	494

Table B – Underlying Data for Figure 1 Bridge and Test Years - 2024 - 2030 ($'000s)

	Bridge Years		Test Years				
	2024	2025	2026	2027	2028	2029	2030
Program Costs	$ 212,307	$ 230,290	$ 358,844	$ 363,917	$ 311,469	$ 324,524	$ 323,887
FTEs	628	641	716	766	780	769	771

b) Table C provides the breakdown of FTE by Appendix 2-JC OM&A program. It includes full time permanent and temporary positions as detailed in Note 3 of Appendix 2-K. This is in addition to Table 1 in Exhibit 4-1-3, which focuses on full time permanent positions. A breakout of Distribution Operations into its sub-programs is not possible as these programs don't have positions dedicated to them. Rather, employees charge hours to these programs based on the work being performed. In lieu of this, Table D has been added below which provides the allocation of trades time to the programs that fall under Distribution Operations.

Table C - FTEs by Appendix 2-JC OM&A Programs

	Historical Years				Bridge Years	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Collections	9	7	5	8	8	8	8	8	8	8
Customer Billing	30	28	25	33	27	28	29	37	29	29
Corporate Costs	3	3	3	3	3	3	3	3	3	3
Customer & Community Relations	40	44	32	36	41	42	43	43	43	43
Distribution Operations	265	266	204	272	269	310	336	337	337	337
Engineering & Design	83	87	82	103	121	142	158	162	158	160
Facilities	6	7	7	8	6	6	7	7	7	7
Finance	31	29	29	29	29	29	31	32	33	33
Human Resources	26	29	26	26	25	28	28	28	28	28
Information Management & Technology	35	37	35	42	40	45	46	46	46	46
Metering	20	18	14	24	23	26	28	28	28	28
Regulatory Affairs	8	9	7	10	14	9	10	10	10	10
Safety, Environment & Business Continuity	12	12	11	15	16	20	21	22	22	22
Supply Chain	20	18	13	16	17	18	18	18	18	18
Total	**585**	**595**	**494**	**624**	**641**	**716**	**766**	**780**	**769**	**771**

Table D - Allocation of Trades Time to Distribution Operations Programs

Allocation of Trades Time			% of Time
Capital			55%
Third Party Services			11%
Maintenance			34%
	JC OM&A Programs:		
	System Ops & 24/7	34%	
	Stations Maintenance	22%	
	Testing, Inspection & Maintenance	14%	
	Distribution O/H & U/G Maintenance	10%	
	Minor Maintenance	6%	
	Metering	6%	
	Vegetation Management	4%	
	U/G Locates	4%	
	Sub total	**100%**	
Total			**100%**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-51

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Attachment A, pp. 3-6

QUESTION(S):

a) (PP. 3-4) With respect to forecasting compensation costs for the 2026 test year, please explain the methodology applied with respect to the application of merit increases to the previous year's base salary. If it is based on historical actual merit increases, please provide the average merit increase applied during the historical period in percent and also provide the total dollar value of the merit increases year- over year during the historical period.

b) (PP. 5) Please provide an update to Table 2 that reflects 2024 incentive pay.

c) (P. 5) Please provide the expected number of employees that will be eligible for incentive pay in 2025 and 2026.

d) (P. 4) Please provide the corporate and divisional priorities (and the related specific metrics) that are used to determine incentive pay.

RESPONSE(S):

a) The forecast for merit increases is based on historical and current trends. The forecast represents a percentage and is applied to compensation at time of Merit. Merit is performance based, with differing increases applied based on the employee's overall performance rating and

salary scale. Employee performance is linked to corporate goals and evaluated with an overall score assigned by their direct supervisor. Scores are reviewed, calibrated and approved at the executive level. Table A reflects the average merit increase applied and the total value of merit year over year for 2021 to 2023.

Table A - Average and Total Merit Increases, 2021-2023

	2021	2022	2023
Average Percent Increase	2.5%	3.0%	2.9%
$ Value of Merit	$398,415	$486,569	$507,620

b) Table B provides an update to Table 2 that reflects 2024 incentive pay.

Table B - Average Annual Incentive-Based Pay, 2021-2024

	2021	2022	2023	2024	4-Year Average
Number of Employees	38	39	43	56	44
Average Amount	$18,818	$18,701	$18,388	$12,204	$18,278

c) Table C provides the expected number of employees that will be eligible for incentive pay in 2025 and 2026.

Table C - Number of Employees Eligible for Incentive-Based Pay, 2025-2026

Year	2025	2026
Number of Employees Eligible for Incentive	63	67

d) Table A below provides the latest version of the corporate priorities that have been approved by the Boards of Directors of Hydro Ottawa Limited and Hydro Ottawa Holding Inc., and which help to serve as the basis for determining incentive payment for the utility's executives. These priorities are mapped against the eight strategic objectives in the 2021-2025 Strategic Direction for the parent company.

1

Table A - 2025 Corporate Priorities

2021-2025 Strategic Objectives	2025 Corporate Priorities
Achieve net-zero operations by 2030	• Continue electrifying our vehicle fleet and facilities • Launch employee engagement and change management programs • Integrate net-zero concepts into design and construction of major substation projects (Piperville, Hydro Road) • Develop and implement external branding for net zero commitment
Become the partner of first choice for signature green energy and carbon reduction projects in our community	• Support City's Energy Evolution plan

Accelerate digital transformation to enable sustainable business practices	• Implement priority technology projects:
	  ○ Back-Up Data Center Modernization
	  ○ Corporate Network Segmentation
	  ○ IT Asset Management Automation
	• Complete next phase of Advanced Distribution Management System (including upgraded Outage Management System)
	• Strengthen cybersecurity protections and enhance disaster recovery plans
	• Continue growing internal AI aptitude

Leverage and promote distributed energy resources	• Develop plans and pilot projects to enable customer adoption of DERs • Deliver energy efficiency programming and Ottawa Retrofit Accelerator initiative • Complete EV Everywhere project • Identify energy saving product/service offerings for customers
Continue to grow and diversify our revenue sources	• Submit and defend 2026-2030 HOL rate application in OEB proceeding • Achieve or exceed targeted HOL revenue
Grow our social license to operate	• Conduct public and government engagement campaigns to preserve stakeholder confidence and trust • Align community investment program with net-zero and energy transition goals • Coordinate planning for Board terms ending in June 2025
Ensure organizational capacity, culture, and leadership to deliver in a post-pandemic environment	• Implement strategies to support talent attraction, development and retention, and to increase future organizational capabilities • Continue to shift organizational culture in support of Strategic Direction • Expand succession planning and leadership programs to next wave of employees • Roll-out new employee safety campaign
Continue to provide best-in-class customer service	• Achieve system reliability targets • Deliver distribution maintenance and capital programs on time/budget • Implement scalable cloud-based Contact Center software platform • Expand MyAccount online portal to commercial customers

2021-2025 Strategic Objectives	2025 Corporate Priorities
	• Expand digital self-service tools for customers (e.g. energy management analytics and disaggregation solution)

Table B below outlines the performance metrics which inform the determination of incentive pay. In addition to the metrics included in Table B, the results against the metrics included in Hydro Ottawa Limited's Custom Performance Scorecard and Performance Outcomes Accountability Mechanism for the 2021-2025 rate term are also taken into account.

Table B - 2025 Performance Metrics

Financial	System Reliability	Customer Service	Organizational Capacity & Health and Safety

• Net Income
• Revenue
• OM&A – Net
• Return on Equity
• Cash Flow from Operations
• Cumulative Capital Additions:
  ○ General Plant (including CCRAs)
  ○ System Renewal & Service
• Labour Allocation to Maintenance & Administrative Work (Regular Hours)
• Debt to Capitalization Ratio
	• SAIFI – Customer Interruption (Average # of Times)
	  ○ Annual excluding LOS and MEDs
	  ○ Annual including LOS and MEDs
	• SAIDI – Customer Interruption (Average # of Hours)
	  ○ Annual excluding LOS and MEDs
	  ○ Annual including LOS and MEDs
	• FEMI (Feeders Experiencing Multiple Interruptions)
	  ○ # of Feeders with 10 or More Interruptions per Year
		• Contact Centre Satisfaction – Transactional Feedback
		• % of Positive / Neutral Media Stories:
		  ○ Traditional Media
		  ○ Social Media
		• CIP Mandated Investments:
		  ○ Low-Income Energy Assistance Program (LEAP)
		  ○ Ontario Electricity Support Program (OESP)
			• All Injury/Illness Frequency Rate
			• Lost Time Severity Rate
			• Attrition
			• Vacancy Rate
			• Hours of Training per Employee (includes safety training)

Technology	**Productivity**	**ESG - Environmental**	**ESG - Social & Governance**

• IT Portfolio Performance to Pla
• Percentage of IT Spending (% Operate : % Enhance/Innovate
• Click Through Rate for Employee Email Phishing Campaigns
	• Productive Time
	• Average Sick Days per FTE (annualized)
	• e-Learning Training per employee (annualized)
	• Bad Debt as a % of Total Electricity Revenue
	• Technology Infrastructure Cost per Employee (annualized)
	• EBITDA as a % Revenue
	• Inventory Turnover Ratio and Value
		• Scope 1 GHG Emissions (fleet, natural gas consumption, SF6 - metric tonnes)
		• Scope 2 GHG Emissions (electricity consumed, line losses - metric tonnes)
		• Priority Spills (#)
		• Non-Hazardous Waste Diversion Rate
		• Green Suppliers
		• Fleet Electrification (electric & hybrid)
			<u>Social</u>
			• Employee Gender Diversity By 2030:
			  ○ 30% Women in Trades and Technical
			  ○ 50% Women Engineers & Engineering Interns
			  ○ 50% Women in Leadership
			• Community Investments
			• Annual Employee United Way Charitable Campaign
			
