EXHIBIT 2 – RATE BASE & CAPITAL

2027 Cost of Service

Ottawa River Power Corporation
EB-2026-0066

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2.1 OVERVIEW OF RATE BASE

2.1.1 RATE BASE OVERVIEW

The net fixed assets used to determine the utility's Rate Base include distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. ORPC does not have non-distribution assets, nor does it conduct non-distribution activities through its distribution company. Controllable expenses include operations and maintenance, billing and collecting and administration expenses which are discussed in detail in Exhibit 4.

ORPC has calculated its Test Year 2027 Rate Base to be $22,478,878. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6. Table 1 below presents ORPC's Rate Base calculations for the Test Year compared to the 2022 Board Approved amount.

Table 1 - Test Year Rate Base

Particulars	**MIFRS Last Board Approved**	**MIFRS 2027**	**Var from last BA**
Net Capital Assets in Service:			
Average Gross Assets	$18,926,106	$33,454,548	$14,528,442
Average Accumulated Depreciation	$(7,675,477)	$(13,226,691)	$(5,551,214)
Average Balance	$11,250,629	$20,227,857	$8,977,228
Working Capital Allowance	$1,784,286	$2,251,021	$466,735
Total Rate Base	**$13,034,914**	**$22,478,878**	**$9,443,964**
Expenses for Working Capital	**MIFRS Last Board Approved**	**MIFRS 2027**	**Var from last BA**
Eligible Distribution Expenses:			
3500-Distribution Expenses - Operation	$872,757	$1,084,238	$211,481
3550-Distribution Expenses - Maintenance	$576,747	$755,925	$179,178
3650-Billing and Collecting	$934,527	$1,232,010	$297,483
3700-Community Relations	$42,318	$38,080	$(4,238)
3800-Administrative and General Expenses	$1,197,045	$2,104,854	$907,809
Total Eligible Distribution Expenses	$3,623,394	$5,215,106	$1,591,712
3350-Power Supply Expenses	$20,167,080	$24,798,513	$4,631,433
Total Expenses for Working Capital	$23,790,475	$30,013,619	$6,223,144
Working Capital factor	7.50%	7.50%	
Total Working Capital	**$1,784,286**	**$2,251,021**	**$466,735**

2.1.2 RATE BASE TREND

The Rate Base trend in Table 2 presents ORPC's Rate Base calculations from 2022 OEB Approved to the 2027 Test Year. Year-over-year variance analysis follows.

Table 2 - Rate Base Trend

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particulars	**Last Board Approved**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Net Capital Assets in Service:							
Average Gross Assets	$18,926,106	$24,177,719	$25,181,126	$26,528,623	$28,463,446	$30,834,233	$33,454,548
Average Accumulated Depreciation	$(7,675,477)	$(10,392,790)	$(10,250,182)	$(10,654,330)	$(11,324,481)	$(12,273,504)	$(13,226,691)
Average Balance	**$11,250,629**	**$13,784,928**	**$14,930,944**	**$15,874,293**	**$17,138,965**	**$18,560,729**	**$20,227,857**
Working Capital Allowance	$1,784,286	$2,000,469	$1,947,511	$1,954,973	$2,034,739	$2,032,179	$2,251,021
Total Rate Base	**$13,034,914**	**$15,785,397**	**$16,878,455**	**$17,829,266**	**$19,173,704**	**$20,592,908**	**$22,478,878**
	MIFRS	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Expenses for Working Capital	**Last Board Approved**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Eligible Distribution Expenses:							
3500-Distribution Expenses - Operation	$872,757	$773,946	$943,452	$812,188	$1,224,942	$940,920	$1,084,238
3550-Distribution Expenses - Maintenance	$576,747	$680,047	$577,974	$587,754	$712,695	$696,942	$755,925
3650-Billing and Collecting	$934,527	$868,547	$817,614	$1,045,682	$1,119,399	$1,154,809	$1,232,010
3700-Community Relations	$42,318	$36,357	$28,354	$29,510	$23,586	$26,163	$38,080
3800-Administrative and General Expenses	$1,197,045	$1,479,963	$1,785,901	$1,661,970	$1,632,423	$1,776,887	$2,104,854
Total Eligible Distribution Expenses	**$3,623,394**	**$3,838,861**	**$4,153,296**	**$4,134,104**	**$4,713,045**	**$4,595,722**	**$5,215,106**
3350-Power Supply Expenses	$20,167,080	$22,834,063	$21,813,522	$21,932,198	$22,416,811	$22,500,000	$24,798,513
Total Expenses for Working Capital	**$23,790,475**	**$26,672,924**	**$25,966,818**	**$26,066,302**	**$27,129,856**	**$27,095,722**	**$30,013,619**
Working Capital factor	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Total Working Capital	**$1,784,286**	**$2,000,469**	**$1,947,511**	**$1,954,973**	**$2,034,739**	**$2,032,179**	**$2,251,021**

The Rate Base for the 2027 Test Year has increased by $3,305,174 over the last actual (2025) and by $6,693,481 since 2022. The increase from the 2022 Cost of Service is mainly due to the capital projects coming in-service as listed in the Rate Base Variance Analysis in section 2.1.3. The Working Capital Allowance has remained relatively stable since 2022.

Increased Power Supply Expenses

ORPC has forecasted an increase in the 2027 Power Supply Expenses of $4,631,433 or 23% over its 2022 Cost of Service approved amount. This is primarily due to increased supply costs combined with a forecasted 3% growth in customer count and consumption from 2022 actuals and 6% over its 2022 Load Forecast which are used to calculate the Cost of Power.

Increased Distribution Expenses

The 2027 forecast for OM&A reflects an increase of $1,591,712 from the 2022 Board Approved amount. The details of the increases in OM&A are provided in Exhibit 4 which include the following key increases:

- Wage inflation, progressions, and adjustments to industry benchmarks;
- Facilities Rent;
- An Engineering Technician;
- Regulatory expenses; and
- Significant inflation of materials.

The Working Capital Allowance has increased by $466,735 over the 2022 Board Approved amount. The reason for the increase from the 2022 Board Approved to the Test Year 2027 is due to the increases in Power Supply Expenses and OM&A.

2.1.3 RATE BASE VARIANCE ANALYSIS

The following paragraphs and tables provide a narrative on the changes that have driven the increase in rate base since ORPC's 2022 Board Approved Cost of Service Application.

Filing Requirements state that a distributor with a distribution revenue requirement less than $10 million may use $50,000 as a materiality threshold. ORPC's 2027 proposed distribution revenue requirement is less than $10 million therefore the LDC has used $50,000 as a materiality threshold.

ORPC has provided the following variance analysis to account for the change in the LDC's Rate Base:

- ✓ 2027 Test Year vs. 2026 Bridge Year
- ✓ 2026 Bridge Year vs. 2025 Actual
- ✓ 2025 Actual vs. 2024 Actual
- ✓ 2024 Actual vs. 2023 Actual
- ✓ 2023 Actual vs. 2022 Actual
- ✓ 2022 Actual vs. 2022 Board Approved

2022 BOARD APPROVED VS. 2022 ACTUAL:

Table 3 - 2022 BA to 2022 Actual Rate Base Variance

	MIFRS	MIFRS		
Particulars	**Last Board Approved**	**2022**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	$18,926,106	$24,177,719		
Average Accumulated Depreciation	$(7,675,477)	$(10,392,790)		
Average Balance	**$11,250,629**	**$13,784,928**	**$2,534,299**	**23%**
Working Capital Allowance	$1,784,286	$2,000,469	$216,183	12%
Total Rate Base	**$13,034,914**	**$15,785,397**	**$2,750,482**	**21%**
Expenses for Working Capital	**Last Board Approved**	**2022**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$872,757	$773,946		
3550-Distribution Expenses - Maintenance	$576,747	$680,047		
3650-Billing and Collecting	$934,527	$868,547		
3700-Community Relations	$42,318	$36,357		
3800-Administrative and General Expenses	$1,197,045	$1,479,963		
Total Eligible Distribution Expenses	**$3,623,394**	**$3,838,861**	**$215,467**	**6%**
3350-Power Supply Expenses	$20,167,080	$22,834,063	$2,666,983	13%
Total Expenses for Working Capital	**$23,790,475**	**$26,672,924**	**$2,882,449**	**12%**
Working Capital factor	7.50%	7.50%		
Total Working Capital	**$1,784,286**	**$2,000,469**		

The total Rate Base in 2022 Actual of $15,785,397 was $2,750,482 higher or 21% more than the 2022 Board Approved. The main reasons for the variance are:

- The inadvertent exclusion of $2,059,754 in ICM assets from its previous rate base. As filed in application EB-2025-0209, ORPC noted that following a review of the Fixed Asset Continuity Schedule in its filed and settled 2022 Chapter 2 Filing Requirements Appendices, the worksheet 'App.2-BA_Fixed Asset Cont' formulas contained in the 2022 Opening Balance cells D342, D343, D344, D345, D346, D347 and D361, (where the asset values of its ICM project were to be added) were incorrectly adding the 2022 Closing Balance in cells G384 to G390. These formulas were intended to add the 2021 Closing Balance in cells G323 to G329. ORPC noted that the formulas used to calculate the accumulated depreciation amounts correctly included the ICM accumulated depreciation and depreciation expense.
- System Access: Project ORPC-21-009 at $145,880
    - Externally initiated 42-unit apartment building. The 2022 DSP forecast placed this project beyond 2022.
- System Renewal: Pembroke MS#6 Transformer Replacement at $1,082,420
    - Transformer Replacement approved in DSP at $750,000. In 2022, the costs included additional contractor fees of $83,185 to replace the obsolete and non-functional SCADA system and replace the aged feeder cable at the same time as the transformer. ORPC also included $19,739 of labour, equipment usage and materials

to install 4 new composite poles as the old poles had significant woodpecker damage.

Total working capital expenses increased by $2,882,449 driven by increases of $215,467 in OM&A expenses and $2,666,983 in Power Supply Expenses. Power Supply Expenses in 2022 Board Approved figures included $(3,312,299) in 4710 Cost of Power Adjustments that did not materialize.

2022 ACTUAL VS. 2023 ACTUAL:

Table 4 - 2022-2023 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2022**	**2023**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	$24,177,719	$25,181,126		
Average Accumulated Depreciation	$(10,392,790)	$(10,250,182)		
Average Balance	**$13,784,928**	**$14,930,944**	**$1,146,016**	**8%**
Working Capital Allowance	$2,000,469	$1,947,511	$(52,958)	(3)%
Total Rate Base	**$15,785,397**	**$16,878,455**	**$1,093,058**	**7%**
Expenses for Working Capital	**2022**	**2023**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$773,946	$943,452		
3550-Distribution Expenses - Maintenance	$680,047	$577,974		
3650-Billing and Collecting	$868,547	$817,614		
3700-Community Relations	$36,357	$28,354		
3800-Administrative and General Expenses	$1,479,963	$1,785,901		
Total Eligible Distribution Expenses	**$3,838,861**	**$4,153,296**	**$314,435**	**8%**
3350-Power Supply Expenses	$22,834,063	$21,813,522	$(1,020,541)	(4)%
Total Expenses for Working Capital	**$26,672,924**	**$25,966,818**	**$(706,106)**	**(3)%**
Working Capital factor	7.50%	7.50%		
Total Working Capital	$2,000,469	$1,947,511		

The total Rate Base in 2023 increased by $1,093,058 as compared to 2022 actual. The primary capital projects in 2023 were:

- System Access: Highway 148 Upgrades at $230,279
  - Externally initiated system access located on Highway 148 in Pembroke consisting of the upgrade of 10 poles, the upgrade or relocation of 5 line transformers, and upgrading the conductor along 563m of road. ORPC also upgraded a 44kV airbrake switch, anchors and other assets. This project started in 2023 and finished in 2025 and required significant coordination between ORPC, Hydro One, Brookfield, and the Ministry of Transportation. This project was along a busy stretch of road requiring police presence for traffic control.
- System Access: Boundary Road West of Subdivision at $254,185
  - Externally initiated housing development in Pembroke for 46 homes requiring 2,600m of secondary, 1,000m of copper cables, 2 switch cubicles, and 5 line transformers.
- System Renewal: Pembroke MS#1 Transformer Replacement at $280,069
  - To replace a substation transformer that unexpectedly failed in Pembroke. ORPC minimized the costs by installing a used transformer. The physical age of MS#1 indicates that the substation is approaching its useful life expectancy and parts are becoming obsolete. However, the substation is still required to allow for redundancy in ORPC's 5kV system which is operated between Pembroke MS#1 and MS#3 until ORPC can convert all to its 12.4kV system.

- System Renewal: Pembroke MS#6 Transformer Replacement at $73,845
  - Final costs of transformer replacement noted in 2022 variance explanation to upgrade overhead conductor.
- General Plant: Transportation Equipment Engine Replacement at $65,438
  - ORPC's 2005 International 4400 large bucket truck had an engine failure requiring full replacement of the engine at a cost of $65,438. This vehicle has exceeded its useful life and will be replaced in 2027.
- General Plant: ArcGIS Computer Hardware and Software at $82,574
  - ORPC's vendor officially retired ArcGIS Desktop (including ArcMap) on March 1, 2026. The existing platform would no longer be supported, so an upgrade was required. Additionally, the upgrade would improve data accuracy through versioned map edits, expanded field verification, and real-time editing by field staff. Importantly, it enables the transition to the modern data standard for utility GIS to ultimately position ORPC's GIS to integrate directly with future SCADA and OMS deployments and support longer-term operational technology roadmaps.

Power Supply Expenses decreased and reduced the working capital by $52,958.

2023 ACTUAL VS. 2024 ACTUAL:

Table 5 - 2023-2024 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2023**	**2024**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	$25,181,126	$26,528,623		
Average Accumulated Depreciation	$(10,250,182)	$(10,654,330)		
Average Balance	**$14,930,944**	**$15,874,293**	**$943,349**	**6%**
Working Capital Allowance	$1,947,511	$1,954,973	$7,462	0%
Total Rate Base	**$16,878,455**	**$17,829,266**	**$950,811**	**6%**
Expenses for Working Capital	**2023**	**2024**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$943,452	$812,188		
3550-Distribution Expenses - Maintenance	$577,974	$587,754		
3650-Billing and Collecting	$817,614	$1,045,682		
3700-Community Relations	$28,354	$29,510		
3800-Administrative and General Expenses	$1,785,901	$1,661,970		
Total Eligible Distribution Expenses	**$4,153,296**	**$4,134,104**	**$(19,192)**	**0%**
3350-Power Supply Expenses	$21,813,522	$21,932,198	$118,676	1%
Total Expenses for Working Capital	**$25,966,818**	**$26,066,302**	**$99,484**	**0%**
Working Capital factor	7.50%	7.50%		
Total Working Capital	$1,947,511	$1,954,973		

The Total Rate Base in 2024 increased by $950,811 compared to 2023. The main contributors to the variance are:

- System Access: Highway 148 Upgrades at $386,161
  - Continuation of the externally initiated system access located on Highway 148 in Pembroke noted in the 2023 variance explanation.
- System Access: Golfview Subdivision at $173,214
  - Phase 1A of an externally initiated system access located in Pembroke consisting of 2,000m of copper cable, 2,000m of secondary cable, 4 switch cubicles and 3 line transformers to enable the future connection of 96 electricity meters.
- System Renewal: Courthouse Transformer Replacement at $84,557
  - To replace a 750 kVa transformer located at the Pembroke courthouse that failed.
- System Renewal: Pembroke MS#4 SCADA replacement at $175,342
  - Internally initiated project to replace obsolete or non-functional substation SCADA systems with the intention to replace 1 or 2 SCADA systems annually until all systems are functional. This allows for improved monitoring of its systems and the ability to operate equipment remotely. Additionally, ORPC would be better able to collect operational data.
- General Plant: Propane Generator installation in Pembroke at $53,518
  - Replacement of Pembroke premises generator which was found to be not up to code including relocation of generator outside of the office.

- General Plant: Tandem Axle Pole Trailer at $52,110
    - ORPC was required to purchase a trailer with sufficient length to carry its 70' and 75' poles. Previously, the LDC was only able to carry poles up to 55' with its existing trailers.

OM&A and Power Supply Expenses remained stable compared to 2023 increasing the working capital allowance by only $7,462.

2024 ACTUAL VS. 2025 ACTUAL:

Table 6 - 2024-2025 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2024**	**2025**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	$26,528,623	$28,463,446		
Average Accumulated Depreciation	$(10,654,330)	$(11,324,481)		
Average Balance	**$15,874,293**	**$17,138,965**	**$1,264,672**	**8%**
Working Capital Allowance	$1,954,973	$2,034,739	$79,766	4%
Total Rate Base	**$17,829,266**	**$19,173,704**	**$1,344,438**	**8%**
Expenses for Working Capital	**2024**	**2025**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$812,188	$1,224,942		
3550-Distribution Expenses - Maintenance	$587,754	$712,695		
3650-Billing and Collecting	$1,045,682	$1,119,399		
3700-Community Relations	$29,510	$23,586		
3800-Administrative and General Expenses	$1,661,970	$1,632,423		
Total Eligible Distribution Expenses	**$4,134,104**	**$4,713,045**	**$578,941**	**14%**
3350-Power Supply Expenses	$21,932,198	$22,416,811	$484,613	2%
Total Expenses for Working Capital	**$26,066,302**	**$27,129,856**	**$1,063,554**	**4%**
Working Capital factor	7.50%	7.50%		
Total Working Capital	**$1,954,973**	**$2,034,739**		

The Total Rate Base in 2025 increased by $1,344,438 when compared to 2024. This increase was primarily caused by the following capital projects:

- System Access: Steel Street 8-unit Building in Pembroke at $53,985
  - Externally initiated project for an 8-unit building in its Pembroke service territory which required a new line transformer and 3-phase primary framing on 7 poles.
- System Renewal: PCB Line Transformer Replacements at $331,238
  - Environment and Climate Change Canada mandated that transformers containing PCB concentrations exceeding 50 parts per million (PPM) be removed from service by the end of 2025. ORPC's renewal program in 2025 addressed this mandate through replacement of positive-testing line transformers.
- System Renewal: Almonte MS#2 Transformer Replacement at $276,400
  - Unanticipated transformer replacement at Almonte MS#2 due to a lightning strike that made the transformer fail.
- System Renewal: Pembroke MS#8 SCADA Replacement at $106,329
  - Continuation of internally initiated project to replace obsolete or non-functional substation SCADA systems as noted in 2024 variance analysis.
- System Renewal: Pembroke MS#1 Bus Cable Replacement at $73,348
  - The bus duct experienced a major ground fault for the second time in 10 years due to ice buildup caused from temperature differential issues between inside and outside the substation. A decision was made to convert to a cable bus instead of a bus duct to prevent the issue from recurring.

- System Renewal: Pembroke Mall U/G Primary Conductor Replacement at $54,543
  - Replaced 708m of underground primary conductor that had reached its end-of-life and experienced a fault. This project required 241 labour hours and $30,839 in materials.
- System Renewal: Evelyn Street Pole Replacement Project in Pembroke at $50,492
  - Originally included in 2022 Cost of Service test year at an estimated cost of $50,600 but delayed due to other projects taking priority. This project required the replacement of 3 poles and secondary conductor upgrades in a rear lot.
- General Plant: 2023 Ford E-Transit Cargo Van at $52,214
  - Replacement for 2012 Dodge Grand Caravan that experienced engine failures.
- General Plant: 2025 Ford F150 XLT at $67,121
  - Replacement for 2014 Dodge Ram 1500 that experienced engine failures.

Power Supply and OM&A Expenses escalated the working capital allowance by $79,766.

2025 ACTUAL VS. 2026 BRIDGE YEAR:

Table 7 - 2025-2026 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2025**	**2026**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	$28,463,446	$30,834,233		
Average Accumulated Depreciation	$(11,324,481)	$(12,273,504)		
Average Balance	**$17,138,965**	**$18,560,729**	**$1,421,764**	**8%**
Working Capital Allowance	$2,034,739	$2,032,179	$(2,560)	0%
Total Rate Base	**$19,173,704**	**$20,592,908**	**$1,419,204**	**7%**
Expenses for Working Capital	**2025**	**2026**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$1,224,942	$940,920		
3550-Distribution Expenses - Maintenance	$712,695	$696,942		
3650-Billing and Collecting	$1,119,399	$1,154,809		
3700-Community Relations	$23,586	$26,163		
3800-Administrative and General Expenses	$1,632,423	$1,776,887		
Total Eligible Distribution Expenses	**$4,713,045**	**$4,595,722**	**$(117,323)**	**(2)%**
3350-Power Supply Expenses	$22,416,811	$22,500,000	$83,189	0%
Total Expenses for Working Capital	**$27,129,856**	**$27,095,722**	**$(34,134)**	**0%**
Working Capital factor	7.50%	7.50%		
Total Working Capital	**$2,034,739**	**$2,032,179**		

The Total Rate Base for the 2026 Bridge Year is estimated to increase by $1,419,204 when compared to 2025. The main reasons for the variance are:

- System Renewal: SREPs program at $271,015
    - ORPC submitted an Expression of Interest to the Smart Renewables and Electrification Pathways Program (SREPs) on December 13, 2024. ORPC, along with the consortium of 16 LDCs, have submitted and received approval for the full proposal with work expected to begin in 2026 and end by 2029. The program aims to modernize electricity systems and provides funding for SCADA systems, smart fault indicators, Outage Management Systems and Automated Switches and Reclosers. The funding covers 50% of the overall cost to alleviate financial burden. With these technologies, ORPCP would see improved grid reliability through faster restoration times and better asset management which in turn would lead to enhanced customer satisfaction and future-ready infrastructure.
- System Renewal: Pembroke SCADA Replacement at $120,000
    - Continuation of internally initiated project to replace obsolete or non-functional substation SCADA systems as noted in 2024 variance analysis. Additionally, SREP funding would cover 50% of the total cost.
- System Service: Pembroke MS#4 Land Purchase at $150,000
    - Due to an easement issue with ORPC conductor crossing vacant privately-owned land, the owner had requested that ORPC pay rent annually for the crossing. ORPC analyzed its options and determined that it would be most beneficial and cost-

effective to purchase the land that is already adjacent to Pembroke MS#4 to eliminate any rent payments.

- General Plant: Large utility vehicle at $583,309
    - In January 2026, ORPC purchased a 50' Single Bucket Hydraulic Over Center Material Handling Device to replace an existing model that had reached its end-of-life and was experiencing multiple failures and significant repair costs.

Power Supply and OM&A Expense are projected to decrease the working capital by $2,560.

2026 BRIDGE VS. 2027 TEST YEAR:

Table 8 - 2026-2027 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2026**	**2027**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	$30,834,233	$33,454,548		
Average Accumulated Depreciation	$(12,273,504)	$(13,226,691)		
Average Balance	**$18,560,729**	**$20,227,857**	**$1,667,128**	**9%**
Working Capital Allowance	$2,032,179	$2,251,021	$218,842	11%
Total Rate Base	**$20,592,908**	**$22,478,878**	**$1,885,970**	**9%**
Expenses for Working Capital	**2026**	**2027**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$940,920	$1,084,238		
3550-Distribution Expenses - Maintenance	$696,942	$755,925		
3650-Billing and Collecting	$1,154,809	$1,232,010		
3700-Community Relations	$26,163	$38,080		
3800-Administrative and General Expenses	$1,776,887	$2,104,854		
Total Eligible Distribution Expenses	**$4,595,722**	**$5,215,106**	**$619,384**	**13%**
3350-Power Supply Expenses	$22,500,000	$24,798,513	$2,298,513	10%
Total Expenses for Working Capital	**$27,095,722**	**$30,013,619**	**$2,917,897**	**11%**
Working Capital factor	7.50%	7.50%		
Total Working Capital	**$2,032,179**	**$2,251,021**		

The Total Rate Base for the test year is expected to increase by $1,885,970 as compared to 2026. The main reasons for the variance are:

- System Renewal: Pembroke MS#4 44 kV Renewal at $600,000
    - This project addresses 44 kV oil circuit breakers (vintage 1960) that are beyond typical industry service life and have exhibited operational control deficiencies and active oil leakage at a primary supply interface. Continued reliance on this equipment introduces elevated risk of failure, reduced operational reliability, and increasing maintenance and safety exposure associated with aging high-voltage oil interrupting technology. Given the critical system function performed by these breakers and the limited practical mitigation available through maintenance alone, replacement represents a prudent risk management measure.
- System Renewal: SREPs program at $256,520
    - Continuation of Smart Renewables and Electrification Pathways Program (SREPs). The program aims to modernize electricity systems and provides funding for SCADA systems, smart fault indicators, Outage Management Systems and Automated Switches and Reclosers.
- System Renewal: Pembroke SCADA Replacement at $130,000
    - Continuation of internally initiated project to replace obsolete or non-functional substation SCADA systems as noted in 2024 variance analysis. Additionally, SREP funding would cover 50% of the total cost.
- General Plant: Large utility vehicle at $575,422

- Large vehicle #8 (a Posi-Plus 400-50) will require replacement in 2027. Large vehicle #8 is a material handling aerial device and is used as a person lift for service work and as material handler on capital and maintenance projects. In addition, it is used to restore power during outages. The vehicle was purchased in 2008 and has been used 1,066 hours per year on average. It has 174,653 km and 14,339 engine hours. In addition to having reached its end of 15-year life, the vehicle has experienced multiple failures, with an engine rebuild being carried out in 2015, an exhaust and emissions system failure in 2018 and cracking of pistons in 2023. This has led to increased maintenance costs year on year compared to other vehicles and the vehicle has also been out of service for extended periods of time, averaging non-recurring maintenance costs of $22,562 per year since 2016. The vehicle will be replaced with a Posi-Plus 50' Single Bucket Hydraulic Over Center Material Handling Device.

- General Plant: Small vehicle at $75,000
  - Small vehicle #14 will require replacement in 2027. This vehicle is a passenger vehicle mainly used in essential maintenance and capital works and in responding to emergency calls. The vehicle was purchased new and has been used an average of 780 hours per year. It has 203,848 km. It has reached the end of its useful life and maintenance costs are trending towards $4,000 per year. The vehicle has experienced issues with the doors in 2021, 2022 and 2025 and holes in the floor

were repaired in 2022 due to issues with rust. This vehicle will be replaced with a similar model, to be determined based on availability at the time of purchase.

Increases in Distribution and Power Supply expenses are projected to increase the working capital by $218,842.

2.1.4 FIXED ASSET CONTINUITY SCHEDULE

This Schedule presents a continuity schedule of its investment in capital assets, the associated accumulated amortization and the net book value for each Capital USoA account for the 2022 to 2025 Actuals and 2026 Bridge and 2027 Test Years.

ORPC attests that the OEB Appendices 2-BA continuity statements presented at the next page reconcile with the calculated depreciation expenses, under Exhibit 4 – Operating Costs and presented by asset account. The utility also attests that the net book value balances reported on Appendix 2-BA and balances reconcile with the rate base calculation. The capital expenditures presented are equivalent to in-service additions.

Information on year-over-year variance and explanations where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in ORPC's 2027 Distribution System Plan.

ORPC does not have any Asset Retirement Obligation related to decommissioning.

Below are the Fixed Asset Continuity Schedules for 2022 to 2027 which show the capital additions by traditional function. Following each continuity schedule are the gross fixed additions as categorized by the four main Distribution System Plan capital expenditure categories.

In compliance with the filing requirements, the capital additions are presented by traditional functions in the table below:

Table 9 - 2022 Continuity Schedule

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Accounting Standard	MIFRS
Year	2022

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$0				$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$183,296	$41,526	-$11,474	$213,348	-$53,042	-$61,418	$11,474	-$102,987	$110,362
CEC	1612	Land Rights (Formally known as Account 1906)	$2,748			$2,748	-$2,680	-$68		-$2,748	$0
N/A	1805	Land	$258,350			$258,350				$0	$258,350
47	1808	Buildings	$255,661	$12,091		$267,752	-$105,652	-$6,613	$0	-$112,265	$155,486
13	1810	Leasehold Improvements	$314,650		-$258	$314,393	-$72,624	-$15,711	$258	-$88,077	$226,315
47	1815	Transformer Station Equipment >50 kV				$0				$0	$0
47	1820	Distribution Station Equipment <50 kV	$3,729,199	$901,604	-$247,926	$4,382,877	-$850,596	-$105,872	$247,926	-$708,541	$3,674,336
47	1825	Storage Battery Equipment				$0				$0	$0
47	1830	Poles, Towers & Fixtures	$4,431,534	$265,370	-$324,838	$4,372,066	-$2,493,825	-$120,241	$324,838	-$2,289,228	$2,082,839
47	1835	Overhead Conductors & Devices	$5,172,979	$254,788		$5,427,767	-$2,026,445	-$150,423		-$2,176,868	$3,250,899
47	1840	Underground Conduit	$1,126,556	$45,150	-$71,311	$1,100,395	-$815,517	-$29,507	$71,311	-$773,712	$326,683
47	1845	Underground Conductors & Devices	$1,382,718	$147,219		$1,529,937	-$393,312	-$42,500		-$435,812	$1,094,125
47	1850	Line Transformers	$3,943,103	$659,921	-$83,450	$4,519,573	-$1,445,419	-$102,625	$83,450	-$1,464,594	$3,054,979
47	1855	Services (Overhead & Underground)	$2,069,778	$125,935		$2,195,713	-$760,540	-$65,172		-$825,713	$1,370,001
47	1860	Meters	$659,932	$75,738		$735,670	-$115,077	-$39,123		-$154,200	$581,470
47	1860	Meters (Smart Meters)	$1,645,231		-$56,148	$1,589,083	-$1,312,460	-$105,939	$56,148	-$1,362,251	$226,832
N/A	1905	Land				$0				$0	$0
47	1908	Buildings & Fixtures				$0				$0	$0
13	1910	Leasehold Improvements				$0				$0	$0
8	1915	Office Furniture & Equipment (10 years)	$85,893	$1,120	-$2,572	$84,441	-$28,135	-$8,388	$2,572	-$33,951	$50,490
8	1915	Office Furniture & Equipment (5 years)				$0				$0	$0
10	1920	Computer Equipment - Hardware	$210,058	$6,439	-$5,446	$211,051	-$60,118	-$67,039	$5,446	-$121,711	$89,340
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$0				$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$0				$0	$0
10	1930	Transportation Equipment	$1,361,281		-$401,326	$959,954	-$832,462	-$118,079	$401,326	-$549,215	$410,739
8	1935	Stores Equipment	$3,472			$3,472	-$521	-$347	$0	-$868	$2,604
8	1940	Tools, Shop & Garage Equipment	$90,975	$2,376	-$5,114	$88,238	-$66,980	-$8,085	$5,114	-$69,951	$18,286
8	1945	Measurement & Testing Equipment	$36,373			$36,373	-$22,013	-$3,637		-$25,650	$10,723
8	1950	Power Operated Equipment				$0				$0	$0
8	1955	Communications Equipment				$0				$0	$0
8	1955	Communication Equipment (Smart Meters)				$0				$0	$0
8	1960	Miscellaneous Equipment	$14,603			$14,603	-$10,663	-$1,460		-$12,124	$2,479
47	1970	Load Management Controls Customer Premises				$0				$0	$0
47	1975	Load Management Controls Utility Premises				$0				$0	$0
47	1980	System Supervisor Equipment	$78,575	$67,824	-$12,648	$133,751	-$24,531	-$22,752	$12,648	-$34,635	$99,116
47	1985	Miscellaneous Fixed Assets				$0				$0	$0
47	1990	Other Tangible Property				$0				$0	$0
47	1995	Contributions & Grants	-$1,526,789		-$492,310	-$2,019,099	$569,453	$73,614	$492,310	$1,135,377	-$883,722
47	2440	Deferred Revenue[5]	-$1,735,414	-$160,369	$34,000	-$1,861,782	$169,145	$43,014	-$34,000	$178,159	-$1,683,623
	2005	Property Under Finance Lease[7]				$0				$0	$0
		Sub-Total	**$23,794,763**	**$2,446,733**	**-$1,680,822**	$24,560,674	**-$10,754,015**	**-$958,372**	**$1,680,822**	**-$10,031,565**	**$14,529,109**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0
		Total PP&E for Rate Base Purposes	**$23,794,763**	**$2,446,733**	**-$1,680,822**	**$24,560,674**	**-$10,754,015**	**-$958,372**	**$1,680,822**	**-$10,031,565**	**$14,529,109**
		Construction Work In Progress				$0				$0	$0
		Total PP&E	**$23,794,763**	**$2,446,733**	**-$1,680,822**	**$24,560,674**	**-$10,754,015**	**-$958,372**	**$1,680,822**	**-$10,031,565**	**$14,529,109**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 958,372**			

Table 10 - 2022 Gross Fixed Asset Additions by Capital Investment Categories

Projects	2022
Reporting Basis	**MIFRS**
System Access	
New Services and Service Upgrades	555,625
Highway 148	
Subdivisions	8,342
System Access Gross Expenditures	**563,967**
System Access Capital Contributions	160,369
Sub-Total	**403,598**
System Renewal	
Line Transformers - PCB Replacements	60,617
SREPs	
Capital Renewal and Replacements	806,076
Substation Buildings & Equipment	1,112,890
System Supervisory Equipment	
System Renewal Gross Expenditures	**1,979,583**
System Renewal Capital Contributions	0
Sub-Total	**1,979,583**
System Service	
Easements	
Land - Pembroke MS#4	
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6	
SCADA Master Data Concentrator	
System Service Gross Expenditures	**0**
System Service Capital Contributions	
Sub-Total	**0**
General Plant	
Information Technology	47,965
Leasehold Improvements	12,091
Tools and Equipment	3,496
Small Vehicles and Trailers	
Large Vehicles	
General Plant Gross Expenditures	**63,552**
General Plant Capital Contributions	
Sub-Total	**63,552**
Miscellaneous	
Total	**2,446,733**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	
Total	**2,446,733**

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Table 11 - 2023 Continuity Schedule

Accounting Standard: MIFRS
Year: 2023

CCA Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$0			$0	$0			$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$213,348	$150,507	-$16,660	$347,195	-$102,987	-$89,735	$16,660	-$176,062	$171,134
CEC	1612	Land Rights (Formally known as Account 1906)	$2,748	$20,326	-$2,748	$20,326	-$2,748	-$1,270	$2,748	-$1,270	$19,056
N/A	1805	Land	$258,350			$258,350	$0			$0	$258,350
47	1808	Buildings	$267,752			$267,752	-$112,265	-$6,855		-$119,120	$148,631
13	1810	Leasehold Improvements	$314,393	$43,328	-$699	$357,021	-$88,077	-$16,551	$699	-$103,929	$253,092
47	1815	Transformer Station Equipment >50 kV	$0			$0	$0			$0	$0
47	1820	Distribution Station Equipment <50 kV	$4,382,877	$451,301	-$2,229	$4,831,949	-$708,541	-$122,349	$2,229	-$828,661	$4,003,288
47	1825	Storage Battery Equipment	$0			$0	$0			$0	$0
47	1830	Poles, Towers & Fixtures	$4,372,066	$291,983	-$269,429	$4,394,621	-$2,289,228	-$114,818	$269,429	-$2,134,616	$2,260,004
47	1835	Overhead Conductors & Devices	$5,427,767	$301,657		$5,729,424	-$2,176,868	-$155,214		-$2,332,082	$3,397,342
47	1840	Underground Conduit	$1,100,395	$59,450	-$109,010	$1,050,834	-$773,712	-$23,831	$109,010	-$688,533	$362,301
47	1845	Underground Conductors & Devices	$1,529,937	$236,603		$1,766,540	-$435,812	-$47,297		-$483,109	$1,283,430
47	1850	Line Transformers	$4,519,573	$245,619	-$49,913	$4,715,279	-$1,464,594	-$104,693	$49,913	-$1,519,375	$3,195,905
47	1855	Services (Overhead & Underground)	$2,195,713	$182,456		$2,378,169	-$825,713	-$68,529		-$894,241	$1,483,928
47	1860	Meters	$735,670	$46,748		$782,418	-$154,200	-$46,046		-$200,246	$582,172
47	1860	Meters (Smart Meters)	$1,589,083		-$74,434	$1,514,650	-$1,362,251	-$100,977	$74,434	-$1,388,794	$125,856
N/A	1905	Land	$0			$0	$0			$0	$0
47	1908	Buildings & Fixtures	$0			$0	$0			$0	$0
13	1910	Leasehold Improvements	$0			$0	$0			$0	$0
8	1915	Office Furniture & Equipment (10 years)	$84,441	$5,301		$89,742	-$33,951	-$8,640		-$42,591	$47,151
8	1915	Office Furniture & Equipment (5 years)	$0			$0	$0			$0	$0
10	1920	Computer Equipment - Hardware	$211,051	$56,042	-$13,428	$253,664	-$121,711	-$69,755	$14,127	-$177,339	$76,325
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0			$0	$0			$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$0	$0			$0	$0
10	1930	Transportation Equipment	$959,954	$68,448	-$30,643	$997,759	-$549,215	-$119,743	$30,643	-$638,315	$359,445
8	1935	Stores Equipment	$3,472			$3,472	-$868	-$347	$0	-$1,215	$2,257
8	1940	Tools, Shop & Garage Equipment	$88,238	$2,884	-$12,399	$78,723	-$69,951	-$7,414	$12,399	-$64,967	$13,756
8	1945	Measurement & Testing Equipment	$36,373			$36,373	-$25,650	-$2,733	$0	-$28,383	$7,990
8	1950	Power Operated Equipment	$0			$0	$0			$0	$0
8	1955	Communications Equipment	$0			$0	$0			$0	$0
8	1955	Communication Equipment (Smart Meters)	$0			$0	$0			$0	$0
8	1960	Miscellaneous Equipment	$14,603			$14,603	-$12,124	-$855		-$12,979	$1,624
47	1970	Load Management Controls Customer Premises	$0			$0	$0			$0	$0
47	1975	Load Management Controls Utility Premises	$0			$0	$0			$0	$0
47	1980	System Supervisor Equipment	$133,751			$133,751	-$34,635	-$25,602		-$60,237	$73,514
47	1985	Miscellaneous Fixed Assets	$0			$0	$0			$0	$0
47	1990	Other Tangible Property	$0			$0	$0			$0	$0
47	1995	Contributions & Grants	-$2,019,099		$3,220	-$2,015,879	$1,135,377	$71,182	-$3,220	$1,203,339	-$812,540
47	2440	Deferred Revenue[5]	-$1,861,782	-$343,377		-$2,205,159	$178,159	$45,767	$0	$223,927	-$1,981,233
	2005	Property Under Finance Lease[7]	$0			$0	$0			$0	$0
		Sub-Total	**$24,560,674**	**$1,819,276**	**-$578,372**	$25,801,578	**-$10,031,565**	**-$1,016,304**	**$579,071**	**-$10,468,798**	**$15,332,779**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$0				$0	$0
		Total PP&E for Rate Base Purposes	**$24,560,674**	**$1,819,276**	**-$578,372**	**$25,801,578**	**-$10,031,565**	**-$1,016,304**	**$579,071**	**-$10,468,798**	**$15,332,779**
		Construction Work In Progress				$0				$0	$0
		Total PP&E	**$24,560,674**	**$1,819,276**	**-$578,372**	**$25,801,578**	**-$10,031,565**	**-$1,016,304**	**$579,071**	**-$10,468,798**	**$15,332,779**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						-$ 1,016,304			