			<u>Governance</u>
			• Women Board of Directors
			• Board Independence

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-52

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Attachment A, pp. 13, 15-17 Appendix 2-K

QUESTION(S):

a) Please provide a revised version of Appendix 2-K that reflects 2024 actuals and the 2025 forecast using the current best available information. Please also make any necessary updates to 2026 based on the current best available information. As part of the response, please also provide the number of employees, total salary and wages (with a further breakout of overtime and incentive pay), total benefits and total compensation by the following categories: Executive, Management, Union, and Non-Union for each year 2021-2026.

b) Please explain how overtime-related compensation was forecast for the 2026 test year.

c) (P. 13) Please confirm that the temporary equivalents form part of the total FTEs shown in Appendix 2-K

d) (P. 16) Please provide a revised version of Table 10 that shows the actual vacancy- related reconciliation for the 2021-2023 period in the same format.

e) (P. 16) Please provide an updated version of Table 10 that provided the actual vacancy rate for 2024 using the current best available information.

f) (P. 16) Please explain how the forecast vacancy assumption of 8% for the 2025 and 2026 was determined.

g) (P. 17) Please explain how the number of forecast FTE vacancies (and offset by temp/part-time workers) is converted to compensation figures. As part of the response, please provide the detailed calculations that support Table 11.

h) (P. 17) Please provide the forecast reduction to 2026 compensation resulting from the application of a: (i)10% vacancy rate assumption; and (ii) 12% vacancy rate assumption.

RESPONSE(S):

a) To address this request,

- Please see Attachment 1-Staff-1(A) - Chapter 2 Appendies in the response to interrogatory 1-Staff-1 for Appendix 2-K with 2024 actuals.
- Please see Attachment 4-CCC-52(A) - Breakout of Appendix 2-K to address your request to see Appendix 2-K broken out by Executive, Management, Union, and Non-Union for each year 2021-2026.
- The 2025 forecast will not be available until October 2025 and there is no update to the 2026 information. Please see the response to Interrogatory 4-SEC-66, which shows June YTD actuals for 2025 by Appendix 2-JC OM&A programs.

b) Overtime is budgeted based on recent trends, excluding outlier years. While the overall 2024-2025 bridge years and 2026 test year is accurate, it may not align perfectly with individual employee classes because non-union and management overtime is not budgeted per employee.

c) Yes, temporary equivalents form part of the total FTEs shown in Appendix 2-K.

d) Table A shows the requested data, reconciling the number of budgeted positions to actual FTEs. Please note that for 2021-2024 actuals, the difference between the number of budgeted positions and FTEs is not solely explained by positions vacancies, but will include a variety of factors including the impact of an 84 day labour strike, short-term sick leaves, short-term acting

assignments, position overlaps to support knowledge transfer for succession, etc., these are collectively referred to FTE adjustment in the table below for the actual historical years below.

Table A - Reconciliation of Positions to FTEs in Appendix 2-K

	OEB Approved	Historical Years				Bridge Year	Test Year
	2021	2021	2022	2023	2024	2025	2026
Number of Full-Time Permanent Positions	611	617	617	617	667	667	748
Vacancy Rate	4%	10%	12%	12%	11%	8%	8%
Vacancy Assumption translated into FTEs	(24)	(62)	(74)	(74)	(73)	(56)	(60)
Temps and Part Time	28	25	28	26	36	30	28
Other FTE Adjustment		5	24	(75)	(6)		
Number of FTEs (Appendix 2K)	**616**	**585**	**595**	**494**	**624**	**641**	**716**

e) See Table A above for Table 10 of the reference with 2024 actuals. As noted in the response to d) above, the difference between positions and FTEs when looking at historical actuals is not a vacancy rate. For the actual 2024 vacancy rate, see the response to interrogatory 4.0-VECC-42.

f) Forecast vacancy rate is based on historical trending, the implementation of HR Programs that support recruiting/attraction and retention of talent and current external labour market conditions.

g) When developing the compensation budget, the first step is to determine the total cost of salaries and benefits for all HOL approved positions. From this total, an amount is subtracted for expected vacancies, calculated by applying a vacancy percentage to the overall compensation. This provides a specific dollar value for those vacant positions. The net compensation and vacancy amounts shown in Table 11 come directly from the general ledger and represent the true compensation budget.

h) See Table B below for the hypothecal scenarios requested, please refer to interrogatory response to 4.0-VECC-42 part d) for the actual vacancy rate as of June 30th, 2025 which was 9%.

Table B - 2026 Total Compensation with Requested Vacancy Rates ($M)

	Test	Requested	
	2026	2026	2026
Compensation ($)	113	113	113
Vacancy %	8%	10%	12%
Vacancy Assumption ($)	(9)	(11)	(13)
TOTAL - NET COMPENSATION ($)	**104**	**102**	**100**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-53

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Attachment B, pp. 18-19

QUESTION(S):

a) (P. 18) Please provide the analysis undertaken by Hydro Ottawa related to the comparison of operational demand hours (including the assumptions/methodology used to forecast operational demand hours) and internal labour supply.

b) (P. 19) Please provide the analysis (or internal documentation) associated with the rationalization process whereby Hydro Ottawa's executive management team reduced the "overall ask by 11.5%."

RESPONSE(S):

a) Please see the response to interrogatory 4-Staff-159 to show how operational demand hours are linked to internal labour supply. With regards to the assumption/methodology used to forecast operational demand hours, as described in the noted reference, where reasonably feasible, Hydro Ottawa forecasts labour needs by project and work program. When direct forecasting is not available, historical labour needs are used to inform future work programs.

b) Please see Attachment 1-CCC-13(A) - Rate Application Material provided to the Hydro Ottawa Limited Board of Directors, pages 15 to 20, specifically the section titled Need versus Affordability - Part 1 Financial Affordability. As part of the review and prioritization of programs to

fit within the capital expenditure spend limit and the review of OM&A in light of these changes and overall affordability, Hydro Ottawa's executive management team reduced the overall ask for new positions by 11.5%. The reductions are reflected in Table A.

Table A - Headcount Reductions by Appendix 2-JC OM&A Program

	Original	Reduction	Current Ask	% Reduction
Metering	11	3	8	27%
Engineering & Design	62	4	58	6%
Distribution Operations	94	8	86	9%
Customer Billing	1	0	1	0%
Customer & Community Relations	3	2	1	67%
Information Management & Technology	11	4	7	36%
Safety, Environment & Business Continuity	8	1	7	13%
Human Resources	3	0	3	0%
Finance	4	0	4	0%
Facilities	1	1	0	100%
Regulatory Affairs	2	0	2	0%
TOTAL	**200**	**23**	**177**	**11.5%**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-54

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Attachment C, pp. 13-14, 17, 21-23, 29-30

QUESTION(S):

a) (PP. 13-14) Please provide the underlying data in tabular format that supports Figures 5 and 6.

b) (P. 17, 23) With respect to the installation and operation of BESSs, please provide a further explanation regarding the new skills/expertise required. As part of the response, please provide the number positions (or FTEs) that are being created specifically related to BESS-related projects/implementation.

c) (P. 21) With respect to the distribution system observability activities, please provide the number positions (or FTEs) that are being created specifically to support these initiatives.

d) (P. 22) With respect to the distribution system resilience program, please provide the number positions (or FTEs) that are being created specifically to support these initiatives.

e) (P. 29) With respect to cyber security, please provide the number positions (or FTEs) that are being created specifically to support these initiatives. As part of the response, please also discuss Hydro Ottawa's reliance on external services for cyber security support.

f) (P. 30) Please provide the number of positions (or FTEs) that are currently focused on cloud computing-related initiatives.

g) (P. 30) Please further discuss the "AI-driven" enhancements to customer service and the AI models for grid modernization and operational improvements. As part of the response, please discuss Hydro Ottawa's reliance on external services/software for customer service platforms.

RESPONSE(S):

a) Please find the underlying data for Figure 5 and 6 in Attachment 4-1-2(C) - Workforce Growth. The costs represent the capital, maintenance, and services to third-parties supported by Distribution Operations. Please note Figure 5 and 6 were titled Gross Operations Expenditures by Object but should be Distribution Programs.

Table A - 2021-2025 Distribution Programs

Gross Operations Expenditures		
	2021-2025	
	($000,000)	%
Materials	$ 231	27.1%
Outside Services	$ 389	45.5%
Internal labour including Overhead	$ 234	27.4%
Total	**$ 855**	

Table B - 2026-2030 Distribution Programs

Gross Operations Expenditures		
	2026-2030	
	($000,000)	%
Materials	$ 495	32.2%
Outside Services	$ 683	44.4%
Internal labour including Overhead	$ 360	23.4%
Total	**$ 1,538**	

b) To successfully manage Battery Energy Storage Systems (BESS), a new asset class for Hydro Ottawa, new skills and expertise will be essential, as detailed in Sections 3.1.2.2 and 3.1.2.3 of Attachment 4-1-3(C) - Workforce Growth. Hydro Ottawa's existing methodologies for planning, design, standards, construction, commissioning, and maintenance of its current asset base are insufficient for BESS. Though some of the aforementioned items are transferable, BESS installations necessitate unique engineering, maintenance and operation. The foundational knowledge and competencies for utility-owned BESS are largely new to Hydro Ottawa.

Hydro Ottawa's workforce planning does not forecast new positions based on specific assets like BESS systems. Instead, positions are forecast by Work Program, as described in Section 3 of Schedule 4-1-3 - Workforce Staffing and Compensation, and Sections 3.1.1 and 3.1.2 of Attachment 4-1-3(C) - Workforce Growth.

c) Hydro Ottawa does not forecast new headcount by specific activities associated with Observability. Instead, positions are forecast by Work Program, as described in Section 3 of Schedule 4-1-3 - Workforce Staffing and Compensation, and Sections 3.1.1 and 3.1.2 of Attachment 4-1-3(C) - Workforce Growth.

d) Hydro Ottawa does not forecast new headcount by specific activities associated with Resilience. Instead, positions are forecast by Work Program, as described in Section 3 of Schedule 4-1-3 - Workforce Staffing and Compensation, and Sections 3.1.1 and 3.1.2 of Attachment 4-1-3(C) - Workforce Growth.

e) Hydro Ottawa will hire two Cybersecurity positions in 2026 in addition to the one that was hired in 2024 to bring the increase to three new positions to their program headcount.

Hydro Ottawa currently relies on an ecosystem of partners to help deliver on its Cybersecurity strategies and objectives that are defined in its program roadmap.

f) Hydro Ottawa currently does not have any employees dedicated to cloud computing-related initiatives and relies on external consultants for this work. The addition of a Cloud Engineer in 2026 will enable Hydro Ottawa to develop cloud computing-related skill sets internally.

g) Hydro Ottawa will explore and implement AI solutions in the 2026-2030 timeframe. Like many businesses, Hydro Ottawa is looking to AI for a wide range of strategic and operational benefits. The adoption of AI is driven by its potential to address key business challenges and unlock new opportunities for growth, operational efficiency and to improve employee and customer experience. As noted in the evidence, Hydro Ottawa will explore AI enhancements including:

- Agent assistants - empower agents to be more efficient, accurate, and responsive, leading to better outcomes for both the company and the customer
- Chatbots - automate and streamline customer interactions, providing immediate support and information while optimizing human agent capacity to handle inquiries efficiently and dedicate their expertise to complex customer needs
- Cloud based contact center AI - enable intelligent routing, generate call summaries, update customer records automatically, automate routine tasks, and facilitate advanced analytics including sentiment, tone and quality analysis.
- Customer self-serve and automation opportunities - further evolution of our customer portal and website with AI tools to streamline the customer experience.
- Grid related AI includes "disaggregation" - breaking down the total energy usage into its constituent parts without the need for individual sensors on every appliance to provide granular, appliance-level insights into energy consumption.
- Other Grid related AI could include AI-based time series power flow analysis, real-time reporting of power constraints and violations, generation of bridging solutions for demand flexibility and topology control.

Hydro Ottawa will rely on external partners to assist in the implementation and ongoing support of AI enhancements. The new FTE will oversee this work and be “hands on” where possible.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-55

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 1, p. 1
Appendix 2-N

QUESTION(S):

Please describe what activities are undertaken within Hydro Ottawa Energy Services Inc. Please fully describe all of the services Hydro Ottawa Holding Inc. and Hydro Ottawa Limited provide to Hydro Ottawa Energy Services Inc.

RESPONSE(S):

As shown in Figure 1 of Schedule 1-6-1 - Corporate Structure and Governance, Hydro Ottawa Energy Services Inc. is wholly owned by Hydro Ottawa Holding Inc. and is a subsidiary holding company that owns the power generation business currently operated by Energy Ottawa Inc., also known as Portage Power and other non-regulated affiliates.

For more details on the services Hydro Ottawa Holding Inc provides to Hydro Ottawa Energy Services Inc, please see part (f) of Hydro Ottawa's response to interrogatory 1-CCC-12.

For more details of the services Hydro Ottawa Limited provides to Hydro Ottawa Energy Services Inc. and other affiliates, please see Table A below, this provides additional service detail descriptions to those provided in Table 1 of Schedule 4-2-1 - Shared Services and Corporate Cost Allocation.

Table A - Details on Hydro Ottawa Limited Services Provided to Affiliates

Functional Services	Service Details
Human Resources, Safety, Environment, Business Continuity	Includes HR administration, recruitment, training, performance management, payroll, benefits, and labor relations. Also covers health and safety, environmental compliance, emergency management, and business continuity.
Information Technology	Provides general IT support, maintenance, and contingency planning. This includes equipment upgrades, rentals, and disposal services.
Facilities	Includes solar panel space rentals and limited shared office space.
Finance	Manages procurement, accounts payable and receivable, and banking. Also provides accounting support, tax compliance, and audit assistance.
Regulatory, Legal, Corporate Communications	Provides regulatory guidance and support for compliance and filings. Offers supplemental legal services and manages corporate communications, including media relations, public outreach, and online support.
Data Services	Includes web portal data services.
Mechanic Services	Provides electrical, mechanical, and civil services by a fitter mechanic.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-56

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 1, p. 6

Preamble:
Hydro Ottawa Holding Inc.'s service costs to Hydro Ottawa are increasing from $3.8 million in 2021 to $7.7 million in 2026. The increase stems from several key factors including the demand for executive management time which has significantly increased.

QUESTION(S):

a) Please set out the overall increase in executive management costs which are subject to the allocation, prior to the allocation, from 2021 to 2026.

b) If the demand for executive management are increasing for Hydro Ottawa Limited, have they decreased for the other entities? Please explain.

RESPONSE(S):

a) The overall pool of Hydro Ottawa Holding Inc.'s costs subject to allocation to Hydro Ottawa has increased by 46% from 2021 to 2026, representing an average annual increase of 8%. It should be noted that costs reflected in Attachment 4-2-1(A) - OEB Appendix 2-N - Shared Services and Corporate Cost Allocation represent only the costs that Hydro Ottawa shares with other affiliates. There are additional costs within the holding company that may be borne by the holding company itself or other non-regulated affiliates that are not included in this Appendix.

b) While the overall pool of costs subject to allocation has grown from 2021 to 2026 due to factors such as general inflation, the allocation percentage to the other entities has decreased. This is a result of two primary drivers. First, the demand for executive management time dedicated to Hydro Ottawa has increased, as detailed in the response to interrogatory 4-Staff-156, due to events such as the 2023 strike and severe weather events, as well as evolving regulatory and strategic demands. Second, the non-regulated affiliates have grown significantly and hired their own senior management staff, which has allowed them to perform some of the duties that were previously fulfilled by the executive management team. This has, in turn, reduced the proportionate share of the cost pool allocated to these other entities. Despite this decrease in the proportionate share, the costs allocated to the other entities have still increased from 2021 because the overall pool of costs being allocated has grown. Additionally, there are other costs at the holding company that are only applicable to affiliates.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-57

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 1, p. 6

QUESTION(S):

For each member of the Executive Management Team, please provide the percentage of their time allocated to Hydro Ottawa Limited for each year 2021-2026. Please explain why it is more cost-effective for Hydro Ottawa Limited to contract for the Executive Management Team, rather than having them as full-time employees and contracting their services to other related/affiliated companies.

RESPONSE(S):

The percentage of time allocated to Hydro Ottawa is not done on a per individual basis but rather by the type of Management Service as outlined in Table 2 of Schedule 4-2-1 - Shared Services and Corporate Allocation and Attachment 4-2-1(A) - OEB Appendix 2-N - Shared Services and Corporate Cost Allocation. Appendix 2-N includes the % of Corporate Costs Allocated which one can extrapolate to mean their percentage of time allocated to Hydro Ottawa in each of the years. For ease of reference, in Table A below, the percentages by service offered which includes an executive are presented. For example Management Services includes the portion of Chief Executive Officer's time and Customer Service, Corporate Communications includes the portion of the Chief Customer Officer's time. For a representation of the Executive Management Team, please refer to Figure 2 in Schedule 1-6-1 -Corporate Structure and Governance.

Table A - Percentage of Corporate Costs Allocated from HOHI to HOL (Services that include members of the Executive Management Team)

Management Service	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Management Services	50%	66%	69%	69%	69%	70%
Finance, Internal Audit, Risk Management	75%	71%	71%	70%	70%	70%
Human Resources	80%	80%	84%	83%	83%	85%
Customer Service, Corporate Communications	46%	67%	80%	80%	80%	80%
Legal	38%	40%	40%	40%	40%	40%
Information Management & Technology	53%	64%	60%	60%	60%	60%
Distribution Leadership	0%	0%	0%	0%	75%	75%

From a pricing methodology perspective, both having executive management as full-time employees of Hydro Ottawa Limited or as employees of Hydro Ottawa Holding Inc. use the same pricing methodology for services rendered, as such there is no difference in cost between the two methods. Please refer to the response to interrogatory 4.0-VECC-40 Table A for the overall percentage of FTEs allocated to Hydro Ottawa from the holding company.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-58

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 1, p. 6

QUESTION(S):

Has Hydro Ottawa Limited or Hydro Ottawa Holding Inc. ever retained outside consultants to assess their overall corporate structure and the cost-effectiveness of that structure? If so, please provide the results of that work. If not, why not?

RESPONSE(S):

No, Hydro Ottawa Limited nor Hydro Ottawa Holding Inc. has retained outside consultants to assess their overall corporate structure and the cost-effectiveness of that structure.