Table 12 - 2023 Gross Fixed Asset Additions by Capital Investment Categories

Projects	2023
Reporting Basis	**MIFRS**
System Access	
New Services and Service Upgrades	415,575
Highway 148	230,279
Subdivisions	415,196
System Access Gross Expenditures	**1,061,050**
System Access Capital Contributions	343,377
Sub-Total	**717,673**
System Renewal	
Line Transformers - PCB Replacements	
SREPs	
Capital Renewal and Replacements	238,378
Substation Buildings & Equipment	516,388
System Supervisory Equipment	
System Renewal Gross Expenditures	**754,766**
System Renewal Capital Contributions	0
Sub-Total	**754,766**
System Service	
Easements	20,326
Land - Pembroke MS#4	
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6	
SCADA Master Data Concentrator	
System Service Gross Expenditures	**20,326**
System Service Capital Contributions	
Sub-Total	**20,326**
General Plant	
Information Technology	206,549
Leasehold Improvements	43,328
Tools and Equipment	8,185
Small Vehicles and Trailers	3,011
Large Vehicles	65,438
General Plant Gross Expenditures	**326,511**
General Plant Capital Contributions	
Sub-Total	**326,511**
Miscellaneous	
Total	**1,819,276**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	
Total	**1,819,276**

Table 13 - 2024 Continuity Schedule

Accounting Standard	MIFRS
Year	2024

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$0			$0	$0			$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$347,195	$43,213		$390,408	-$176,062	-$96,161		-$272,223	$118,185
CEC	1612	Land Rights (Formally known as Account 1906)	$20,326			$20,326	-$1,270	-$2,541		-$3,811	$16,515
N/A	1805	Land	$258,350			$258,350	$0			$0	$258,350
47	1808	Buildings	$267,752			$267,752	-$119,120	-$6,855		-$125,975	$141,777
13	1810	Leasehold Improvements	$357,021	$63,476		$420,497	-$103,929	-$18,687		-$122,615	$297,882
47	1815	Transformer Station Equipment >50 kV	$0			$0	$0			$0	$0
47	1820	Distribution Station Equipment <50 kV	$4,831,949	$44,590		$4,876,540	-$828,661	-$128,205		-$956,867	$3,919,673
47	1825	Storage Battery Equipment	$0			$0	$0			$0	$0
47	1830	Poles, Towers & Fixtures	$4,394,621	$281,375	-$124,438	$4,551,558	-$2,134,616	-$107,944	$124,438	-$2,118,122	$2,433,435
47	1835	Overhead Conductors & Devices	$5,729,424	$477,858	-$61,679	$6,145,604	-$2,332,082	-$161,898	$61,679	-$2,432,301	$3,713,303
47	1840	Underground Conduit	$1,050,834	$7,550	-$6,712	$1,051,672	-$688,533	-$18,159	$6,712	-$699,979	$351,693
47	1845	Underground Conductors & Devices	$1,766,540	$218,375	-$108,640	$1,876,275	-$483,109	-$52,984	$108,640	-$427,454	$1,448,821
47	1850	Line Transformers	$4,715,279	$690,913	-$167,253	$5,238,939	-$1,519,375	-$109,741	$167,253	-$1,461,862	$3,777,077
47	1855	Services (Overhead & Underground)	$2,378,169	$146,188	-$41,666	$2,482,692	-$894,241	-$72,121	$41,666	-$924,697	$1,557,995
47	1860	Meters	$782,418	$166,261		$948,680	-$200,246	-$51,941		-$252,187	$696,493
47	1860	Meters (Smart Meters)	$1,514,650		-$110,761	$1,403,889	-$1,388,794	-$70,471	$110,761	-$1,348,504	$55,385
N/A	1905	Land	$0			$0	$0			$0	$0
47	1908	Buildings & Fixtures	$0			$0	$0			$0	$0
13	1910	Leasehold Improvements	$0			$0	$0			$0	$0
8	1915	Office Furniture & Equipment (10 years)	$89,742	$10,158		$99,899	-$42,591	-$9,176		-$51,767	$48,132
8	1915	Office Furniture & Equipment (5 years)	$0			$0	$0			$0	$0
10	1920	Computer Equipment - Hardware	$253,664	$10,397		$264,061	-$177,339	-$48,964		-$226,303	$37,758
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0			$0	$0			$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$0	$0			$0	$0
10	1930	Transportation Equipment	$997,759	$57,755		$1,055,514	-$638,315	-$126,742		-$765,057	$290,457
8	1935	Stores Equipment	$3,472			$3,472	-$1,215	-$347		-$1,563	$1,909
8	1940	Tools, Shop & Garage Equipment	$78,723	$17,684		$96,407	-$64,967	-$6,130		-$71,097	$25,309
8	1945	Measurement & Testing Equipment	$36,373			$36,373	-$28,383	-$1,828		-$30,211	$6,162
8	1950	Power Operated Equipment	$0			$0	$0			$0	$0
8	1955	Communications Equipment	$0	$615		$615	$0	-$102		-$102	$512
8	1955	Communication Equipment (Smart Meters)	$0			$0	$0			$0	$0
8	1960	Miscellaneous Equipment	$14,603			$14,603	-$12,979	-$250		-$13,229	$1,374
47	1970	Load Management Controls Customer Premises	$0			$0	$0			$0	$0
47	1975	Load Management Controls Utility Premises	$0			$0	$0			$0	$0
47	1980	System Supervisor Equipment	$133,751	$134,287		$268,038	-$60,237	-$23,196		-$83,433	$184,605
47	1985	Miscellaneous Fixed Assets	$0			$0	$0			$0	$0
47	1990	Other Tangible Property	$0			$0	$0			$0	$0
47	1995	Contributions & Grants	-$2,015,879			-$2,015,879	$1,203,339	$71,182		$1,274,521	-$741,358
47	2440	Deferred Revenue [5]	-$2,205,159	-$295,456		-$2,500,616	$223,927	$51,050		$274,977	-$2,225,639
	2005	Property Under Finance Lease [7]	$0			$0	$0			$0	$0
		Sub-Total	**$25,801,578**	**$2,075,239**	**-$621,149**	$27,255,668	**-$10,468,798**	**-$992,213**	**$621,149**	**-$10,839,862**	**$16,415,806**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0
		Total PP&E for Rate Base Purposes	**$25,801,578**	**$2,075,239**	**-$621,149**	**$27,255,668**	**-$10,468,798**	**-$992,213**	**$621,149**	**-$10,839,862**	**$16,415,806**
		Construction Work In Progress				$0				$0	$0
		Total PP&E	**$25,801,578**	**$2,075,239**	**-$621,149**	**$27,255,668**	**-$10,468,798**	**-$992,213**	**$621,149**	**-$10,839,862**	**$16,415,806**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 992,213**			

Table 14 - 2024 Gross Fixed Asset Additions by Capital Investment Categories

Projects	**2024**
Reporting Basis	**MIFRS**
System Access	
New Services and Service Upgrades	567,616
Highway 148	389,161
Subdivisions	216,747
System Access Gross Expenditures	**1,173,524**
System Access Capital Contributions	295,456
Sub-Total	**878,068**
System Renewal	
Line Transformers - PCB Replacements	
SREPs	
Capital Renewal and Replacements	814,998
Substation Buildings & Equipment	3,535
System Supervisory Equipment	175,342
System Renewal Gross Expenditures	**993,875**
System Renewal Capital Contributions	0
Sub-Total	**993,875**
System Service	
Easements	
Land - Pembroke MS#4	
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6	
SCADA Master Data Concentrator	
System Service Gross Expenditures	**0**
System Service Capital Contributions	
Sub-Total	**0**
General Plant	
Information Technology	53,609
Leasehold Improvements	63,476
Tools and Equipment	28,456
Small Vehicles and Trailers	52,110
Large Vehicles	5,645
General Plant Gross Expenditures	**203,296**
General Plant Capital Contributions	
Sub-Total	**203,296**
Miscellaneous	
Total	**2,075,239**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	
Total	**2,075,239**

Table 15 - 2025 Continuity Schedule

Accounting Standard	MIFRS
Year	2025

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$0			$0	$0			$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$390,408	$26,796		$417,204	-$272,223	-$75,960		-$348,183	$69,020
CEC	1612	Land Rights (Formally known as Account 1906)	$20,326			$20,326	-$3,811	-$2,541		-$6,352	$13,974
N/A	1805	Land	$258,350			$258,350	$0			$0	$258,350
47	1808	Buildings	$267,752	$26,332		$294,083	-$125,975	-$7,147		-$133,122	$160,961
13	1810	Leasehold Improvements	$420,497	$23,648		$444,145	-$122,615	-$20,429		-$143,045	$301,101
47	1815	Transformer Station Equipment >50 kV	$0			$0	$0			$0	$0
47	1820	Distribution Station Equipment <50 kV	$4,876,540	$361,340		$5,237,879	-$956,867	-$132,852		-$1,089,719	$4,148,160
47	1825	Storage Battery Equipment	$0			$0	$0			$0	$0
47	1830	Poles, Towers & Fixtures	$4,551,558	$317,270		$4,868,827	-$2,118,122	-$109,403		-$2,227,525	$2,641,302
47	1835	Overhead Conductors & Devices	$6,145,604	$333,508		$6,479,112	-$2,432,301	-$159,009		-$2,591,310	$3,887,802
47	1840	Underground Conduit	$1,051,672	$12,104		$1,063,776	-$699,979	-$16,804		-$716,783	$346,993
47	1845	Underground Conductors & Devices	$1,876,275	$249,505		$2,125,780	-$427,454	-$58,574		-$486,028	$1,639,752
47	1850	Line Transformers	$5,238,939	$717,662		$5,956,602	-$1,461,862	-$121,818		-$1,583,680	$4,372,921
47	1855	Services (Overhead & Underground)	$2,482,692	$218,970		$2,701,662	-$924,697	-$74,421		-$999,118	$1,702,543
47	1860	Meters	$948,680	$100,370		$1,049,050	-$252,187	-$60,141		-$312,327	$736,722
47	1860	Meters (Smart Meters)	$1,403,889			$1,403,889	-$1,348,504	-$39,184		-$1,387,688	$16,201
N/A	1905	Land	$0			$0	$0			$0	$0
47	1908	Buildings & Fixtures	$0			$0	$0			$0	$0
13	1910	Leasehold Improvements	$0			$0	$0			$0	$0
8	1915	Office Furniture & Equipment (10 years)	$99,899	$6,958		$106,857	-$51,767	-$9,691		-$61,458	$45,399
8	1915	Office Furniture & Equipment (5 years)	$0			$0	$0			$0	$0
10	1920	Computer Equipment - Hardware	$264,061	$36,096		$300,157	-$226,303	-$29,235		-$255,538	$44,619
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0			$0	$0			$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$0	$0			$0	$0
10	1930	Transportation Equipment	$1,055,514	$128,260		$1,183,775	-$765,057	-$110,931		-$875,988	$307,787
8	1935	Stores Equipment	$3,472	$2,866		$6,338	-$1,563	-$491		-$2,053	$4,285
8	1940	Tools, Shop & Garage Equipment	$96,407	$29,175		$125,581	-$71,097	-$6,092		-$77,189	$48,392
8	1945	Measurement & Testing Equipment	$36,373			$36,373	-$30,211	-$1,506		-$31,717	$4,656
8	1950	Power Operated Equipment	$0			$0	$0			$0	$0
8	1955	Communications Equipment	$615			$615	-$102	-$205		-$307	$307
8	1955	Communication Equipment (Smart Meters)	$0			$0	$0			$0	$0
8	1960	Miscellaneous Equipment	$14,603			$14,603	-$13,229	-$250		-$13,478	$1,125
47	1970	Load Management Controls Customer Premises	$0			$0	$0			$0	$0
47	1975	Load Management Controls Utility Premises	$0			$0	$0			$0	$0
47	1980	System Supervisor Equipment	$268,038	$106,329		$374,367	-$83,433	-$26,648		-$110,081	$264,286
47	1985	Miscellaneous Fixed Assets	$0			$0	$0			$0	$0
47	1990	Other Tangible Property	$0			$0	$0			$0	$0
47	1995	Contributions & Grants	-$2,015,879		$36,658	-$1,979,221	$1,274,521	$69,716	-$36,658	$1,307,579	-$671,643
47	2440	Deferred Revenue[5]	-$2,500,616	-$318,289		-$2,818,905	$274,977	$61,037		$336,014	-$2,482,891
	2005	Property Under Finance Lease[7]	$0			$0	$0			$0	$0
		Sub-Total	**$27,255,668**	**$2,378,898**	**$36,658**	$29,671,224	**-$10,839,862**	**-$932,579**	**-$36,658**	**-$11,809,099**	**$17,862,125**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$0				$0	$0
		Total PP&E for Rate Base Purposes	**$27,255,668**	**$2,378,898**	**$36,658**	**$29,671,224**	**-$10,839,862**	**-$932,579**	**-$36,658**	**-$11,809,099**	**$17,862,125**
		Construction Work In Progress				$0				$0	$0
		Total PP&E	**$27,255,668**	**$2,378,898**	**$36,658**	**$29,671,224**	**-$10,839,862**	**-$932,579**	**-$36,658**	**-$11,809,099**	**$17,862,125**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						-$ 932,579			

Table 16 - 2025 Gross Fixed Asset Additions by Capital Investment Categories

Projects	2025
Reporting Basis	**MIFRS**
System Access	
New Services and Service Upgrades	646,207
Highway 148	78,514
Subdivisions	69,919
System Access Gross Expenditures	**794,640**
System Access Capital Contributions	318,289
Sub-Total	**476,351**
System Renewal	
Line Transformers - PCB Replacements	331,238
SREPs	
Capital Renewal and Replacements	823,510
Substation Buildings & Equipment	387,671
System Supervisory Equipment	106,329
System Renewal Gross Expenditures	**1,648,748**
System Renewal Capital Contributions	0
Sub-Total	**1,648,748**
System Service	
Easements	
Land - Pembroke MS#4	
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6	
SCADA Master Data Concentrator	
System Service Gross Expenditures	**0**
System Service Capital Contributions	
Sub-Total	**0**
General Plant	
Information Technology	62,892
Leasehold Improvements	23,648
Tools and Equipment	38,998
Small Vehicles and Trailers	119,335
Large Vehicles	8,926
General Plant Gross Expenditures	**253,799**
General Plant Capital Contributions	
Sub-Total	**253,799**
Miscellaneous	
Total	**2,378,898**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	
Total	**2,378,898**

Table 17 - Bridge Year 2026 Continuity Schedule

Accounting Standard: MIFRS
Year: 2026

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$0			$0	$0			$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$417,204	$20,000		$437,204	-$348,183	-$51,754		-$399,937	$37,267
CEC	1612	Land Rights (Formally known as Account 1906)	$20,326	$20,000		$40,326	-$6,352	-$3,791		-$10,143	$30,183
N/A	1805	Land	$258,350	$150,000		$408,350	$0			$0	$408,350
47	1808	Buildings	$294,083			$294,083	-$133,122	-$7,440		-$140,562	$153,521
13	1810	Leasehold Improvements	$444,145	$28,000		$472,145	-$143,045	-$21,462		-$164,507	$307,638
47	1815	Transformer Station Equipment >50 kV	$0			$0	$0			$0	$0
47	1820	Distribution Station Equipment <50 kV	$5,237,879	$3,601		$5,241,480	-$1,089,719	-$136,633		-$1,226,352	$4,015,128
47	1825	Storage Battery Equipment	$0			$0	$0			$0	$0
47	1830	Poles, Towers & Fixtures	$4,868,827	$278,127		$5,146,954	-$2,227,525	-$109,690		-$2,337,215	$2,809,739
47	1835	Overhead Conductors & Devices	$6,479,112	$630,772		$7,109,884	-$2,591,310	-$159,686		-$2,750,996	$4,358,888
47	1840	Underground Conduit	$1,063,776	$7,167		$1,070,943	-$716,783	-$14,414		-$731,197	$339,747
47	1845	Underground Conductors & Devices	$2,125,780	$308,863		$2,434,643	-$486,028	-$65,554		-$551,582	$1,883,060
47	1850	Line Transformers	$5,956,602	$232,604		$6,189,205	-$1,583,680	-$130,857		-$1,714,538	$4,474,668
47	1855	Services (Overhead & Underground)	$2,701,662	$174,398		$2,876,060	-$999,118	-$75,926		-$1,075,044	$1,801,016
47	1860	Meters	$1,049,050	$143,374		$1,192,424	-$312,327	-$68,574		-$380,902	$811,522
47	1860	Meters (Smart Meters)	$1,403,889			$1,403,889	-$1,387,688	-$8,872		-$1,396,560	$7,329
N/A	1905	Land	$0			$0	$0			$0	$0
47	1908	Buildings & Fixtures	$0			$0	$0			$0	$0
13	1910	Leasehold Improvements	$0			$0	$0			$0	$0
8	1915	Office Furniture & Equipment (10 years)	$106,857	$28,207		$135,065	-$61,458	-$9,921		-$71,378	$63,686
8	1915	Office Furniture & Equipment (5 years)	$0			$0	$0			$0	$0
10	1920	Computer Equipment - Hardware	$300,157	$9,000		$309,157	-$255,538	-$26,338		-$281,876	$27,281
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0			$0	$0			$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$0	$0			$0	$0
10	1930	Transportation Equipment	$1,183,775	$608,566		$1,792,341	-$875,988	-$127,798		-$1,003,786	$788,554
8	1935	Stores Equipment	$6,338	$600		$6,938	-$2,053	-$664		-$2,717	$4,221
8	1940	Tools, Shop & Garage Equipment	$125,581	$38,881		$164,462	-$77,189	-$8,412		-$85,601	$78,861
8	1945	Measurement & Testing Equipment	$36,373			$36,373	-$31,717	-$1,183		-$32,900	$3,473
8	1950	Power Operated Equipment	$0			$0	$0			$0	$0
8	1955	Communications Equipment	$615			$615	-$307	-$205		-$512	$103
8	1955	Communication Equipment (Smart Meters)	$0			$0	$0			$0	$0
8	1960	Miscellaneous Equipment	$14,603			$14,603	-$13,478	-$250		-$13,728	$875
47	1970	Load Management Controls Customer Premises	$0			$0	$0			$0	$0
47	1975	Load Management Controls Utility Premises	$0			$0	$0			$0	$0
47	1980	System Supervisor Equipment	$374,367	$120,000		$494,367	-$110,081	-$37,965		-$148,046	$346,321
47	1985	Miscellaneous Fixed Assets	$0			$0	$0			$0	$0
47	1990	Other Tangible Property	$0			$0	$0			$0	$0
47	1995	Contributions & Grants	-$1,979,221			-$1,979,221	$1,307,579	$64,613		$1,372,191	-$607,030
47	2440	Deferred Revenue[5]	-$2,818,905	-$476,143		-$3,295,048	$336,014	$73,966		$409,980	-$2,885,068
	2005	Property Under Finance Lease[7]	$0			$0	$0			$0	$0
		Sub-Total	**$29,671,224**	**$2,326,017**	**$0**	$31,997,241	**-$11,809,099**	**-$928,809**	**$0**	**-$12,737,908**	**$19,259,333**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0
		Total PP&E for Rate Base Purposes	**$29,671,224**	**$2,326,017**	**$0**	**$31,997,241**	**-$11,809,099**	**-$928,809**	**$0**	**-$12,737,908**	**$19,259,333**
		Construction Work In Progress				$0				$0	$0
		Total PP&E	**$29,671,224**	**$2,326,017**	**$0**	**$31,997,241**	**-$11,809,099**	**-$928,809**	**$0**	**-$12,737,908**	**$19,259,333**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 928,809**			

Table 18 - 2026 Gross Fixed Asset Additions by Capital Investment Categories

Projects	2026 Bridge Year
Reporting Basis	**MIFRS**
System Access	
New Services and Service Upgrades	846,888
Highway 148	
Subdivisions	
System Access Gross Expenditures	**846,888**
System Access Capital Contributions	280,635
Sub-Total	**566,253**
System Renewal	
Line Transformers - PCB Replacements	
SREPs	271,015
Capital Renewal and Replacements	657,401
Substation Buildings & Equipment	3,601
System Supervisory Equipment	120,000
System Renewal Gross Expenditures	**1,052,017**
System Renewal Capital Contributions	195,508
Sub-Total	**856,509**
System Service	
Easements	20,000
Land - Pembroke MS#4	150,000
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6	
SCADA Master Data Concentrator	
System Service Gross Expenditures	**170,000**
System Service Capital Contributions	
Sub-Total	**170,000**
General Plant	
Information Technology	29,000
Leasehold Improvements	28,000
Tools and Equipment	67,689
Small Vehicles and Trailers	20,257
Large Vehicles	588,309
General Plant Gross Expenditures	**733,255**
General Plant Capital Contributions	
Sub-Total	**733,255**
Miscellaneous	
Total	**2,326,017**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	
Total	**2,326,017**

Table 19 - Test Year 2027 Continuity Schedule

Accounting Standard: MIFRS
Year: 2027

CCA Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$0			$0	$0			$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$437,204	$15,000		$452,204	-$399,937	-$25,301		-$425,238	$26,966
CEC	1612	Land Rights (Formally known as Account 1906)	$40,326	$20,000		$60,326	-$10,143	-$6,291		-$16,433	$43,893
N/A	1805	Land	$408,350			$408,350	$0			$0	$408,350
47	1808	Buildings	$294,083	$15,000		$309,083	-$140,562	-$7,590		-$148,152	$160,931
13	1810	Leasehold Improvements	$472,145	$39,800		$511,945	-$164,507	-$22,818		-$187,325	$324,620
47	1815	Transformer Station Equipment >50 kV	$0			$0	$0			$0	$0
47	1820	Distribution Station Equipment <50 kV	$5,241,480	$603,772		$5,845,252	-$1,226,352	-$142,251		-$1,368,603	$4,476,649
47	1825	Storage Battery Equipment	$0			$0	$0			$0	$0
47	1830	Poles, Towers & Fixtures	$5,146,954	$353,185		$5,500,140	-$2,337,215	-$112,610		-$2,449,825	$3,050,314
47	1835	Overhead Conductors & Devices	$7,109,884	$627,587		$7,737,470	-$2,750,996	-$158,704		-$2,909,700	$4,827,770
47	1840	Underground Conduit	$1,070,943	$14,884		$1,085,828	-$731,197	-$13,882		-$745,078	$340,749
47	1845	Underground Conductors & Devices	$2,434,643	$276,611		$2,711,254	-$551,582	-$71,667		-$623,250	$2,088,004
47	1850	Line Transformers	$6,189,205	$276,843		$6,466,048	-$1,714,538	-$133,931		-$1,848,468	$4,617,580
47	1855	Services (Overhead & Underground)	$2,876,060	$178,986		$3,055,046	-$1,075,044	-$76,273		-$1,151,317	$1,903,728
47	1860	Meters	$1,192,424	$141,538		$1,333,962	-$380,902	-$78,041		-$458,943	$875,019
47	1860	Meters (Smart Meters)	$1,403,889			$1,403,889	-$1,396,560	-$4,351		-$1,400,911	$2,978
N/A	1905	Land	$0			$0	$0			$0	$0
47	1908	Buildings & Fixtures	$0			$0	$0			$0	$0
13	1910	Leasehold Improvements	$0			$0	$0			$0	$0
8	1915	Office Furniture & Equipment (10 years)	$135,065	$5,000		$140,065	-$71,378	-$10,007		-$81,386	$58,679
8	1915	Office Furniture & Equipment (5 years)	$0			$0	$0			$0	$0
10	1920	Computer Equipment - Hardware	$309,157	$12,800		$321,957	-$281,876	-$18,898		-$300,775	$21,183
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0			$0	$0			$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$0	$0			$0	$0
10	1930	Transportation Equipment	$1,792,341	$650,422		$2,442,763	-$1,003,786	-$180,111		-$1,183,897	$1,258,865
8	1935	Stores Equipment	$6,938	$3,764		$10,702	-$2,717	-$882		-$3,599	$7,103
8	1940	Tools, Shop & Garage Equipment	$164,462	$13,709		$178,171	-$85,601	-$10,173		-$95,774	$82,397
8	1945	Measurement & Testing Equipment	$36,373	$15,318		$51,691	-$32,900	-$1,899		-$34,799	$16,892
8	1950	Power Operated Equipment	$0			$0	$0			$0	$0
8	1955	Communications Equipment	$615	$4,400		$5,015	-$512	-$836		-$1,348	$3,667
8	1955	Communication Equipment (Smart Meters)	$0			$0	$0			$0	$0
8	1960	Miscellaneous Equipment	$14,603			$14,603	-$13,728	-$250		-$13,978	$625
47	1970	Load Management Controls Customer Premises	$0			$0	$0			$0	$0
47	1975	Load Management Controls Utility Premises	$0			$0	$0			$0	$0
47	1980	System Supervisor Equipment	$494,367	$130,000		$624,367	-$148,046	-$50,465		-$198,511	$425,856
47	1985	Miscellaneous Fixed Assets	$0			$0	$0			$0	$0
47	1990	Other Tangible Property	$0			$0	$0			$0	$0
47	1995	Contributions & Grants	-$1,979,221			-$1,979,221	$1,372,191	$63,700		$1,435,891	-$543,330
47	2440	Deferred Revenue [5]	-$3,295,048	-$484,008		-$3,779,056	$409,980	$85,968		$495,948	-$3,283,107
	2005	Property Under Finance Lease [7]	$0			$0	$0			$0	$0
		Sub-Total	**$31,997,241**	**$2,914,613**	**$0**	$34,911,854	**-$12,737,908**	**-$977,565**	**$0**	**-$13,715,473**	**$21,196,381**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$0				$0	$0
		Total PP&E for Rate Base Purposes	**$31,997,241**	**$2,914,613**	**$0**	**$34,911,854**	**-$12,737,908**	**-$977,565**	**$0**	**-$13,715,473**	**$21,196,381**
		Construction Work In Progress				$0				$0	$0
		Total PP&E	**$31,997,241**	**$2,914,613**	**$0**	**$34,911,854**	**-$12,737,908**	**-$977,565**	**$0**	**-$13,715,473**	**$21,196,381**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 977,565**			

Table 20 - 2027 Gross Fixed Asset Additions by Capital Investment Categories

Projects	2027 Test Year
Reporting Basis	**MIFRS**
System Access	
New Services and Service Upgrades	943,687
Highway 148	
Subdivisions	
System Access Gross Expenditures	**943,687**
System Access Capital Contributions	290,748
Sub-Total	**652,939**
System Renewal	
Line Transformers - PCB Replacements	
SREPs	256,520
Capital Renewal and Replacements	669,429
Substation Buildings & Equipment	618,772
System Supervisory Equipment	130,000
System Renewal Gross Expenditures	**1,674,721**
System Renewal Capital Contributions	193,260
Sub-Total	**1,481,461**
System Service	
Easements	20,000
Land - Pembroke MS#4	
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6	
SCADA Master Data Concentrator	
System Service Gross Expenditures	**20,000**
System Service Capital Contributions	
Sub-Total	**20,000**
General Plant	
Information Technology	27,800
Leasehold Improvements	39,800
Tools and Equipment	42,191
Small Vehicles and Trailers	75,000
Large Vehicles	575,422
General Plant Gross Expenditures	**760,213**
General Plant Capital Contributions	
Sub-Total	**760,213**
Miscellaneous	
Total	**2,914,613**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	
Total	**2,914,613**

2.2 GROSS ASSETS

2.2.1 GROSS ASSET VARIANCE ANALYSIS

Accounting treatment of the cost of funds for construction work-in-progress

Virtually all ORPC's capital work is completed within the same fiscal year. If a project spans over multiple years, ORPC will follow the OEB's accounting processes and use account 2055 – Construction Work In Progress (Electric). However, most projects that cross multiple years are performed in phases with assets being installed and in-service by the end of the expenditure fiscal year.

ORPC confirms there were no expenditures for non-distribution activities in the LDC's capital investment plan or actual expenditures for 2022-2026 or for forecasted expenditures for 2027-2031.

Table 21 below compares ORPC's actual capital expenditure versus planned for the historical period 2022 to 2026 and the plan investment period of 2027 to 2031 by capital investment category:

Table 21 - OEB Appendix 2-AB Capital Expenditures

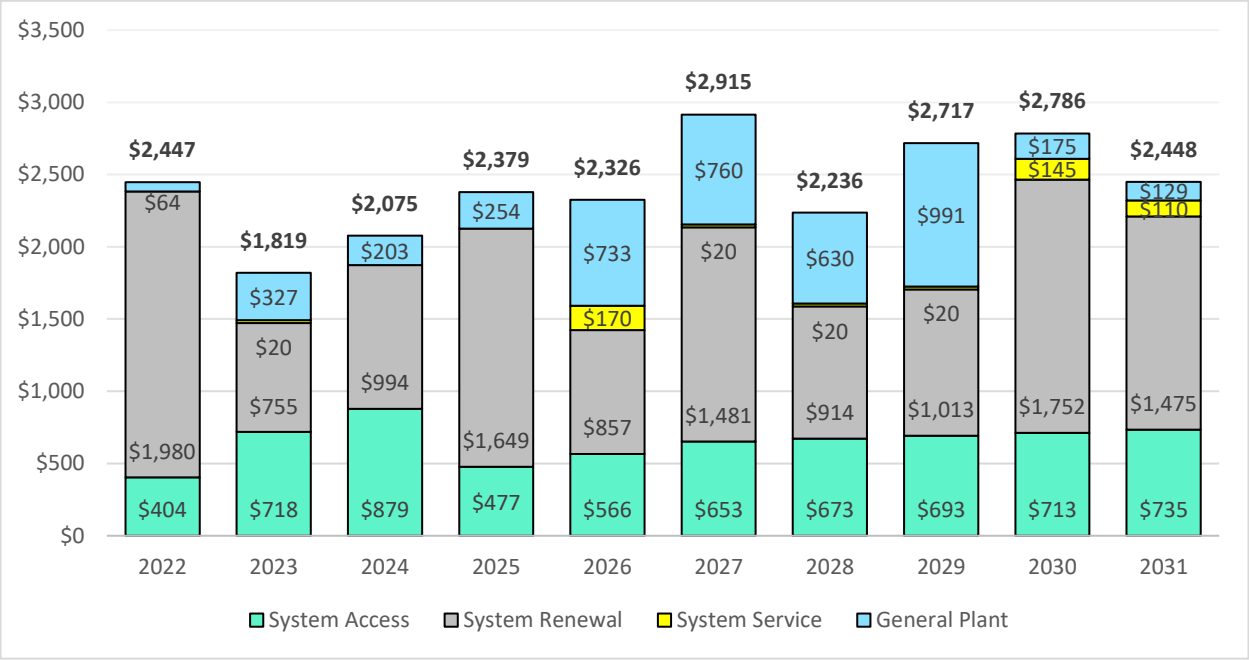
1

CATEGORY	2022			2023			2024			2025			2026		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual2	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	833	564	-32%	547	1,061	94%	662	1,174	77%	542	795	47%	526	847	61%
System Renewal	648	1,980	206%	889	755	-15%	921	994	8%	1,011	1,649	63%	943	1,052	12%
System Service	105	-	-100%	162	20	-87%	62	-	-100%	70	-	-100%	75	170	126%
General Plant	139	64	-54%	19	327	1583%	30	203	580%	7	254	3330%	428	733	71%
TOTAL EXPENDITURE	1,725	2,607	51%	1,617	2,163	34%	1,674	2,371	42%	1,631	2,697	65%	1,973	2,802	42%
Capital Contributions	424	160	-62%	334	343	3%	426	295	-31%	337	318	-5%	347	476	37%
NET CAPITAL EXPENDITURES	1,302	2,447	88%	1,282	1,819	42%	1,248	2,075	66%	1,295	2,379	84%	1,626	2,326	43%
CWIP															
System O&M	1,450	1,454	0%	1,507	1,521	1%	1,538	1,397	-9%	1,568	1,938	24%	1,600	1,638	2%

CATEGORY	Forecast Period (planned)				
	2027	2028	2029	2030	2031
	$ '000				
System Access	944	972	1,001	1,031	1,062
System Renewal	1,675	1,264	1,440	2,242	1,475
System Service	20	20	20	145	110
General Plant	760	630	991	175	129
TOTAL EXPENDITURE	3,399	2,886	3,453	3,593	2,775
Capital Contributions	484	649	736	808	327
NET CAPITAL EXPENDITURES	2,915	2,237	2,717	2,786	2,448
CWIP					
System O&M	1,840	1,895	1,952	2,011	2,071

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Figure 1 - OEB Appendix 2-AB Capital Expenditures



The tables below summarize ORPC's 2022 DSP plan as compared to actual expenditures by OEB investment category for each year.

Historical Plan Period - Variances between Plan and Actual

Detailed below are the factors that resulted in any material variance of =/+ $50,000 per year by OEB investment category for the historical 4-year period of 2022-2025 covered by the previous Distribution System Plan:

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2022 CAPEX PLAN VERSUS ACTUAL:

Table 22 - Variance Analysis: 2022

	2022			
	Plan	**Actual**	**Var**	
	$ '000		*$ '000*	%
System Access	833	564	-270	-32%
System Renewal	648	1,980	1,332	206%
System Service	105	0	-105	-100%
General Plant	139	64	-76	-54%
TOTAL EXPENDITURE	1,725	2,607	882	51%

System Access - $269,653 Decrease

The 2022 DSP plan assumed a gross total spend of $833,350 for system access compared to actual expenditures of $563,697. The 2022 plan included $100,000 for Highway 148 Upgrades, $93,600 for a 44kV Overhead Line Relocation, and $64,502 for Orchardview Phase 2. The Highway 148 project did not begin until 2023, the 44kV Line Relocation project did not occur due to a change in land ownership, and Orchardview Phase 2 was redesigned and completed in 2025. This category captures externally initiated development projects that can vary significantly year by year.

System Renewal - $1,331,803 Increase

Regarding system renewal, the plan included $150,000 to replace a failed transformer at Pembroke MS#6. The settlement agreement included $150,000 per year over the 5-year period for a total

project cost of $750,000. The actual incurred expenditures in 2022 were $1,082,420, for a total increase of $932,420 compared to the amount included in rates for 2022. Additionally, ORPC increased its metering and transformer replacements by $392,702 due to long supply chain lead times following the pandemic.

System Service - $105,000 Decrease

The system service category assumed a budget of $45,000 for SCADA assessments, scouting and configuration and $60,000 for the RTU and relay replacement. Actual SCADA replacements did not begin until 2024 and were categorized as System Renewal. The Pembroke MS#4 RTU replacement originally planned for 2022 occurred in 2024.

General Plant - $75,658 Decrease

In its plan for 2022, ORPC included $45,000 for a new e-billing system, $27,000 for eavestrough replacements in Pembroke and $19,210 for an infrared camera. The actual 2022 expenditures were $22,500 for the e-billing system whereas the eavestrough and infrared camera expenditures did not occur until 2023 and 2025, respectively. These 3 items contributed $68,710 to the variance.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2023 CAPEX PLAN VERSUS ACTUAL:

Table 23 - Variance Analysis: 2023

	2023			
	Plan	**Actual**	**Var**	
	$ '000		*$ '000*	%
System Access	547	1,061	514	94%
System Renewal	889	755	-134	-15%
System Service	162	20	-142	-87%
General Plant	19	327	307	1583%
TOTAL EXPENDITURE	1,617	2,163	546	34%

System Access - $514,280 Increase

The 2023 DSP plan assumed a gross total spend of $546,770 for system access compared to actual incurred expenditures of $1,061,050. The actual incurred expenditures include $230,279 for the beginning of the Highway 148 Upgrades project which was originally estimated at $100,000 in 2022. Other material expenses in 2023 included $254,185 for a Boundary Road West Subdivision and $161,011 for an industrial park lighting project.

System Renewal - $133,843 Decrease

Regarding system renewal, the plan included $463,000 for overhead renewal of poles, overhead conductor and transformers. This renewal program did not reach forecasted expenditures due to

the significant resource requirements for the Highway 148 System Access project. Material renewal projects did however include $280,069 for the Pembroke MS#1 transformer that experienced a failure and $73,845 in additional renewal costs for the Pembroke MS#6 transformer project that was largely completed in 2022. The Pembroke MS#6 transformer replacement costs were included at $150,000 per year over the DSP period although all costs were incurred in 2022.

System Service - $141,584 Decrease

The system service category included a plan of $162,000 in 2023 compared to $20,326 actually incurred. Planned material projects for system service addressed reliability issues with the current SCADA system installed at ORPC stations. SCADA replacements began in 2024 and were categorized as System Renewal.

General Plant - $307,111 Increase

The previous DSP included a planned $19,000 in 2023 for general plant expenditures. Actual material expenses included $87,574 for ArcGIS and $65,438 for an engine replacement in large vehicle #8. As noted in its rate base variance analysis, ORPC's vendor officially retired ArcGIS Desktop on March 1, 2026. The existing platform would no longer be supported, so an upgrade was required including data conversion to match the new platform requirements. Separately, the engine in vehicle #8 failed which required replacement to continue operation of the vehicle and ORPC's maintenance and capital programs. Non-material actual expenses in 2023 included $25,000 for the continuation of the implementation of the new e-billing platform originally

planned for 2022, $20,708 for the implementation of the Green Button initiative requirements, $27,739 for the Pembroke eavestrough originally planned for 2022 and $27,801 in miscellaneous computer hardware replacements including laptops, monitors, workstations, and a server.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2024 CAPEX PLAN VERSUS ACTUAL:

Table 24 - Variance Analysis: 2024

	2024			
	Plan	**Actual**	**Var**	
	$ '000		*$ '000*	%
System Access	662	1,174	512	77%
System Renewal	921	994	73	8%
System Service	62	0	-62	-100%
General Plant	30	203	173	580%
TOTAL EXPENDITURE	1,674	2,371	697	42%

System Access - $512,024 Increase

The 2024 DSP plan assumed a gross total spend of $661,500 for system access compared to actual incurred expenditures of $1,173,524. The actual expenditures include $389,161 for the continuation of the Highway 148 Upgrades project which was originally estimated at $100,000 in 2022. Additionally, 2024 includes $173,214 in incremental expenditures for the Golfview Subdivision located in Pembroke which is anticipated to connect 96 customers.

System Renewal - $73,085 Increase

Regarding system renewal, the plan included $920,790 across its entire program as compared to $993,875 in actual expenditures. The primary difference arose from the Pembroke MS#6 transformer replacement costs being included at $150,000 per year over the DSP period although all costs were realized in 2022 offset by the purchase of $193,849 for transformer and metering replacements.

System Service - $62,300 Decrease

The system service category assumed a budget of $62,300 in 2024 compared to no actual expenditures incurred. System Service category investments are driven by the need to ensure that ORPC's distribution system continues to meet operational objectives, and to maintain the security of supply. One of the major initiatives included within this category is the upgrade of the SCADA system. ORPC incurred expenses of $175,342 for the SCADA replacement of Pembroke MS#4 in 2024 and included this in the System Renewal category as the primary driver was to replace obsolete equipment and not to expand the functionality.

General Plant - $173,396 Increase

The DSP included planned expenditures of $29,900 in 2024 including $12,400 for computer hardware, $12,500 for facilities improvements, and $5,000 for fleet. Actual expenditures included $18,213 for the new e-billing platform, $53,518 for the replacement and relocation of a propane generator that was inside one of ORPC's Pembroke offices and not up to code, $11,560 in software

expenses for OESP and Net Metering enhancements, $10,158 for new office chairs, $52,110 for a Tandem Axle Pole Trailer to accommodate transportation of pole sizes greater than 55', and $17,684 in Tools, Shop & Garage Equipment, specifically for a 15kV 200 AMP Load Break, crimpers, a grounding elbow and other miscellaneous items.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2025 CAPEX PLAN VERSUS ACTUAL:

Table 25 - Variance Analysis: 2025

	2025			
	Plan	**Actual**	**Var**	
	$ '000		*$ '000*	%
System Access	542	795	252	47%
System Renewal	1,011	1,649	637	63%
System Service	70	0	-70	-100%
General Plant	7	254	246	3330%
TOTAL EXPENDITURE	1,631	2,697	1,066	65%

System Access - $252,340 Increase

The 2025 DSP plan assumed a total of $542,300 for system access compared to actual incurred expenditures of $794,640. The actual incurred expenditures include costs of $78,514 for the completion of Highway 148 upgrades and $69,919 for the Golfview Subdivision located in Pembroke. Other material costs included $61,857 for a 3 unit building on Irving Street in Pembroke requiring 4 pole upgrades and 3 50kVa pole mounted transformers, $53,985 for an 8 unit building

on Steel Street in Pembroke, and $52,765 for a business customer connection within its Almonte service territory.

System Renewal - $637,439 Increase

Regarding System Renewal, the plan included $1,011,310 compared to actual costs of $1,648,749. Actual costs included the following material projects:

- $331,238 for PCB Transformer Replacements. Environment and Climate Change Canada mandated that transformers containing PCB concentrations exceeding 50 parts per million (PPM) be removed from service by the end of 2025. ORPC's renewal program in 2025 addressed this mandate through replacement of positive-testing line transformers.
- $50,492 for the Evelyn Street Pole Replacement project. Originally included in the 2022 Cost of Service test year at an estimated cost of $50,600 but delayed due to other projects taking priority. This project required the replacement of 3 poles and secondary conductor upgrades in a rear lot.
- $276,400 to replace its Almonte MS#2 transformer that failed from a lightning strike.
- $73,348 for the Pembroke MS#1 Bus Cable replacement. The bus duct experienced a major ground fault for the second time in 10 years due to ice buildup caused from temperature differential issues between inside and outside the substation. A decision was made to convert to a cable bus instead of a bus duct to prevent the issue from recurring.
- $106,329 for the Pembroke MS#8 SCADA replacement. Replacement of obsolete or non-functional substation SCADA systems with the intention to replace 1 or 2 SCADA systems

annually until all systems are functional. This allows for improved monitoring of its systems and the ability to operate equipment remotely. Additionally, ORPC is better able to collect operational data.

- $54,543 for the primary conductor replacement at the Pembroke Mall. ORPC replaced 708m of underground primary conductor that had reached its end-of-life and experienced a fault.

System Service - $70,080 Decrease

The system service category assumed a budget of $70,080 in 2025 compared to no actual costs incurred. One of the major initiatives included within this category in the last DSP was the upgrade of the SCADA system. ORPC incurred expenditures of $106,239 for the SCADA replacement of Pembroke MS#8 in 2025 but included this in its System Renewal category as the primary driver was to replace obsolete equipment and not to expand the functionality.

General Plant - $246,398 Increase

The DSP included $7,000 for all general plant expenditures in 2025 including IT, vehicles, office equipment, and miscellaneous tools and measurement and testing equipment. Actual incurred material general plant expenditures included $52,214 for a 2023 Ford E-Transit Cargo van and $67,121 for a 2025 Ford F150 XLT which replaced passenger vehicles that experienced engine failures. Other expenditures included $36,096 for computer hardware and equipment, $23,372 for

the continuation of the ARCGis migration, $23,648 for various leasehold improvements, and $32,040 for tools, shop, stores, and garage equipment.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2026 CAPEX PLAN VERSUS PROJECTED ACTUAL:

Table 26 - Variance Analysis: 2026

	2026			
	Plan	**Actual**	**Var**	
	$ '000		*$ '000*	%
System Access	526	847	321	61%
System Renewal	943	1,052	109	12%
System Service	75	170	95	126%
General Plant	428	733	305	71%
TOTAL EXPENDITURE	1,973	2,802	829	42%

System Access - $320,458 Increase

System Access capital expenditures have steadily increased since 2022, resulting in average annual expenditures of $898,295 in the 2022 to 2025 period. ORPC anticipates these expenditures to remain relatively consistent with the average in 2026 as customers continue to approach ORPC with subdivisions and connection requests.

System Renewal - $108,957 Increase

The projected increase can be attributed to $391,015 in capital expenditures under NRCAN's Smart Renewable Electricity Program which includes $120,000 for Pembroke MS#7's SCADA replacement, $30,561 for underground smart devices and $240,454 for overhead smart devices. ORPC submitted an Expression of Interest to the Smart Renewables and Electrification Pathways Program (SREPs) on December 13, 2024. ORPC, along with a consortium of 16 LDCs, has submitted and received approval for the full proposal with work expected to begin in 2026 and end in 2030. The program aims to modernize electricity systems and provides funding for SCADA systems, smart fault indicators, Outage Management Systems and Automated Switches and Reclosers. The funding covers 50% of the overall cost. With these technologies, ORPCP is expected to see improved grid reliability through faster restoration times and better asset management which in turn will lead to enhanced customer satisfaction and future-ready infrastructure.

System Service - $94,730 Increase

The system service category assumed a budget of $75,270 in 2026 mainly for the upgrade of ORPC SCADA systems. whereas actual projected expenses include $150,000 for the Pembroke MS#4 land purchase. Due to an easement issue with ORPC conductor crossing vacant privately-owned land, the owner had requested that ORPC pay rent annually for the crossing. ORPC analyzed its options and determined that it would be most beneficial and cost-effective to purchase the land that is already adjacent to Pembroke MS#4 to eliminate any rent payments.

General Plant - $304,854 Increase

The increase of $304,854 in general plant expenditures is primarily driven by an increase of $181,309 in the large vehicle replacement cost from the estimate of $407,000 to an actual of $588,309 due to significant inflation of raw materials. ORPC also incurred $20,257 for significant unanticipated repairs of a woodchipper utilized in tree trimming activities. ORPC also reached the end of term on its postage machine and entered a new agreement at $23,561 for a new postage machine which was replaced due to aging. The 2026 forecasts $20,000 in computer software expenditures, $28,000 in leasehold improvements, and $44,127 for tools, shop and garage equipment, measurement and testing equipment, and office equipment.

2.3 DEPRECIATION, AMORTIZATION, AND DEPLETION

2.3.1 ACCUMULATED DEPRECIATION

ORPC has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at the following link:

https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf

The rates used are presented below, and the Continuity Schedules of Accumulated Depreciation are presented in the table below. ORPC's capitalization policy and methodology are provided on the next page. The rates have remained unchanged since the 2022 Cost of Service filing.

2.3.2 DEPRECIATION RATES AND METHODOLOGY

In accordance with the July 17, 2012, letter from the Board on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies and as such, ORPC has adopted a range of the Kinetrics proposed useful lives and componentization. ORPC does not deviate from the practice of depreciating significant parts or components of PP&E separately.

Continuity Statements of the historical and forecasted depreciation expenses are presented in the tables below and are filed in live Excel format along with this application.

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Table 27 - Depreciation Schedule 2022

Year 2022

Account	Description	Book Values				Service Lives		Depreciation Expense				
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column K	Variance [4]	Variance [%]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1611	Computer Software (Formally known as Account 1925)	$183,296.23	$16,660.16	$41,526.00	$11,474.01	$175,925.06	3.00	33.33%	**$58,641.69**	$61,418.38	**$2,776.69**	**5%**
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$2,747.84			$0.00	8.00	12.50%	**$0.00**	$67.84	**$67.84**	**100%**
1805	Land	$258,350.32				$258,350.32		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1808	Buildings	$255,660.79		$12,090.78		$261,706.18	38.96	2.57%	**$6,717.30**	$6,613.06	**-$104.24**	**-2%**
1810	Leasehold Improvements	$314,650.39	-$78,408.41		$257.70	$392,801.10	25.00	4.00%	**$15,712.04**	$15,711.47	**-$0.57**	**0%**
1815	Transformer Station Equipment >50 kV					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1820	Distribution Station Equipment <50 kV	$3,729,199.41		$901,604.21		$4,180,001.52	37.41	2.67%	**$111,722.39**	$105,871.51	**-$5,850.88**	**-6%**
1825	Storage Battery Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1830	Poles, Towers & Fixtures	$4,431,534.43		$265,370.16	$324,838.39	$4,239,381.12	30.98	3.23%	**$136,827.01**	$120,241.33	**-$16,585.68**	**-14%**
1835	Overhead Conductors & Devices	$5,172,979.04		$254,787.88		$5,300,372.98	35.56	2.81%	**$149,033.61**	$150,422.67	**$1,389.06**	**1%**
1840	Underground Conduit	$1,126,556.12		$45,150.12	$71,311.44	$1,077,819.74	29.87	3.35%	**$36,083.69**	$29,506.56	**-$6,577.13**	**-22%**
1845	Underground Conductors & Devices	$1,382,717.85		$147,219.18		$1,456,327.44	34.51	2.90%	**$42,200.16**	$42,499.54	**$299.38**	**1%**
1850	Line Transformers	$3,476,601.82		$195,477.74	$83,450.36	$3,490,890.33	31.94	3.13%	**$109,297.13**	$102,625.43	**-$6,671.70**	**-7%**
1855	Services (Overhead & Underground)	$2,069,778.42		$125,934.67		$2,132,745.76	33.04	3.03%	**$64,541.82**	$65,172.43	**$630.61**	**1%**
1860	Meters	$544,015.73		$166,899.25		$627,465.36	15.93	6.28%	**$39,381.51**	$39,123.17	**-$258.34**	**-1%**
1860	Meters (Smart Meters)	$1,645,231.00			$56,147.84	$1,589,083.16	15.00	6.67%	**$105,938.88**	$105,938.87	**-$0.01**	**0%**
1905	Land					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1908	Buildings & Fixtures					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1910	Leasehold Improvements					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1915	Office Furniture & Equipment (10 years)	$85,893.07		$1,119.99	$2,572.20	$83,880.87	10.00	10.00%	**$8,388.09**	$8,388.10	**$0.01**	**0%**
1915	Office Furniture & Equipment (5 years)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equipment - Hardware	$210,058.15	$13,428.49	$6,439.00	$5,446.05	$194,403.11	3.00	33.33%	**$64,801.04**	$67,039.13	**$2,238.09**	**3%**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1930	Transportation Equipment	$1,361,280.53	$30,643.43		$401,326.19	$929,310.91	8.00	12.50%	**$116,163.86**	$118,079.07	**$1,915.21**	**2%**
1935	Stores Equipment	$3,472.21				$3,472.21	10.00	10.00%	**$347.22**	$347.27	**$0.05**	**0%**
1940	Tools, Shop & Garage Equipment	$90,974.66	$12,398.51	$2,376.48	$5,113.61	$74,650.78	10.00	10.00%	**$7,465.08**	$8,085.02	**$619.94**	**8%**
1945	Measurement & Testing Equipment	$36,372.91				$36,372.91	10.00	10.00%	**$3,637.29**	$3,637.30	**$0.01**	**0%**
1950	Power Operated Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communications Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communication Equipment (Smart Meters)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1960	Miscellaneous Equipment	$14,603.00				$14,603.00	10.00	10.00%	**$1,460.30**	$1,460.30	**$0.00**	**0%**
1970	Load Management Controls Customer Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1975	Load Management Controls Utility Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1980	System Supervisor Equipment	$78,574.82		$67,824.00	$12,648.09	$99,838.73	4.39	22.79%	**$22,751.64**	$22,751.63	**-$0.01**	**0%**
1985	Miscellaneous Fixed Assets					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1990	Other Tangible Property					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1995	Contributions & Grants	-$1,526,788.80	-$3,219.67		$492,310.09	-$2,015,879.22	28.34	3.53%	**-$71,122.62**	-$73,613.77	**-$2,491.15**	**3%**
2440	Deferred Revenue	-$1,735,413.61		-$160,368.81	-$34,000.00	-$1,781,598.02	40.00	2.50%	**-$44,539.95**	-$43,014.45	**$1,525.50**	**-4%**
2005	Property Under Finance Lease					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
	Total	**$23,212,346.33**	**-$5,749.65**	**$2,073,450.65**	**$ 1,432,896**	**$22,821,925.34**	**$472.95**		**$985,449.18**	**$958,371.86**	**-$27,077.32**	**-3%**

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Table 28 - Depreciation Schedule 2023

Year 2023

Account	Description	Book Values				Service Lives		Depreciation Expense				
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column K	Variance [4]	Variance [%]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1611	Computer Software (Formally known as Account 1925)	$213,348.22		$150,507.38	$16,660.16	$271,941.75	3.00	33.33%	**$90,647.25**	$89,735.02	**-$912.23**	**-1%**
1612	Land Rights (Formally known as Account 1906)	$2,747.84		$20,326.14	$2,747.84	$10,163.07	8.00	12.50%	**$1,270.38**	$1,270.38	**$0.00**	**0%**
1805	Land	$258,350.32				$258,350.32		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1808	Buildings	$267,751.57				$267,751.57	38.97	2.57%	**$6,871.25**	$6,854.87	**-$16.38**	**0%**
1810	Leasehold Improvements	$314,392.69	-$78,408.41	$43,327.84	$699.39	$413,765.63	25.00	4.00%	**$16,550.63**	$16,550.64	**$0.01**	**0%**
1815	Transformer Station Equipment >50 kV					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1820	Distribution Station Equipment <50 kV	$4,382,877.34		$451,300.75	$2,228.72	$4,606,299.00	37.85	2.64%	**$121,689.20**	$122,348.79	**$659.59**	**1%**
1825	Storage Battery Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1830	Poles, Towers & Fixtures	$4,372,066.20		$291,983.32	$269,428.88	$4,248,628.98	32.15	3.11%	**$132,145.02**	$114,817.68	**-$17,327.34**	**-15%**
1835	Overhead Conductors & Devices	$5,427,766.92		$301,656.81		$5,578,595.33	36.31	2.75%	**$153,657.24**	$155,213.84	**$1,556.60**	**1%**
1840	Underground Conduit	$1,100,394.80		$59,449.78	$109,010.24	$1,021,109.45	30.00	3.33%	**$34,036.98**	$23,831.11	**-$10,205.87**	**-43%**
1845	Underground Conductors & Devices	$1,529,937.03		$236,602.65		$1,648,238.36	35.37	2.83%	**$46,595.31**	$47,297.31	**$702.00**	**1%**
1850	Line Transformers	$3,588,629.20	$49,912.58	$282,855.64		$3,680,144.44	32.31	3.09%	**$113,896.48**	$104,692.87	**-$9,203.61**	**-9%**
1855	Services (Overhead & Underground)	$2,195,713.09		$182,456.27		$2,286,941.23	33.37	3.00%	**$68,528.48**	$68,528.81	**$0.33**	**0%**
1860	Meters	$714,394.87		$42,053.90		$735,421.82	15.94	6.27%	**$46,146.46**	$46,045.81	**-$100.65**	**0%**
1860	Meters (Smart Meters)	$1,589,083.16	$74,433.66			$1,514,649.50	15.00	6.67%	**$100,976.63**	$100,976.64	**$0.01**	**0%**
1905	Land					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1908	Buildings & Fixtures					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1910	Leasehold Improvements					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1915	Office Furniture & Equipment (10 years)	$84,440.86		$5,301.10		$87,091.41	10.00	10.00%	**$8,709.14**	$8,639.72	**-$69.42**	**-1%**
1915	Office Furniture & Equipment (5 years)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equipment - Hardware	$211,051.10	$13,428.49	$56,041.71		$225,643.47	3.00	33.33%	**$75,214.49**	$69,755.01	**-$5,459.48**	**-8%**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1930	Transportation Equipment	$959,954.34	$30,643.43	$68,448.49		$963,535.16	8.00	12.50%	**$120,441.89**	$119,743.20	**-$698.69**	**-1%**
1935	Stores Equipment	$3,472.21				$3,472.21	10.00	10.00%	**$347.22**	$347.27	**$0.05**	**0%**
1940	Tools, Shop & Garage Equipment	$88,237.53	$12,398.51	$2,883.86		$77,280.95	10.00	10.00%	**$7,728.10**	$7,414.43	**-$313.66**	**-4%**
1945	Measurement & Testing Equipment	$36,372.91				$36,372.91	10.00	10.00%	**$3,637.29**	$2,732.80	**-$904.49**	**-33%**
1950	Power Operated Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communications Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communication Equipment (Smart Meters)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1960	Miscellaneous Equipment	$14,603.00				$14,603.00	10.00	10.00%	**$1,460.30**	$855.10	**-$605.20**	**-71%**
1970	Load Management Controls Customer Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1975	Load Management Controls Utility Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1980	System Supervisor Equipment	$133,750.73				$133,750.73	5.12	19.53%	**$26,123.19**	$25,601.67	**-$521.52**	**-2%**
1985	Miscellaneous Fixed Assets					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1990	Other Tangible Property					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1995	Contributions & Grants	-$2,015,879.22				-$2,015,879.22	28.34	3.53%	**-$71,122.63**	-$71,181.67	**-$59.04**	**0%**
2440	Deferred Revenue	-$1,861,782.42		-$343,377.00		-$2,033,470.92	40.00	2.50%	**-$50,836.77**	-$45,767.14	**$5,069.63**	**-11%**
2005	Property Under Finance Lease					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
	Total	**$23,611,674.29**	**$102,408.26**	**$1,851,818.64**	**$ 400,775**	**$24,034,400.12**	**$477.73**		**$1,054,713.54**	**$1,016,304.16**	**-$38,409.38**	**-4%**

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Table 29 - Depreciation Schedule 2024

Year 2024

Account	Description	Book Values				Service Lives		Depreciation Expense				
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1611	Computer Software (Formally known as Account 1925)	$347,195.44		$43,212.50		$368,801.69	3.00	33.33%	**$122,933.90**	$96,161.34	**-$26,772.56**	**-28%**
1612	Land Rights (Formally known as Account 1906)	$20,326.14				$20,326.14	8.00	12.50%	**$2,540.77**	$2,540.77	**$0.00**	**0%**
1805	Land	$258,350.32				$258,350.32		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1808	Buildings	$267,751.57				$267,751.57	38.96	2.57%	**$6,872.47**	$6,854.87	**-$17.60**	**0%**
1810	Leasehold Improvements	$357,021.14	-$78,408.41	$63,476.00		$467,167.55	25.00	4.00%	**$18,686.70**	$18,686.71	**$0.01**	**0%**
1815	Transformer Station Equipment >50 kV					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1820	Distribution Station Equipment <50 kV	$4,831,949.37		$44,590.17		$4,854,244.46	37.86	2.64%	**$128,222.56**	$128,205.25	**-$17.31**	**0%**
1825	Storage Battery Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1830	Poles, Towers & Fixtures	$4,394,620.64	$687,201.73	$281,375.39	$124,438.15	$3,723,668.46	34.69	2.88%	**$107,346.62**	$107,944.09	**$597.47**	**1%**
1835	Overhead Conductors & Devices	$5,729,423.73		$477,858.43	$61,678.59	$5,906,674.36	36.86	2.71%	**$160,246.18**	$161,897.66	**$1,651.47**	**1%**
1840	Underground Conduit	$1,050,834.34	$131,475.80	$7,550.40		$923,133.74	30.94	3.23%	**$29,836.26**	$18,158.88	**-$11,677.38**	**-64%**
1845	Underground Conductors & Devices	$1,766,539.68		$218,374.92		$1,875,727.14	35.40	2.82%	**$52,984.49**	$52,984.46	**-$0.03**	**0%**
1850	Line Transformers	$3,821,572.26		$527,006.47	$167,253.38	$3,917,822.12	33.22	3.01%	**$117,943.99**	$109,740.58	**-$8,203.41**	**-7%**
1855	Services (Overhead & Underground)	$2,378,169.36		$146,188.28		$2,451,263.50	33.99	2.94%	**$72,117.20**	$72,121.40	**$4.20**	**0%**
1860	Meters	$756,448.77		$136,318.79		$824,608.17	15.83	6.32%	**$52,091.48**	$51,940.64	**-$150.84**	**0%**
1860	Meters (Smart Meters)	$1,514,649.50	$301,134.17		$110,760.80	$1,102,754.53	15.00	6.67%	**$73,516.97**	$70,471.00	**-$3,045.97**	**-4%**
1905	Land					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1908	Buildings & Fixtures					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1910	Leasehold Improvements					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1915	Office Furniture & Equipment (10 years)	$89,741.96	$1,387.96	$10,157.50		$93,432.75	10.00	10.00%	**$9,343.28**	$9,176.44	**-$166.83**	**-2%**
1915	Office Furniture & Equipment (5 years)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equipment - Hardware	$253,664.32	$32,756.85	$10,396.78		$226,105.86	3.00	33.33%	**$75,368.62**	$48,964.16	**-$26,404.46**	**-54%**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1930	Transportation Equipment	$997,759.40	$11,179.46	$57,754.88		$1,015,457.38	8.00	12.50%	**$126,932.17**	$126,742.18	**-$189.99**	**0%**
1935	Stores Equipment	$3,472.21				$3,472.21	10.00	10.00%	**$347.22**	$347.27	**$0.05**	**0%**
1940	Tools, Shop & Garage Equipment	$78,722.88	$6,273.28	$17,683.69		$81,291.45	10.00	10.00%	**$8,129.14**	$6,130.29	**-$1,998.85**	**-33%**
1945	Measurement & Testing Equipment	$36,372.91	$18,090.00			$18,282.91	10.00	10.00%	**$1,828.29**	$1,828.30	**$0.01**	**0%**
1950	Power Operated Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communications Equipment			$614.95		$307.48	3.00	33.33%	**$102.49**	$102.49	**$0.00**	**0%**
1955	Communication Equipment (Smart Meters)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1960	Miscellaneous Equipment	$14,603.00	$12,104.00			$2,499.00	10.00	10.00%	**$249.90**	$249.90	**$0.00**	**0%**
1970	Load Management Controls Customer Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1975	Load Management Controls Utility Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1980	System Supervisor Equipment	$133,750.73	$3,247.00	$134,287.07		$197,647.27	6.22	16.08%	**$31,776.09**	$23,196.19	**-$8,579.90**	**-37%**
1985	Miscellaneous Fixed Assets					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1990	Other Tangible Property					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1995	Contributions & Grants	-$2,015,879.22				-$2,015,879.22	28.34	3.53%	**-$71,122.63**	-$71,181.67	**-$59.04**	**0%**
2440	Deferred Revenue	-$2,205,159.42		-$295,456.49		-$2,352,887.67	40.00	2.50%	**-$58,822.19**	-$51,050.42	**$7,771.77**	**-15%**
2005	Property Under Finance Lease					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
	Total	**$24,881,901.03**	**$1,126,441.84**	**$1,881,389.73**	**$ 464,131**	**$24,232,023.14**	**$487.31**		**$1,069,471.96**	**$992,212.78**	**-$77,259.18**	**-8%**

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Table 30 - Depreciation Schedule 2025

Year 2025

Account	Description	Book Values				Service Lives		Depreciation Expense				
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1611	Computer Software (Formally known as Account 1925)	$390,407.94	$155,162.06	$26,795.60		$248,643.68	3.00	33.33%	**$82,881.23**	$75,960.22	**-$6,921.01**	**-9%**
1612	Land Rights (Formally known as Account 1906)	$20,326.14				$20,326.14	8.00	12.50%	**$2,540.77**	$2,540.77	**$0.00**	**0%**
1805	Land	$258,350.32				$258,350.32		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1808	Buildings	$267,751.57		$26,331.76		$280,917.45	39.29	2.54%	**$7,149.11**	$7,147.45	**-$1.66**	**0%**
1810	Leasehold Improvements	$420,497.14	-$78,408.41	$23,648.05		$510,729.58	25.00	4.00%	**$20,429.18**	$20,429.19	**$0.01**	**0%**
1815	Transformer Station Equipment >50 kV					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1820	Distribution Station Equipment <50 kV	$4,876,539.54	$10,494.38	$361,339.63		$5,046,714.98	37.99	2.63%	**$132,859.72**	$132,852.28	**-$7.44**	**0%**
1825	Storage Battery Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1830	Poles, Towers & Fixtures	$4,551,557.88	$802,389.56	$317,269.54		$3,907,803.09	35.72	2.80%	**$109,400.98**	$109,402.75	**$1.77**	**0%**
1835	Overhead Conductors & Devices	$6,145,603.57	$184,813.53	$333,508.48		$6,127,544.28	38.54	2.59%	**$159,008.68**	$159,008.54	**-$0.14**	**0%**
1840	Underground Conduit	$1,051,672.29	$455,921.51	$12,103.72		$601,802.64	35.84	2.79%	**$16,790.06**	$16,803.67	**$13.61**	**0%**
1845	Underground Conductors & Devices	$1,876,274.63	-$102,175.30	$249,505.27		$2,103,202.57	35.91	2.79%	**$58,574.41**	$58,574.45	**$0.04**	**0%**
1850	Line Transformers	$4,181,325.35	$279,089.45	$723,553.26		$4,264,012.53	35.01	2.86%	**$121,798.31**	$121,818.32	**$20.01**	**0%**
1855	Services (Overhead & Underground)	$2,482,692.03	-$3,651.70	$218,969.53		$2,595,828.50	34.88	2.87%	**$74,421.69**	$74,421.26	**-$0.43**	**0%**
1860	Meters	$892,767.56		$110,233.47		$947,884.30	15.72	6.36%	**$60,297.98**	$60,140.60	**-$157.38**	**0%**
1860	Meters (Smart Meters)	$1,403,888.70	$402,228.61			$1,001,660.09	15.00	6.67%	**$66,777.34**	$39,183.98	**-$27,593.36**	**-70%**
1905	Land					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1908	Buildings & Fixtures					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1910	Leasehold Improvements					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1915	Office Furniture & Equipment (10 years)	$99,899.46	$4,724.96	$6,957.80		$98,653.40	10.00	10.00%	**$9,865.34**	$9,690.63	**-$174.71**	**-2%**
1915	Office Furniture & Equipment (5 years)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equipment - Hardware	$264,061.10	$191,183.61	$36,096.24		$90,925.61	3.00	33.33%	**$30,308.54**	$29,235.37	**-$1,073.17**	**-4%**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1930	Transportation Equipment	$1,055,514.28	$14,219.46	$128,260.48		$1,105,425.06	8.00	12.50%	**$138,178.13**	$110,931.03	**-$27,247.10**	**-25%**
1935	Stores Equipment	$3,472.21		$2,865.64		$4,905.03	10.00	10.00%	**$490.50**	$490.50	**$0.00**	**0%**
1940	Tools, Shop & Garage Equipment	$96,406.57	$46,250.68	$29,174.62		$64,743.20	10.00	10.00%	**$6,474.32**	$6,091.87	**-$382.45**	**-6%**
1945	Measurement & Testing Equipment	$36,372.91	$18,090.00			$18,282.91	10.00	10.00%	**$1,828.29**	$1,505.69	**-$322.60**	**-21%**
1950	Power Operated Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communications Equipment	$614.95				$614.95	3.00	33.33%	**$204.98**	$204.98	**$0.00**	**0%**
1955	Communication Equipment (Smart Meters)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1960	Miscellaneous Equipment	$14,603.00	$12,104.00			$2,499.00	10.00	10.00%	**$249.90**	$249.90	**$0.00**	**0%**
1970	Load Management Controls Customer Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1975	Load Management Controls Utility Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1980	System Supervisor Equipment	$268,037.80	$54,719.00	$106,329.00		$266,483.30	10.00	10.00%	**$26,648.33**	$26,648.33	**$0.00**	**0%**
1985	Miscellaneous Fixed Assets					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1990	Other Tangible Property					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1995	Contributions & Grants	-$2,015,879.22			-$36,657.95	-$1,979,221.27	28.41	3.52%	**-$69,656.31**	-$69,715.59	**-$59.28**	**0%**
2440	Deferred Revenue	-$2,500,615.91		-$318,289.48		-$2,659,760.65	40.00	2.50%	**-$66,494.02**	-$61,037.26	**$5,456.76**	**-9%**
2005	Property Under Finance Lease					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
	Total	**$26,142,141.81**	**$2,447,155.40**	**$2,394,652.61**	**-$ 36,658**	**$24,928,970.67**	**$502.31**		**$991,027.47**	**$932,578.93**	**-$58,448.54**	**-6%**

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Table 31 - Depreciation Schedule 2026

Year 2026

Account	Description	Book Values				Service Lives		Depreciation Expense				
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1611	Computer Software (Formally known as Account 1925)	$417,203.54	$196,688.06	$20,000.00		$230,515.48	3.00	33.33%	**$76,838.49**	$51,753.92	**-$25,084.57**	**-48%**
1612	Land Rights (Formally known as Account 1906)	$20,326.14		$20,000.00		$30,326.14	8.00	12.50%	**$3,790.77**	$3,790.77	**$0.00**	**0%**
1805	Land	$258,350.32		$150,000.00		$333,350.32		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1808	Buildings	$294,083.33				$294,083.33	39.52	2.53%	**$7,441.68**	$7,440.02	**-$1.66**	**0%**
1810	Leasehold Improvements	$444,145.19	-$78,408.41	$28,000.00		$536,553.60	25.00	4.00%	**$21,462.14**	$21,462.15	**$0.01**	**0%**
1815	Transformer Station Equipment >50 kV					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1820	Distribution Station Equipment <50 kV	$5,237,879.17	$20,608.80	$3,600.78		$5,219,070.76	38.10	2.62%	**$136,982.44**	$136,632.93	**-$349.51**	**0%**
1825	Storage Battery Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1830	Poles, Towers & Fixtures	$4,868,827.42	$960,562.86	$278,126.88		$4,047,328.00	36.90	2.71%	**$109,679.23**	$109,689.88	**$10.65**	**0%**
1835	Overhead Conductors & Devices	$6,479,112.05	$375,740.66	$630,771.75		$6,418,757.27	40.20	2.49%	**$159,686.35**	$159,686.47	**$0.12**	**0%**
1840	Underground Conduit	$1,063,776.01	$520,636.28	$7,167.35		$546,723.41	37.98	2.63%	**$14,394.20**	$14,413.78	**$19.58**	**0%**
1845	Underground Conductors & Devices	$2,125,779.90	-$102,175.30	$308,862.79		$2,382,386.60	36.34	2.75%	**$65,554.10**	$65,554.06	**-$0.04**	**0%**
1850	Line Transformers	$4,904,878.61	$351,800.15	$232,603.60		$4,669,380.26	35.89	2.79%	**$130,104.72**	$130,857.34	**$752.62**	**1%**
1855	Services (Overhead & Underground)	$2,701,661.56	$52,789.40	$174,398.15		$2,736,071.24	36.04	2.77%	**$75,925.67**	$75,925.60	**-$0.07**	**0%**
1860	Meters	$1,003,001.03		$143,373.96		$1,074,688.01	15.63	6.40%	**$68,764.19**	$68,574.30	**-$189.89**	**0%**
1860	Meters (Smart Meters)	$1,403,888.70	$1,230,028.18			$173,860.52	15.00	6.67%	**$11,590.70**	$8,871.66	**-$2,719.04**	**-31%**
1905	Land					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1908	Buildings & Fixtures					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1910	Leasehold Improvements					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1915	Office Furniture & Equipment (10 years)	$106,857.26	$8,219.36	$28,207.34		$112,741.57	10.00	10.00%	**$11,274.16**	$9,920.56	**-$1,353.60**	**-14%**
1915	Office Furniture & Equipment (5 years)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equipment - Hardware	$300,157.34	$197,622.61	$9,000.00		$107,034.73	3.00	33.33%	**$35,678.24**	$26,337.95	**-$9,340.29**	**-35%**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1930	Transportation Equipment	$1,183,774.76	$450,172.70	$608,565.75		$1,037,884.94	8.00	12.50%	**$129,735.62**	$127,798.33	**-$1,937.29**	**-2%**
1935	Stores Equipment	$6,337.85		$600.00		$6,637.85	10.00	10.00%	**$663.79**	$663.78	**-$0.01**	**0%**
1940	Tools, Shop & Garage Equipment	$125,581.19	$53,899.03	$38,881.18		$91,122.75	10.00	10.00%	**$9,112.28**	$8,411.89	**-$700.39**	**-8%**
1945	Measurement & Testing Equipment	$36,372.91	$24,542.30			$11,830.61	10.00	10.00%	**$1,183.06**	$1,183.07	**$0.01**	**0%**
1950	Power Operated Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communications Equipment	$614.95				$614.95	3.00	33.33%	**$204.98**	$204.98	**$0.00**	**0%**
1955	Communication Equipment (Smart Meters)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1960	Miscellaneous Equipment	$14,603.00	$12,104.00			$2,499.00	10.00	10.00%	**$249.90**	$249.90	**$0.00**	**0%**
1970	Load Management Controls Customer Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1975	Load Management Controls Utility Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1980	System Supervisor Equipment	$374,366.80	$54,719.00	$120,000.00		$379,647.80	10.00	10.00%	**$37,964.78**	$37,964.78	**$0.00**	**0%**
1985	Miscellaneous Fixed Assets					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1990	Other Tangible Property					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1995	Contributions & Grants	-$1,979,221.27	-$127,567.73			-$1,851,653.54	28.68	3.49%	**-$64,553.60**	-$64,612.73	**-$59.13**	**0%**
2440	Deferred Revenue	-$2,818,905.39		-$476,142.54		-$3,056,976.66	40.00	2.50%	**-$76,424.42**	-$73,966.16	**$2,458.26**	**-3%**
2005	Property Under Finance Lease					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
	Total	**$28,573,452.37**	**$4,201,981.95**	**$2,326,016.99**	**$ -**	**$25,534,478.92**	**$510.28**		**$967,303.47**	**$928,809.23**	**-$38,494.24**	**-4%**

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Table 32 - Depreciation Schedule 2027

Year 2027

Account	Description	Book Values				Service Lives		Depreciation Expense				
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1611	Computer Software (Formally known as Account 1925)	$437,203.54	$347,195.44	$15,000.00		$97,508.10	3.00	33.33%	**$32,502.70**	$25,300.63	**-$7,202.07**	**-28%**
1612	Land Rights (Formally known as Account 1906)	$40,326.14		$20,000.00		$50,326.14	8.00	12.50%	**$6,290.77**	$6,290.77	**$0.00**	**0%**
1805	Land	$408,350.32				$408,350.32		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1808	Buildings	$294,083.33		$15,000.00		$301,583.33	39.64	2.52%	**$7,608.35**	$7,590.02	**-$18.33**	**0%**
1810	Leasehold Improvements	$472,145.19	-$78,408.41	$39,800.00		$570,453.60	25.00	4.00%	**$22,818.14**	$22,818.06	**-$0.08**	**0%**
1815	Transformer Station Equipment >50 kV					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1820	Distribution Station Equipment <50 kV	$5,241,479.95	$68,679.24	$603,772.00		$5,474,686.71	38.40	2.60%	**$142,555.82**	$142,251.49	**-$304.33**	**0%**
1825	Storage Battery Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1830	Poles, Towers & Fixtures	$5,146,954.30	$1,062,650.43	$353,185.26		$4,260,896.50	37.84	2.64%	**$112,610.35**	$112,610.31	**-$0.04**	**0%**
1835	Overhead Conductors & Devices	$7,109,883.80	$671,633.04	$627,586.51		$6,752,044.02	42.54	2.35%	**$158,704.00**	$158,704.06	**$0.06**	**0%**
1840	Underground Conduit	$1,070,943.36	$538,964.20	$14,884.43		$539,421.38	38.86	2.57%	**$13,881.58**	$13,881.55	**-$0.03**	**0%**
1845	Underground Conductors & Devices	$2,434,642.69	-$72,049.78	$276,611.39		$2,644,998.17	36.91	2.71%	**$71,667.43**	$71,667.40	**-$0.03**	**0%**
1850	Line Transformers	$5,137,482.21	$433,778.22	$276,843.24		$4,842,125.61	36.15	2.77%	**$133,930.56**	$133,930.58	**$0.02**	**0%**
1855	Services (Overhead & Underground)	$2,876,059.71	$117,723.30	$178,985.91		$2,847,829.37	37.34	2.68%	**$76,273.24**	$76,273.32	**$0.08**	**0%**
1860	Meters	$1,146,374.99		$141,538.46		$1,217,144.22	15.55	6.43%	**$78,261.36**	$78,041.37	**-$219.99**	**0%**
1860	Meters (Smart Meters)	$1,403,888.70	$1,311,599.09			$92,289.61	15.00	6.67%	**$6,152.64**	$4,351.27	**-$1,801.37**	**-41%**
1905	Land					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1908	Buildings & Fixtures					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1910	Leasehold Improvements					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1915	Office Furniture & Equipment (10 years)	$135,064.60	$35,291.45	$5,000.00		$102,273.15	10.00	10.00%	**$10,227.32**	$10,007.38	**-$219.94**	**-2%**
1915	Office Furniture & Equipment (5 years)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equipment - Hardware	$309,157.34	$253,664.32	$12,800.00		$61,893.02	3.00	33.33%	**$20,631.01**	$18,898.21	**-$1,732.80**	**-9%**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1930	Transportation Equipment	$1,792,340.51	$481,169.93	$650,422.00		$1,636,381.58	8.00	12.50%	**$204,547.70**	$180,111.12	**-$24,436.58**	**-14%**
1935	Stores Equipment	$6,937.85		$3,764.20		$8,819.95	10.00	10.00%	**$882.00**	$881.99	**-$0.01**	**0%**
1940	Tools, Shop & Garage Equipment	$164,462.37	$67,905.98	$13,709.00		$103,410.89	10.00	10.00%	**$10,341.09**	$10,173.33	**-$167.76**	**-2%**
1945	Measurement & Testing Equipment	$36,372.91	$24,542.30	$15,318.15		$19,489.69	10.00	10.00%	**$1,948.97**	$1,899.03	**-$49.94**	**-3%**
1950	Power Operated Equipment					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1955	Communications Equipment	$614.95		$4,400.00		$2,814.95	3.00	33.33%	**$938.32**	$835.83	**-$102.49**	**-12%**
1955	Communication Equipment (Smart Meters)					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1960	Miscellaneous Equipment	$14,603.00	$12,104.00			$2,499.00	10.00	10.00%	**$249.90**	$249.90	**$0.00**	**0%**
1970	Load Management Controls Customer Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1975	Load Management Controls Utility Premises					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1980	System Supervisor Equipment	$494,366.80	$54,719.00	$130,000.00		$504,647.80	10.00	10.00%	**$50,464.78**	$50,464.78	**$0.00**	**0%**
1985	Miscellaneous Fixed Assets					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1990	Other Tangible Property					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
1995	Contributions & Grants	-$1,979,221.27	-$150,392.30			-$1,828,828.97	28.74	3.48%	**-$63,640.66**	-$63,699.65	**-$58.99**	**0%**
2440	Deferred Revenue	-$3,295,047.93		-$484,007.84		-$3,537,051.85	40.00	2.50%	**-$88,426.30**	-$85,968.04	**$2,458.26**	**-3%**
2005	Property Under Finance Lease					$0.00		0.00%	**$0.00**	$0.00	**$0.00**	**0%**
	Total	**$30,899,469.36**	**$5,180,769.45**	**$2,914,612.71**	**$ -**	**$27,176,006.27**	**$516.97**		**$1,011,421.06**	**$977,564.71**	**-$33,856.35**	**-3%**

2

2.3.3 DEPRECIATION EXPENSE ASSOCIATED WITH RETIREMENT OBLIGATION

ORPC does not have any asset retirement obligations (AROs) or any associated depreciation or accretion expenses related to an asset retirement obligation.