Hydro Ottawa has not felt the need or justification to undergo such a comprehensive and costly study. The existing corporate structure and shared service allocation model have been developed and refined internally to realize economies of scale, manage costs, and maintain service levels, as detailed in the original evidence.

While a comprehensive assessment has not been conducted, external consultants have been engaged for specific purposes, such as for tax planning and legal advice related to corporate structure, including the recent restructuring for Hydro Ottawa Capital Corporation to acquire 100% of the shares in the issued and outstanding capital of Hydro Ottawa Limited from Hydro Ottawa Holding Inc. (EB-2024-0164).

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-59

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 2, p. 4

QUESTION(S):

Please provide Table 1- Material Strategic Alliance, Sole Source and Directed Source Purchases for the years 2024-2025 and the budget for 2026. Please identify the cost categories where each of these purchases are accounted for.

RESPONSE(S):

Table A and B below provides the same information as in Schedule 4-2-2 - Purchases of Non-Affiliate Services, Table 1 to Table 3 for 2024 and 2025 January to June. Note that the amounts in these tables include HST. Hydro Ottawa does not budget at the procurement level and therefore cannot provide a comparable table for 2026. With respect to the cost categories, please refer to the applicable footnotes.

Table A – Material Strategic Alliance, Sole Source and Directed Source Purchases (2024)

Procurement Method	Supplier	Service / Product	Cost
Strategic Alliance	Anixter Power Solutions	O/H & U/G Transformers and hardware, O/H cable[1]	$ 38,099,036
Strategic Alliance	Prysmian Cables and Systems Canada Ltd.	U/G Cable[1]	$ 6,605,086
Strategic Alliance	S&C Electric Canada Ltd.	Switchgear[1]	$ 4,585,356
Strategic Alliance	Elster Solutions Canada Inc.	Smart Meters[1]	$ 3,866,958
Strategic Alliance	Stella-Jones Inc.	Wood Poles[1]	$ 3,768,726
Strategic Alliance	Rexel Utility	Pole Hardware: Connectors, Elbows, Heat Shrink, Crossarms, etc.[1]	$ 2,250,079
Strategic Alliance	Pioneer Transformers Ltd.	Vault Transformers[1]	$ 2,888,912
Strategic Alliance	Bel Volt Sales Ltd.	Inline and Disconnect Switches, Connectors, Fault Indicators, etc[1]	$ 1,757,483
Strategic Alliance	RS Technologies	Composite Poles[1]	$ 1,162,634
Directed Source	J.W. Leslie Utilities	Light Underground Electrical Services[2]	$ 3,681,033
Directed Source	Posi-Plus Technologies Inc.	Utility Vehicles[3]	$ 2,462,223
Directed Source	Relevantz Technology Services Canada Inc	MyAccount customer portal redesign[4]	$ 2,296,698
Directed Source	Black & Veatch Canada Company	Project Consulting Services[5]	$ 2,195,033
Directed Source	Intergraph Canada Ltd. (Hexagon)	Software Support for Oracle, OMS, GIS[6]	$ 1, 959,586
Sole Source	Oracle Canada ULC	Software Maintenance and Support[7]	$ 2,554,248

[1] For all inventory items, these are originally recorded into inventory and then charged to the applicable work as it is being used whether that be capital, maintenance or work for others
[2] This is charged to the System Access capital program and work for others
[3] Utility vehicles are charged to the General Plant capital program
[4] This is charged to General Plant capital program
[5] This is charged to the System Service capital program and one-time regulatory consulting costs
[6] This is charged to the Engineering & Design OM&A Program and System Service capital program
[7] This is charged to the Information Management and Technology OM&A Program

Table B – Material Strategic Alliance, Sole Source and Directed Source Purchases (January 1, 2025 to June 30, 2025)

Procurement Method	Supplier	Service / Product	Cost
Strategic Alliance	Anixter Power Solutions	O/H & U/G Transformers and hardware, O/H cable[1]	$ 22,929,152
Strategic Alliance	Prysmian Cables and Systems Canada Ltd.	U/G Cable[1]	$ 4,145,402
Strategic Alliance	Stella-Jones Inc.	Wood Poles[1]	$ 2,231,292
Strategic Alliance	Elster Solutions Canada Inc.	Smart Meters[1]	$ 2,141,566
Strategic Alliance	S&C Electric Canada Ltd.	Switchgear[1]	$ 1,516,507
Directed Source	J.W. Leslie Utilities	Light Underground Electrical Services[2]	$ 2,028,884
Directed Source	Siemens Canada Ltd.	Gas Insulated Switchgear for Piperville MTS[8]	$ 1,182,382

[8] This is charged to the Piperville project under the System Service capital program.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-60

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 3

Preamble:
The one-time Regulatory Costs associated with the Application are $5.396 million as compared to $2.424 million for the last rebasing actual costs.

QUESTION(S):

a) Please provide all assumptions used to develop this budget including the assumption for expert witness costs, legal costs, consultant's costs, intervenor costs, compensation costs and OEB Section 30 Costs.

b) Please explain why Regulatory One-Time legal costs are increasing from $136,000 to $950,000. Please provide all assumptions used to derive the 2026 budget.

c) Please explain what is included in "Compensation Costs" amounting to $613,900.

d) Please provide a table setting out expert witness costs, legal costs, consultant's costs, and compensation costs incurred to date.

RESPONSE(S):

a) Please see the response to interrogatory 4-Staff-174, part b) for the assumptions used to develop the budget for one-time Regulatory Costs.

b) Incremental legal fees in this application compared to the 2021-2025 application are driven by the need for additional legal support in the preparation and defence of the application. In the preparatory stages, Hydro Ottawa required greater support from external counsel to conduct a comprehensive review of Hydro Ottawa's evidence to ensure that the evidence is: (i) clear and robust to support the requested rate increase and regulatory approvals, and (ii) responsive to incremental requirements related to growth and electrification and other recent business and regulatory changes, including rate framework evolutions, cloud computing investments, non-wires solutions, flexibility mechanisms to address greater uncertainty, incremental workforce requirements, and grid modernization investments to advance resilience and support DER enablement and integration.

Further, compared to the last application Hydro Ottawa is relying on external legal counsel to provide greater support with respect to the discovery phases of the proceeding (i.e. interrogatories and technical conference) as well as the oral hearing and argument phases of the process. This additional legal support is necessary because the volume and complexity of the issues in this proceeding is greater than what Hydro Ottawa faced in the last application for the reasons noted above and because Hydro Ottawa requires greater incremental funding and more sophisticated regulatory approvals than it did in the past to deliver its 2026-2030 investment plans.

In addition, in comparing the budget for the last application and the current proceeding, it is important to note that Hydro Ottawa's previous rate application resulted in a substantial settlement on all but one issue. As a result, the previous fees do not reflect the external legal costs of an oral hearing and argument phases of the proceeding which are very labour intensive in terms of legal support.

c) As noted in the response to interrogatory 4-Staff-174, part b), Compensation includes the compensation of staff hired specifically for the preparation of this rate application or staff

seconded to work on the rate application whose substantive positions were backfilled and an estimate of the overtime required throughout the application process.

d) The costs incurred to date are shown in the following Table A. They include costs incurred to the date of filing, and some subsequent activities such as the error checking process, confidentiality process and some training costs for next steps in the rate application process. However, there were no accruals made for intervenor or OEB costs to the end of June.

Table A - One-Time Regulatory Costs Incurred to June 30, 2025

Regulatory Costs (One-Time)	2026 Application Cost Incurred to June 2025
Expert Witness costs	-
Legal costs	$ 322,823
Consultants' costs	$ 2,021,672
Intervenor costs	-
OEB Section 30 Costs (application-related)	-
Compensation	$ 192,731
Travel and Miscellaneous	$ 5,135
TOTAL	**$ 2,542,361**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-61

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 4, p. 2

Preamble:
On-going Regulatory Costs are increasing from $2.551 million in 2021 to $3.762 million in 2026.

QUESTION(S):

a) Please confirm these costs are included in the overall 2026 OM&A budget envelope.

b) Please provide a detailed variance analysis between 2021 and 2026 with respect to the on-going regulatory costs.

RESPONSE(S):

a) Yes, these on-going regulatory costs are included in the overall 2026 OM&A budget envelope.

b) Table A on the next page shows the variance between 2021 and 2026 for the on-going regulatory costs, including the compound annual growth rate (CAGR) of each cost category.

Table A - On-Going Regulatory Costs Variances Between 2021 and 2026

Regulatory Costs	Historical 2021	Test 2026	2021-2026 $ Variance	2021-2026 % Variance	CAGR[1]
Compensation and Other	$ 977	$ 1,349	$ 372	38.1%	6.7%
OEB Annual Assessment	$ 1,354	$ 2,164	$ 810	59.8%	9.8%
Other Regulatory Memberships	$ 157	$ 175	$ 18	11.5%	2.2%
Section 30 Costs	$ 63	$ 75	$ 12	19.0%	3.5%
Total	**$ 2,551**	**$ 3,762**	**$ 1,211**	**47.5%**	**8.1%**

Compensation of regulatory affairs employees and the OEB Annual Assessment represent over 90% of the on-going regulatory costs, and explains 98% of the variance.

- The variance in compensation is the result of annual increases in salaries and benefits and some increase in the number of employees in response to the increasing complexity of the regulatory landscape. A fuller description of what activities the Regulatory Affairs programs entails can be found in Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs, subsection 3.20 Regulatory Affairs. This also includes general costs such as conferences, training and travel.
- As noted in Section 3 of Schedule 4-2-4 - Regulatory Costs, changes to the OEB's cost assessment model substantially increased Hydro Ottawa's allocation of OEB's costs, which started to be reflected in 2021 actuals. As the industry has experienced an increase in policy consultations and working groups, a higher than inflationary impact was experienced through the 2022-2024 period and is estimated to continue into the 2026 Test Year. Subsequent to the filing of this Application, the OEB has indicated their current annual budget of $57.7M for 2024/2025 is estimated to increase to $70.1M (see Attachment 4-CCC-61(A) - OEB Letter re. Cost Assessment Fiscal Year 2025-2026). Based on this information provided by the OEB, the estimate for the 2026 Test Year is too low.
- Other Regulatory Memberships represent the annual fee paid to the Electrical Safety Authority as required under the Electrical Distribution Safety Regulation, Ontario Regulation 22/04. Normal annual inflationary increases have been observed.

[1] CAGR is Compound Annual Growth Rate

- Section 30 Costs are invoiced by the OEB to payor groups including distributors and include both Intervenor Costs and OEB costs. The intervenor costs are submitted publicly to the OEB and approved and reflect the cost of intervenor participation in consultations and working groups, and on occasion expert evidence. The OEB does not generally provide details on its portion of the cost and as such no comment can be made on the make-up. Given the OEB letter referenced above, it is unclear if these costs are also impacted by the change to the OEB Budget or if these costs will be determined as policy initiatives commence.

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

BY EMAIL

April 3, 2025

To: Regulated Entities Subject to OEB Cost Assessment

Re: Cost Assessment - Fiscal Year 2025-2026

Under Section 26 of the *Ontario Energy Board Act, 1998*, capital and operating expenses of the Ontario Energy Board (OEB) are recovered from regulated entities through cost assessments.

Cost allocation follows an approved budget for the fiscal year and updated information outlined in the OEB's Cost Assessment Model (CAM).

The OEB's 2025-2028 Business Plan, which is pending approval of the Minister of Energy and Mines and includes our budget for FY2025/26, is focused on providing value to the people of Ontario through the lenses of consumer protection and customer choice, regulatory policy leadership, innovation, and adjudicative excellence. Anticipating greater expectations for delivery across adjudicative and policy files, the OEB projected a budget of approximately $70.1 million. While awaiting approval, the OEB is issuing Q1 invoices based on the approved FY2024/25 budget, which was $57.7 million. Upon the Minister's approval of the budget for FY2025/26, necessary adjustments will be made to invoices for the remaining quarters.

FY2025-2026 Assessment by Class of Payor

To allocate costs among payor classes, we rely on the OEB's Cost Assessment Model. The following table outlines the cost allocation by payor class for Q1 of fiscal year 2025-2026. Any necessary adjustments will be reflected during the Q2, Q3 and Q4 billing cycles to reconcile to the approved budget for FY2025/26.

Class of Payor	2025-2026 Q1 Assessment	
	$*	% share of total cost
Electricity Distribution	7,828	56
Gas Utilities	3,489	25
Electricity Transmission	1,047	8
Independent Electricity System Operator	597	4
Ontario Power Generation	477	3
Unit Sub-Meter Providers	346	2
Retailers	144	1
Marketers	111	1
Total	14,040	100

(* in thousands)

Payment of Cost Assessment

Cost assessments are payable quarterly, beginning with the period from April 1, 2025, to June 30, 2025, quarter (Q1). Enclosed with this letter, you will find your cost assessment invoice along with electronic payment instructions for the first quarter payment to the OEB. Electronic payment for each assessment is due 30 days from the invoice date.

Please direct any questions you may have relating to the attached invoice to accountsreceivable@oeb.ca

Sincerely,

Original signed by,

Walter Carvajalino

Manager, Finance & Risk | Ontario Energy Board

Attachments: Invoice dated April 3, 2025 & Electronic Payment Instructions

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

4-CCC-62

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 5, p. 2

QUESTION(S):

What is the projected carryover of LEAP funds in 2026? Is the amount of funds available expected to exceed the demand?

RESPONSE(S):

Hydro Ottawa does not have the ability to project the carryover of LEAP funds in 2026, as this projection relies on 2025 year-end data, which is not yet available. Furthermore, the program is managed by an external provider, and the demand from low-income customers is inherently difficult to project.

Hydro Ottawa has made recent changes to the delivery of the program that should result in increased accessibility. Hydro Ottawa has already experienced increased use of the program and anticipates this trend will continue. However, the amount of funds available is expected to exceed the demand, at least in the short-term. While Hydro Ottawa is confident that these recent changes will allow a lower carryover of funds going forward, there is currently insufficient historical data to fully assess the impact of these changes.

Please refer to Schedule 4-2-5 - Low-Income Energy Assistance Program for more details on elements impacting the demand of this program.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

5-CCC-63

EVIDENCE REFERENCE:

Exhibit 5, Tab 1, Schedule 1, pp. 7-8

QUESTION(S):

a) (P. 7) Please advise whether the July 2, 2025 promissory note was entered into. If so, please provide the note.

b) (P. 8) Please provide the 2024 achieved ROE.

RESPONSE(S):

a) On July 2, 2025, Hydro Ottawa Limited issued a promissory note to its parent company, Hydro Ottawa Capital Corporation, in the amount of $72,600,000 maturing on January 30, 2035 at an interest rate of 4.429%. Please see Attachment 5-CCC-63(A) - Hydro Ottawa Limited $72.6M Promissory Note.

b) Please see the response to interrogatory 5-Staff-181 for the 2024 achieved ROE.

PROMISSORY NOTE

(the "**Promissory Note**")

July 2, 2025 **Principal Sum: $72,600,000**

FOR VALUE RECEIVED, and subject to the terms and conditions set forth in his promissory note, Hydro Ottawa Limited, its successors and assigns (the "**Borrower**") hereby unconditionally promises to pay to the order of Hydro Ottawa Capital Corporation/Société de Capitaux Hydro Ottawa (the "**Lender**") the principal sum of seventy two million six hundred thousand dollars ($72,600,000) in lawful money of Canada at such place as the Lender may designate by notice in writing to the Borrower (the "**Principal Amount**").

1. INTEREST RATE

The rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 4.429% per annum from July 2, 2025 to January 30, 2035.

2. TERMS OF PAYMENT

The interest payable hereunder shall be calculated and payable monthly in arrears on the first day of each month, both before and after demand, default and judgment. The Borrower shall pay to the Lender on demand, interest on overdue interest at the rate described in Section 1 hereof compounded on each date for the payment of interest on this Promissory Note before and afterjudgment.

3. REPAYMENT

(a) Subject to the terms and conditions set out in Subsection 3(d) herein, the Borrower may, at any time, repay in whole or in part the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note and interest owing under this Promissory Note.

(b) The Lender may require that the Borrower repay the Principal Amount and interest payable within 30 days following a change of control of the Borrower For the purpose of this sub-section control means with respect to the Borrower at any time:

1. holding, as owner or other beneficiary, other than solely as beneficiary of an unrealized security interest, directly or indirectly, securities or ownership interests of the Borrower carrying votes or ownership interests sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of the Borrower; or

2. the exercise of de facto control of the Borrower, whether direct or indirect and whether through ownership of securities or ownership interests, by contract, trust or otherwise.

The Lender shall provide the Borrower with no less than twenty (20) days' prior notice of the requirement to repay Principal and interest.

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with Subsection 3(d) herein.

(c) The Lender may require that the Borrower repay the Principal Amount and interest payable in the event that the Borrower:

1. disposes of substantially all of its property or assets;

2. fails to pay any principal, premium or interest on an indebtedness however incurred beyond any period of grace applicable to such indebtedness, where the amount of the indebtedness is $25 million or greater;

3. fails to perform or observe an agreement, term or condition contained in any agreement under which an indebtedness in the amount of $25 million or greater becomes due and payable; or

4. for any other reason causes the whole or any part of the Principal Amount to be repayable to the Lender in advance of the Due Date;

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with Subsection 3(d) herein.

(d) In the event that the Borrower chooses to repay or is required to repay in whole or in part the Principal Amount remaining unpaid and accrued and unpaid interest in accordance with Subsections 3(a), (b) or (c) herein, the Borrower shall:

1. Provide, where such repayment is initiated at the request of the Borrower, at least fifty (50) days' prior notice in writing to the Lender setting out the proposed amount of the Principal Amount and accrued and unpaid interest that it proposes to pay and the date of such payment;

2. Pay to the Lender in respect of the Principal Amount and accrued and unpaid interest to be paid, an amount calculated and determined by the Lender in the same manner and subject to the same conditions (subject to any necessary changes) as the Redemption Price respecting an equivalent payment of principal as is set out in the Series 2025 — 1 Supplemental Indenture dated January 30, 2025 between the Lender and BNY Trust Company of Canada; and

3. Indemnify the Lender., in addition to the amount calculated and determined pursuant to Subsection 3(d)(2) herein, for any damages, losses, liabilities, claims, demands, interest, charges, fines, penalties, assessments, judgments, costs and expenses suffered or asserted directly or indirectly arising from any payment made pursuant to Subsection 3(a), (b) or (c) herein or any delay in providing such payment.

4. SUBORDINATION

The obligation of the Borrower to pay the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note, together with interest thereon in accordance with and pursuant to this Promissory Note is subordinated and postponed to the obligations of the Borrower to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of the Borrower.