2.3.4 ADOPTION OF THE HALF YEAR RULE

ORPC confirms that it has applied the half-year rule for the purposes of computing the Net Book Value of Property, Plant and Equipment and General Plant to include in rate base. Under the half-year rule acquisitions and investments made during the year are amortized assuming they entered service at the mid-point of the year.

2.3.5 DEPRECIATION POLICY

Depreciation of PP&E is recorded in the statement of income and comprehensive income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and amortization methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

The estimated useful lives utilized in its General Policy for Capitalization and Depreciation can be found in section 2.8.3.

2.4 ALLOWANCE FOR WORKING CAPITAL

2.4.1 DERIVATION OF WORKING CAPITAL

ORPC has used the 7.5% Allowance Approach for the purpose of calculating its Allowance for Working Capital. This was done in accordance with the letter issued by the Board in December 2025, for a rate of 7.5% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). ORPC confirms that the Cost of Power is determined by the split between RPP and non-RPP customers based on actual data, using the most current RPP price and using current UTR. The Ontario Energy Rebate of 23.5% is applied to reduce the cost of power of RPP customers. Table 2 – Rate Base Trend above shows ORPC's calculations in determining its Allowance for Working Capital.

2.4.2 LEAD LAG STUDY

ORPC is not proposing to use a lead lag study to determine its Working Capital Allowance and has chosen to follow the Board's June 3, 2015 letter which provided two options for the calculation of the allowance for working capital:

(1) The 7.5% allowance approach; or

(2) The filing of a lead/lag study.

ORPC notes that it has not previously been directed by the Board to undertake a lead/lag study.

2.4.3 CALCULATION OF COST OF POWER

ORPC calculated the cost of power for the 2026 Bridge Year and the 2027 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's "Regulated Price Plan - Price Report November 1, 2025 to October 31, 2026". Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, ORPC will update the electricity prices in the forecast. The global adjustment rate is adjusted by the share of electricity purchased from Evolugen. Based on a 5-year average of the share of total ORPC purchased from Evolugen, 19.2% of the global adjustment rate is reduced by 50%.

The sale of energy is a flow through revenue, and the cost of power is a flow through expense. Energy sales and the cost of power expense are presented in the table below. ORPC records no profit or loss resulting from the flow through energy revenues and expenses. Any temporary variances are included in the RSVA account balances.

The components of ORPC's cost of power are summarized in the table below:

Table 33 - Summary of Cost of Power 2027

2027 Test Year - Cop	**Cop**
4705 -Power Purchased	$19,929,768
4707- Global Adjustment	$3,581,326
4708-Charges-WMS	$1,063,911
4714-Charges-NW	$2,208,130
4716-Charges-CN	$1,792,429
4750-Charges-LV	$772,790
4751-IESO SME	$59,808
Misc A/R or A/P	$(4,609,649)
TOTAL	**$24,798,513**

The details of ORPC's components of cost of power are provided below:

Commodity:

The Commodity share of the Cost of Power is calculated in the same manner as has been previously approved by the OEB in ORPC's previous Cost of Service application as well as other applications. The utility used the commodity prices as published in the Board's "Regulated Price Plan - Price Report November 1, 2025, to October 31, 2026". The global adjustment rate is adjusted downward based on a 5-year average of the share of total ORPC purchased from Evolugen. Compared to the $59.81/MWh rate for global adjustment in the RPP report, the weighted average rate used in the cost of power calculation is $54.07/MWh ($59.81 x 80.8% + $59.81 x 50% x 19.2%).

Table 34 - Calculation of Commodity

Electricity Commodity	Units	2027 Test Year Volume	RPP Rate	RPP $	2027 Test Year Volume	non-RPP Rate	non-RPP $	Total $
Class per Load Forecast								
Residential	kWh	97,420,060		11,901,637	805,628		46,332	
GS < 50	kWh	26,142,603		3,193,796	5,857,960		336,891	
GS > 50	kWh	5,701,820		696,581	62,942,538		3,619,825	
Street Light	kWh	55,296		6,755	1,020,317		58,678	
Sentinel Light	kWh	137,506		16,799	21,010		1,208	
USL	kWh	229,617		28,052	403,621		23,212	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
SUB-TOTAL				15,843,621			4,086,147	$ 19,929,768

Global Adjustment non-RPP	Units	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential - Class B	kWh			0			43,559	
GS < 50 - Class B	kWh			0			316,730	
GS > 50 - Class B	kWh			0			2,862,939	
Street Light - Class B	kWh			0			55,167	
Sentinel Light - Class B	kWh			0			1,136	
USL - Class B	kWh			0			21,823	
				0			-	
				0			-	
				0			-	
				0			-	
				0			-	
1 - Class A				0			124,867	
2 - Class A				0			155,106	
				0			-	
				0			-	
				0			-	
SUB-TOTAL				0			3,581,326	$ 3,581,326

Table 35 - 2027 Forecasted Commodity Prices

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		**non-RPP**	**RPP**
Day Ahead Market Ontario Zonal Price (DAM OZP) and Load Forecast Deviation Adjustment (LFDA) ($/MWh)	Load-Weighted Price for RPP Consumers		$57.51	$57.51
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$54.07	$54.07
Adjustments ($/MWh)				$10.59
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$122.17**

The utility uses the split between the RPP and Non-RPP to determine the weighted average price. The weighted average price is applied to the projected 2027 Load Forecast to determine the commodity to be included in the Cost of Power. The commodity cost for 2027 is projected at $19,929,768.

Transmission Network:

The Transmission Network charges are calculated in the OEB's RTSR model. The rates are applied to the 2027 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application. The Transmission Network charges included in the Cost of Power for 2027 are projected at $2,208,130.

Table 36 - Transmission Network

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	97,420,060	0.0109	1,066,641	805,628	0.0109	8,821	
GS < 50	kWh	26,142,603	0.0098	257,320	5,857,960	0.0098	57,660	
GS > 50	kW	16,287	4.0871	66,569	179,797	4.0871	734,856	
Street Light	kW	146	3.0825	450	2,691	3.0825	8,296	
Sentinel Light	kW	360	3.0977	1,115	55	3.0977	170	
USL	kWh	229,617	0.0098	2,260	403,621	0.0098	3,973	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				1,394,354			813,776	2,208,130

Transmission Connection:

The Transmission Connection charges are also calculated in the OEB's RTSR model. The rates are applied to the 2027 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application. The Transmission Connection charges included in the Cost of Power for 2027 are projected at $1,792,429.

Table 37 - Transmission Connection

Transmission - Connection								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	97,420,060	0.0090	880,880	805,628	0.0090	7,285	
GS < 50	kWh	26,142,603	0.0080	209,790	5,857,960	0.0080	47,009	
GS > 50	kW	16,287	3.2345	52,681	179,797	3.2345	581,548	
Street Light	kW	146	2.5008	365	2,691	2.5008	6,731	
Sentinel Light	kW	360	2.5535	919	55	2.5535	140	
USL	kWh	229,617	0.0080	1,843	403,621	0.0080	3,239	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				1,146,477			645,951	1,792,429

Wholesale Market Services (WMS) & Capacity Based Recovery (CBR):

On December 11, 2025, the OEB released Decision and Order (EB-2025-0299) for the Wholesale Market Service (WMS) and Capacity Based Recovery (CBR) effective January 1, 2026. The Board's decision is summarized as follows:

- The WMS rate used by rate-regulated distributors to bill their customers shall be $0.0041 per kilowatt-hour, effective January 1, 2026. For Class B customers, a CBR component of $0.0006 per kilowatt-hour shall be added to the WMS rate for a total of $0.0047 per kilowatt-hour. For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to peak.

In compliance with this order, ORPC has applied the Board Approved $0.0047/kWh to its 2027 Load Forecast to include $943,469 in its Cost of Power.

Table 38 - Wholesale Market

Wholesale Market Service								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	97,420,060	0.0041	399,422	805,628	0.0041	3,303	
GS < 50	kWh	26,142,603	0.0041	107,185	5,857,960	0.0041	24,018	
GS > 50	kWh	5,701,820	0.0041	23,377	62,942,538	0.0041	258,064	
Street Light	kWh	55,296	0.0041	227	1,020,317	0.0041	4,183	
Sentinel Light	kWh	137,506	0.0041	564	21,010	0.0041	86	
USL	kWh	229,617	0.0041	941	403,621	0.0041	1,655	
		-		-	-		-	
		-		-	-		-	
		-		-	-		-	
		-		-	-		-	
		-		-	-		-	
SUB-TOTAL				531,716			291,309	823,026

Class B CBR								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	97,420,060	0.0006	58,452	805,628	0.0006	483	
GS < 50	kWh	26,142,603	0.0006	15,686	5,857,960	0.0006	3,515	
GS > 50	kWh	5,701,820	0.0006	3,421	62,942,538	0.0006	37,766	
Street Light	kWh	55,296	0.0006	33	1,020,317	0.0006	612	
Sentinel Light	kWh	137,506	0.0006	83	21,010	0.0006	13	
USL	kWh	229,617	0.0006	138	403,621	0.0006	242	
		-		-			-	
		-		-			-	
		-		-			-	
		-		-			-	
		-		-			-	
SUB-TOTAL				77,812			42,631	120,443

Rural or Remote Electricity Rate Protection:

On December 11, 2025, the OEB released EB-2025-0299 Decision and Order for the Rural or Remote Electricity Rate Protection (RRRP) effective January 1, 2026. The Board's decision is summarized as follows:

- The IESO's RRRP charge to rate-regulated distributors shall be $0.0006 per kilowatt-hour for electricity consumed on or after January 1, 2026

In compliance with this order, ORPC has applied the Board Approved $0.0006/kWh to its 2027 Load Forecast to include $120,443 in its Cost of Power.

Table 39 - Rural or Remote Electricity Rate Protection

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	97,420,060	0.0006	58,452	805,628	0.0006	483	
GS < 50	kWh	26,142,603	0.0006	15,686	5,857,960	0.0006	3,515	
GS > 50	kWh	5,701,820	0.0006	3,421	62,942,538	0.0006	37,766	
Street Light	kWh	55,296	0.0006	33	1,020,317	0.0006	612	
Sentinel Light	kWh	137,506	0.0006	83	21,010	0.0006	13	
USL	kWh	229,617	0.0006	138	403,621	0.0006	242	
		-		-	-		-	
		-		-	-		-	
		-		-	-		-	
		-		-	-		-	
		-		-	-		-	
SUB-TOTAL				77,812			42,631	120,443

Smart Meter Entity Charge:

On September 8, 2022, the Ontario Energy Board (OEB) approved the application by the Independent Electricity System Operator (IESO), in its' capacity as the Smart Metering Entity (SME), for a smart metering charge (SMC) for the 2023-2027 period, for a new SMC of $0.42 per smart meter (Residential and General Service <50 kW) per month.

In compliance with this order, ORPC has applied the Board Approved rate of $0.42 per month for the forecasted Residential and General Service<50kW customers for Test Year 2027 and included the projected amount of $59,808 in its' Cost of Power as illustrated below:

Table 40 - Smart Meter Entity

Smart Meter Entity Charge								
Class per Load Forecast		Customers/Connections	Rate	$	Customers/Connections	Rate	$	Total
Residential		10,513	0.42	52,983	87	0.42	438	
GS < 50		1,035	0.42	5,217	232	0.42	1,169	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				58,201			1,607	59,808

Low Voltage Charge:

The table below presents the derivation of proposed retail rates for Low Voltage ("LV") service. The projections were allocated to customer classes, according to each class' share of projected Transmission-Connection revenue, in accordance with Board policy. The resulting allocated LV charges for each class were divided by the applicable 2025 volumes from the load forecast, as presented in Exhibit 3. Current LV revenues are recovered through a separate rate adder and therefore are not embedded within the approved Distribution Volumetric rate. 2027 LV rates appear on a distinct line item on the proposed schedule of rates. The Low Voltage charges included in the Cost of Power for 2027 are projected at $772,790.

Table 41 - Low Voltage Charges

Low Voltage - No TLF adjustment								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	92,070,749	0.0040	372,037	761,391	0.0040	3,077	
GS < 50	kWh	24,707,119	0.0036	88,604	5,536,301	0.0036	19,854	
GS > 50	kW	16,287	1.4454	23,542	179,797	1.4454	259,885	
Street Light	kW	146	1.1176	163	2,691	1.1176	3,008	
Sentinel Light	kW	360	1.1411	411	55	1.1411	63	
USL	kWh	217,009	0.0036	778	381,458	0.0036	1,368	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				485,535			287,254	772,790

2.5 DISTRIBUTION SYSTEM PLAN

ORPC has filed its' 2027 Distribution System Plan as a separate document as Appendix 2A.

2.6 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

ORPC is not proposing any special or different approach to funding its capital expenditure in this rate application.

2.7 ICM AND ACM ADDITIONS TO RATE BASE

ORPC does not have any previously approved ICM or ACM projects to add to its rate base, other than to correct the inadvertent omission of its previously approved ICM project from its 2022 rate base as described in section 2.1.3 of this exhibit.

ORPC is not requesting an ACM as part of this Cost of Service application, as it has not yet identified any projects within the DSP the details of which are sufficiently developed to warrant ACM consideration at this time. However, ORPC may seek ICM treatment during the IRM period for qualifying investments if and when those investments become sufficiently developed to allow ORPC to present them to the OEB for approval. To that end, ORPC notes the following non-exhaustive list of investments that may be submitted for ICM treatment in a future proceeding:

a) the replacement of a double-bucket truck in 2029, as detailed in *Appendix 2A – 2027 Distribution System Plan, Appendix A5 – Small and Large Vehicles and Trailers*;
b) a 44kV system renewal project at one of ORPC's substations, as detailed at *Appendix 2A – 2027 Distribution System Plan, Appendix A3 – Substation Equipment – Transformers, Switchgear and 44kV Renewal*; and
c) investments that may be required to address emerging system capacity constraints as a result of customer and load growth, as noted in *Exhibit 1, Appendix 1G – Business, Section 7.3 System Capacity*.

If and when the need for and scope of an ICM eligible project becomes sufficiently developed, ORPC will file for ICM approval as required. ORPC believes that this is in accordance with the OEB's filing requirements, which recognizes that capital projects not anticipated at the time of the DSP or for which cost forecasts are not sufficiently robust may still qualify for ICM treatment, and that such projects may be proposed for ICM treatment in a subsequent Price Cap IR application to be thoroughly tested at that time.

2.8 CAPITALIZATION

2.8.1 ACCOUNTING STANDARD

ORPC utilized Modified International Financial Reporting Standards (MIFRS) in the preparation of this application. Property, plant and equipment ("PP&E") are recognized at cost less accumulated depreciation and any accumulated impairment losses. Cost includes the purchase price and directly attributable cost of acquisition or construction required to bring the asset to the location and condition necessary to be capable of operating in the manner intended by the Corporation, including eligible borrowing costs.

2.8.2 PLANNING

ORPC's distribution system strategy is the set of policies, rules, guidelines and objectives that the LDC utilizes to transition its current system into its desired future system. The strategy, as

described in the 2027-2031 Distribution System Plan provides the rationale for the capital expenditures and supporting activities planned for the investment period.

As part of this Cost of Service application process, ORPC retained the services of BBA Consultants and Rockwood Engineering, independent power sector consulting firms, to perform Asset Condition Assessments (ACA) of the fixed assets employed on ORPC's distribution system. These studies have assisted the LDC in reaffirming its asset replacement methodology and processes as well as identifying data gaps.

The ACA reports evaluate the risk of an assets' failure in service by considering all available information, including age, operating conditions, results of visual inspections and non-destructive testing and identifies the assets in poor condition that present unacceptably high risk of failure in service.

The ACA reports are included within ORPC's 2027 Distribution System Plan which has been filed at Appendix 2A.

ORPC has relied on BBA Consultants and Rockwood Engineering, who in turn were informed by the OEB's Chapter 5 filing requirements to guide their presentation of its policies, practices, and decision-making processes.

BBA Consultants and Rockwood Engineering work included interviews with ORPC subject matter experts to define the Health Indices appropriate for the asset types, review and consolidation of the client's data sets, analysis of ORPC's asset records to calculate the Health Index values, and

preparation of the final document. In total BBA Consultants assessed and calculated Health Index ("HI") values for the following asset classes:

- Poles
- Overhead Conductors
- Underground Cables
- Distribution Transformers
- Distribution Overhead Switches

All asset condition data used in the study are maintained by ORPC as part of its regular asset management practices.

2.8.3 CAPITALIZATION POLICY

ORPC's capitalization policy has not changed since its last Cost of Service application in 2022. All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits. The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. ORPC only capitalizes interest on assets under construction while the construction is in progress.

ORPC's adherence to the capitalization policy is as follows:

CAPITALIZATION POLICY UNDER IFRS

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably

The cost of an item of PP&E includes any costs that are directly attributable to the cost of acquisition or construction in order to bring the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. All costs are documented, recorded historically, including methods and sources used to establish any estimated costs and are reviewed at the end of each annual reporting period.

Directly attributable

The term "directly attributable" is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the assets more capable of being used than if the cost had not been incurred.

General Policy for Capitalization and Depreciation

ORPC's capital assets, and their designated service life, are categorized as follows as per Appendix 2-BB:

Table 42 - Asset Service Life

USoA Account Number	USoA Account Description	Typical Service life
1611	Computer Software	3
1805	Land	N/A
1810	Leasehold Improvements	25
1820	Distributions Station Equipment <50kV	40
1830	Poles, Towers & Fixtures	45
1835	Overhead Conductors & Devices	40, 45 or 60
1840	Underground Conduit	50
1845	Underground Conduit & Devices	40
1850	Line Transformers	40
1855	Services (Overhead & Underground)	60
1860	Meters	15
1915	Office Furniture & Equipment	10
1920	Computer Equipment - Hardware	3
1930	Transportation Equipment	8
1935	Stores Equipment	10
1940	Tools, Shop & Garage Equipment	10
1945	Measurement & Testing Equipment	10
1955	Communications Equipment	5
1960	Miscellaneous Equipment	10
1980	System Supervisor Equipment	10

All ORPC service lives are within the Kinectric report ranges.

In addition to the direct cost, ORPC applies labour and vehicle burdens for these direct costs. These burden costs are described further below. ORPC typically doesn't capitalize items below $500.

Accounts 1805 to 1860 – Land, Leasehold Improvements, Distribution Station Equipment, Poles, OH Conductors, UG Conduit, UG Conductors and Devices, Services, Transformers and Meters

The capitalized expenditures for these accounts include:

- Material and supplies direct costs
- Labour direct cost
- Labour burden
- Vehicle and equipment burden

Material and supplies direct costs

The material and supplies direct cost is comprised of all the eligible material that is used on a capital project, including its freight to destination. No storage, stockroom expenses or administrative charges are added.

Labour Direct Cost

The labour direct cost consists of all the eligible salaries for staff and supervisors on a capital project.

Labour Burden

The Labour Burden is comprised of employee benefits including:

- Employment Insurance Premiums (Employer portion)
- Canada Pension Plan Premiums (Employer portion)
- Employer Health Tax Premiums
- OMERS (Employer portion)
- Medical and Health Benefits
- Life Insurance
- WSIB
- Vacations
- Statutory Holidays

ORPC's labour burden totals 45% of direct labour costs and is automatically calculated through the accounting software on each hour.

Vehicle and Equipment Burden

A vehicle burden rate is calculated for each class of vehicle based on the budgeted costs of operating each vehicle and the budgeted hours of usage for each class. The hourly rate is based on an average of the total vehicle expenses divided by vehicle usage hours. This hourly rate is allocated to capital based on the time that the vehicle is used on the job-site, thus establishing the fact that the use of the vehicle is directly attributable to an item of PP&E. The expenses below are included in the operating costs:

- Depreciation
- Vehicle Maintenance
- Fuel
- Insurance
- Licences and Permits

Accounts 1611 and 1915 to 1980 – Office Furniture, Computer Software and Hardware, Vehicles, Tools and Other Equipment

Labour and labour burdens are not capitalized for general assets. The total invoice or contract price is used, including its freight to destination. No storage, stockroom expenses or administrative charges are added. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not capitalized.

ASSET RETIREMENT POLICY

ORPC generally retires capital assets from its balance sheet when the asset is no longer in service. When an item is disposed, any gain or loss is recognized in full in the statement of income and comprehensive of income.

The table below illustrates ORPC's depreciable rates by asset class.

Table 43 - Depreciation Rates Service Life Comparison Table F-1 from Kinectrics Report

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
				Steel	30	70	95	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures	60	2%	60	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
				Steel	30	70	95	1830	Poles, Towers and Fixtures	60	2%	60	2%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80	1830	Poles, Towers and Fixtures	60	2%	60	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
				Steel	30	70	95	1830	Poles, Towers and Fixtures	60	2%	60	2%	No	No
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	45	2%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25	1835	Overhead Conductors & Devices	25	4%	25	4%	No	No
	6	OH Line Switch RTU			15	20	20	1835	Overhead Conductors & Devices	20	5%	20	5%	No	No
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors & Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	60	2%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40	N/A							
	11	Reclosers			25	40	55	N/A							
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Line Transformers	40	3%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40	1820	Distribution Station Equipment	40	3%	40	3%	No	No
	15	Station DC System	Overall		10	20	30	1820	Distribution Station Equipment	20	5%	20	5%	No	No
			Battery Bank		10	15	15	1820	Distribution Station Equipment	15	7%	15	7%	No	No
			Charger		20	20	30	1820	Distribution Station Equipment	20	5%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment	45	2%	45	2%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment	50	2%	50	2%	No	No
	19	Electromechanical Relays			25	35	50	1820	Distribution Station Equipment	35	3%	35	3%	No	No
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment	30	3%	30	3%	No	No
	21	Digital & Numeric Relays			15	20	20	1820	Distribution Station Equipment	20	5%	20	5%	No	No
	22	Rigid Busbars			30	55	60	1820	Distribution Station Equipment	55	2%	55	2%	No	No
	23	Steel Structure			35	50	90	1820	Distribution Station Equipment	50	2%	50	2%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	N/A							
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25	1845	Underground Conductors & Devices	25	4%	25	4%	No	No
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30	1845	Underground Conductors & Devices	25	4%	25	4%	No	No
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductors & Devices	25	4%	25	4%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1855	Services	35	3%	35	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1855	Services	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	35	3%	35	3%	No	No
	36	UG Foundation			35	55	70	1840	Underground Conduit	55	2%	55	2%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50	1845	Underground Conductors & Devices	35	3%	35	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	30	3%	30	3%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	50	2%	50	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80	1840	Underground Conduit	55	2%	55	2%	No	No
	42	Cable Chambers			50	60	80	1840	Underground Conduit	60	2%	60	2%	No	No
S	43	Remote SCADA			15	20	30								

Table 44 - Table F-2 from Kinectrics Report

#	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture & Equipment	8	13%	8	13%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	12	8%	12	8%	No	No
		Trailers	5	20	1930	Transportation Equipment	10	10%	10	10%	No	No
		Vans	5	10	1930	Transportation Equipment	5	20%	5	20%	No	No
3	Administrative Buildings		50	75	200/201	Building & Fixtures	60	2%	60	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1808	Building & Fixtures	60	2%	60	2%	No	No
		Parking	25	30	1808	Building & Fixtures	25	4%	25	4%	No	No
		Fence	25	60	1808	Building & Fixtures	25	4%	25	4%	No	No
		Roof	20	30	1808	Building & Fixtures	25	4%	25	4%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5	1925	Computer Equipment - Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	8	13%	8	13%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shops Garage Equipment	8	13%	8	13%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	8	13%	8	13%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters - Mechanical	25	4%	25	4%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Industrial/Commercial Energy Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Wholesale Energy Meters	15	7%	15	7%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Current & Potential Transformer (CT & PT	40	3%	40	3%	No	No
13	Smart Meters		5	15	1860	Smart Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15	1860	Repeaters - Smart Metering	15	7%	15	7%	No	No
15	Data Collectors - Smart Metering		15	20	1860	Data Collectors - Smart Metering	15	7%	15	7%	No	No

2.8.4 OVERHEAD COSTS

Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not capitalized. ORPC does capitalize employee benefit costs directly attributed to an employee's wage. Additionally, ORPC did not historically capitalize engineering and mapping as it often couldn't determine if a project were to proceed in the same year as the engineering and mapping performed. ORPC developed a calculation in 2024 to capture the engineering and mapping that was performed on the project and previously included in O&M in order to capture all costs associated with the project.

2.8.5 BURDEN RATES

The calculation of burdens related to capitalization and how the burden was derived is identified in section 2.8.3.

2.9 COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

ORPC attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its' capital costs or in its Distribution System Plan. Additionally, ORPC has not included any costs for supporting IESO programs funded under the eDSM Framework in its revenue requirement. As such, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement are not applicable in this case.

ORPC is not considering incremental conservation initiatives to defer or avoid future infrastructure projects as part of distribution system planning processes nor is it planning on applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs, etc.

2.10 APPENDICES

Appendix 2A	2027 Distribution System Plan

2.10.1 APPENDIX 2A – 2027 DISTRIBUTION SYSTEM PLAN

Ottawa River Power

Distribution System Plan

2027 - 2031 Cost of Service Application

Historical Period:

2022 – 2025

Bridge Year:

2026

Forecast Period:

2027 – 2031

August 2026

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Appendix E	Greater Ottawa Region Needs Assessment
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LIST OF ACRONYMS

Acronym	Meaning
ORPC	Ottawa River Power Corporation
DSP	Distribution System Plan
ACA	Asset Condition Assessment
AM	Asset Management
AMI	Advanced Metering Infrastructure
APUL	Assets Past Useful Life
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CC&B	Customer Care & Billing
CDM	Conservation Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
CIA	Connection Impact Assessment
CMI	Customer Minutes of Interruption
DER	Distribution Energy Resource
DOE	Department of Energy
DSC	Distribution System Code
EOL	End of Life
ESA	Electrical Safety Authority
GIS	Geographical Information System
GS	General Service
HCI	Hydroelectric Contract Initiative
HI	Health Index
HONI	Hydro One Networks Inc.
ICE	Interruption Cost Estimate
IESO	Independent Electricity System Operator
IRRP	*Integrated Regional Resource Plan*
IT	*Information Technology*
LDC	*Local Distribution Company*
LOS	Loss of Supply
MDM	Meter Data Management
MED	Major Event Day
MS	Municipal Station
NA	Needs Assessment
OEB	Ontario Energy Board
OH	Overhead
O&M	Operations & Maintenance
REG	Renewable Energy Generation
RESOP	Renewable Energy Standard Offer Program
RIP	Regional Infrastructure Plan
RRFE	Renewed Regulatory Framework for Electricity Distributors
RTU	Remote Terminal Units
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SREP	Smart Grid Renewables and Electrification Pathways Program
TS	Transformer Station
TSC	Transmission System Code
TUL	Typical Useful Life
UG	Underground
VASH	Vulnerability Assessment and System Hardening
XLPE	Cross-Linked Polyethylene

5.2 DISTRIBUTION SYSTEM PLAN

Ottawa River Power Corporation (ORPC) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) Chapter 5 – Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, dated 16 December 2025 (the "Filing Requirements") as part of its 2026 Cost of Service Application (the Application).

The DSP is a stand-alone document that is filed in support of ORPC's Application. The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. The DSP covers the historical period of 2022 to 2026, with 2026 being the bridge year, and a forecast period of 2027 to 2031, with 2027 being the Test Year.

The DSP contents are organized into three major sections:

- Section 5.2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement.
- Section 5.3 provides an overview of asset management practices, including an overview of the assets managed and asset lifecycle optimization policies and practices.
- Section 5.4 provides a summary of the capital expenditure plan, including a variance analysis of historical expenditures, an analysis of forecast expenditures, and justification of material projects above the materiality threshold.

The materiality threshold for Ottawa River Power Corporation is $50,000 and detailed descriptions of specific projects/programs exceeding the materiality threshold are provided in Section 5.4.1.1 and Appendix A. Other pertinent information relevant to this DSP is included in the Appendices.

This DSP follows the chapter and section headings in accordance with the Chapter 5 Filing Requirements.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

Ottawa River Power Corporation ("ORPC") has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") Chapter 5 Consolidated Distribution System Plan Filing Requirements dated 16 December 2025 ("the Filing Requirements") as part of its 2026 Cost of Service Application (the Application). ORPC retained BBA Consultants to advise on and assist with the preparation of this DSP.

5.2.1.1 Description of the Utility Company

ORPC is an electricity distributor licensed by the OEB. ORPC provides electricity distribution services in the City of Pembroke, the former Village of Beachburg (in the Whitewater Region), the former Village of Killaloe (in the Renfrew County), and the former Town of Almonte (in the Town of Mississippi Mills), serving approximately 11,800 customers.

ORPC is incorporated under the Ontario Business Corporations Act. ORPC is owned by the Corporation of City of Pembroke, the Corporation of the Township of Whitewater Region, and the Corporation of the Township of Killaloe, Hagarty and Richards, and the Corporation of the Municipality of Mississippi Mills.

ORPC receives power from Hydro One Networks Inc. ("HONI") and delivers electricity to its customers. ORPC is responsible for maintaining distribution and infrastructure assets deployed over 35 square kilometers (including 12 municipal substations, 490 kilometers of overhead and underground lines) within its service areas, as shown in Figure 5.2-1, Figure 5.2-2, Figure 5.2-3, and Figure 5.2-4.

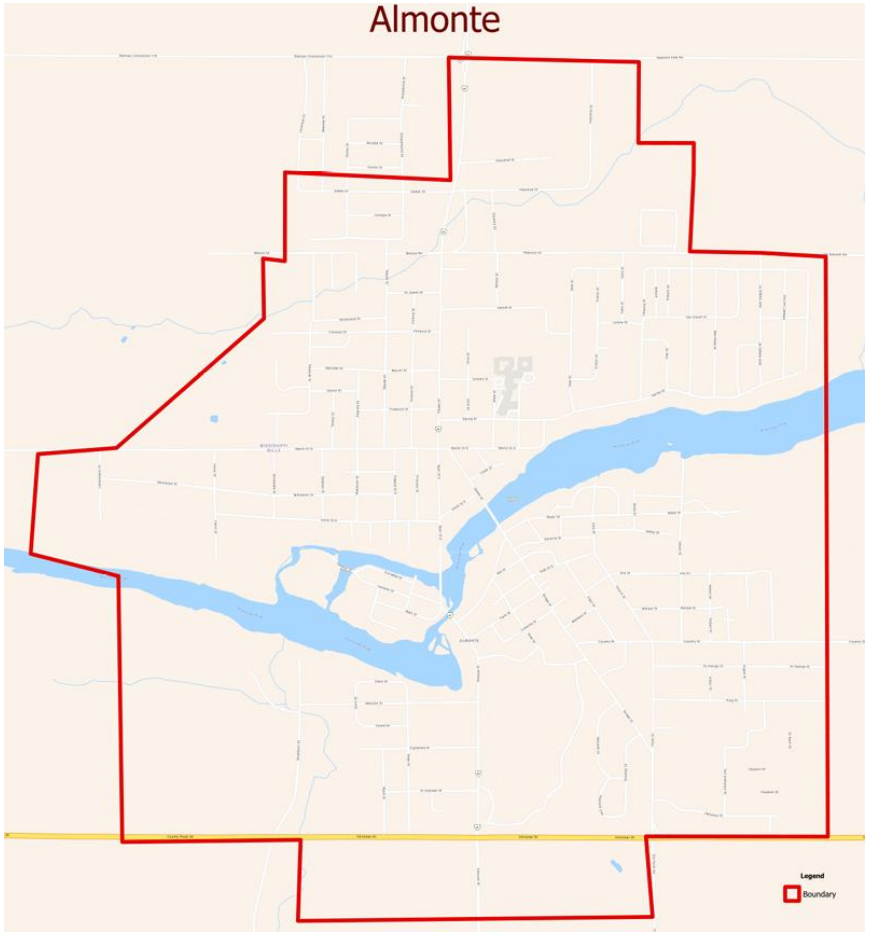


Figure 5.2-1: Almonte Service Area

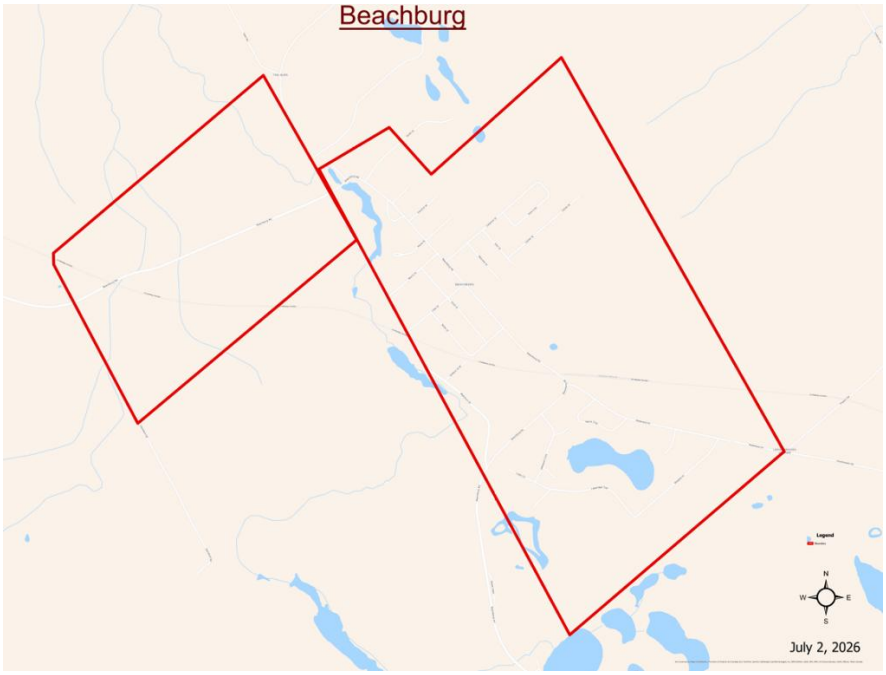


Figure 5.2-2: Beachburg Service Area

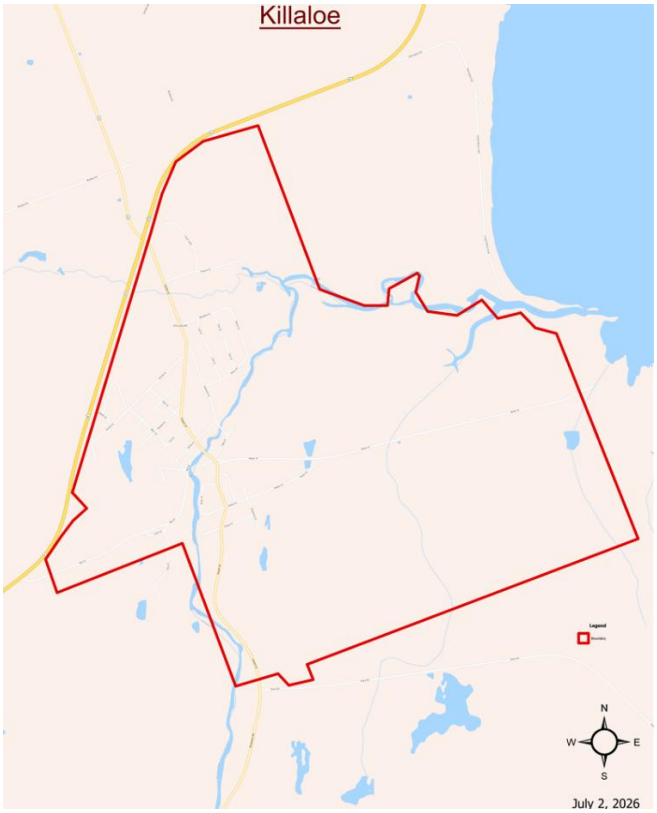


Figure 5.2-3: Killaloe Service Area

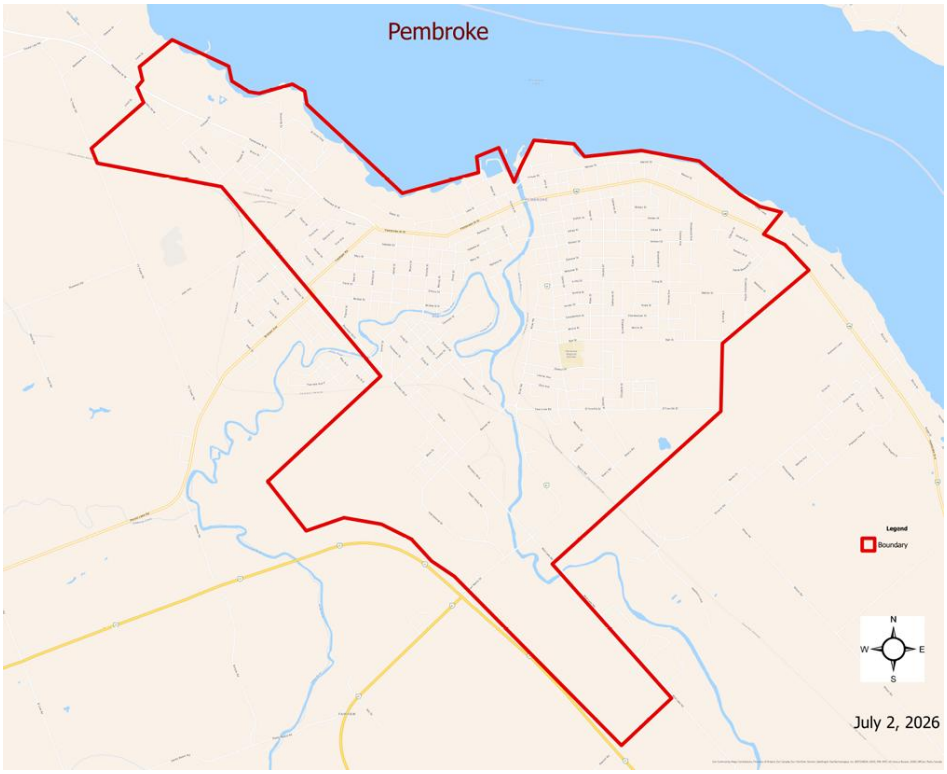


Figure 5.2-4: Pembroke Service Area

1. Mission and Core Values Statement

Mission

Ottawa River Power Corporation is an electricity distributor committed to the pursuit of excellence in safety and reliability for the customers and communities we serve. We continue to seek innovation through energy conservation and technology while striving to be the trusted energy advisor for our customers and continuing to create value for our shareholders.

Core Values

To be a responsible corporate leader in the community

To be part of a productive and effective work force where fulfillment, self-esteem and team spirit fuel the desire of employees to be their best

To have a strong customer focus, seeking new and better ways to help customers with their energy needs

To be innovative and creative

To uphold the highest standards of safety and integrity in all our actions

2. Customers Served

In 2025, ORPC served 11,819 electricity distribution customers across its service areas.

The four communities ORPC serves have diverse characteristics. OPRC has two offices, one located in Pembroke and one located in Almonte, providing support to the customer base within ORPC's system and service area. The Killaloe and Beachburg service areas mostly contain residential customers located in a rural area with minimal population growth in recent years.

Table 5.2-1 below illustrates the changes in ORPC's customer base over the historical period, which includes residential, general service less than 50 kW, general service greater or equal to 50 kW, and large users. Distribution system investments to date have focused on sustaining the existing distribution system infrastructure with a minimal cost impact to customers and expanding the distribution system to meet customer needs.

Table 5.2-1: Changing Trends in Customer

Annual Year	Residential	General Service <50 kW	General Service ≥50 kW	Total
2022	10223	1274	141	11638
2023	10326	1267	139	11732
2024	10367	1271	137	11775
2025	10411	1273	135	11819

Total customers grew modestly from 11,638 in 2022 to 11,819 in 2024, driven by steady gains in residential accounts. Small commercial customers and larger commercial and industrial customers remained relatively stable with a slight decline.

5.2.1.2 Background & Drivers

The Filing Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. However, all drivers of a given project or activity were considered in the analysis of capital investment options and are further described in Section 5.4.1 of the DSP.

Table 5.2-2: ORPC category drivers for DSP identified projects

OEB Category	Driver	Description
System Access	Customer Service Requests	The utility's obligation to connect a customer to its system. This includes both traditional demand customers and distributed generation customers. The utility performs expansion or enhancements within their system when a connection cannot be made with existing infrastructure.
	Third Party Infrastructure	The fulfillment of utility obligations to relocate an electrical installation due to 3rd party modification projects such as roadway modifications, railway infrastructures, bridges, etc.
	Mandated Service Obligations	Compliance with all legal and regulatory requirements and government directives.
System Renewal	Failure Risk	When there is a risk of failure due to age or condition deterioration. The potential failures will result in significant reliability impacts to customers as well as potential safety risks to crew workers or to the public.
	Functional Obsolescence	The asset and/or its installation is no longer aligned to Utility's processes and practices such that it can no longer be maintained (e.g. lack of vendor support) or utilized as intended to support the utility's operations. For e.g. voltage conversions, etc.
System Service	System Constraints	Expected changes in load will constrain the ability of the system to provide consistent service delivery and handle demand requirements.
	Reliability	Maintaining or improving reliability
	Safety	Investment to improve electrical distribution safety and to ensure continued compliance with Regulation 22/04 (Electrical Distribution Safety
General Plant	System Maintenance Support	To support day to day business operational and maintenance. For e.g. land, building, office supplies
	Business Operations Efficiency	The ability to mitigate and recover from disruptions to core business functions. For e.g. information technology such as computers, workstations, etc.
	Non-System Physical	Rolling stock vehicles, tools and equipment

5.2.1.3 Capital Investment Highlights

Ottawa River Power Corporations' capital investments over the planning period have been aligned to the 4 categories of system access, system renewal, system service, and general plant outlined in the Filing Requirements. Table 5.2-3 presents Ottawa River Power Corporations' historical actuals and forecast expenditures for both capital and O&M categories.

Table 5.2-3: Historical and Forecast Capital Expenditures and System O&M

Category	Historical				Bridge		Forecast			
	in ($ '000)									
	2022	2023	2024	2025	2026[1]	2027	2028	2029	2030	2031
System Access (Gross)	564	1061	1174	795	847	944	972	1001	1031	1062
System Renewal (Gross)	1980	755	994	1649	1052	1675	1264	1440	2242	1475
System Service (Gross)	-	20	-	-	170	20	20	20	145	110
General Plant (Gross)	64	327	203	254	733	760	630	991	175	129
Gross Capital Expenses	2607	2163	2371	2698	2802	3399	2886	3453	3593	2775
Contributed Capital	-160	-343	-295	-318	-476	-484	-649	-736	-808	-327
Net Capital Expenses after Contributions	2447	1819	2075	2379	2326	2915	2237	2717	2786	2448
System O&M	1454	1521	1397	1938	1638	1840	1895	1952	2011	2071

5.2.1.3.1 System Access

Expenditures within the System Access category are driven entirely by external requirements, such as connecting new customer service requests and relocating distribution assets when requested by road or municipal authorities. Investment in this cost category is considered mandatory, and the specific timing of these investments is dictated by external parties.

The majority of the forecasted investments in this category are established using historical averages, supplemented by active planning data and infrastructure development schedules provided by external agencies and municipalities operating within the ORPC service territory.

5.2.1.3.2 System Renewal

System Renewal investments involve the systematic replacement of ORPC's system assets. These investments are designed to mitigate asset failure risk, as an unexpected equipment failure can have a significant impact on customers, system reliability, the environment, and safety. ORPC leverages its mature Asset Management Process to rigorously determine the appropriate level and timing of these capital investments.

[1] 0 months of actual expenditures included in 2026

5.2.1.3.3 System Service

System Service investments involve targeted modifications to the distribution system to achieve ORPC's operational objectives while proactively addressing anticipated future customer electricity service requirements. System Service investments are designed to provide robust reinforcement to critical supply points, manage emerging capacity or operational constraints, and integrate new communications technologies to ensure that system outages are identified, isolated, and resolved with maximum efficiency. ORPC leverages its mature Asset Management Process to rigorously determine the appropriate level and timing of these capital investments.

5.2.1.3.4 General Plant

These investments are modifications, replacements or additions to ORPC's assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock; and electronic devices and software used to support day to day business and operations activities.

5.2.1.4 Key Changes since Last DSP Filing

General Plant investments represent modifications, replacements, or the installation of new assets that do not directly deliver electrical supply to customers but are fundamental to supporting ORPC's day-to-day operations. These assets include land, buildings, fleet vehicles, tools, and test equipment, as well as technology hardware and software applications. ORPC leverages its mature Asset Management Process to rigorously determine the appropriate level and timing of these capital investments.

5.2.1.5 DSP Objectives

This DSP is a stand-alone document and will be filed in support of ORPC's Application. ORPC's DSP describes and substantiates ORPC's asset management ("AM") processes and capital expenditure plan for the period from 2027 onwards to 2031. The DSP documents the practices, policies, and processes that are in place to ensure that investment decisions cost-effectively support ORPC's desired outcomes and provide value to customers.

ORPC's DSP is formulated to support the achievement of the four key OEB established Renewed Regulatory Framework ("RRF") performance outcomes:

1. **Customer Focus:** Services are provided in a manner that responds to identified customer preferences;

2. **Operational Effectiveness:** Continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives;
3. **Public Policy Responsiveness:** Utilities deliver on obligations mandated by government (e.g. in legislation and regulatory requirements imposed further to Ministerial directives to the Board); and
4. **Financial Performance:** Financial viability is maintained, and savings from operational effectiveness are sustainable.

5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Customers

In 2025, ORPC served 11,819 electricity distribution customers across its service area. The four communities ORPC serves have diverse characteristics. Section 5.3.2 provides further details of these characteristics including population and economic growth along with its geographical location and climatic conditions. OPRC has two offices, one located in Pembroke, and one located in Almonte, which represents most of the service area and customer base within ORPC's system. The Killaloe and Beachburg service area mostly contain residential customers located in a rural area with minimal population growth in recent years.

5.2.2.1.1 Customer Engagement Survey

ORPC promoted its DSP customer survey through a broad outreach campaign that included direct email communications, website advertising, and a participant incentive. The survey received 50 responses over the 31-day survey period, for June 11th, 2026 – July 12th, 2026 (inclusive). Although the sample is not intended to be statistically representative of ORPC's full customer base, the feedback provides meaningful qualitative insight into customer satisfaction, customer priorities, and emerging areas of interest that support the development of the DSP.

Overall, respondents demonstrated a strong awareness of ORPC's operations, with 92% indicating they were either somewhat familiar or very familiar with the utility and its activities, see Figure 5.2-5. Survey results also indicate a positive perception of ORPC's performance. Approximately 84% of respondents reported being somewhat or very satisfied with ORPC's overall service, while only 6% expressed dissatisfaction. Satisfaction with reliability and outage management was similarly strong, with 86% of respondents reporting they were satisfied with the reliability of electricity service and ORPC's outage response.

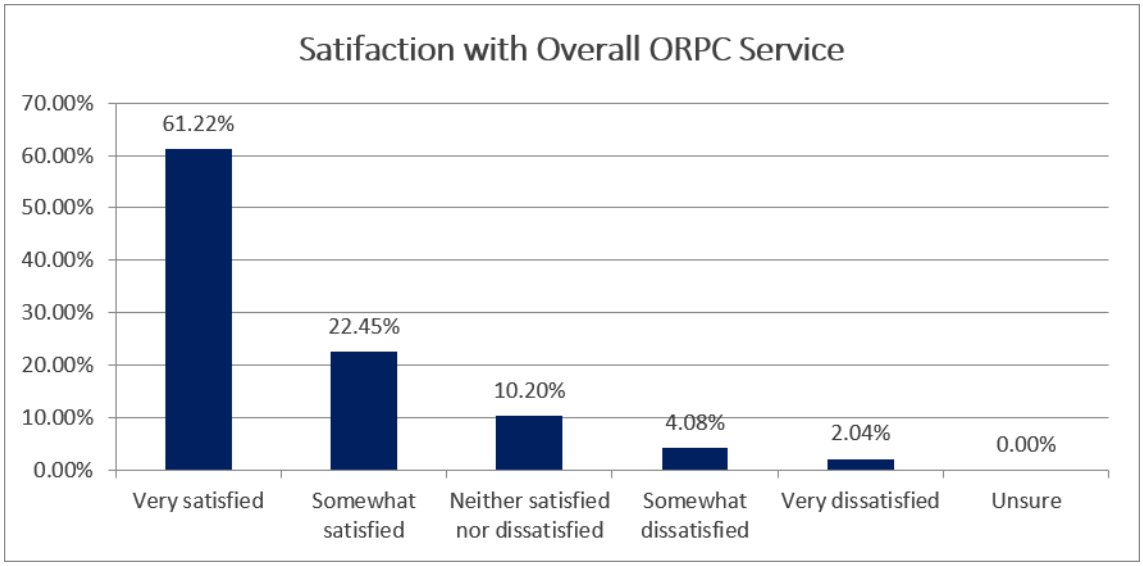


Figure 5.2-5: Customer Satisfaction

The survey also explored customer priorities to help inform future planning and investment decisions. Respondents were asked to rank five key objectives: reliability of electricity service, maintaining reasonable electricity distribution rates, safety of electricity service, customer service and communications, and preparing the system for future growth. Weighted scores were calculated based on respondents' rankings, with higher scores indicating a greater concentration of top-priority rankings (where 5 represents the highest possible score and 1 the lowest).

As shown in Table 5.2-4, reliability of electricity service emerged as the clear top priority, receiving the highest weighted score of 4.57. Maintaining reasonable electricity distribution rates ranked second at 3.78, highlighting the importance customers place on affordability. Safety of electricity service was the third-highest priority, with a score of 2.90. While still important to customers, customer service and communications (2.12) and preparing the system for future growth (1.63) received lower rankings relative to reliability, affordability, and safety. Overall, the results demonstrate that customers place the greatest value on maintaining a reliable, safe, and cost-effective electricity service.

Table 5.2-4: Customer Priority Ranks and Scores

Priority	Score	Rank
Reliability of electricity service	4.57	1
Maintaining reasonable rates	3.78	2
Safety of electricity service	2.90	3
Customer service & communications	2.12	4
Preparing for future growth	1.63	5

Respondents were also asked for their input on the proposed 2027–2031 Distribution System Plan. Overall, it was well received, with the largest share of customers (41%) agreeing that the plan appropriately balances reliability, safety, system condition, future needs, and affordability, shown in Figure 5.2-6. An additional 8% favoured increased investment to further enhance reliability and future readiness. While nearly one third of respondents expressed a preference for placing greater emphasis on limiting distribution bill impacts, the results indicate that customers generally support ORPC's balanced investment strategy while continuing to view affordability as an important consideration.

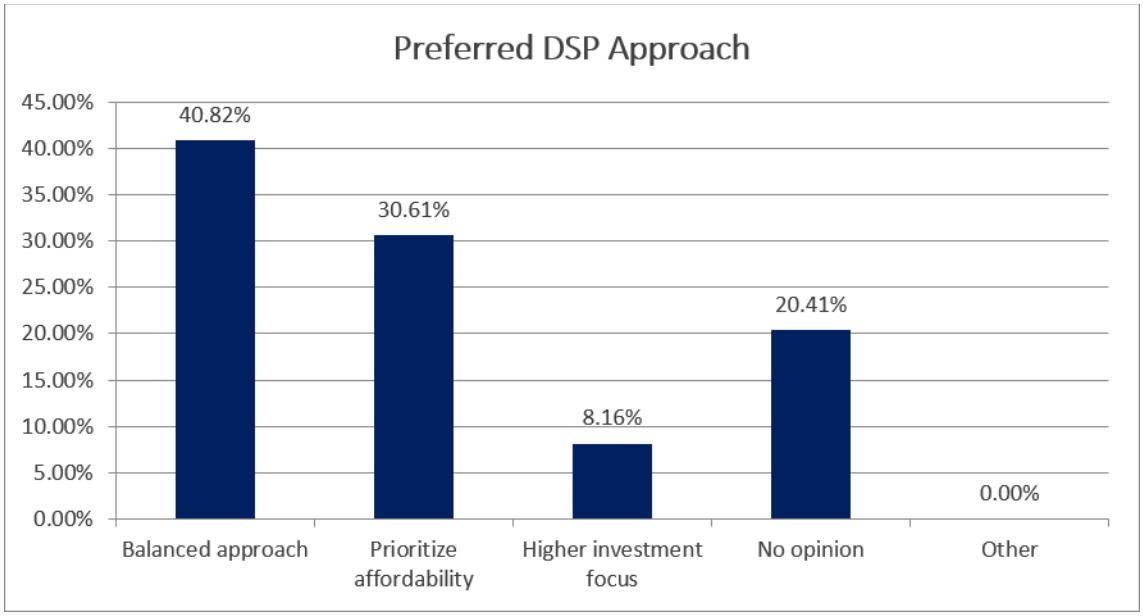


Figure 5.2-6: Preferred DSP approach

Overall, respondents identified reliable electricity service and affordable rates as their key priorities, while satisfaction levels suggest ORPC is generally meeting customer expectations in these areas.

Respondents were then given a section to provide their open-ended feedback. This feedback generally aligned with the above key priorities. Several customers acknowledged improvements in reliability and reduced outage frequency over the past year. Opportunities for improvement focused primarily on outage communications, including requests for estimated restoration times and text-message notifications. Some respondents also expressed interest in enhanced customer information, such as tools that compare electricity pricing options and historical usage trends.

5.2.2.2 Subdivision Developers

Development activity is expected to remain concentrated in the Almonte and Pembroke service areas, with several planned projects currently under review or in various stages of development. Identified projects,

including Hannan Hills, Hilan Village, Weavers Way Phase 1B, 350 International Drive, Stuart St and 127/129 Adelaide St could result in more than 407 new residential connections over the DSP period. These projects, together with forecast customer growth of approximately 0.86% annually, support the need for continued investment in customer connections and distribution system expansion.

Table 5.2-5: Residential Connections Related Projects

Project #	Description	Service Territory	Est. Connections
ORPC-26-060	Weavers Way (Phase 1B)	Almonte	60 Residential
ORPC-26-040	Hannan Hills	Almonte	110 Residential
ORPC-26-039	350 International Drive	Pembroke	3 x 16 Unit Residential Buildings (48 Units)
ORPC-25-076	Hilan Village	Almonte	115 Residential
ORPC-26-015	Stuart St	Pembroke	7 x 8 (56 Units)
ORPC-26-064	127/129 Adelaide St	Almonte	3 x 6 (18 Units)

Feedback received through engagement with developers has emphasized the importance of timely servicing, clear connection requirements, and sufficient system capacity to support housing growth. ORPC incorporates this information into its planning process to coordinate distribution investments with anticipated development activity, while continuing to meet its obligations under the Distribution System Code. This proactive approach helps facilitate residential growth, supports municipal housing objectives, and ensures new customers can be connected safely, reliably, and efficiently.

5.2.2.3 Municipalities

ORPC serves the City of Pembroke in addition to Almonte Ward (within the Town of Mississippi Mills), Beachburg (within the Township of Whitewater Region), and Killaloe (within the Township of Killaloe, Hagarty, and Richards). ORPC maintains strong coordination with all its municipalities and townships for regional planning purposes. The purpose of this consultation is to understand the potential impacts of developments such as population growth leading to new customer connections, installation of new and/ or relocation of existing infrastructure by 3rd parties. The objective of these discussions is to make sure ORPC maintains an all-time capability to accommodate such non- discretionary projects within its distribution system through well-informed planning decisions.

5.2.2.3.1 Coordination with Corporation of the Municipality of Mississippi Mills

Almonte continues to be the primary growth area within ORPC's service territory. ORPC maintains regular communication with municipal planning staff and monitors active development applications to understand potential future customer growth and infrastructure requirements. As of January 2026, several residential

developments are in various stages of approval or construction, including Weaver's Way, Hilan Village, Hannan Hills, Browns Lands (Strathburn), Mill Run, Menzie Enclaves, Baker's Quarry, and Mill Valley Living.

ORPC incorporates known development activity into its customer growth assumptions and planning processes, while overall customer forecasts are based primarily on historical customer growth trends. Notable developments include Weaver's Way (approximately 535 units), Hilan Village (116 units), Hannan Hills (110 units), and Menzie Enclaves (rumoured to include approximately 58 residential units), which contribute to the long-term growth outlook for the Almonte service area.

ORPC will continue to monitor development activity and work with the Municipality to identify projects that may affect future distribution system requirements.

5.2.2.3.2 Coordination with Township of Killaloe, Hagarty, and Richards

ORPC maintains communication with the Township regarding municipal infrastructure and community development initiatives. Current growth expectations within the Village of Killaloe remain modest, with no major residential or commercial developments anticipated to significantly impact the distribution system during the planning period.

5.2.2.3.3 Coordination with Township of Whitewater Region

ORPC monitors development activity and municipal planning initiatives affecting its Beachburg service territory. Growth expectations remain relatively moderate; however, ORPC continues to assess potential impacts through municipal consultation and participation in regional planning activities.

The 2026 Renfrew Region Needs Assessment identified emerging capacity requirements at Cobden DS and Cobden TS under forecast growth scenarios, highlighting the importance of continued monitoring of electricity demand throughout the region.

5.2.2.3.4 Coordination with the City of Pembroke

ORPC regularly coordinates with the City of Pembroke regarding municipal infrastructure projects, road reconstruction programs, and development activity that may affect the distribution system. This engagement supports the identification of plant relocation requirements and allows municipal projects to be incorporated into ORPC's capital planning process.

ORPC also participates in regional electricity planning activities through the Renfrew Technical Working Group. The 2026 Renfrew Region Needs Assessment incorporated municipal growth inputs, load forecasts, and identified several transmission and station capacity needs requiring ongoing monitoring and coordination

among regional planning participants. Ottawa River Power Corporation is identified as a participating LDC in the ongoing regional planning process.

5.2.2.4 Transmitter

ORPC customers are supplied via HONI transmission and transformation assets within the Greater Ottawa and Renfrew planning regions. ORPC, HONI, and the IESO maintain ongoing coordination through the regional planning process to monitor system capability and planned changes.

Recent regional planning activities, including the Renfrew IRRP and the Greater Ottawa RIP identify capacity needs in parts of the ORPC service territory and consider potential station expansions, new transformation capacity, and system reconfiguration to address localized load growth.

These upstream investments remain under assessment and are being advanced through HONI-led regional planning processes. At this time, no direct transmission-related capital expenditures are forecast by ORPC within the 2027–2031 DSP period. ORPC will continue to monitor regional planning outcomes and coordinate with HONI and the IESO as plans evolve.

5.2.2.5 Other LDCs

At the time of this DSP, ORPC is not participating in any formal coordinated planning or operational initiatives with other LDCs, aside from its involvement in regional planning processes led by the IESO and Hydro One.

5.2.2.6 IESO

Outside of the Renewable Energy Generation (REG) investment process, regional planning process, Cyber security coordination, MicroFIT contracts and long-term energy supply process, ORPC does not regularly engage with the IESO

5.2.2.7 Regional Planning Process

The Regional Planning Process represents a coordinated, transparent, and cost-effective planning of electrical infrastructure at the regional level which was mandated by the OEB in 2013 through amendments to the Transmission System Code (“TSC”) and DSC. To facilitate effective planning, the Province of Ontario is divided into 21 regions and prioritized into three groups, including Group 1, Group 2, and Group 3. Prioritization is performed based on the anticipated need to address supply and reliability issues at the regional level. As the lead transmitter, HONI conducts a Need Assessment (“NA”) and develops a Regional Infrastructure Plan (“RIP”) that involves representatives from the Independent Electricity System Operator (“IESO”), and Local Distribution Companies (“LDCs”) of the planning region.

ORPC is the part of the Renfrew region which belongs to Group 3 of the prioritization region. The Renfrew region includes all of Renfrew County made up of 17 municipalities and the City of Pembroke. As illustrated in Figure 5.2-7.

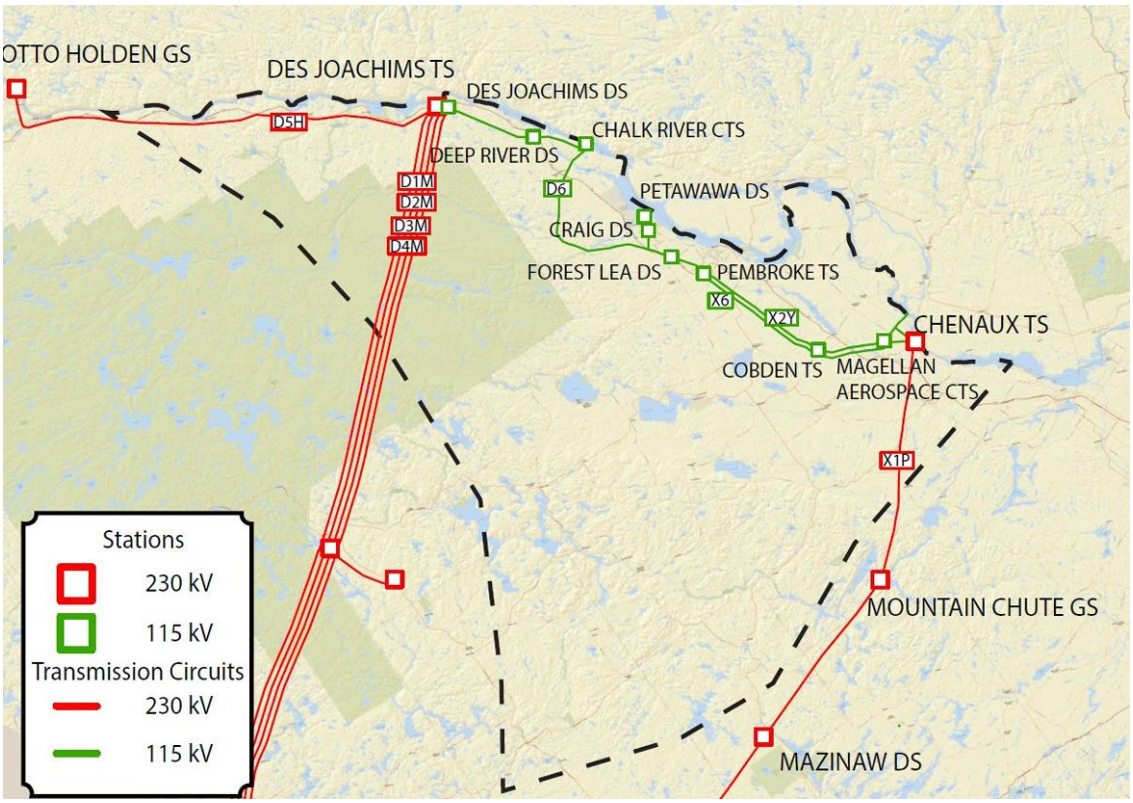


Figure 5.2-7: Renfrew Region - Regional Planning Group 3

ORPC is also part of the Greater Ottawa region which belongs to Group 1 of the prioritization region. The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Stewartville in the West to Hawkesbury in the East and North of Highway 43 as illustrated in Figure 5.2-8. At the center of this region is the Ottawa Area, comprising the City of Ottawa and surrounding municipalities including Kanata, Nepean, and Orleans.

The Greater Ottawa region is divided into two sub-regions:

- Ottawa Area Sub-region
- Outer Ottawa Sub-region

As an embedded LDC within the Outer Ottawa Sub-region (Western Part), ORPC supplies its customers within the Town of Almonte from HONI's Almonte TS via HONI (Distribution)'s 44kV feeder. ORPC does directly participate in the regional planning for the Greater Ottawa Region.

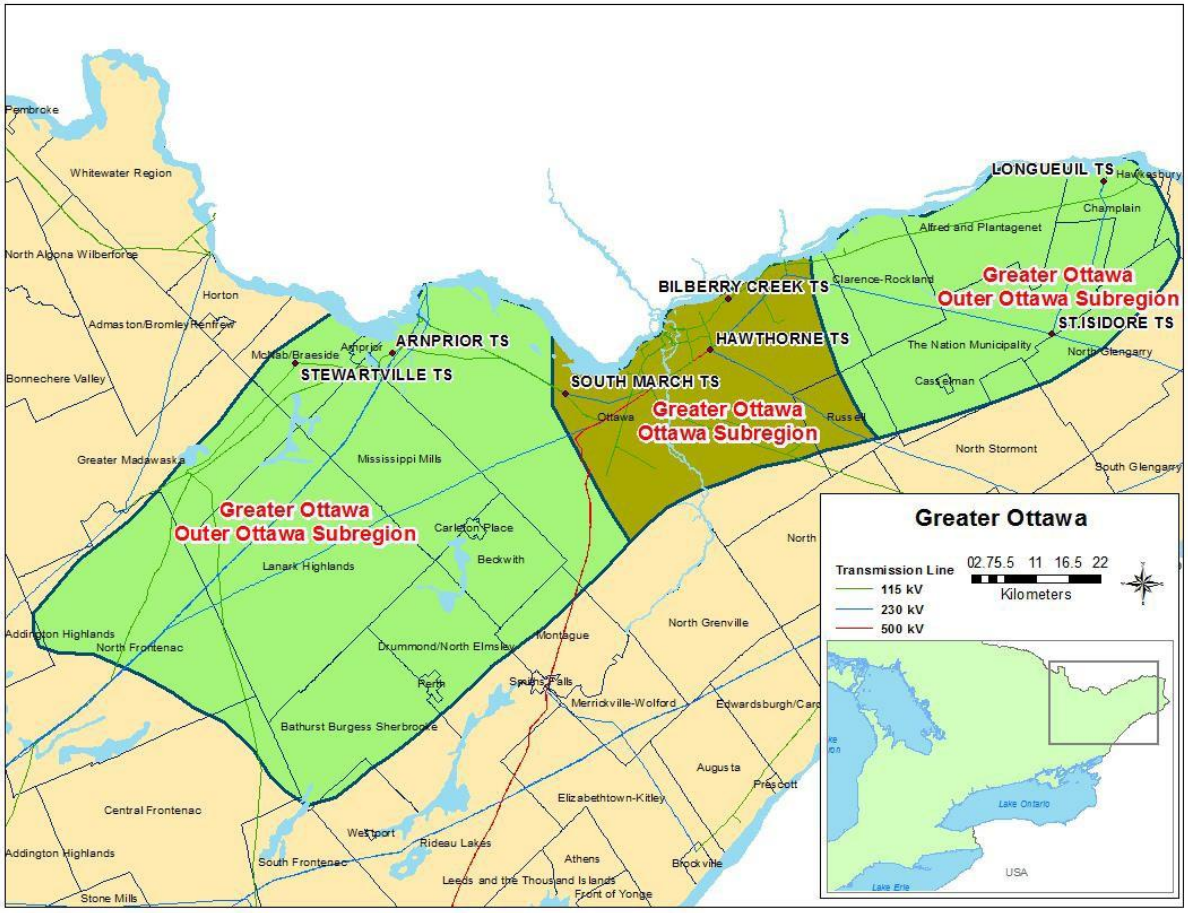


Figure 5.2-8: Greater Ottawa Region

5.2.2.7.1 Summary of Consultation

The purpose of the Regional Planning Process is to collaborate with HONI, the IESO, and LDCs within the planning region to address electrical supply needs identified in previous planning exercises and any additional needs identified based upon new and/or updated information provided by the RIP Working Group. As the lead transmitter, HONI conducts an NA which included a review of transmission system connection facilities capability, which covers station loading, thermal, and voltage analysis, system reliability, and assets approaching end-of-life.

For the Renfrew Regional Planning Process, other participants besides ORPC included:

- HONI (the lead transmitter);
- IESO;
- Renfrew Hydro Inc.; and
- HONI (Distribution).

For the Greater Ottawa Regional Planning Process, other participants besides ORPC included:

- HONI (the lead transmitter);
- Hydro Ottawa Limited;
- IESO;
- HONI (Distribution); and
- Hydro Hawkesbury Inc.
- Hydro 2000

Effect on the DSP

Renfrew Regional Planning: The third cycle of regional planning for the Renfrew Region is currently underway. Capacity constraints have been identified within the region and coordinated regional planning activities are ongoing to assess infrastructure investments required to maintain reliability and accommodate forecast load growth.

Greater Ottawa Regional Planning: The third cycle of regional planning for the Greater Ottawa Region has identified several transmission and transformation capacity, reliability, and asset renewal needs across the region. While no specific needs were identified within ORPC's service territory, the Regional Infrastructure Plan recommends several transmission and distribution infrastructure investments to accommodate forecast load growth and maintain system reliability.

5.2.2.7.2 Summary of Final Deliverables for the Consultation

Renfrew Region

The second cycle of regional planning for the Renfrew Region was completed with the publication of the Regional Infrastructure Plan (RIP) in July 2023. The third regional planning cycle was initiated in 2026 through a Needs Assessment led by Hydro One and the Renfrew Technical Working Group, which includes representatives from the IESO, Hydro One Distribution, and Ottawa River Power Corporation (ORPC).

The assessment reviewed regional load forecasts, station capacity, transmission adequacy, reliability, and operational performance over the 2026–2035 planning horizon. While the region remains adequately supplied under the normal forecast, several emerging needs were identified that require further regional coordination, including capacity constraints at Cobden DS, potential future capacity needs at Cobden TS, transmission limitations on the 115 kV D6 and X2Y circuits under high-growth scenarios, and voltage and load restoration concerns associated with these facilities.

The Needs Assessment also confirmed that previously identified capacity concerns at Pembroke TS are no longer anticipated within the planning horizon due to updated transformer loading studies and revised station ratings. In addition, Hydro One is proceeding with the refurbishment of the 115 kV D6 transmission line between Des Joachims TS and Pembroke TS, with completion expected in 2027, which will improve the load-serving capability and reliability of the circuit.

As a participant in the Renfrew Technical Working Group, ORPC will continue to participate in future regional planning activities to monitor emerging needs and ensure that regional transmission infrastructure continues to support customer growth and reliability requirements within its service territory. The 2026 Renfrew Region Needs Assessment is included as Appendix G.

Greater Ottawa – Ottawa Area Sub-region

The third cycle of the Greater Ottawa Regional Planning Process was initiated in 2022 due to increased load growth in the region and included a Needs Assessment, Scoping Assessment, Integrated Regional Resource Plan ("IRRP"), and Regional Infrastructure Plan ("RIP"). The planning process identified a number of emerging capacity, reliability, and asset renewal needs across the Greater Ottawa Region, including transformation capacity needs in the Kanata–Stittsville area, supply capacity limitations on portions of the transmission system, and several major transmission and station infrastructure investments. The Greater Ottawa RIP was published in February 2026 and recommends a number of transmission and distribution infrastructure projects to address forecast load growth and system reliability requirements over the planning horizon.

As an embedded Local Distribution Company ("LDC") within the Outer Ottawa Sub-region (Western Area), ORPC supplies customers in the Town of Almonte from Hydro One's Almonte TS through Hydro One Distribution's 44 kV system. No specific needs affecting ORPC's service territory were identified through the regional planning process, and ORPC did not directly participate in the development of the regional plans.

Role of ORPC in Greater Ottawa Regional Planning

ORPC is an embedded LDC supplied from Hydro One's Almonte TS via Hydro One Distribution's 44 kV feeder system within the Outer Ottawa Sub-region (Western Area). ORPC did not directly participate in the Greater Ottawa regional planning process and no regionally planned transmission investments were identified that directly impact ORPC's distribution system.

5.2.2.7.3 Relevant Documents in the Process

Renfrew Region

Regional planning activities for the Renfrew Region were completed through the Needs Assessment (2021), Scoping Assessment (2021), and Integrated Regional Resource Plan (2022), with participation from ORPC, the IESO, Hydro One Transmission, and Hydro One Distribution. ORPC provided load forecast data, distribution system information, and operational inputs to support the assessment of regional electricity needs. The planning process considered historical demand, long-term load forecasts, conservation and demand management. The resulting IRRP identified emerging capacity needs within the region and recommended further analysis through the Regional Infrastructure Planning process to develop and refine infrastructure solutions.

Greater Ottawa Region

ORPC did not directly participate in the planning process.

5.2.2.8 Telecommunication Entities

ORPC engages with telecommunications companies operating within its service territory on an ad hoc and as-needed basis. These engagements typically occur when coordination is required for specific projects, such as development-related construction, road reconstruction, or distribution asset relocations. Through these consultations, ORPC seeks to facilitate effective coordination of infrastructure activities, minimize conflicts during construction, and reduce impacts to customers and the public. Where applicable, information exchanged through these engagements is considered during project planning and execution. There are currently no known plans that has impacted the forecast capital cost ORPC is putting forward as part of this DSP period.

5.2.2.9 Renewable Energy Generation (REG)

Not Applicable.

5.2.2.9.1 IESO Comment Letter

Not Applicable.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

This section provides a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to ORPC's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

5.2.3.1.1 Objectives for Continuous Improvement Set out in Last DSP Filing

As part of the settlement proposal, Ottawa River Power Corporation also agreed to implement the five recommendations provided for in the Reliability Assessment Report. Specifically, Ottawa River Power will:

1. Create a standard outage reporting tool

2. Standardize reporting

3. Establish corporate reliability targets

4. Increase investigation into power outage causes, particularly unknown events and defective equipment

5. Document improvement in understanding of power outage characteristics, review of major outages and consideration given to design improvements, process, and data collection improvement

5.2.3.1.2 Performance Scorecard

ORPC performs tracking of qualitative and quantitative measures of system performance as part of its continuous improvement process. The purpose of monitoring is to gain knowledge about the effectiveness of its overall distribution system from all aspects of its operation and to track the quality of its capital expenditure planning. To remain responsive to the system needs and to continue its obligation of supplying electricity to customers in an effective manner, ORPC uses an outcome-based approach to track its performance. ORPC's performance outcomes for monitoring the quality of ORPC's capital plans can be divided into the following three groups:

- Customer-Oriented Performance
- Cost Efficiency and Effectiveness
- Asset/System Performance

Each of the above performance outcomes contains associated qualitative and/or quantitative measures and sub measures. Where applicable, the measures also have established minimum levels of performance which are expected to be achieved. The monitoring of these measures allows ORPC to improve and/or adjust their capital expenditure plans. Table 5.2-6 provides the desired outcomes for measures associated with each of the three groups. The purpose of this section is to address performance measures published by the OEB in the performance scorecard, yearbook of electricity distributors, along with an additional measure proposed by ORPC as part of its continuous improvements.