5. WAIVER OF NOTICE IN EVENT OF DEFAULT

The Borrower hereby waives presentment, protest and notice of any kind in the enforcement of this Promissory Note. The Borrower further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Promissory Note, or any payment of interest thereon is not made when due.

6. RIGHTS AND REMEDIES IN EVENT OF DEFAULT

The rights and remedies of the Lender under this Promissory Note which it may have at law or in equity against the Borrower shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by the Lender, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of the Borrower under this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by the Lender which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by the Lender in the enforcement of any covenant, promise or agreement of the Borrower hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of the Lender shall only occur and be valid when set forth in writing by the Lender. No waiver of any event of default shall discharge or release any person at any time liable for the payment of this Promissory Note from such liability. No single or partial exercise of any of the Lender's powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

7. ASSIGNMENT

This Promissory Note may not be assigned by the Borrower without the written consent of the Lender.

8. GOVERNING LAW

This Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

[*Signature page immediately follows*]

IN WITNESS WHEREOF, the undersigned has caused this Promissory Note to be duly executed and delivered on the date first above written.

HYDRO OTTAWA LIMITED

Per : Signed by: Geoff Simpson 43DC885CF33E43F...
Name: Geoff Simpson
Title: Chief Financial Officer

Per : DocuSigned by: Neal Tejwani 65C84A67A8E34B8...
Name: Neal Tejwani
Title: Treasurer

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

7-CCC-64

EVIDENCE REFERENCE:

Exhibit 7, Tab 1, Schedule 1, p. 11

Preamble:

Hydro Ottawa has introduced a new method to calculate in-house demand factors that reflect current and expected load requirements. Demand profiles for this Application have been based on an analysis of six-years historical load from 2018-2023.

QUESTION(S):

Please explain why this new approach is appropriate.

RESPONSE(S):

The Ontario Energy Board (OEB) Chapter 2 Filing Requirements Section 2.7.1.1 (Load Profiles and Demand Allocators) describes two options for creating utility-specific load profiles: multivariate regression analysis or historical averaging. Both methods use weather-normalized historical data to predict future load patterns.

Hydro Ottawa has chosen the historical averaging approach, based on the Utilities Standards Forum's (USF) Demand Allocators Model. The USF model has a proven track record, having been successfully used in three previous Cost of Service Applications[1]. The Hydro Ottawa adaptation of

[1] Wellington North Power Inc.'s 2021 Cost Of Service application (EB-2020-0061), Brantford Power Inc.'s 2022 Cost of Service application (EB-2021-0009 2021) and Centre Wellington's 2025 Cost of Service Application (EB-2024-0012).

this model aligns with OEB guidelines by developing weather-normalized load shapes over a ten-year comparison period and using at least three to five years of historical data to predict Coincident Peak (CP) and Non-Coincident Peak (NCP) values for the test period.

Please refer to Attachment 7-1-1 (G) - 2026 Demand Allocators for a complete description of the method, including the appropriateness of choosing this methodology.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

7-CCC-65

EVIDENCE REFERENCE:

Exhibit 7, Tab 1, Schedule 1, p. 11

Preamble:
The cost study initiatives undertaken by Hydro Ottawa shift $11.9 million in revenue requirement to the Residential customer class from the General Service, Large use and Street Light classes.

QUESTION(S):

Please provide the residential bill impact resulting from the cost study initiatives.

RESPONSE(S):

Note that this analysis has been based on revised Cost allocation and RRWF workforms, updated for 2024 actual results, submitted as Attachment 1-Staff-1(H) - 2026 Cost Allocation Model in interrogatory response 1-Staff-1.

Table A shows the impact of the cost study initiatives on bill impacts for the Residential rate class. Viewed in isolation, the change in cost allocation increases the revenue/cost ratio (R/C) from 99.56% to 106.58%. As the ratio still falls within boundary ranges for the class, no rate mitigation is required and rates are calculated on the basis of scaled revenue at status quo resulting in no impact on the proposed billed rate for the residential customer class. This scenario does not incorporate any rate mitigation necessary to manage revenue to cost ratios and thus must be viewed as an

example only.

Table A – Summary of Residential Rate Impacts

Rate Class		2026 Bill Impacts - Residential Class	
		Attachment 1-Staff-1 2026 Cost Allocation Model	Removing the Cost Study Initiative
Residential (750 kWh)	Distribution Charge	$40.34	$40.34
	Change in Distribution Charge	$5.83	$5.83
	% Distribution Increase	16.89%	16.89%
	% Increase of Total Bill	8.68%	8.68%
	Revenue / Cost Ratio	99.57%	106.60%

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

8-CCC-66

EVIDENCE REFERENCE:

Exhibit 8, Tab 3, Schedule 2, pp. 1-5

Preamble:
Hydro Ottawa is proposing to increase its Standard Supply Service Administration Charge (SSS Charge).

QUESTION(S):

a) Please set out, in detail, how the $6.7 million amount was derived.

b) Please demonstrate that these costs are incremental to the proposed OM&A costs and are not included in the proposed 2026 OM&A amounts.

c) Is Hydro Ottawa aware of any other LDCs that have proposed utility specific SSS Charges and obtained OEB approval for these charges? If so, please indicate which utilities have specific charges and what those charges are.

RESPONSE(S):

a) Please see Table A for a breakdown of how the $6.7 million was derived.

Table A - Breakdown of 2026 SSS Cost Estimate ($'000)

	Test Year 2026 SSS Expense
Labour - RPP & Commodity	$1,178
Labour - Wholesale Market	$335
Labour - Monthly Settlement	$506
Outside Services	$620
Working Capital	$4,125
TOTAL	**$6,764**

To determine the working capital amount, Hydro Ottawa included the cost of power estimate (which is not grossed up for kWh losses) and the OM&A estimate detailed in Table A. The labour and outside service expenses included have been described in Schedule 8-3-2 - Standard Supply Service Charge.

b) The incremental OM&A costs to provide SSS services are included in the 2026 proposed OM&A amounts and are not recorded in Other Revenue. The annual SSS revenue collected is included in Other Revenue amounts which is an offset to the total Service Revenue requirement. This reduces the amount (base revenue requirement) to be recovered through distribution rates. Please refer to Schedule 6-1-1 - Revenue Requirement and Revenue Deficiency or Sufficiency and Schedule 6-3-4 - Other Operating Revenue for further details.

c) Hydro Ottawa is not aware of any local distribution companies (LDCs) that have proposed a utility specific SSS charge. Hydro Ottawa notes it was one of the first (and perhaps the only) LDCs to propose and receive approval for utility specific retailer service charges (RSCs) and one of the first to receive utility-specific pole attachment charges as part of its 2016 Custom IR Application.[1] Subsequent to these proposals and OEB approvals, the OEB began its Review of Miscellaneous Service Charges.[2] The consultation and OEB Decisions for both RSC[3] and

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Approved Settlement Proposal*, EB-2015-0004 (December 7, 2015)
[2] Ontario Energy Board Letter, Review of Miscellaneous Rate and Charges, EB-2015-0304 (November 5, 2015)
[3] Report of the Ontario Energy Board, *Energy Retailer Service Charges,* EB-2015-0304 (November 29, 2018)

Wireline Pole Attachment charge[4] led to an increase in province-wide rates, ultimately better enabling distributors to recover their current costs for providing these services. The OEB Decisions also mandated an annual inflationary increase for these service charges to ensure the rates continue to recover the costs for retailer and pole attachment services.

As part of Hydro Ottawa's 2021-2025 Approved Settlement Agreement, the following statement was included "Notwithstanding the agreement amongst the Parties on the use of the SSS Charge, the Parties acknowledge that the charge has not been adjusted to reflect actual costs or inflation since it was first introduced in 2002. The Parties believe that timely review of the rate design methodology associated with the SSS Charge is warranted as part of the OEB's ongoing review of miscellaneous rates and charges."[5] At this time, no such review has occurred.

[4] Report of the Ontario Energy Board, *Wireline Pole Attachment Charges,* EB-2015-0304 (March 22, 2018)
[5] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020), page. 29.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

8-CCC-67

EVIDENCE REFERENCE:

Exhibit 8, Tab 4, Schedule 2, p. 1

Preamble:
Generator Service Charges are declining in the 2026-2030 rate plan period.

QUESTION(S):

To what extent are Hydro Ottawa's unregulated affiliates benefitting from these changes?

RESPONSE(S):

As described in Schedule 8-4-1 - Specific Service Charges Hydro Ottawa undertook a review of many routine service charges to ensure they reflected the associated costs of providing services and achieved efficiencies in the 2021-2024 period. From this review, Hydro Ottawa has proposed reducing some of the Generator monthly service charges as a result of business efficiencies and automating processes for generation accounts. The proposed charges ensure all generation customers are paying for the costs to provide these services and no cross-subsidization is occurring between customers.

The Micro generators charge <10KW (for which net metering used to be part of this category) saw a reduction in the charge mainly as a result of reducing the amount of staff time required on these accounts due to further automation. On average time spent on each account went from 6 minutes to 4 minutes per account per month. A monthly savings of approximately 30 hours per month (close to

one week's work of time) or 356 hours per year. This is not a main area in which Affiliates currently own generation.

The charge for Feed in Tariff (FIT) and Other generators >10KW has increased and therefore all generators in this class will experience a cost increase including the FIT generators owned by Affiliates.

Hydro Ottawa's affiliates also fall within the Hydro Electric Contract Initiative (HCI), Renewable Energy Standard Offer Program (RESOP), and Other Energy Resource Service generation class. The main reason for the cost decrease is a change in generations from seven to nine. Although it's only an extra two generators a 28.6% growth is impactful when sharing the relatively fixed portions of the costs. The two new generators are Hydro Ottawa affiliate owned, although the monthly charge per account has decreased, from a total dollars perspective they have taken on more of the fixed costs to provide these services.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-68

EVIDENCE REFERENCE:
Exhibit 9, Tab 1, Schedule 3, p. 4

QUESTION(S):

Please provide specific references to the applications, settlements and/or decisions where the OEB-approved gains/losses on utility property for the 2020-2023 period can be found.

RESPONSE(S):

Hydro Ottawa established the Account 1508 Sub-account Gains and Loss on disposal of Fixed Assets Variance Account, effective January 1, 2016, to record the difference between the forecast and actual loss on the disposal of fixed assets, related to retirement of assets or damage to plant. Please refer to Ontario Energy Board, *Decision and Order* EB-2015-0004 (December 22, 2015), Schedule C.

As part of Hydro Ottawa Limited's Custom Incentive Rate-setting Application EB-2019-0261, the Gains and Loss of Disposal of Fixed Variance Account was proposed to continue for 2021-2025. Please refer to Schedule 9-1-1, Table 4. Hydro Ottawa also provided the estimated variances in Schedule 9-1-3 Group 2 Accounts. The Parties accepted Hydro Ottawa's proposal to continue Account 1508 Sub-account Gains and Loss on disposal of Fixed Assets Variance Account as described in the evidence (Exhibit 9) and agreed to the continuation of this 1508 Sub-Account. Please refer to Ontario Energy Board, 2021 Hydro Ottawa Limited Electricity Distribution Rate Application - Settlement Proposal (September 18, 2020), page 30.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-69

EVIDENCE REFERENCE:

Exhibit 9, Tab 1, Schedule 3, pp. 6-10

QUESTION(S):

a) (P. 6) Please provide the evidence from the 2021-2025 application and settlement agreement showing the specific methodology applied and approved for the disposition of the 2016-2018 balances in the ESMVA.

b) (P. 8) Please provide a detailed explanation for each of the adjustments made in Table 3.

c) (P. 9) Please provide a detailed explanation for each of the adjustments made in Table 4.

d) (P. 10) Please explain the statement that "Hydro Ottawa proposes any resultant balance be returned to customers in accordance with the materiality levels described by the OEB for Group 2 Accounts." Please explain why a materiality threshold would be applied to overearnings.

RESPONSE(S):

a) Please refer to page 32, 34 and 35 in Hydro Ottawa's 2021-2025 Approved Settlement Agreement[1] for details on the specific methodology applied to the ESM Variance Account.

[1] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020).

Please also see Attachment 9-CCC-69(A) - Hydro Ottawa 2021-2025 TC_JT 3.9 for further details, which is referenced as evidence of the calculation.

b) Per Schedule 9-1-3 - Group 2 Accounts, this Group 2 Account credits customers for 50% of any earnings that are above Hydro Ottawa's approved regulatory Return on Equity (ROE). There is no dead band for this credit. Additionally, adjustments may be made to the ESM account to ensure that amounts recorded or recovered through other deferral and variance accounts (DVAs) are not duplicated in the ESM account. For example, the ESM calculation was adjusted for amounts related to the:

- Facilities Renewal Program (FRP)
- Lost Revenue Adjustment Mechanism (LRAM)
- Connection Cost Recovery Agreement (CCRA)

These 2019 adjustments were made because the amounts were either related to a prior period or were already recorded in a different deferral and variance account, and therefore shouldn't have been included in the ESM calculation.

c) See response for b).

d) The purpose of a materiality assessment is related to when administratively the amount would be disposed to ensure efficiency by only processing refunds for overpayments that are large enough to create a rate for most customer classes.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.9

JT 3.9

To calculate whether there would have been earnings sharing if the dead band of 150 basis points had been in place during the last term.

RESPONSE:

As an initial note, Hydro Ottawa has identified an error in the calculation of the Earnings Sharing Mechanism ("ESM"). Hydro Ottawa records any ESM in the year after the period being considered for over earnings, in order to align with the adjustments related to the Lost Revenue Adjustment Mechanism ("LRAM"). In reviewing the calculation, it was realized that the customer portion was not being added back to the Distribution Net Income submitted as part of the Reporting and Record Keeping Requirements ("RRRs") filing in determining the current year's sharing. Table 8 in UPDATED Exhibit 9-1-3: Group 2 Accounts has been revised below accordingly.

Excess earnings during the individual years of 2016 and 2018, from both RRR filings and as adjusted for LRAM and previous years' earnings sharing, were below 1% or 100 basis points. For 2017, they were below 1.5% or 150 basis points. Therefore, for the finalized 2016-2018 years, Hydro Ottawa would not have had earnings sharing if a dead band of 150 basis points had been in place. As indicated during the Technical Conference held in this proceeding, the 2019 excess earnings have not been adjusted and the LRAM calculation has not been completed for 2019. In addition, at this time it cannot be determined if earnings would be above the 150 basis points for 2020. As such, Hydro Ottawa is only proposing to clear balances as calculated in the revised version of Table 8 below. Please refer to the responses to interrogatories CCC-26 and CCC-78 for further information on the ESM.

Table 8 from UPDATED Exhibit 9-1-3 (Filed May 5, 2020) – ESM Calculation ($'000s)[1]

	2016	2017	2018
Net Income (per RRR)	$33,483	$36,114	$34,605
Deduct Previous Years' LRAM[2]	$(1,042)	$(1,081)	($1,081)
Add Current Year LRAM[3]	$773	$935	$935
PILS Grossed-up on CDM Adjustments[4]	$(172)	$222	($45)
Net Income after Adjustments	**$33,311**	**$36,336**	**$34,559**
Deemed Equity (per RRR)	$341,540	$357,578	$378,652
ESM Achieved ROE	9.75%	10.16%	9.13%
Deemed ROE	9.19%	9.19%	9.19%
% Return Above Deemed	**0.56%**	**0.97%**	**(0.06)%**
Earnings Above Regulated Return	$1,924	$3,475	($239)
50% of Earnings above Regulated Return	$962	$1,737	$0
PILS Grossed-up[5]	$347	$626	$0
RATEPAYERS' SHARE OF OVEREARNING[6]	**$1,309**	**$2,364**	**$0**

[1] "Current year" means 2016 for the purposes of the column with information for 2016, and 2017 for the purposes of the column with information for 2017.
[2] Previous years' LRAM includes adjustment to any year not related to the current year.
[3] Current year LRAM includes adjustments in reporting years subsequent to the current year.
[4] Tax rate = 26.5%.
[5] Tax rate = 26.5%.
[6] Totals may not sum due to rounding.

Table 8 from UPDATED Exhibit 9-1-3 – AS REVISED AUGUST 2020 – ESM Calculation ($'000s)[7]

	2016	2017	2018
Net Income (per RRR)	$33,483	$36,114	$34,605
Deduct Previous Years' LRAM[8]	$(1,042)	$(1,081)	($482)
Add Current Year LRAM[9]	$804	$1,429	$411
Add ESM recorded	$0	$1,385	$1,976
Deduct PILS Grossed-up on CDM Adjustments[10]	$(86)	$625	$687
Net Income after Adjustments	**$33,311**	**$37,222**	**$35,823**
Deemed Equity (per RRR)	$341,540	$357,578	$378,652
ESM Achieved ROE	9.76%	10.41%	9.46%
Deemed ROE	9.19%	9.19%	9.19%
% Return Above Deemed	**0.57%**	**1.22%**	**0.27%**
Earnings Above Regulated Return	$1,944	$4,360	$1,025
50% of Earnings above Regulated Return	$972	$2,180	$513
PILS Grossed-up[11]	$350	$786	$185
RATEPAYERS' SHARE OF OVEREARNING[12]	**$1,322**	**$2,966**	**$697**

[7] "Current year" means 2016 for the purposes of the column with information for 2016, and 2017 for the purposes of the column with information for 2017, and so on.
[8] Previous years' LRAM includes adjustment to any year not related to the current year.
[9] Current year LRAM includes adjustments in reporting years subsequent to the current year.
[10] Tax rate = 26.5%.
[11] Tax rate = 26.5%.
[12] Totals may not sum due to rounding.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-70

EVIDENCE REFERENCE:
Exhibit 9, Tab 1, Schedule 3, pp. 10-17

QUESTION(S):

a) (PP. 10-11) Please confirm that for the 2016-2020 period, there were no CCRA payments reflected in the revenue requirement.

b) (P. 11) Please provide the evidence from the 2021-2025 application and settlement agreement showing the specific methodology applied and approved for the disposition of the 2017-2019 balances in the CCRADA.

c) (P. 14) Please explain the 2021 opening gross cumulative asset balance of $(588K).

d) (P. 14) Please provide the evidence from the 2021-2025 application and settlement agreement showing the approved CCRA payment amounts for the 2021-2023 period. Please also provide a comparison of the approved CCRA payments for each year during the 2021-2023 period relative to the actual payments for the same period.