Table 5.2-6: DSP Performance Measure

Performance Outcome	Measure	Metric	2021	2022	2023	2024	2025	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	100.00%	93.10%	100.00%	90%
		Scheduled Appointments Met on Time	97.58%	98.11%	100.00%	99.53%	100.00%	90%
		Telephone Calls Answered on Time	94.33%	96.05%	97.24%	94.52%	95.44%	65%
	Customer Satisfaction	First Contact Resolution	98%	98%	97%	97%	99.40%	No target
		Billing Accuracy	99.88%	99.92%	99.79%	99.92%	99.90%	98%
		Customer Satisfaction Survey	81%	79%	79%	84%	84%	No target
Operational Effectiveness	Safety	Level of Public Awareness	83.50%	83.50%	84.20%	84.20%	82.10%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	0	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	0
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	3.36	1.77	1.49	0.95	2.99	2.59
		Ave. Number of Times that Power to a Customer is Interrupted	1.39	1.33	1.09	0.53	1.72	0.83
	Asset Management	Distribution System Plan Implementation Progress	In Progress	In Progress	In Progress	In Progress	In Progress	No target
	Cost Control	Efficiency Assessment	2	1	1	1	-	No target
		Total Cost per Customer	$521	$592	$668	$673	-	No target
		Total Cost per km of Line	$11,805	$13,519	$15,370	$15,537	-	No target
Public Policy Responsiveness	Connection of Renewable generation	New Micro-embedded Generation Facilities Connected on Time	-	-	-	100.00%	100.00%	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	0.96	2.01	1.45	1.73	1.31	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	0.75	0.71	0.70	0.69	0.71	No target
		Regulatory ROE – Deemed (included in rates)	9.19%	8.66%	8.66%	8.66%	8.66%	No target
		Regulatory ROE - Achieved	8.57%	10.59%	3.84%	4.50%	3.30%	No target

Overall performance remains strong, with most customer service metrics consistently exceeding targets, though there was a temporary dip in on-time connections in 2024 that rebounded in 2025. Reliability shows the most notable fluctuation, with outage duration and frequency improving through 2024 before increasing in 2025 above targets. Cost metrics have steadily risen over time, indicating growing operational expenses, while financial performance shows volatility in achieved ROE, declining sharply after 2022 despite relatively stable deemed returns.

Except for 2024, the average number of times that power to a customer was interrupted exceeded the target of 0.83. Defective equipment outages contributed the most to the increase in this ratio as the utility's infrastructure continues to age. However, through its previous DSP, ORPC has been implementing its capital replacement program which led to decreased outages related to defective equipment.

In 2025 the targets for both average number of times and hours that power to a customer was interrupted were not met. Ottawa River Power Corporation's outages in 2025 included 87,359 customer hours and 11,134 customers interrupted as a result of a loss of supply. Defective equipment and scheduled outages together were the cause of 14% of customer hours interrupted in 2025 making them the second and third highest contributing causes that year.

5.2.3.2 Service Quality and Reliability

5.2.3.2.1 Service Quality Requirements

ORPC on an annual basis reports service quality requirements as stated within Section 7 of the DSC. These requirements act as a baseline for the quality of service that is expected to be delivered and is an indicator of day-to-day performance. ORPC monitors its performance and takes measures to continuously align its performance to attain minimum service quality standards as stated in the DSC. Service Quality requirements include the following major measures:

- New Residential/Small Business Services Connected on Time
- Scheduled Appointments Met on Time
- Telephone Calls Answered on Time

In addition to the above, the following sub-measures are also tracked by ORPC:

- Telephone Accessibility
- Telephone Call Abandon Rate
- Connection of New Services

- Appointments Scheduling
- Appointments Met
- Missed Appointments Rescheduling
- Written Response to Inquiries
- Emergency Response
- Reconnection Performance
- Billing Accuracy

The descriptions for the above-mentioned service quality measures are provided in Section 7 of the DSC as published by the OEB. As part of ORPCs performance monitoring procedures, failing to meet minimum service quality targets would result in actions being executed to realign performance with the DSC requirements. These measures are closely related to ORPC's objectives to provide robust and quality connections and services to customers. ORPC is committed to meeting and exceeding all targets found within the Service Quality performance measure group.

Table 5.2-7: Historical Service Quality Metrics

Service Quality Metric	2022	2023	2024	2025	Minimum Standards
Low Voltage Connections	100.00%	100.00%	93.10%	100.00%	> 90%
High Voltage Connections	100.00%	-	-	100.00%	> 90%
Telephone accessibility	96.05%	97.24%	94.52%	95.44%	> 65%
Appointments met	98.11%	100.00%	99.53%	100.00%	> 90%
Written response to enquiries	99.84%	99.61%	99.50%	99.28%	> 80%
Emergency Urban Response	100.00%	100.00%	92.86%	100.00%	> 80%
Emergency Rural Response	-	-	-	-	> 80%
Telephone call abandon rate	3.95%	4.50%	4.01%	3.22%	< 10%
Appointment scheduling	100.00%	100.00%	98.08%	99.06%	> 90%
Rescheduling a Missed Appointment	100.00%	-	100.00%	100.00%	100%
Reconnection Performance Standard	99.18%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	-	-	100.00%	100.00%	> 90%
Billing Accuracy	99.92%	99.79%	99.92%	99.90%	> 98%

Year over year, ORPC has consistently exceeded the OEB targets for service quality as part of the Customer Focus section of the OEB Scorecard. ORPC customer service representatives respond to varying call volumes per year within the 30-second window as prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of ORPC's dedication to being an organization focused on customer service.

Table 5.2-7 represents the focus areas and their measures and for tracking ORPC's performance in the service quality category.

5.2.3.2.2 Reliability Requirements

The key metrics that ORPC tracks to measure reliability are the SAIDI, System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). SAIDI, SAIFI and CAIDI are measured under three scenarios:

1. By including all power interruptions.
2. By excluding interruptions due to Loss of Supply (LOS).
3. By excluding interruptions due to LOS and Major Event Days (MED).

In addition, the root cause of power interruptions is monitored and analyzed. Each power outage that occurs on ORPC's distribution system is recorded and an outage cause code is assigned. The number of customer interruption hours for each cause code provides a picture of the root cause of power interruptions. There are no targets for root cause of power interruptions, but it is monitored for investment planning purposes. ORPC's reliability metric values for the historical period are shown in the tables and figures below.

Table 5.2-8: Historical Reliability Performance Metrics – All Cause Codes

Metric	2022	2023	2024	2025	Average
SAIDI	11.03	3.69	5.87	10.37	7.74
SAIFI	3.99	3.25	2.54	2.67	3.11
CAIDI	2.76	1.14	2.31	3.88	2.52

Table 5.2-8 presents ORPCs historical SAIDI, SAIFI, and CAIDI with all cause code included. The historical reliability performance metrics with loss of supply and major event days excluded are shown below in Table 5.2-9.

Table 5.2-9: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2022	2023	2024	2025	Average
Loss of Supply Adjusted (including MEDs, excluding LOS)					
SAIDI	10.44	1.49	0.96	2.99	3.97
SAIFI	2.32	1.09	0.53	1.72	1.42
CAIDI	4.50	1.37	1.81	1.74	2.36
Major Event Days Adjusted (including LOS, excluding MEDs)					
SAIDI	2.36	3.69	5.87	10.37	5.87
SAIFI	2.99	3.25	2.54	2.67	2.86
CAIDI	2.76	1.14	2.31	3.88	2.52
Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)					
SAIDI	1.77	1.49	0.96	2.99	1.80
SAIFI	1.33	1.09	0.53	1.72	1.17

Metric	2022	2023	2024	2025	Average
CAIDI	1.33	1.37	1.81	1.74	1.56

The year-over-year SAIDI, SAIFI, and CAIDI with MED and LOS adjusted are shown below in Figure 5.2-9, Figure 5.2-10, and Figure 5.2-11.

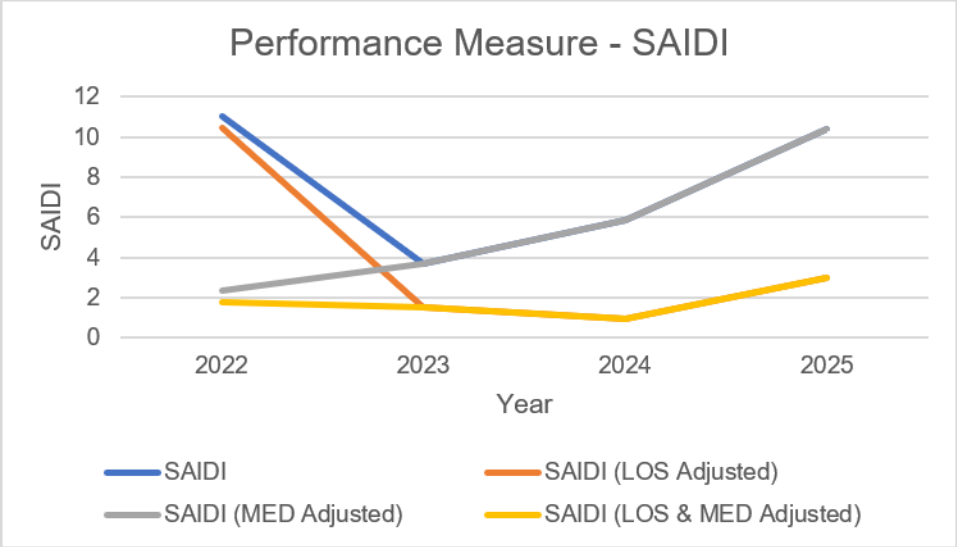


Figure 5.2-9: Performance Measure: SAIDI

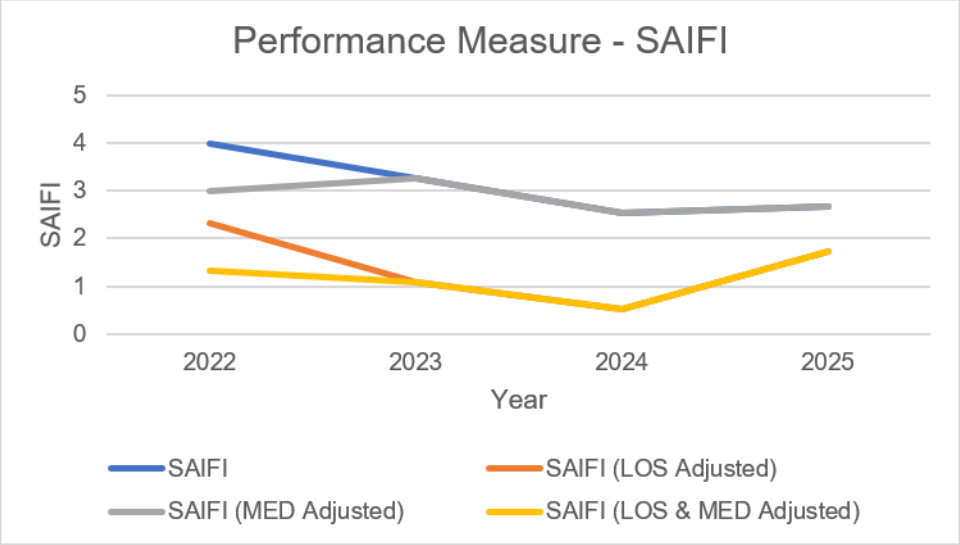


Figure 5.2-10: Performance Measure: SAIFI

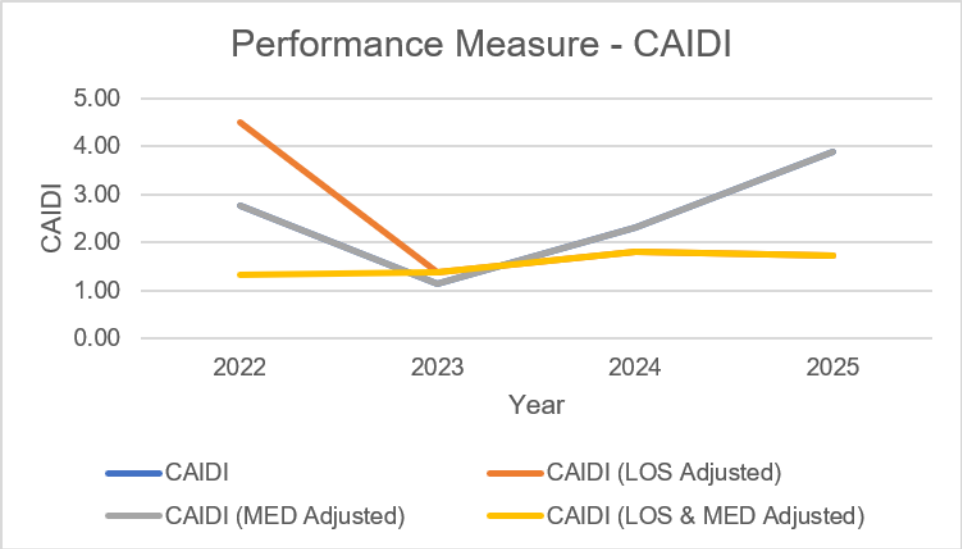


Figure 5.2-11: Performance Measure: CAIDI

ORPC experienced a spike SAIDI, SAIFI and CAIDI in 2022 mainly due to defective equipment and adverse weather. However, when excluding interruptions due to LOS and MED, ORPC's historical SAIDI, SAIFI, and CAIDI show relatively stable overall trend.

ORPC uses the SAIDI, SAIFI and CAIDI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. A number of investments in the System Renewal and System Service category that are planned to replace assets at the end of their service life and accommodate load growth will assist in maintaining system reliability. These include planned renewal of end-of-life assets such as poles, transformers, and switches, as well as substation rehabilitation. Investments in system reliability through smart devices such as fault indicators, switches, control systems and outage response software, will continue to help improve overall system reliability over the long term.

5.2.3.2.3 Outage Details for Years 2022-2025

Table 5.2-10: Summary of MEDs over the Historical Period

Year	# of MEDs	Cause of MEDs
2022	1	Loss of supply due to adverse weather
2023	N/A	N/A
2024	N/A	N/A
2025	1	Loss of Supply Transmission

Table 5.2-11: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
2022-05-21	11,590	The main contributing cause of the Major Event was #7 Adverse Weather. Secondary to the main contributing cause were #2 Loss of Supply and #3 Tree Contacts.
2025-10-19	9,000	The main contributing cause of the Major Event was #2.1 Loss of Supply: Transmission. Hydro One identified a tree on the line outside of ORPC city limits and experienced delays immobilizing crews and removing the tree.

A large portion of the transmission and distribution systems in Ontario were affected by the adverse weather, including Hydro One transmission systems, which resulted in prolonged Loss of Supply issues across all four of ORPC's territories. ORPC also encounter Tree Contact issues in our Almonte territory resulting in multiple broke poles and trees lying on conductor.

Table 5.2-12: Number of Outages (2022-2025)

Categorization	2022	2023	2024	2025
All interruptions	110	81	68	122
All interruptions excluding LOS	102	72	59	116
All interruption excluding MED and LOS	102	72	59	116

Table 5.2-13 presents the count of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. ORPC continues to assess and execute capital and O&M projects to manage the number of outages experienced

Table 5.2-13: Outage Numbers by Cause Codes – Excluding MEDs

Cause Code	2022	2023	2024	2025	Total Outages	%
0-Unknown/Other	2	1	2	5	10	3%
1-Scheduled Outage	27	19	18	56	120	31%
2-Loss of Supply	8	9	9	6	32	8%
3-Tree Contacts	4	4	2	1	11	3%
4-Lightning	5	2	3	5	15	4%
5-Defective Equipment	36	16	21	22	95	25%
6-Adverse Weather	5	16	1	11	33	9%
7-Adverse Environment	-	-	-	-	0	0%
8-Human Element	3	-	-	-	3	1%

Cause Code	2022	2023	2024	2025	Total Outages	%
9-Foreign Interference	20	14	12	16	62	16%
Total	**110**	**81**	**68**	**122**	**381**	**100%**

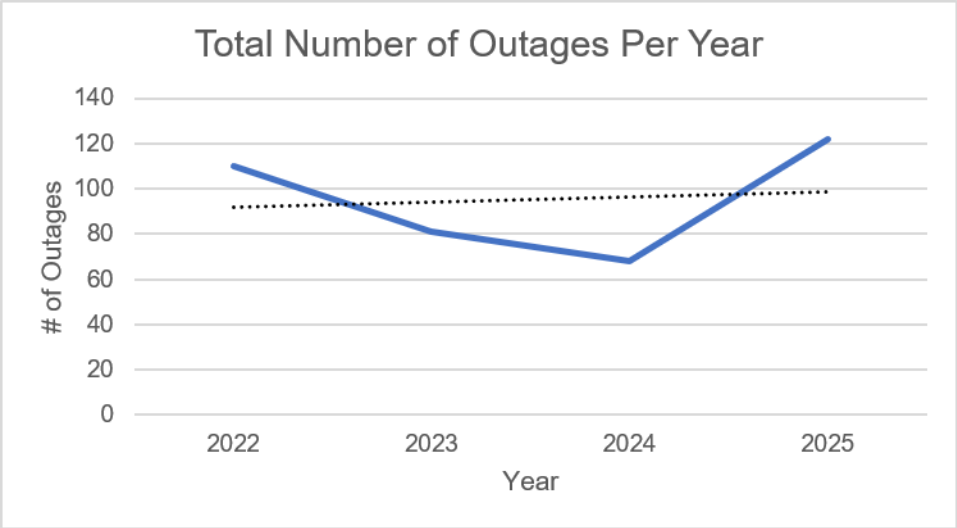


Figure 5.2-12: Total Number of Outages per Year

As shown in Table 5.2-13 and Figure 5.2-12, the number of outages decreased from 2022 to 2024, then spiked up in 2024, mainly driven by scheduled outages. The planned outages are required to improve service over time for customers. The majority of these planned outages are taken to address defective equipment, which is the largest cause of unplanned outages. The total number of interruptions over the historical period varies from a low of 68 to a high of 122, with a slight decrease in the overall trend in the period.

A summary of the causes of outages within ORPC's system is presented in Figure 5.2-13, along with the percentage of overall outage incidents attributable to each cause type.

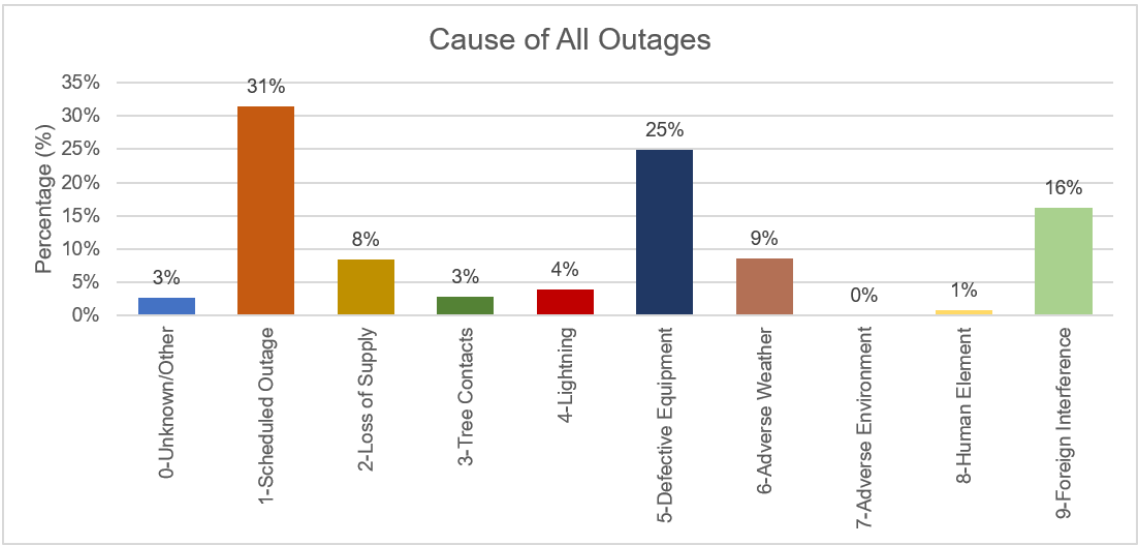


Figure 5.2-13: Percentage of Outages by Cause Code

Scheduled outages, defective equipment, and foreign interference causes have been identified to be the three most common causes for outages on ORPC's distribution system over the historical period. Together, these causes contributed to 73% of the total number of outages from 2022 to 2025, excluding MEDs.

At 31%, Scheduled Outages is the top contributing cause to the total outages experienced by ORPC. These outages are due to the disconnection of service for ORPC to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. ORPC aims to plan and execute capital work and maintenance appropriately in times that would affect minimal customers and with short durations. In 2025, ORPC also performed its PCB replacement program as mandated by Environment Canada, resulting in an additional 25 scheduled outages that year.

Defective Equipment is the second top contributing cause to the total outages. Defective Equipment accounted for 25% of the total outages experienced by ORPC over the historical period. These failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. ORPC has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. ORPC utilizes the ACA to assist in prioritizing investments in asset classes.

Foreign Interference outages are the third top contributing cause to the total outages experienced at 16%. The outages contributing to the cause include animal interference, dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized such as educating the public about calling before digging or installing animal guards in areas observed to have a high activity of animals, both of which ORPC continues

to do. However, other factors such as vehicle collisions can happen at random and, depending on the extent and where the collision happens, may result in a large impact.

Table 5.2-14: Customers Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2022	2023	2024	2025	Total CI	%
0-Unknown/Other	109	227	18	7,293	7,647	6%
1-Scheduled Outage	1,587	1,491	193	1,519	4,790	4%
2-Loss of Supply	19,355	25,273	23,805	11,134	79,567	59%
3-Tree Contacts	1,105	197	387	550	2,239	2%
4-Lightning	623	330	471	2,194	3,618	3%
5-Defective Equipment	6,151	4,073	4,789	4,771	19,784	15%
6-Adverse Weather	2,288	6,217	19	3,291	11,815	9%
7-Adverse Environment	0	0	0	0	0	0%
8-Human Element	2,603	0	0	0	2,603	2%
9-Foreign Interference	952	249	326	776	2,303	2%
Total	**34,773**	**38,057**	**30,008**	**31,528**	**134,366**	**100%**

Table 5.2-14 summarizes the total number of customer interruptions by outage cause from 2022 to 2025, excluding Major Event Days ("MEDs"). Over the four-year period, ORPC recorded 134,366 customer interruptions. Loss of Supply was the leading cause, accounting for 79,567 customer interruptions (59% of the total), reflecting the significant impact of upstream supply interruptions on customer reliability. Defective Equipment was the second-largest contributor, responsible for 19,784 interruptions (15%), followed by Adverse Weather at 11,815 interruptions (9%). All other causes, including scheduled outages, tree contacts, lightning, human element, and foreign interference, each accounted for 17% of total customer interruptions. The results indicate that customer interruptions are largely driven by external supply events and equipment-related failures.

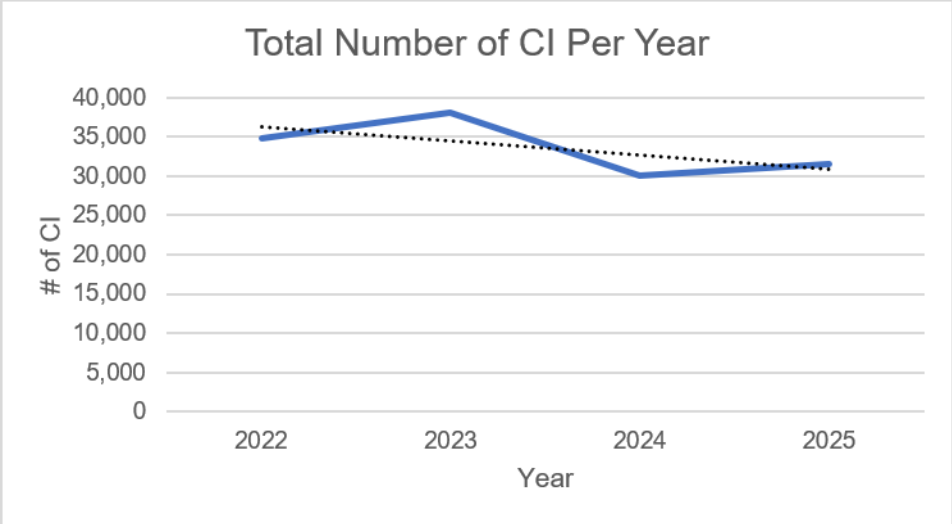


Figure 5.2-14: Total Number of Customers Interrupted by Year

Figure 5.2-14 illustrates the total number of customer interruptions recorded annually from 2022 to 2025, excluding MEDs. Annual customer interruptions remained relatively consistent over the period, ranging from approximately 30,000 to 38,000 interruptions.

Table 5.2-15: Customer Hours Interrupted Numbers (rounded) by Cause Codes – Excluding MEDs

Cause Code	2022	2023	2024	2025	Total CHI	%
0-Unknown/Other	150	435	12	6,704	7,301	3%
1-Scheduled Outage	2,590	1,234	430	8,826	13,080	5%
2-Loss of Supply	6,840	25,712	57,908	87,359	177,819	68%
3-Tree Contacts	1,182	1,046	4,668	486	7,382	3%
4-Lightning	741	250	707	5,786	7,484	3%
5-Defective Equipment	7,849	6,304	4,993	8,521	27,667	11%
6-Adverse Weather	5,971	7,858	11	4,321	18,161	7%
7-Adverse Environment	0	0	0	-	0	0%
8-Human Element	1,100	0	0	-	1,100	0%
9-Foreign Interference	1,006	382	442	693	2,523	1%
Total	**27,429**	**43,221**	**69,171**	**122,696**	**341,800**	**100%**

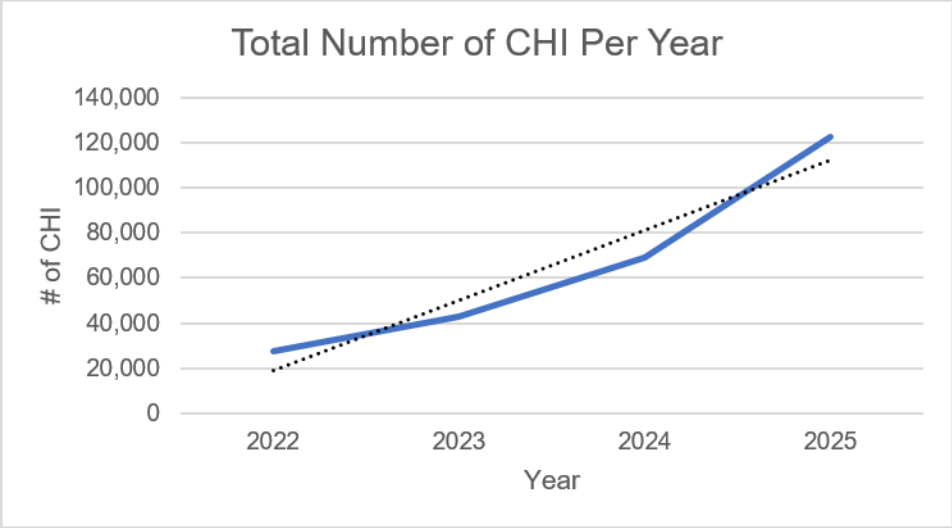


Figure 5.2-15: Total Number of Customers Interrupted by Year

Shown in Figure 5.2-15, the trend for total number of CI over the historical period is decreasing and the trend for total number of CHI over the historical period is increasing. The increase in CHI observed over the 2022-2025 period is largely driven by Loss of Supply.

When analyzing CI and CHI, Loss of Supply, Defective Equipment, and Adverse Weather are among the top three cause codes for both CI and CHI.

- Loss of Supply outages are caused by issues occurring upstream, are often beyond the control of ORPC. However, ORPC does what it can to minimize these outages (i.e.: grid hardening, predictive maintenance).
- The top cause code that can be controlled and managed by ORPC is Defective Equipment. As previously noted, there are several ongoing and planned efforts to manage the number of controllable outages and continue meeting reliability targets. These efforts include ongoing inspection and maintenance of assets to identify and mitigate potential problems and planned capital investment programs to replace assets before experiencing a failure that may cause an outage (i.e.: ORPC planned transformer, pole, recloser, switch, and switchgear replacement programs).
- Adverse weather is beyond the control of ORPC. However, ORPC has and will continue to design and invest in storm hardening measures (i.e.: physical improvements that can make utility infrastructure more resistant to weather), which also aligns with one of the top priorities identified by ORPC customers.

5.2.3.3 Distributor Specific Reliability Targets

ORPC established a corporate reliability target in 2026 that aligns with the Ontario Energy Board's prescribed methodology for annual reliability performance improvement targets issued to all distributors on October 3, 2025. This approach adopts the OEB's framework, which bases reliability targets on historical performance (five-year SAIDI and SAIFI averages), performance trends, and benchmarking adjustments, rather than developing a distinct alternative methodology.

By adopting the OEB-prescribed targets, ORPC ensures consistency with regulatory expectations and avoids the need to justify alternative performance thresholds. These targets are used as a key input into ORPC's capital and operational planning processes, supporting investment decisions aimed at maintaining or improving system reliability. This alignment demonstrates that reliability performance expectations are embedded within the utility's planning framework and are considered in the prioritization of distribution system investments.

5.3 ASSET MANAGEMENT PROCESS

This section outlines ORPC's Asset Management Process, describing key elements, practices and policies that informed the development of ORCP's Capital Expenditure Plan.

5.3.1 ASSET MANAGEMENT PLANNING PROCESS

5.3.1.1 Overview

This section details ORPC's Asset Management Process ("AM Process"), which represents the systematic approach applied by the utility to:

- Capture and organize all data relating to its physical assets as well as their current and future operating conditions.
- Manage and optimize the life cycle of the asset base via necessary in-field maintenance activities as well as proactive replacement of asset infrastructure.
- Develop prudent long-term and short-term investment plans which account for the needs of the system, preferences from customers as well as available resources.

ORPC's AM process proactively identifies, manages, and mitigates risks within their electricity distribution system, thereby allowing ORPC to achieve a desired level of service for their customer for a cost as accepted by their customers. This outcome closely aligns with ORPC's mission statement as follows:

"*Ottawa River Power Corporation is an electricity distributor committed to the pursuit of excellence in safety and reliability for the customers and communities we serve. We continue to seek innovation through energy conservation and technology while striving to be the trusted energy advisor for our customers and continuing to create value for our shareholders.*"

Integrated within ORPC's AM process, are Asset Management Objectives ("AM Objectives") that are largely driven by relevant legislative and regulatory obligations. This includes the following components from the OEB's DSC as well as the Ontario Energy Board Act, 1998:

- "A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short- term and long-term basis."
- "To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service."

Table 5.3-1 further illustrates the linkages between the Renewed Regulatory Framework for Electricity ("RRFE") and each of ORPC's strategic corporate goals, AM objectives, measures, and targets.

Table 5.3-1: Asset Management Objectives, Measures, Targets, and their relationship to the RRFE

RRFE Outcomes	Strategic Corporate Goals	Asset Management Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Health & Safety	To manage and operate the system in a safe manner and in accordance with good utility practices.	▪ Lost / Non-Lost Time Injury ▪ ESA Non-Compliance ▪ ESA Serious Electrical Incident Index (SEII)	1. WSIB Rate Class 10-year Benchmarks 2.Zero (Max 1 N) 3.SEII = 0
	Asset Management	To manage and optimize the life-cycle of the asset base via capital and maintenance investments.	DSP Implementation	DSP Progress Variance +/- 10% to Plan
Customer Focus	Customer Satisfaction	To ensure a continued and reliable supply of electricity, ORPC can continue being a trusted energy advisor for our customers.	▪ SAIFI ▪ SAIDI	Met OEB Reliability Performance Target (EB-2021-0307)
Financial Performance	Financial Management	Prudent and optimal investment planning to manage rate impacts while upholding corporate financial stability and long-term performance.	▪ Investment Spending ▪ DSP implementation	Capital Expenditure +/- 20% to Estimate DSP Annual Investment Category Spending +/- 10% of Plan
Public Policy Responsiveness	Environmental Awareness	Ensure that environmental risks are appropriately managed and that the environmental considerations are considered with respect to capital and maintenance planning of the system.	Reportable Spills to the Ministry of Environment	Zero Reportable Spills to Ministry of Environment from Code 5 Events

ORPC has applied its Asset Management Process and underlying objectives in order to develop the 2027-2031 Capital Expenditure Plan, which is further detailed in Section 5.4.

5.3.1.2 The Planning Process

This section outlines the major components and inter-relationships within ORPC's AM process, as well as the key inputs and outputs.

As illustrated in Figure 5.3-1, ORPC's AM process contains four stages, including (a) the gathering of data from ORPC's various systems and repositories, (b) the planning process that results in decision- making and the development of capital and maintenance investment programs, (c) execution of the capital and maintenance investment programs in the field, and (d) validation and review of the programs in order to drive continuous improvements. This process is cyclical in nature, as improvements established during the validation stages will result in enhancements to the input data, which then results in enhanced planning and execution.

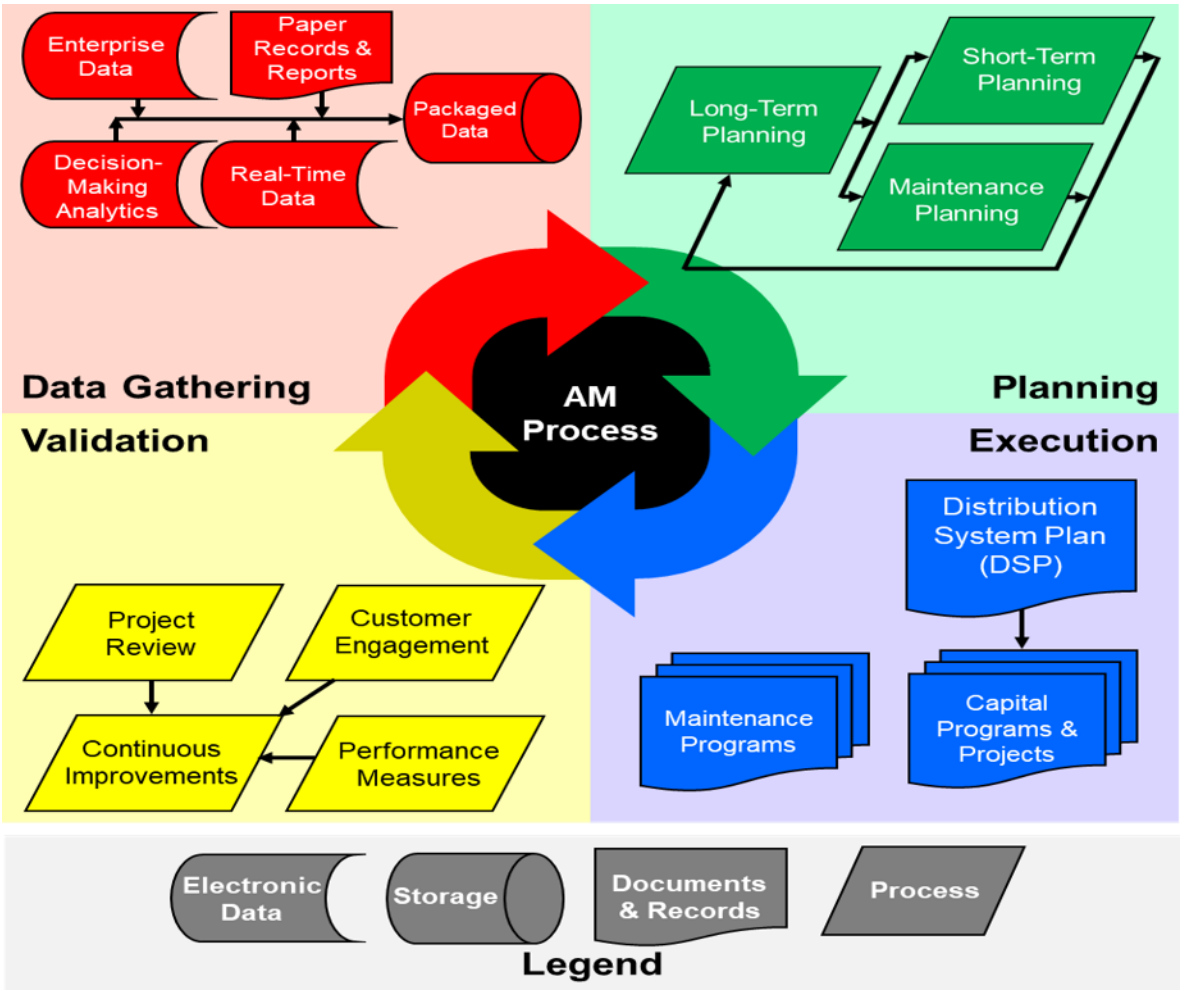


Figure 5.3-1: ORPC's AM Process & Underlying Components

Details for the four stages of ORPC's AM process:

5.3.1.2.1 Data Gathering

The first stage of ORPC's AM process is to gather data across all repositories within the utility to support the planning processes. ORPC's data is available in several formats, including data from ORPC's various enterprise

systems, data embedded with paper records and third-party reports, decision-making analytical data as well as real-time data. The Data Gathering process is further illustrated in Figure 5.3-2.

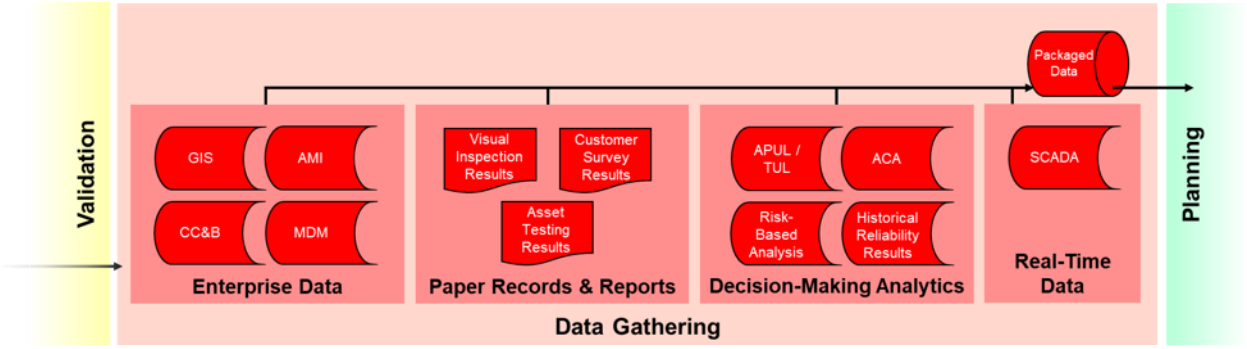


Figure 5.3-2: ORPC's Data Gathering Process

Key forms of data within ORPC include the following:

- **Enterprise Data**: This includes data that can be easily extracted from ORPC's enterprise systems including ORPC's Geographical Information System ("GIS"), Customer Care & Billing ("CC&B") system, Advanced Metering Infrastructure ("AMI") and Meter Data Management ("MDM") systems, respectively. The complexity to access this data remains low, as these enterprise systems contain internal functionality to allow for data extracts to be produced in accessible file formats, including Microsoft Excel (.xlsx) spreadsheets.

- **Paper Records & Reports**: This includes data that is captured from the field via maintenance, testing and inspection processes and recorded in paper format. This also includes information embedded within external reports, such as results from customer engagements (e.g., customer satisfaction surveys). Information as captured from the customer engagement results are used to help identify new investment opportunities within the system, ensuring that customer preferences are considered within the broader AM process. Paper record and report information remains the most complex to access, as the information must first be electronically converted.

- **Decision-Making Analytics**: ORPC's AM Process also integrates a number of analytical outputs that serve to support decision-making with respect to capital and maintenance planning activities. Key examples include the age-based assets past useful life ("APUL") analysis - which considers the TUL of each individual asset class, the asset condition assessment ("ACA") analysis, as well as a risk-based analysis that is performed when developing discrete projects as part of short-term planning procedures. Data captured from historical reliability events are separately stored within accessible Excel spreadsheets.

- **Real-Time Data**: Real-time operational data captured from ORPC's SCADA system is used to support the planning processes, including load forecasting. This information is easily accessible and extractable in electronic format.

Data packaging represents the final stage of data gathering process, where all data is brought to the same level of quality and usability, meaning that data integrated within paper records and reports is digitized into an electronic format, data is reviewed and appropriately scrubbed in order to alleviate any data quality concerns, and ultimately all data is consolidated into a centralized location for the purposes of optimally and efficiently supporting the "Planning" stage of the AM process, which includes long-term and short-term capital investment planning as well as maintenance investment planning procedures.

As noted previously, the AM process is cyclical in nature, meaning that any outputs that are derived from the "Validation" stage of the AM process are used to drive data quality and data accessibility improvements. As the foundational data is improved over time, these improvements are carried over proportionally in other parts of the AM process, including the "Planning" and "Execution" stages, respectively.

ORPC continues to strive for improvements to their data. During the last rate period ORPC implemented major advancements to its data gathering processes across the following areas:

- Advanced Pole Testing Implementation: ORPC introduced resistograph electronic drill testing into its routine wood pole inspection program. Resistograph electronic drill testing offers significant improvements over traditional structural testing methodologies. It is inherently less destructive to the pole structure, whereas traditional bore testing removes physical wood core samples that can inadvertently provide a pathway for future decay, rot, and insect infestations. Furthermore, electronic drill testing results provide quantifiable, objective data that does not rely on the subjective interpretation and judgment of an inspector. This advanced methodology also eliminates the need for manual excavation to evaluate below-grade pole conditions.

- Transformer Data Infrastructure Update: A comprehensive gathering of transformer inspection data was completed in conjunction with the utility's PCB testing program. This initiative drastically improved the baseline asset condition dataset for the utility's transformer fleet, filling critical historical data gaps and establishing a verified inventory baseline.

- Digital Field Inspection Operationalization: Digital inspection forms were fully operationalized across the field workforce. This modernization allows for direct data collection using mobile tablets, seamlessly linking asset photographs to specific inspection fields and establishing strict quality control measures, such as requiring mandatory field completions before an inspection task can be finalized.

5.3.1.2.2 Planning

The second stage of ORPC's AM process involves the usage of the gathered and consolidated data to initiate the planning sub-processes across the distribution system. This stage encompasses long-term and short-term planning alongside maintenance planning. The Planning process is illustrated in Figure 5.3-3.

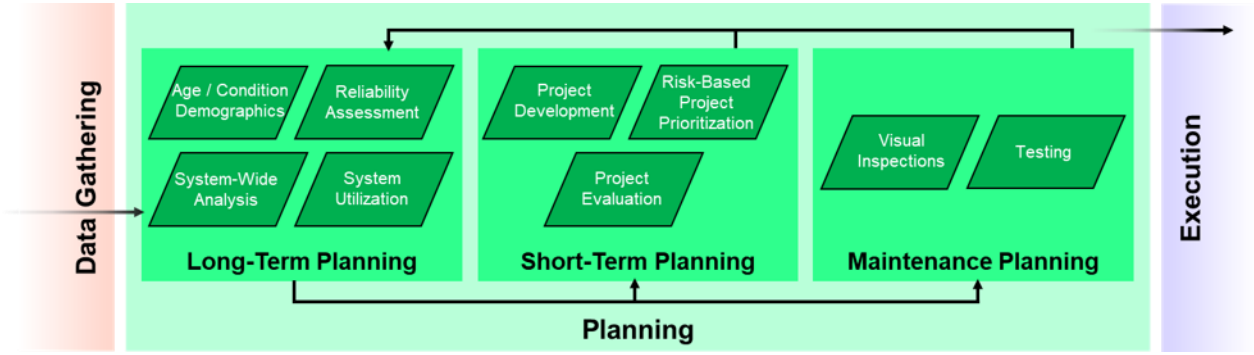


Figure 5.3-3: ORPC's Asset Management Planning Process

This planning stage operates in a continuous, cyclical loop. Outputs from Long-Term Planning establish parameters for Short-Term Planning and Maintenance Planning, while granular insights and data fields captured during short-term planning and field maintenance activities feed back to refine long-term strategic planning. These sub-processes are further explained below:

5.3.1.2.2.1 Long-Term Planning

The Long-Term Planning sub-process provides a holistic, system-wide evaluation of system requirements by combining asset age, physical condition, historical reliability, and load forecasting data. Key foundational elements within this sub-process include:

- Reliability Assessment: Historical reliability data is analyzed to produce a system-wide reliability assessment. This process identifies system-wide trends and risks that must be managed over the next 5-year period. This work ultimately provides the groundwork for targeted system investment and intervention.
- Assets Past Useful Life (APUL): Actual asset age data is used to segregate assets into the following age demographic categories:
    - already past their Typical Useful Life (TUL)
    - will pass their TUL within the next 5-year period
    - not approaching TUL within the next 5-year period

- Asset Condition Assessment (ACA): Inspection and testing results are ingested into condition-scoring algorithms to calculate individual asset Health Index (HI) values. Assets HI values enable assets to be subsequently categorized across standard condition categories:
    - Very Good
    - Good
    - Fair
    - Poor
    - Very Poor
- System Utilization: A comprehensive utilization analysis is performed to ascertain overall grid capacity constraints and peak demand needs. This analysis integrates customer and economic growth forecasts with localized substation and feeder-level capacity loading profiles to identify infrastructure constraint risks over the next 5-year period.

The Long-Term Planning sub-process culminates in a System-Wide Analysis, where output data from reliability, APUL, ACA, and system utilization assessments are synthesized to define long-term investment programs. Each program is mapped to one of the four core OEB investment categories based on their distinct primary and secondary drivers:

- System Renewal Programs: Prioritization integrates individual asset APUL and ACA metrics with Geographic Information System (GIS) layers to spatially identify localized risk clusters. This analysis explicitly accounts for asset-specific replacement drivers, such as legacy infrastructure non-compliance and environmental liabilities.
- System Service Programs: Tailored to manage system-wide capacity constraints, configuration vulnerabilities, and security of supply risks, these programs heavily leverage outputs from the Reliability Assessment and System Utilization analysis to isolate critical system constraints.
- System Access Programs: Planning is governed by customer connection timelines, third-party relocation requests, and statutory mandated service obligations. This planning stream also captures mandatory end-of-life replacement requirements for metering infrastructure.
- General Plant Programs: Planning for Fleet and Facilities infrastructure capital requirements couple asset age with historical maintenance cost trends to derive long-term investment plans. For Information Technology (IT) portfolios, investment decisions are driven by asset age, functional software/hardware obsolescence, and cybersecurity risk profiles. Operational Technology (OT) investments are justified based on quantifiable day-to-day operational efficiency improvements.

5.3.1.2.2.2 Short-Term Planning

The Short-Term Planning sub-process populates established long-term investment programs with targeted, discrete capital projects slated for execution within the next 5-year period. Key elements within this sub-process include:

- **Project Development**:

  Discrete projects are developed in alignment with investment programs drivers and definitions. These projects will be developed within specific neighbourhoods, subdivisions, and locations within ORPC's distribution system, and will leverage different input data depending on the primary (trigger) driver and secondary drivers of the program in question.

- **Risk-Based Project Prioritization**:

  Capital projects are evaluated and prioritized using a structured probability and consequence risk framework, focusing specifically on the Test Year revenue requirement. This optimization process ensures capital is directed to the highest-risk assets first. Because operational realities vary by asset class, tailored prioritization methods are deployed:

  System Renewal: Prioritization relies on quantitative evaluations of customer reliability, environmental, and safety risks.

  - Customer Reliability Risk (Feeder-Level Analysis): ORPC conducts localized risk profiling for every individual feeder in the distribution system. To quantify future performance, historical outage frequency and duration data are compiled for each feeder over a rolling 10-year period. Utilizing this historical dataset, a linear regression analysis is performed to forecast outage trajectories over the upcoming five-year planning horizon. Concurrently, APUL data and ACA results are evaluated to identify assets on each feeder that will reach end-of-life (EOL) during the planning period. EOL is strictly defined as an asset that has exceeded its Typical Useful Life (TUL) and has a condition rating of "Poor" or "Very Poor".

    By overlaying the EOL asset volume over the feeder outage forecast, ORPC can prioritize renewal projects on feeders demonstrating both a high likelihood of asset failure and a declining reliability performance trend.

    Replacement of specific assets on feeders that do not exhibit the worst overall reliability performance may also occur if the physical condition of the asset dictates that the localized customer reliability impact of a failure warrants immediate intervention.

  - Environmental Risk: Environmental risk evaluations focus on containment failure and environment contamination. For example, during project screening, older transformers in

poor condition are prioritized based on total insulating oil volumes and the localized impact of a potential oil release on adjacent soils, groundwater, or sensitive ecosystems.

- Safety Risk: Safety risk evaluations focus on the physical hazard an asset failure presents to utility personnel, the public, and third-party property. For instance, pole replacement prioritization accounts for geographic location factors, such as proximity to high-density pedestrian corridors, arterial roadways, or critical public infrastructure.

System Services: Within the System Services category, project prioritization is driven by quantitative evaluation asset capacity and utilization alongside qualitative strategic benefits for grid modernization and system flexibility.

General Plant: Within the General Plant category, project prioritization is driven by business risk of system failure or system breach.

- **Program Evaluation**:

Program evaluation is performed concurrently with risk-based prioritization. This evaluation applies to all programs proposed within the five-year planning horizon that are not otherwise driven by mandated statutory obligations, third-party requests, or direct customer service connections. For each program, ORPC develops multiple feasible alternatives (including a "status quo" or "deferral" option) and conducts a formal Cost-Benefit Analysis (CBA) to determine the most prudent investment path.

- Program Costs: Preliminary scoping and engineering designs are developed for each program alternative. Expenditure estimates are derived from historical resource effort tracking on programs of comparable scope and scale, adjusted for the most current labor rates, material costs, and contractor pricing.
- Program Benefits: Benefits will vary depending on the specific drivers for the alternate. The following benefits are generally considered:
  - Customer Reliability Benefit: Evaluated at the feeder level, this metric utilizes the five-year forecast of outage frequency established during the risk-based prioritization phase. Outage duration assumptions based on the drivers of each project alternative. The total forecasted customer minutes of interruption (CMI) prevented by an alternative is calculated as follows:

$$\text{Avoided CMI} = \text{Outage Frequency} \times \text{Duration} \quad \text{Connected Customers}$$

This reliability improvement is then monetized using the U.S. Department of Energy's (DOE) Interruption Cost Estimate (ICE) calculator to determine the Customer Interruption Costs saved. The customer benefit is defined as the value of these avoided interruption costs.

- Environment Benefit: Where applicable, environmental benefits are quantified based on risk exposure reduction. This is measured as the avoided financial costs associated with emergency response, site containment, and soil or groundwater remediation of an insulating oil release.
- Operation benefit: This benefit represents the avoided operational expenditure directly linked to emergency system restoration. It is quantified as the reduction in utility labor, overtime, and material costs required to locate faults and restore service following an asset failure.
- General Plant Benefit: For technology assets, benefits are quantified as the mitigation of business risk. This includes the avoidance of system failure operational costs (modeled on historical data) and the reduction of system breach or cyber-security risk costs (quantified using industry-standard benchmarks and expert-elicited engineering assessments).

As the Planning process is cyclical in nature, outputs from the short-term planning process will feed back into the long-term planning process, as discrete projects continue to be developed during the DSP planning period.

5.3.1.2.2.3 Maintenance Planning:

The maintenance planning framework is designed to support the continued, reliable operation of ORPC's distribution asset base throughout its Typical Useful Life (TUL). This is achieved through the systematic execution of standardized visual inspection and equipment testing programs.

Maintenance programs provide the critical data needed for Long-Term Planning to define long-term investment programs within the DSP. Conversely, Long-Term Planning may also drive modifications to maintenance schedules and inspection and testing scopes when new or additional data fields are required to refine the long-term planning of assets.

5.3.1.2.3 Execution

The third stage of ORPC's AM process involves the execution of the outputs produced from the Planning stage to deliver the Distribution System Plan and underlying capital and maintenance investment across the distribution system. The Execution process is illustrated in Figure 5.3-4.

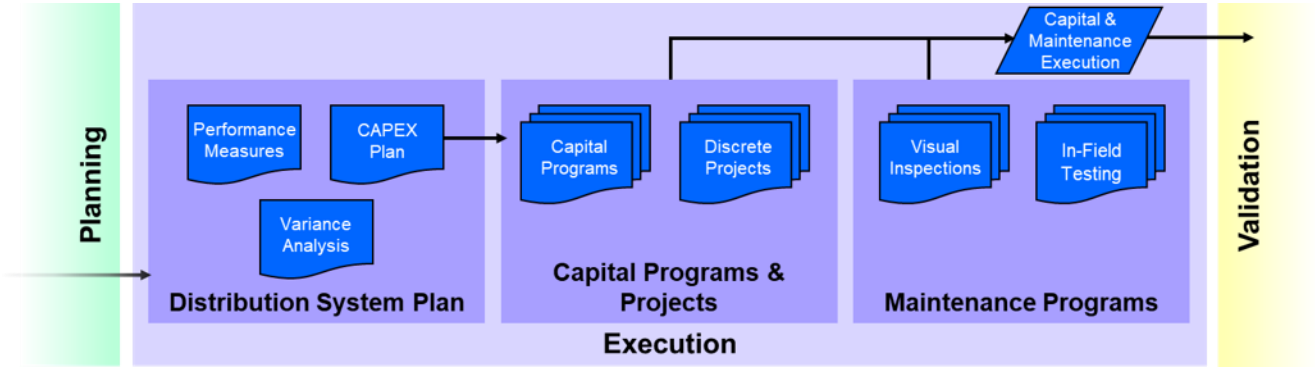


Figure 5.3-4: ORPC's Execution

5.3.1.2.3.1 Distribution System Plan

The DSP is designed to communicate the five-year capital investment plan ("CAPEX Plan"), communicate ORPC's third-party coordination activities and AM Process. The DSP provides the overall architecture and framework used to develop the CAPEX Plan. In addition to these outputs, the DSP communicates ORPC's historical execution performance via the Variance Analysis, which illustrates ORPC's actual spending in the historical 5-year period when compared to the planned estimates presented in the previous DSP. The Performance Measures presented in the DSP allow ORPC to demonstrate the overall effectiveness of its capital and maintenance investments over the planning period.

5.3.1.2.3.2 Capital Programs & Projects

The 5-year capital programs and discrete projects within the test year form the bulk of the CAPEX Plan, and these programs and underlying projects are executed during the term of the planning period. Details on ORPCs capital programs & projects to be executed within this DSP planning period (2027-2031) are presented in Section 5.4.

5.3.1.2.3.3 Maintenance Programs

Maintenance programs consist of visual inspections and in-field testing of asset infrastructure across the distribution system. Different asset classes will have different inspection and testing activities and performed on various cycles based on the complexity of the asset and the quantity of assets that must be inspected or

tested. These activities focus on proactively identifying emerging risks before they result in equipment failure or customer outages.

ORPC's maintenance program is designed to support the continued reliable operation of the asset base over its TUL, through the execution of visual inspection and testing activities. ORPC's maintenance activities meet the Minimum Inspection Requirements as required by the OEB Distribution System Code – Appendix C and the Electrical Distribution Safety requirements as specified by Ontario Regulation 22/04.

Execution-related outputs are further transitioned to the Validation stage of the AM Process to identify and enable continuous improvements for the utility.

5.3.1.2.4 Validation

The fourth and final stage of ORPC's AM process involves the validation of ORPC's DSP, including the review and assessment of ORPC's capital and maintenance investments implemented across the system, tracking performance measures and execution of customer engagements throughout the DSP planning period. The Validation process is further illustrated in Figure 5.3-5.

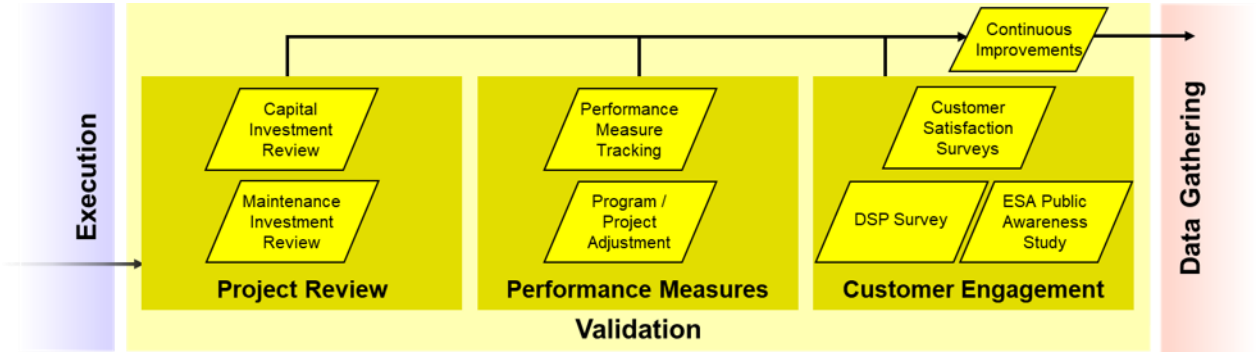


Figure 5.3-5: ORPC's Validation Process

5.3.1.2.4.1 Project Review

As capital and maintenance investments are executed in the field, ORPC will monitor these projects on an annual basis to identify opportunities for improvement. For example, ORPC continually monitors the actual costs for each project when compared to the planned estimates and will make necessary adjustments where necessary in the later years of the DSP planning period to minimize these variances. Execution of these projects also provides insight into the asset data, and any variances identified between the asset data records and actual assets in the field will be noted and corrected as part of future cycles of the AM Process.

5.3.1.2.4.2 Performance Measures

ORPC's performance measures are tracked and monitored throughout the year, and where necessary, ORPC will make the necessary adjustments to the related capital & maintenance investments to meet their desired targets. The performance measures for this DSP planning period (2027-2031) have been fully described in Section 5.2.3.

5.3.1.2.4.3 Customer Engagement

Throughout the DSP planning period, ORPC will execute a series of engagements with their customer base, including the DSP survey presented within this application (Appendix H), customer satisfaction surveys and ESA public awareness surveys. These surveys are further described in Section 5.2.2.1.1. Results from the Validation stage of the AM Process are further used to implement continuous improvements to the underpinning asset data that is collected during the Data Gathering stage of the process. Validation results also flow into the other stages of the AM Process, including Planning & Execution, as new projects will be developed within the later years of the DSP planning process in response to the results from the Project Review, Performance Measures and Customer Engagements, respectively. The Validation stage ultimately completes the full cycle of the AM Process, resulting in continuous improvements to be identified, developed, and implemented over the 5-year DSP planning period.

5.3.1.3 Important Changes to Asset Management Process since last DSP Filing

ORPC continuously refines and improves upon their asset management process. Since the last DSP filing ORPC has made significant advancement in its data gathering process. Specifics details can be found in Section 5.3.1.2.1 Data Gathering.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of System

OPRC is a local distribution company serving 11,819 residential and commercial customers in the City of Pembroke, Beachburg, Killaloe, and Almonte Ward, comprising a 35-square- kilometer urban service area in Eastern Ontario. The company is wholly owned by the Corporation of the City of Pembroke, the Corporation of the Township of Whitewater Region, and the Corporation of the Township of Killaloe, Hagarty and Richards, and the Corporation of the Municipality of Mississippi Mills.

5.3.2.2 Overview of Service Area

ORPC consists of four independent service areas as shown in Figure 5.3-6, Figure 5.3-7, Figure 5.3-8, and Figure 5.3-9.

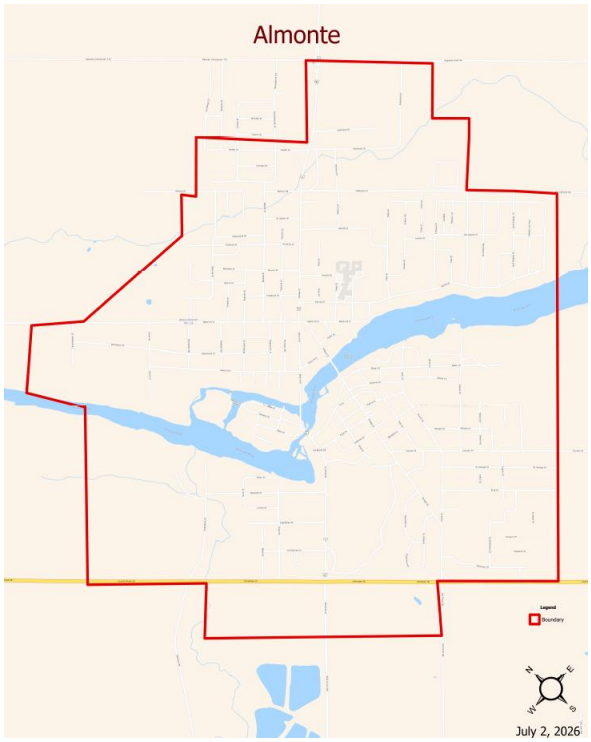


Figure 5.3-6: Almonte Service Area

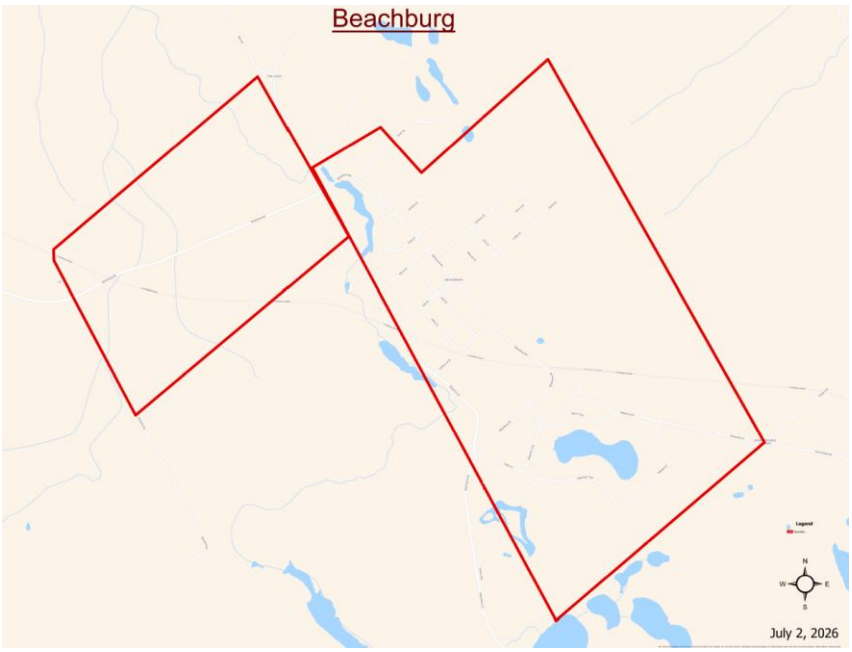


Figure 5.3-7: Beachburg Service Area

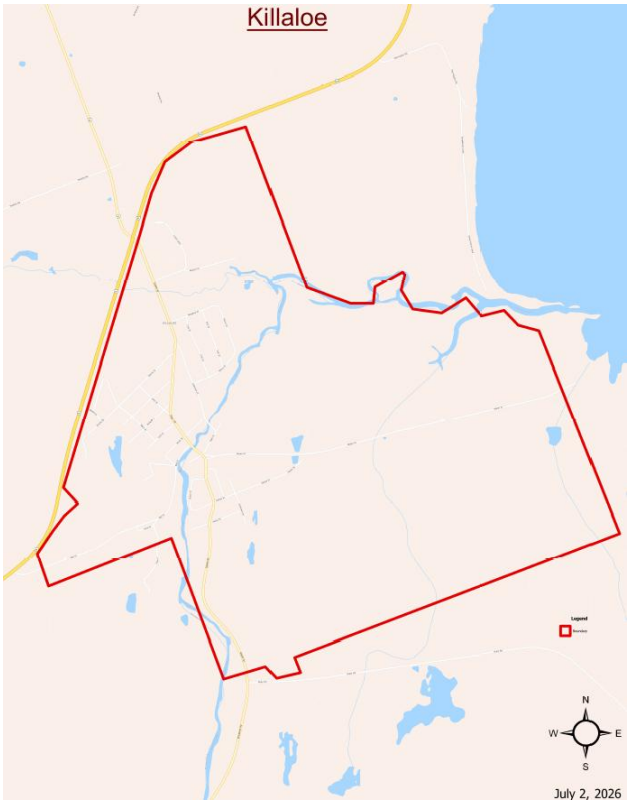


Figure 5.3-8: Killaloe Service Are

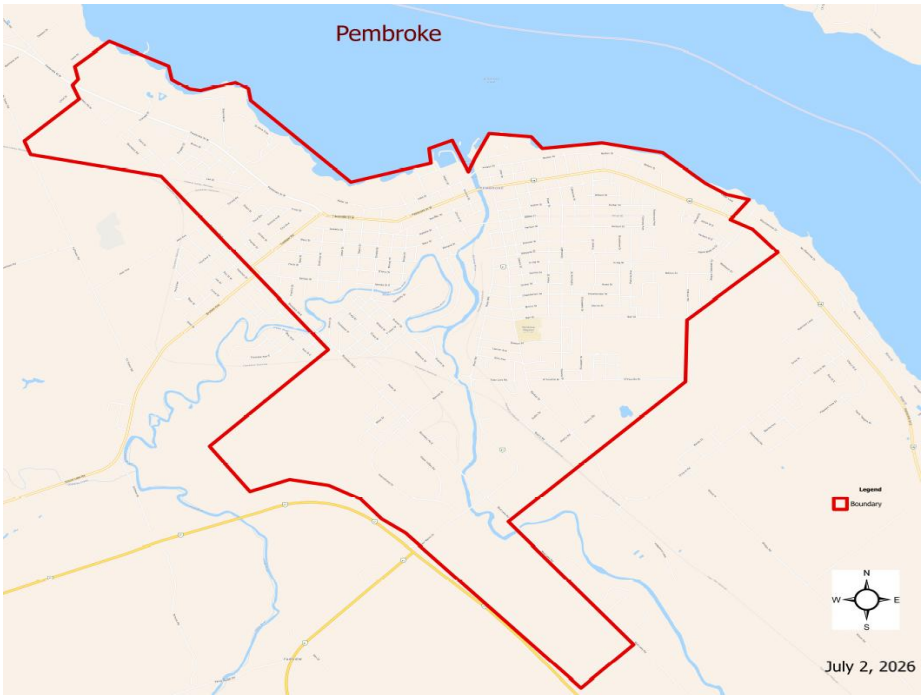


Figure 5.3-9: Pembroke Service Area

Within the four service areas, ORPC maintains 12 municipal substations ("MS"). ORPC receives power from five HONI transformation substations ("TS"). HONI Almonte TS supplies power to ORPC's Almonte service area at the 44kV system voltage via one feeder. The Almonte system is also connected with two power generators, Mississippi River Power Corporation and Enerdu Power Systems Ltd. The systems in Beachburg and Killaloe source the supply from HONI's Beachburg DS and Killaloe DS, respectively, which both are downstream from HONI's Cobden TS. The system in Pembroke is supplied by HONI's Pembroke TS at 44kV via two feeders and interconnected with Hydro Quebec. This service area is illustrated in Figure 5.3-6.

5.3.2.3 Customers Served

Table 5.3-2: ORPC Customer Type and Totals

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2022	10223	1274	141	11638
2023	10326	1267	139	11732
2024	10367	1271	137	11775
2025	10411	1273	133	11817

5.3.2.4 System Demand & Efficiency

Table 5.3-3: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2022	37022	33951	28696
2023	40784	35144	29565
2024	32711	36190	27493
2025	43079	34344	31335

Table 5.3-4: Efficiency of kWh Purchased by ORPC

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2022	185,090,066	196,811,692	6.33%
2023	180,529,177	190,301,502	5.41%
2024	182,078,136	190,368,282	4.55%
2025	195,591,287	205,380,812	5.01%

5.3.2.5 Summary of System Configuration and Assets

ORPC does not own any TS and instead receives power at the 44kV system voltage from four HONI TS/DS as listed in Table 5.3-5.

Table 5.3-5: Connected HONI Station for each ORPC Service Territory

ORPC Service Territory	HONI Station	HONI Upstream TS
Almonte	Almonte TS	
Beachburg	Beachburg DS	Cobden TS
Killaloe	Killaloe DS	
Pembroke	Pembroke TS	

ORPC's distribution system consists of 12 municipal substations operating a total of 13 power transformers, which are supplied by 63.3 km of 44 kV circuits. Nine of the substations distribute power at 4.16 kV, while the remaining three distribute at 12.47 kV. In total, these substations supply the distribution system via 37 customer feeders, comprising 29 operating at 4.16 kV and eight operating at 12.47 kV, as shown in Table 5.3-6. The combined primary circuit length of these feeders is 408.4 km, consisting of 389 km of overhead conductors and 84 km of underground cable. Finally, 340.6 km of secondary distribution circuits provide the final customer connections, divided into 211.2 km of overhead conductors and 129.4 km of underground cable.

Table 5.3-6: Distribution Feeders

Voltage (kV)	Feeder Count
4.16	29
12.47	8

Table 5.3-7: Station Transformer and Capacity (MVA)

Service Area	MS #	Transformer Bank	Rated Capacity (MVA)	Secondary Voltage (kV)
Pembroke	MS1	T1	5	4.16
	MS2	T1	6	4.16
	MS3	T1	5	4.16
	MS4	T1	5	4.16
	MS5	T1	3	4.16
	MS6	T1	10	12.47
		T2	10	12.47
	MS7	T1	10	12.47
	MS8	T1	10	12.47
Almonte	MS1	T2	5	4.16
	MS2	T1	5	4.16
	MS3	T1	3	4.16
	MS4	T1	5	4.16

5.3.2.6 Climate

Pembroke, known as “the heart of the Ottawa Valley,” experiences a warm, humid continental climate with a significant amount of rainfall throughout the year. The average annual temperature is 5°C, with an average of 821 millimeters of precipitation annually. Summer conditions typically span from June to mid-September, with July being the warmest month of the year. Temperatures generally drop below 0°C between November and March. Located 20 kilometers and 40 kilometers away from Pembroke respectively, Beachburg and Killaloe share nearly identical climate and weathering characteristics.

Almonte, located approximately 45 kilometers from Ottawa, experiences the same type of continental climate. Total annual rainfall in Almonte exceeds 800 millimeters. Heavy rainfall is common in July, which is also the warmest month of the year, experiencing average highs of 26°C. Freezing conditions and sub-zero temperatures typically take place from November through March, though localized frost and winter weather risks can extend across a broader seasonal window from late autumn into spring.

ORPC’s Asset Management Process inherently contributes to system hardening against these localized climate patterns by ensuring that all new and replacement assets are designed, procured, and installed in strict accordance with current industry standards, modern engineering practices, and updated utility specifications. These design standards increasingly incorporate structural resilience and climate adaptation considerations to mitigate extreme weather impacts. ORPC’s formal Vulnerability Assessment and System Hardening Assessment, developed in alignment with the OEB-prescribed methodology, is currently in progress and will further formalize these mitigation strategies upon completion.

5.3.2.7 Customer and Load Growth

Total customer accounts are projected to increase from approximately 12,000 in 2027 to 12,418 by 2031, representing an average annual growth rate of approximately 0.86%. Historically, capital investment levels for system growth have aligned closely with population growth and residential development activity, particularly within the Almonte service territory. As population growth continues to drive new residential developments and connection requests, gross capital expenditures for system expansion are expected to increase across the planning period to maintain adequate capacity and service reliability.

5.3.3 Asset Information

5.3.3.1 Asset Age and Condition

5.3.3.1.1 Asset Age

Figure 5.3-10 illustrates the system wide age profile for ORPC overhead and underground distribution system assets. These results are validated as May 2026.

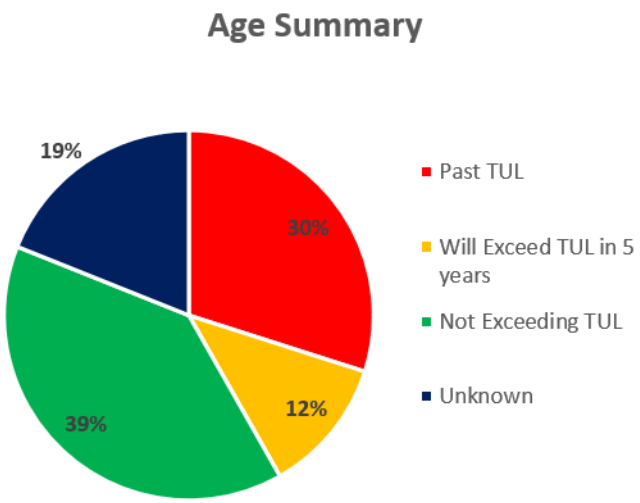


Figure 5.3-10: ORPC Age Profile of ORPC Distribution Assets

ORPC's system age profile highlights an infrastructure asset base requiring timely renewal. Currently, 40 percent of distribution assets have passed their Typical Useful Life (TUL). In the absence of sustained asset renewal investments, nearly half of ORPC's distribution asset portfolio will exceed its TUL by the end of the 2027–2031 planning horizon, significantly elevating operational and reliability risks.

Table 5.3-8 deals the wide age ORPC Municipal Stations (MS). These results are valid as of May 2026.

Table 5.3-8: ORPC Municipal Station Age

Substation Name	Substation Age
Pembroke MS#1	66
Pembroke MS#2	61
Pembroke MS#3	61
Pembroke MS#4	66
Pembroke MS#5	58
Pembroke MS#6	51
Pembroke MS#7	51
Pembroke MS#8	35

Substation Name	Substation Age
Almonte MS#1	17
Almonte MS#2	61
Almonte MS#3	61
Almonte MS#4	7

The highest TUL for any substation asset class is 45 years. With 75% of ORPC's municipal substations currently exceeding 50 years of age, most of the asset base is operating beyond its typical useful service life. A proactive substation renewal strategy is essential to mitigate equipment failure risks and maintain safe, reliable utility operations.

5.3.3.1.2 Asset Condition Assessment

5.3.3.1.2.1 Distribution Assets

Figure 5.3-11 illustrates the system wide condition profile for distribution overhead and underground assets. These results are valid as of May 2026. Further details on methodology and results can be found in Ottawa River Power Corporation Asset Condition Assessment Report 2026 in Appendix B.

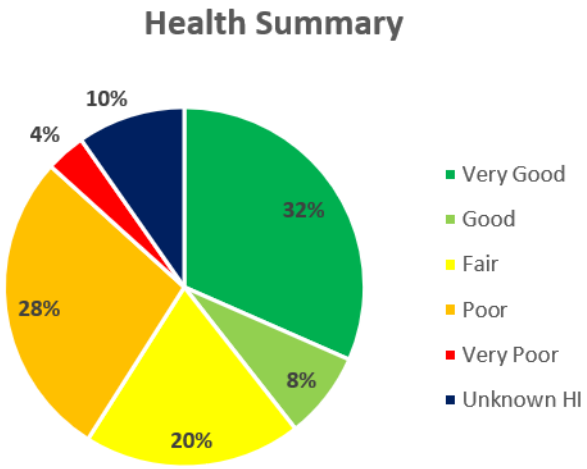


Figure 5.3-11: ORPC's ACA Results

The majority (60%) of ORPC's distribution assets are in Fair to Very Good condition. This indicates that ORPC has taken the necessary steps to manage its asset health and performance for the benefit of its customers. Approximately 8% of distribution assets are classified as Unknown. An asset's condition is classified as Unknown when there is insufficient data available to calculate its Health Index (HI) value.

ORPC continues to work to mitigate gaps in existing data so that more degradation parameters can be assigned actual grades, thus expanding the coverage of valid HI ratings and capturing all possible degradation across the

evaluated asset base. Furthermore, ORPC is working to expand the types of data captured to represent each asset's degradation with the greatest possible accuracy. Figure 5.3-12 and Table 5.3-9 illustrate the detailed condition assessment results across each of ORPC's evaluated distribution asset classes.

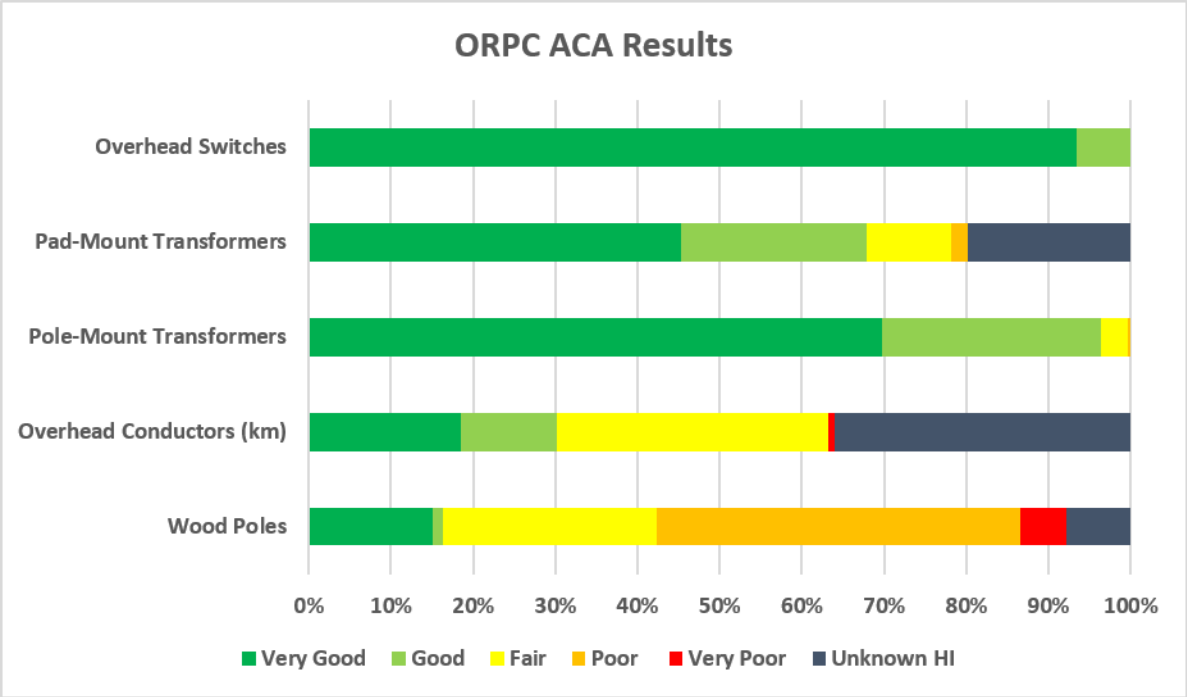


Figure 5.3-12: Health Index Distribution by Asset Class

Table 5.3-9: Health Index Distribution by Asset Class

Asset Category	Population	HI Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	3947	593	50	1031	1741	223	309	93%
Overhead Conductors (km)	389	72	46	128	0	3	140	79%
Pole-Mount Transformers	1047	731	279	34	3	0	0	92%
Pad-Mount Transformers	404	183	91	42	8	0	80	93%
Overhead Switches	446	417	29	0	0	0	0	80%

5.3.3.1.2.2 Substation Assets

The asset condition assessment methodology for substation asset was a qualitative engineering assessment framework that incorporates the underlying principles of probability and consequence evaluation through comparative condition and criticality groupings informed by inspection findings, operational context, asset age and technology considerations, available performance information, and professional engineering judgment.