RESPONSE(S):

a) Hydro Ottawa confirms that for the 2016-2020 period, there were no CCRA payments reflected in the revenue requirement. As part of the 2016-2020 Approved Settlement Agreement,[1] it was

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Approved Settlement Proposal*, EB-2015-0004 (December 7, 2015) pages 14 and 60.

agreed to move any CCRA payments out of the proposed revenue requirement and establish the CCRA Regulatory Account.

b) Please refer to Ontario Energy Board, 2021 Hydro Ottawa Limited Electricity Distribution Rate Application - Settlement Proposal (September 18, 2020)[2], page 32 of 67, that references Table 21 of the "Group 2 deferral and variance accounts ("DVAs") which are proposed for disposition as part of this proceeding". Table 2 includes the principal balance of $814,360 to be disposed of related to CCRAs. The revenue requirement calculation, and same principal balance, is provided in the 2024 Updated Evidence within UPDATED Exhibit 9-1-3 Group 2 Accounts, Updated Table 9.

c) Based on a Hydro One invoice received in 2022, Hydro Ottawa recorded a reduction of $587,900 related to a 2019 CCRA in service addition. Since the revenue requirement for 2021-2025 didn't account for this refund, Hydro Ottawa is disposing of the amount back to customers.

d) Please refer to Ontario Energy Board, 2021 Hydro Ottawa Limited Electricity Distribution Rate Application - Settlement Proposal (September 18, 2020)[1], page 32 of 67. The CCRA Deferral Account includes both new and true-up payments, and will collect or refund the difference in revenue requirement for CCRA payments between what Hydro Ottawa has forecasted and what is actually paid for both new and true-up CCRA payments.

As provided in Excel Attachment JT3.1(C) - Updated Appendix 2-AA - Capital Programs Table - In-Service Additions in response to undertaking JT3.1 as part of the 2021-2025 rate application technical conference, the budgeted CCRA payments were provided. Please see table A below for a comparison of the approved CCRA payments for each year during the 2021-2023 period relative to the actual payments for the same period.

[2] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020), page 32.

Table A - Comparison of Approved to Actual CCRA Payments 2021-2023 ($'000s)

CCRA Payments	2021	2022	2023
OEB Approved	$ 51,224	$ 210	$ 100
Actual	$ 28,449	$ 20,238	$ (4,756)
Difference to Approved	**$ (22,775)**	**$ 20,028**	**$ (4,856)**

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-71

EVIDENCE REFERENCE:

Exhibit 9, Tab 1, Schedule 3, pp. 17-27

QUESTION(S):

a) (P. 18) With respect to the capital accounts being tracked asymmetrically, please further describe and explain the methodology whereby amounts would only be recorded in the account until the actual cumulative net capital additions for 2021- 2025 catch-up to the forecasted cumulative net capital additions. For each year in the 2021-2023 period, is Hydro Ottawa comparing actual annual net capital additions to approved annual net capital additions or does that comparison stop after a certain point?

b) (PP. 20, 22, 24) Please provide the evidence from the 2021-2025 application and settlement agreement showing the relevant approved net capital additions underpinning each of Table 12, 13 and 14 (for the 2021-2023 period). Please also provide a comparison of the relevant OEB-approved net capital additions for each year during the 2021-2023 period relative to the actual additions for the same period.

c) (P. 26) Please provide a table that compares the proposed net in-service additions value for the 2026-2030 period separated between the various CVA accounts/sub- accounts listed on page 26 (i.e., System Access & System Service - Symmetrical, System Access - Asymmetrical, System Renewal / System Service – Asymmetrical, and General Plant - Asymmetrical): (i) using the 2021-2025 approved version of the Capital Related Variance Account; and (ii) using the proposed 2026-2030 version of the Capital Related Variance Account (with the change to the treatment of commercial expansions and capacity upgrades).

RESPONSE(S):

a) On an annual basis, cumulative actual net capital additions for the rate period are compared against approved net capital additions. If cumulative net capital additions are less than approved cumulative additions, an amount is booked in the CVA account. Once cumulative actual additions catch up or exceed cumulative approved net capital additions, no further entries are made. For each year in the 2021-2023 period, Hydro Ottawa compared cumulative actual net additions against cumulative approved net additions each year-end. The comparison continues for each year end in the rate term; if subsequent cumulative shortfalls exist, further amounts are recorded in the CVA account.

b) Please refer to Table 22 - Summary of 2021-2025 Capital Additions (Asymmetrical Sub-Accounts) of the Ontario Energy Board, 2021 Hydro Ottawa Limited Electricity Distribution Rate Application - Settlement Proposal (September 18, 2020), page 38 of 67. Table A below provides the approved and actual capital additions for 2021-2023 for each asymmetric Capital Variance Account.

Table A - Capital Additions Asymmetric Differential Variance Accounts ($'000s)

Differential Variance Account	2021		2022		2023	
	Approved	Actual	Approved	Actual	Approved	Actual
General Plant (excluding CCRA)	$ 14,535	$ 6,013	$ 11,876	$ 12,904	$ 6,137	$ 14,671
System Access (excluding Residential & Plant Relocation	$ 13,305	$ 7,148	$ 10,755	$ 6,335	$ 10,423	$ 6,486
System Renewal & System Service	$ 67,506	$ 72,540	$ 92,463	$ 91,416	$ 53,919	$ 58,372
Total, Excluding CCRA	**$ 95,345**	**$ 85,701**	**$ 115,094**	**$ 110,655**	**$ 70,478**	**$ 79,529**

Table 22 includes the approved balance for Connection Cost Recovery Agreement (CCRA) Payments Deferral Account and is replicated in Table B below.

Table B - Summary of 2021-2025 Capital Additions (Asymmetric Sub-Accounts) ($'000s)

	2021	2022	2023
Total, excluding CCRA	$ 95,345	$ 115,094	$ 70,478
General Plant (CCRA)	$ 51,224	$ 210	$ 100
Total, with CCRA	**$ 146,569**	**$ 115,304**	**$ 70,578**

c) Please refer to Table A - Capital Additions Differential Variance Accounts in the response to interrogatory 9-SEC-87 for a table that compares the proposed net in-service additions value for the 2026-2030 period separated between the various CVA accounts/sub-accounts listed on page 26. Please refer to Table B - Capital Additions Differential Variance Accounts - Existing Approved Framework from EB-2019-0261 in the response to interrogatory 9-SEC-87 for a table of the proposed 2026-2030 asymmetrical accounts under existing methodology. For greater clarity, Hydro Ottawa's proposed capital variance accounts and/or sub-accounts are analyzed for their impact on revenue requirements at the investment category level, not at the program level listed in interrogatory 9-SEC-87.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-72

EVIDENCE REFERENCE:

Exhibit 9, Tab 1, Schedule 3, p. 31

Preamble:
Hydro Ottawa is seeking to clear $486,987.09 regarding the OEB Cost Assessment Variance Account.

QUESTION(S):

Please provide a detailed calculation as to how this amount was derived.

RESPONSE(S):

Please refer to interrogatory response 9-Staff-220.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-73

EVIDENCE REFERENCE:

Exhibit 9, Tab 1, Schedule 4, p. 9
Exhibit 6, Tab 1, Schedule 1, p. 4

QUESTION(S):

a) Please explain the difference between the 2026 and 2027 PILs contributions shown in Table 4 (Exhibit 9, Tab 1, Schedule 4, p. 9) and the PILs contributions for the same years shown in Table 2 (Exhibit 6, Tab 1, Schedule 1, p. 4).

b) With respect to the treatment of the 2021 Immediate Expensing measure, please confirm that instead of treating the impact of this measure as a capital contribution, the $0.476M amount could be disposed of to ratepayers through the PILs and Tax Variance account.

RESPONSE(S):

a) Please see part a) of interrogatory response 9-Staff-214.

b) Disposing the $0.476M through the PILS and Tax Variance (Account 1592) account is another possible mechanism. However, that mechanism results in current rate payers receiving an unequal portion of the tax benefit, over one or two years, related to long lived assets for which rate payers will incur the cost over approximately 36 years.

INTERROGATORY RESPONSES TO CONSUMERS COUNCIL OF CANADA

9-CCC-74

EVIDENCE REFERENCE:

Exhibit 9, Tab 3, Schedule 1, p. 4

QUESTION(S):

a) For the Group 2 DVAs that have been previously disposed, please confirm that there has been no change to the allocation methodology (i.e., balances were allocated based on distribution revenues).

b) Please explain how locate costs reflected in rates were allocated to customer classes during the 2021-2025 CIR term.

RESPONSE(S):

a) Hydro Ottawa confirms there has been no change to the allocation methodology for the Group 2 DVAs that have been previously disposed of.

b) Locate costs are recorded in USofA 5040 - Underground Distribution Lines and Feeders - Operation Labour and USofA 5045 - Underground Distribution Lines & Feeders - Operation Supplies & Expenses. The OEB cost allocation model allocates these two USofAs to customer classes with a 65% weighting on demand and 35% on customer count. For the 2021-2025 Custom Incentive Rate Setting term, Hydro Ottawa completed one cost allocation model, for 2021. The resulting cost allocation pattern was carried forward to the subsequent 2022-2025 years throughout the CIR term.

Table A - Demand and Customer Percentage per Rate Class

	Residential	GS <50	GS 50-1499	GS 1500-4999	LU	Street Lights	Sentinel	USL	Standby GS 50-1499	Standby GS 1500-4999	Standby LU
Demand Percentage	35.33%	11.44%	38.08%	8.31%	6.31%	0.42%	0.00%	0.05%	0.00%	0.06%	0.00%
Customer Percentage	89.88%	7.21%	0.83%	0.02%	0.00%	1.09%	0.02%	0.94%	0.00%	0.00%	0.00%