The condition assessment results are summarized in Table 5.3-10. Further details on methodology and results can be found in Appendix C.

Table 5.3-10: ORPC Substation Condition Summary

Substation	Assessed Condition
Pembroke – MS#1	Fair
Pembroke – MS#2	Fair
Pembroke – MS#3	Fair
Pembroke – MS#4	Poor
Pembroke – MS#5	Fair
Pembroke – MS#6	Good
Pembroke – MS#7	Fair
Pembroke – MS#8	Fair
Almonte – MS#1	Good
Almonte – MS#2	Fair
Almonte – MS#3	Fair
Almonte – MS#4	Good

All substations were rated Fair or Good except for Pembroke – MS#4. Inspection results at Pembroke – MS#4 identified advanced age-related deterioration across primary switching equipment and supporting station infrastructure, including oil leakage observed on 44 kV breakers, bonding deficiencies, corrosion of structural elements, and general site degradation. These findings indicate a station experiencing broad-based asset aging rather than isolated deficiencies.

5.3.3.1.3 Asset Risks

Most of ORPC's OH Switches and Distribution Transformers analyzed are in Fair condition or better, with a significant portion of asset populations in Good or Very Good condition. ORPC's poles require attention in the coming years where a material number of assets are in or are approaching Poor or Very Poor condition. Due to limited data available, only an age assessment was performed for UG Cables and HI results were not calculated.

Overall, ORPC's substation risk profile is manageable but materially influenced by asset age and legacy infrastructure, particularly within portions of the Pembroke system. Several substations contain aging equipment that remains operable but is increasingly susceptible to unplanned outages, maintenance challenges, and condition-driven reliability events. In contrast, the Almonte system includes a higher proportion of newer infrastructure but faces stronger growth and electrification pressures that warrant continued monitoring and adaptive planning.

5.3.3.2 Asset Capacity & Utilization

ORPC performs load forecasting and system utilization analyses as part of the Planning stage of its Asset Management process to identify potential capacity constraints across the system. System utilization is assessed by comparing the peak load of each feeder and station transformer against their respective nameplate or calculated ratings. Feeders are rated based on calculated thermal ampacity, while station transformers are rated according to nameplate capacity.

ORPC has encountered isolated capacity constraints across its system and continues to manage these events operationally to prevent customer service disruptions. Technical studies are currently underway to fully evaluate localized system loading and capacity dynamics. To ensure capital prudence, ORPC has not proposed dedicated capacity-driven capital expenditures for this planning period pending the outcome of these detailed assessments.

5.3.3.2.1 Feeder Capacity and Loading

Table 5.3-11 presents feeder utilization data across ORPC's distribution system. The peak load shown reflects the maximum load recorded across any individual phase during substation maintenance inspections. This dataset is used to analyze capacity constraints at the feeder level. Feeders with utilization exceeding 100 percent have been flagged for further review, and detailed loading and forecasting studies are currently in progress to determine whether feeder upgrades, re-conductoring, or load redistribution across adjacent circuits is required.

Table 5.3-11: ORPC Feeder Loading and Utilization

Feeder	Planning Capacity (Amps)	2025 Peak Load (Amps)	2025 Utilization
Almonte			
1-1	400	223	56%
1-2	400	248	62%
1-3	400	398	100%
2-1	400	85	21%
2-2	400	257	64%
2-3	400	209	52%
3-1	400	95	24%
3-2	400	170	43%
4-1	400	180	45%
4-2	400	187	47%
Pembroke			
1-1	300	150	50%
1-2	300	400	133%
1-3	300	380	127%

Feeder	Planning Capacity (Amps)	2025 Peak Load (Amps)	2025 Utilization
1-4	300	195	65%
2-1	300	165	55%
2-2	300	205	68%
2-3	300	80	27%
2-4	300	90	30%
2-5	300	225	75%
3-1	300	100	33%
3-2	300	220	73%
3-3	300	230	77%
3-4	300	50	17%
4-1	300	177	59%
4-2	300	86	29%
4-4	300	243	81%
4-5	300	244	81%
5-1	300	150	50%
5-4	300	140	47%
6-1	300	250	83%
6-2	300	185	62%
6-3	300	155	52%
6-4	300	110	37%
7-1	300	160	53%
7-2	300	170	57%
8-1	300	270	90%
8-2	300	270	90%

5.3.3.2.2 Transformer Capacity and Loading

Table 5.3-12 details substation transformer peak loading and utilization across the substation system. Utilization is calculated using the non-coincident sum of the peak loads recorded on the individual feeders supplied by each transformer relative to the transformer's rated secondary current. Transformers exhibiting utilization above 100 percent have been flagged, and detailed loading and forecasting studies are underway to evaluate potential transformer upgrades or operational load transfers.

Table 5.3-12: ORPC Substation Transformer Utilization

Municipal Station	Transformer	Rated Capacity (kVA)	Rated Secondary Current Rating (A)	2025 Non-Coincident Feeder Peak (A)	2025 Utilization
	Almonte				
MS1	T2	5,000	694	869	125%
MS2	T1	5,000	694	551	79%
MS3	T1	3,000	416	265	64%
MS4	T1	5,000	694	367	53%

Municipal Station	Transformer	Rated Capacity (kVA)	Rated Secondary Current Rating (A)	2025 Non-Coincident Feeder Peak (A)	2025 Utilization
	Pembroke				
MS1	T1	5,000	694	1,125	162%
MS2	T1	6,000	833	765	92%
MS3	T1	5,000	694	600	86%
MS4	T1	5,000	694	750	108%
MS5	T1	3,000	416	290	70%
MS6	T1	10,000	463	265	57%
	T2	10,000	463	435	94%
MS7	T1	10,000	463	330	71%
MS8	T1	10,000	463	540	117%

5.3.4 Host & Embedded Distributors

ORPC is an embedded distributor who receives its supply from host distributor HONI.

5.3.5 Asset Lifecycle Optimization Policies and Practices

This section provides further details on ORPC's asset lifecycle optimization policies and practices, which are driven by ORPC's AM Process. Asset lifecycle optimization within this context refers to the ongoing management of ORPC's asset infrastructure, from its initial purchase, installation in the field, ongoing maintenance of the assets while they remain in operation, and their eventual replacement or rehabilitation. Asset lifecycle optimization is performed at each sub-process within the parent Planning stage of the AM Process, including long-term and short-term capital planning and maintenance planning sub-processes. The following sub-sections provide further details and insight into the asset lifecycle optimization policies and practices that are executed by ORPC.

5.3.5.1 Asset Lifecycle Optimization Practices

This section provides further details on how ORPC initiates replacement and refurbishment decision- making within the long-term, short-term and maintenance planning sub-processes, and how this decision-making ultimately influences the development of the CAPEX Plan.

5.3.5.1.1 Long-Term Lifecycle Optimization Practices

ORPC's long-term planning sub-process results in the identification and development of the projects within the DSP. Each project is designed to mitigate specific risks identified the system, either through the replacement of asset infrastructure, or through the installation of new infrastructure that is reconfigured in such a manner

that the risk is mitigated. The actions taken by the utility to resolve the risk will be different depending on the primary and secondary drivers associated with that action.

System Renewal programs are driven by one or more of the following risk-based criteria:

- Asset Condition and Performance Risk: Mitigating the elevated failure risk of assets that have exceeded their TUL or are categorized in "Poor" or "Very Poor" condition.
- Functional Obsolescence: Replacing legacy assets that are no longer supported by vendors or cannot meet modern operational requirements.
- Non-Compliance with Standards: Addressing assets that do not align with current ORPC engineering, design, or technical standards.
- Environmental Risk: Minimizing environmental impacts, such as equipment fluid leaks or greenhouse gas emissions.
- Safety Risk: Eliminating identified hazards to ensure the safety of the public and field personnel.

Lifecycle optimization at ORPC relies on our long-term planning framework to proactively identify, prioritize, and schedule asset replacements before performance degrades or risks exceed acceptable thresholds.

Table 5.3-13 provides further insight into the practices utilized for ORPC's program within the System Renewal category.

Table 5.3-13: Summary of Asset Lifecycle Optimization Practices for System Renewal Programs

Program	Asset Lifecycle Optimization Practice
Overhead Renewal	• Failure Risk: This program predominantly consists of poles, pole-mounted transformers and overhead switches that have either reached or will reach their TUL within the DSP planning period or are in Very Poor or Poor condition and must be replaced. • Environmental Risk: Pole-mounted transformers with known quantities of PCBs are also being targeted for replacement due to the associated environmental risks. • Functional Obsolescence: Over the course of the 5-year plan, legacy overhead infrastructure connected to ORPC's 4.16 kV system that is functionally obsolete will also be replaced. This infrastructure also happens to be the oldest vintage within ORPC's overhead system, and therefore many of these assets are also at or past their TUL and/or in Very Poor or Poor condition. Additionally, ORPC has poles within its system that are legacy non- standard designs. • Refurbishment: Overhead conductor by itself is not considered a driver for Overhead Renewal, due to its relatively long TUL and the fact that none of these assets are in Very Poor or Poor condition. Conductor spans will typically be replaced along with the poles and transformers where Overhead Renewal investments have been identified. However, in certain cases where TUL and ACA results are favorable, overhead conductors will be reused and reinstalled

Program	Asset Lifecycle Optimization Practice
	as part of the new overhead infrastructure.
Underground Renewal	• Failure Risk: This program predominantly consists of underground transformers and cables that have either reached or will reach their TUL within the DSP planning period or are in Very Poor or Poor condition and must be replaced. This program includes the replacement of first-generation cross-linked polyethylene ("XLPE") cables with a higher rate of insulation failure. • Environmental Risk: Underground transformers with known quantities of PCBs are also being targeted for replacement due to the associated environmental risks. • Functional Obsolescence: The oldest vintage underground cables (installed prior to 1990) are also functionally obsolete due to their direct-buried installation. When these cables fail reactively in the field, the only course of action is to splice the cable, which represents a repair of the cable as opposed as an outright replacement. These cables are replaced with new cables-in-conduit, where the entire cable segment can be fully replaced from device to device should it fail in the future.
Stations Renewal	• Failure Risk: This program predominantly consists of power transformers, circuit breakers, protection relays, station switches and batteries that have either reached or will reach their TUL within the DSP planning period or are in Very Poor or Poor condition and must be replaced. • Functional Obsolescence: Certain station asset classes, such as protection relays, will also be replaced due to functional obsolescence concerns, particularly in cases where the assets in question are no longer being supported by the original manufacturer, or where spare parts are not available. • Refurbishment: As part of the program execution, the legacy stations assets that are found to be in good working condition will be kept as spares. These assets can then be redeployed into the system should a similar legacy stations asset fail reactively. These spares ultimately reduce the impacts of the outage event, by allowing ORPC to mitigate the reliability event during a reactive scenario as quickly as possible.

System Service programs are largely driven by critical system-wide issues that go "above-and-beyond" any individual asset or group of assets to address System Constraints or Reliability (due to Security-of-Supply) concerns as identified by the System-Wide Analysis. Table 5.3-14 provides further insight into the practices utilized for ORPC's program within the System Service category.

Table 5.3-14: Summary of Asset Lifecycle Optimization Practices for System Service Programs

Program	Asset Lifecycle Optimization Practice
System Enhancements	• Reliability: This program will serve to mitigate serious security-of-supply issues, where the failure of assets will result in system-wide reliability concerns to a broad portion of ORPC's service area and connected customers. Assets will either be replaced or reconfigured in a manner that the security-of-supply risk is

Program	Asset Lifecycle Optimization Practice
	appropriately mitigated. • System Constraints: As discussed in Section 5.3.3.2, current station and feeder utilization levels do not reveal emerging capacity risks within ORPC's distribution system over the next 5-year period. However, system constraints can also emerge should critical failures occur along the 44kV supply points that service the Pembroke and Almonte service areas, respectively. The failure of assets would result introduce serious system constraints and instabilities within ORPC's system. This program is expected to reinforce these supply points through the replacement of the associated infrastructure.
Station Expansion	• Reliability: This program will serve to replace the existing SCADA-related communication infrastructure at substations within the Pembroke service area. Should this infrastructure fail, the utility will be unable to detect outages at the control or remotely operate their circuit breakers or monitor substation loading and other telemetry. The inability to detect outages due to a SCADA system failure would result in prolonged interruptions to the customer. • Functional Obsolescence: The existing remote terminal units ("RTUs") and electro-mechanical relays no longer align to ORPC's standards, and there are limited spare parts and manufacturer support for these assets. Within the scope of this investment program, these assets will be replaced with the newest RTUs and relays that align to current ORPC standards. • Refurbishment: As part of the program execution, the legacy RTUs and relays that are removed will be kept as "grey" spares if they are found tobe in working order. These assets can then be redeployed into the system should a similar legacy RTU or relay fail reactively.These spares ultimately reduce the impacts of the outage event, by allowing ORPC to bring the • SCADA system back to service as quickly as possible.

System Access programs are non-discretionary investments largely driven by mandated service obligations, customer service requests and coordination with third-party entities such as the City of Pembroke, The Municipality of Mississippi Mills, The Township of Whitewater Region or the Township of Killaloe, Hagarty and Richards, respectively. Table 5.3-15 provides further insight into the lifecycle optimization practices being undertaken within ORPC's System Access programs.

Table 5.3-15: Summary of Asset Lifecycle Optimization Practices for System Access Programs

Program	Asset Lifecycle Optimization Practice
Metering	• Mandated Service Obligations: ORPC is obligated as per the DSC and Measurement Canada requirements to replace faulty or expired meters with new metering assets.

Program	Asset Lifecycle Optimization Practice
Externally Initiated Plant Relocation	• Third-Party Infrastructure: This program is designed to replace existing asset infrastructure based upon third-party requests from the city. Such requests may include redesign, rebuilding or widening of existing roadways within ORPC's service area. This investment program therefore presents an opportunity for ORPC to coordinate with the city to replace aging infrastructure. Efficiencies are achieved in this manner by replacing or relocating infrastructure in conjunction with the third-party (City) activities.

General Plant programs represent modifications, replacements or installation of new assets, including facilities, IT and fleet investments, that serve to provide the backbone of ORPC's 24/7 operations and management of the distribution system. Table 5.3-16 provides further insight into the lifecycle optimization practices being undertaken within ORPC's General Plant programs.

Table 5.3-16: Summary of Asset Lifecycle Optimization Practices for General Plant Programs

Program	Asset Lifecycle Optimization Practice
Information Technology	• Business Operations Efficiency: This program deals with the replacement of end-of-life IT hardware and software that are crucial to the continued operation and management of the system. Software upgrades also allow for operational improvements within the organization. • Functional Obsolescence: Legacy software within the organization is either no longer supported or must be supported at a higher cost by the vendor. Therefore, it is in the best interest for ORPC to replace this software with the newest versions such they are properly supported in the most economical manner.
Facilities	• Refurbishment: This program is designed to extend the lifespan of ORPC's existing service centers in Pembroke and Almonte through the introduction of repairs that will mitigate emerging and existing deficiencies and mitigate potential safety and environmental risks to ORPC employees and the general public.
Operational Technologies	• System Maintenance Support: This program does not directly result in the replacement of any specific assets but instead introduces new in-field technologies that can be leveraged for the purpose of enhancing ORPC's maintenance programs, such that more granular data can be made available to support ORPC's decision-making analyses such as ACA. Ultimately, the introduction of these technologies allows for assets to be replaced or repaired to mitigate potential failure risk.
Fleet	• System Maintenance Support: This program deals with the replacement of end of life and faulty vehicles that are crucial in ORPC carrying out it day to

5.3.5.1.2 Short-Term Lifecycle Optimization Practices

As part of the short-term planning subprocess, discrete projects are developed within the investment programs and are prioritized for the test year.

A risk-based project prioritization is performed in order to select and prioritize projects for the test year of the DSP planning period, leveraging both probability and impact-related results. Probabilistic results such as ACA and APUL results are leveraged in conjunction with connected customer count for each project, which quantifies the possible Impacts of failure. Consideration of both probabilistic and impact-related results to select projects for the test year results in an overall risk-based approach that is being leveraged. These probabilistic and impact- related inputs are further explained in Section 5.3.1.2.

The specific asset lifecycle optimization practices that are applied to the assets within a given project – in this case, replacement, or refurbishment – will generally align to the asset lifecycle optimization practices as defined in Section 5.3.5 for the parent investment program that the project is situated within.

The complete grouping of projects in the test year within a given program are further evaluated by applying a Project Evaluation procedure. This procedure will consider different timing and pacing options for the group of projects within the test year which will ultimately influence the overall timing of the lifecycle optimization practices that are applied to the underlying assets. This procedure is further described in Section 5.3.5.1.3.

5.3.5.1.3 Maintenance Lifecyle Optimization Practices

In-field maintenance which consists of visual inspections and in-field testing of asset infrastructure is performed across the distribution system. Different asset classes will have different maintenance cycles, depending on the complexity of the asset and components that must be inspected or tested.

ORPC's maintenance program is designed to support the continued reliable operation of the asset base over its TUL, through the execution of visual inspection and testing activities. ORPC's maintenance activities meet the Minimum Inspection Requirements as required by the OEB Distribution System Code – Appendix C and the Electrical Distribution Safety requirements as specified by Ontario Regulation 22/04.

ORPC's substation infrastructure, including power transformers, circuit breakers, protection relays, station switches and batteries are inspected monthly.

Overhead and underground distribution assets receive visual inspections on a three-year cycle as per the schedule noted below:

- Year 1: Village of Beachburg and the City of Pembroke from the most easterly boundary of the City of Pembroke to the Muskrat River.
- Year 2: Town of Killaloe and the centre of the City of Pembroke from the Muskrat River to Trafalgar Road. The Town of Almonte east of Mississippi River to the most easterly boundary of Almonte.

- Year 3: City of Pembroke from Trafalgar Road to the most westerly part of the City of Pembroke boundary. The Town of Almonte west of the Mississippi River to the most westerly boundary of Almonte.

Visual inspection results are generally recorded in paper format. However, as noted in Section 5.3.3.1.2, ORPC continues to rollout new tools embedded within their GIS system to allow in-field inspectors to enter visual inspection results directly in electronic format as part of continuous improvements. As part of their IT investments (as discussed in Section 5.2.1.3.4), ORPC is also rolling out iPads to allow for electronic data entry to be performed directly from the field. Specific maintenance activities that are performed for overhead, underground and stations infrastructure are noted in Table 5.3-17.

Outputs from the maintenance program feed directly into the capital investment decision-making process, thus establishing a linkage between capital and maintenance investments. As an example, key outputs from the maintenance program, including visual inspection and testing results, are leveraged as part of the ACA process in order to derive the HI results for individual assets. This information in turn, is leveraged to drive capital investment decisions on those assets as part of the Planning stage of the AM Process.

Table 5.3-17: Maintenance Activities for ORPC's System Assets

Assets	Description of Maintenance Activities
Overhead Assets	• Transformers – Visual inspections are performed to identify leaks, damaged bushings, defective connections, grounding concerns, and missing or illegible nomenclature. • Poles – Visual inspections are performed to identify leaning or damaged poles, woodpecker damage, access concerns, and unauthorized posters or attachments. • Switching and Protective Devices – Visual inspections are performed to identify visible damage, deterioration, improper positioning, or other abnormal conditions. • Overhead Conductors – Visual inspections are performed to assess conductor sag, insulation condition, damage, and overall appearance. • Insulators – Visual inspections are performed to identify cracked, broken, contaminated, or flashed insulators. • Guys and Guards – Visual inspections are performed to identify missing or damaged guards, slack or damaged guys, broken guy insulators, and pulling anchors. • Vegetation and Access – Visual inspections are performed to assess vegetation in close proximity to electrical equipment and conductors, as well as access to poles and back-lot facilities. • Nomenclature – Equipment identification and tags are inspected to confirm they are present, accurate, and legible.

Assets	Description of Maintenance Activities
Underground Assets	• Cabinet Condition – Visual inspections are performed to identify loose or broken hinges, damaged paint, corrosion, rust, dents, graffiti, vandalism, and other physical damage. • Cabinet Access and Security – Visual inspections are performed to confirm that locks and penta-bolts are present and secure, and that vegetation, landscaping, or other obstructions do not restrict safe access. • Pad Placement, Grading, and Drainage – Inspections are performed to identify cabinet movement, improper placement on the pad, grading changes, soil erosion, settlement, and groundwater drainage concerns. • Cable Terminations and Connections – Visual inspections are performed to identify evidence of flashover, tracking, cable distortion, missing test points, damaged terminations, and discoloration of neutral or other connections. • Infrared Inspection – Infrared inspections are performed on all accessible electrical connections to identify abnormal heating or potential connection defects. • Switching and Protective Devices – Visual inspections are performed to identify visible damage, deterioration, abnormal positioning, or other deficiencies affecting switching and protective equipment. • Insulators – Visual inspections are performed to identify cracked, broken, contaminated, tracked, or flashed insulators. • Grounding – Grounding connections and conductors are visually inspected for damage, corrosion, looseness, or missing components. • Oil Leaks – Equipment is inspected for evidence of oil leakage, staining, or deterioration of seals and gaskets. • Nomenclature and Identification – Phase indicators, unit numbers, equipment labels, and identification tags are inspected to confirm they are present, correct, undamaged, and legible. • Safety Decals – Safety and warning decals are inspected to confirm they are present, visible, legible, and in good condition.
Substation Assets	• Power Transformers – Testing performed by third-party vendor, including dissolved gas analysis and oil quality analysis. Visual inspection performed to look for oil leaks, bushing condition, main tank corrosion, assess cooling equipment, gauges, gas pressure relief and relays, transformer foundation, conservator, and grounding system. • Circuit Breakers – Visual inspections performed to examine control & operating mechanism components, oil leaks, foundation, support steel and grounding. • Station Switches – Visual inspections performed to examine bushing/insulators, disconnect blades & contacts, power drive train assembly, conductors and connectors and foundation/support steel/grounding. • DC Batteries – Visual inspections performed to assess battery cells & trays, battery plate condition, connections, straps/cables, and electrolyte levels. • Substation Signage – Ensure proper signs are installed and legible and replace damaged or missing signs if necessary

Assets	Description of Maintenance Activities
	• Substation Fencing – Check for damage, vandalism, proper grounding in place, public access under or over fence. • General Building Condition – Visual inspections to assess broken windows, eaves, ice buildup, vandalism, paint, leaking roof.

5.3.5.2 Processes and Tools to Identify, Prioritize & Optimize System Renewal Spending

5.3.5.2.1 Identification

The probability or likelihood of failure plays an important role in determining whether it is necessary to perform proactive replacement on a given asset, or for a group of assets as part of a discrete project. The key decision-making tools determine the probabilistic trends and identify emerging asset-related issues are:

- Reliability Assessment
- Assets Past Useful Life (APUL)
- Asset Condition Assessment (ACA)

5.3.5.2.1.1 Reliability Assessment

A reliability assessment is performed to analyze historical trends with respect to internationally accepted indices such as SAIDI and SAIFI, impacts from Major Event Days, as well as underlying cause codes including:

- Unknown / Other
- Scheduled Outages
- Loss of Supply
- Tree Contacts
- Lightning
- Defective Equipment
- Adverse Weather
- Adverse Environment
- Human Element
- Foreign Interference

Outputs from the reliability assessment provide a foundational starting point into the capital investment programs that ORPC must develop.

5.3.5.2.1.2 Assets Past Useful Life (APUL)

The APUL analysis assesses the age of assets at both an equipment and system level. APUL indicates if an asset has exceeded or will be exceeding its TUL value within the 5-year DSP planning period. The TUL values utilized by ORPC are based upon the Asset Depreciation Study for the Ontario Energy Board report produced in 2010, shown in Table 5.3-18. This report provided ranges of useful lives for distribution asset classes, as well as a TUL value.

Results from the APUL analysis can be utilized in two ways. At a system level, the results can be used to provide an indication with respect to volume of assets that may be approaching their end-of-life criteria which will require significant investment requirements – these are referred to as "asset walls". By understanding the timing of assets that will be approaching or have already exceeded their TUL, the utility can proactively manage these asset walls over time via the replacement of assets within the system. Results at the asset level can be leveraged to identify assets that are heavily aged and expected to approach their TUL and require replacement and/or repair within the DSP planning period.

Table 5.3-18: TUL values that ORPC has assigned to assets

Asset Class	TUL
Pole	45
Overhead Conductor	60
Overhead Transformers	40
Overhead Switches	45
Underground Cables	40
Underground Transformers	40
Power Transformers	45
Circuit Breakers	45
Protective Relays	35
Station Switches	50
Battery	20

5.3.5.2.1.3 Asset Condition Assessment

The ACA analysis is designed to leverage in-field data, including visual inspection and testing information collected for individual assets, to calculate an HI result for each asset within ORPC's system. Whereas the APUL analysis will identify the oldest assets in the system, the HI analysis will provide further indication on which assets are experiencing accelerating aging and degradation due to a specific degradation mode that has been identified via the maintenance program. As the ACA analysis leverages results captured from ORPC's maintenance program, this analysis serves to provide a vital linkage between the maintenance activities and capital investment activities.

Figure 5.3-13 provides the further breakdown of a typical HI formulation. Each HI formula contains a series of degradation factors, which represent the assets' aging mechanisms, testing results or failure modes. Each degradation factor is weighted based upon its importance in determining the assets' end- of-life. Each asset will be assigned a specific condition indicator score, which relates to the state of the degradation modes occurring within the asset, with 4 being the highest score indicating characteristics of a brand-new asset, and 0 being the lowest score indicating characteristics of an asset with non-repairable damages.

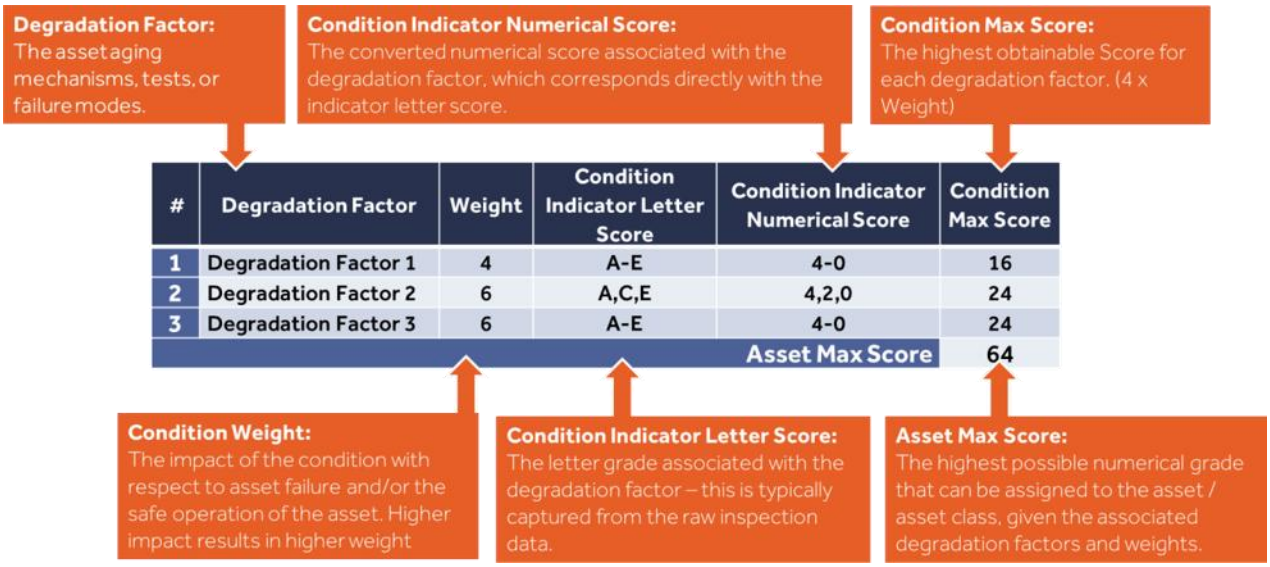


Figure 5.3-13: ACA – Health Index Formulation

The HI is calculated by multiplying each individual degradation factor condition indicator score with its associated weight and then summing the total scores of each degradation factor and dividing this with a maximum score and multiplying this value by 100, which is further illustrated in Equation 3-1.

This procedure allows for the HI to be a normalized score, from 0 (Very Poor) to 100 (Very Good). HI results are used at both the system and individual asset level, to develop the long-term investment program and create the short-term discrete projects.

5.3.5.2.2 Prioritization, Evaluation and Optimization

To determine replacement priority, ORPC leverages ACA and APUL results to establish a probability of failure. This is then weighed against the potential impact of an asset failure, including the extent of customer outages, anticipated restoration times, and any associated environmental or safety hazards. This rigorous screening ensures that capital is directed toward the highest-risk assets within the planning period.

For all programs, multiple alternatives are developed. Each alternative undergoes a rigorous cost-benefit analysis to select the option that produces the most value relative to its costs. ORPC's combination of prioritization and program evaluation produces an optimized capital plan.

5.3.5.2.3 Strategies for Operating within Budget Envelopes

ORPC employs industry best practices to increase the probability of operating within budget envelopes. Strict execution work planning provides visibility into project schedules, costs, and progress across all investment categories. A defined change request process is in place to maintain project control and governance. Management conducts regular reviews of the capital and maintenance work programs to assess the progress of planned work and spending performance, and to provide guidance on how to remove operational barriers.

5.3.6 System Capability Assessment for REG & DERs

5.3.6.1 Applications for Renewable Generators over 10 kW

ORPC's service area currently contains two REG connections established under the Hydroelectric Contract Initiative ("HCI") and Renewable Energy Standard Offer Program ("RESOP"). The details of both connections are presented in Table 5.3-19. Moreover, there are an additional 39 microFIT (<10KW) projects listed within IESO records with a combined capacity of 358.3 kW. The details of these microFIT connections are presented in Table 5.3-20.

Table 5.3-19: List of REG (>10 kW) Connections

Facility	Total REG (MW)	Territory	REG Nature
Mississippi River Power	4.6	Almonte	RESOP
Enerdu	0.995	Almonte	HCI

Table 5.3-20: Details on microFIT Connections

Year	Count (#)	Total Capacity (kW)
2015	7	58.805
2016	-	-
2017	6	49.02
2018	-	-
2019	-	-
Total	**13**	**107.825**

Table 5.3-21 summarized the FIT or net metering connections within ORPC's service territories.

Table 5.3-21: Details on FIT and Net Metering Connections

Year	Count (#)	Total Capacity (kW)
2022	0	0
2023	0	0
2024	4	40
2025	3	30
Total	**7**	**70**

5.3.6.2 Forecast of REG Connections

ORPC forecast only one REG Connection. This connection has moved into the Connection Impact Assessment (CIA) stage. The proposed connection is for 38.8 kW of non-exporting generation located in the Pembroke service territory.

5.3.6.3 Capacity Available

ORPC performs the analysis of its system utilization as part of planning stage of its AM process. The system utilization analysis is based on peak load of each feeder and station transformer relative to their respective ratings. The results did not identify any material capacity issues that would require capacity upgrades at any given substation or on any feeder for REGs and DERs.

5.3.6.4 Constraints to REG Connections

ORPC is aware of upstream capacity constraints at the HONI-owned Pembroke TS and Cobden TS, which are associated to the Pembroke, Beachburg and Killaloe supply feeders. Because of these constraints, HONI is not approving any new REG connections beyond 10 kW.

However, HONI has recently given an exemption to load displacement generators in which the REG is following the load profile such that excess generation is not injected back into the grid. The DSC defines load displacement generators as those that are connected on the customer side of a connection point, and their output is used or intended to be used exclusively for the customer's own consumption. HONI specified during consultation that if the generator is greater than 10 kW and meeting load displacement criteria, then a study will be carried out and CIA will be requested.

5.3.6.5 Constraints – Embedded Distributor

ORPC currently has no Non-Wires Solutions deployed within its distribution system. No Non-Wires Solutions are proposed across the planning horizon of this Distribution System Plan (DSP), as emerging system capacity and operational needs do not require the implementation of non-wires technologies at this time. ORPC will

continue to actively evaluate the technical and economic viability of Non-Wires Solutions as part of its ongoing capacity planning framework to meet future system reinforcement and loading requirements.

5.3.7 CLIMATE VULNERABILITY ASSESSMENT AND SYSTEM HARDENING

Due to the recent introduction of the Ontario Energy Board's Vulnerability Assessment and System Hardening (VASH) Guidelines, ORPC has not yet completed a formal Vulnerability Assessment using the OEB prescribed methodology and supporting tool. ORPC is committed to implementing the VASH framework and will continue to enhance its data collection, analytical capabilities, and planning processes to support a formal assessment in future planning cycles.

While a formal VASH assessment has not yet been completed, ORPC has long incorporated vulnerability and resilience considerations into its asset management, system planning, and capital investment decision making processes. The utility routinely evaluates the condition, performance, and resilience of its assets and identifies opportunities to strengthen the distribution system against extreme weather events, changing environmental conditions, and other emerging risks.

ORPC's capital renewal and replacement programs inherently contribute to system hardening by ensuring that new and replacement assets are designed and installed in accordance with current industry standards, engineering practices, and utility specifications, which increasingly incorporate resilience and climate adaptation considerations. This approach is embedded within the projects proposed ORPC's programs like,

- Capital Renewal and Replacement,
- New Services and Service Upgrades,
- SERP & System Supervisory Equipment and
- Substation Equipment.

ORPC continuously evaluates opportunities to improve the resilience of the distribution system through both internally driven initiatives and customer driven projects. System hardening measures currently being implemented include storm guying, optimized pole spacing, stronger pole classes, assessment of soil and geotechnical conditions, enhanced vegetation management practices, and increased deployment of distribution automation technologies. These initiatives improve the system's ability to withstand and recover from disruptive events while supporting the delivery of safe and reliable electricity service.

ORPC views the OEB's VASH framework as an opportunity to further formalize and enhance these existing practices and intends to continue advancing its vulnerability assessment and system hardening capabilities as the framework matures.

5.4 Capital Expenditure Plan

5.4.1 Capital Expenditure Summary

For the 2027 to 2031 ORPC is forecasting to net capital expenditures of $13.1 million. This represents a $2.0 million increase over net capital expenditures during the historical period spanning 2022 to 2026. The key drivers necessitating this increase in capital expenditure include:

- Higher number for customer service connections.
- Increased investments within the System Renewal category to proactively mitigate asset failure risks associated with aging and obsolete infrastructure.
- Required renewal of the operational vehicle fleet within the General Plant category to maintain field service capabilities.
- Compounding inflationary pressures affecting both external resource availability and material procurement costs.

The proposed 2027 to 2031 net capital expenditure plan did not impact O&M costs and has no expenditures related to non-distribution activities.

Table 5.4-1: Historical Capital Expenditures

Category	Historical												Bridge Year		
	2022			2023			2024			2025			2026		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access															
Gross Capital Spend	410	564	38%	213	1,061	398%	235	1,174	400%	206	795	286%	847	N/A	N/A
Capital Contributions	-	160	-	-	343	-	-	295	-	-	318	-	281	N/A	N/A
Net Capital Expenditures	410	404	-1%	215	718	234%	235	878	274%	206	476	131%	566	N/A	N/A
System Renewal															
Gross Capital Spend	1,248	1,980	59%	739	755	2%	771	994	29%	861	1,649	92%	1,052	N/A	N/A
Capital Contributions	-	-	-	-	-	-	-	-	-		-	-	196	N/A	N/A
Net Capital Expenditures	1,248	1,980	59%	739	755	2%	771	994	29%	1,011	1,649	92%	857	N/A	N/A
System Service															
Gross Capital Spend	105	-	-100%	162	20	-88%	62	-	-100%	70	-	-100%	170	N/A	N/A
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	N/A
Net Capital Expenditures	105	-	-100%	162	20	-88%	62	-	-100%	70	-	-100%	170	N/A	N/A
General Plant															
Gross Capital Spend	139	64	-54%	19	327	1621%	30	203	577%	7	254	3330%	733	N/A	N/A
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	0	N/A	N/A
Net Capital Expenditures	139	64	-54%	19	327	1621%	30	203	577%	7	254	3330%	733	N/A	N/A
Total Expenditure, Gross	**1,902**	**2,607**	**37%**	**1,133**	**2,163**	**91%**	**1,098**	**2,371**	**116%**	**1,144**	**2,698**	**136%**	**2,802**	N/A	N/A
Total Capital Contribution	**0**	**160**	**-**	**0**	**343**	**-**	**0**	**295**	**-**	**0**	**318**	**-**	**476**	N/A	N/A
Total Expenditure, Net	**1,902**	**2,447**	**29%**	**1,133**	**1,819**	**61%**	**1,098**	**2,075**	**89%**	**1,144**	**2,379**	**108%**	**2,326**	N/A	N/A

Table 5.4-2: Forecast Capital Expenditures

Category	Forecast				
	2027	2028	2029	2030	2031
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	944	972	1,001	1,031	1,062
Capital Contributions	291	299	308	318	327
Net Capital Expenditures	653	673	693	713	735
System Renewal					
Gross Capital Spend	1,675	1,264	1,440	2,242	1,475
Capital Contributions	193	350	427	490	0
Net Capital Expenditures	1,481	914	1,013	1,752	1,475
System Service					
Gross Capital Spend	20	20	20	145	110
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	20	20	20	145	110
General Plant					
Gross Capital Spend	760	630	991	175	129
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	760	630	991	175	129
Total Expenditure, Gross	**3,399**	**2,886**	**3,453**	**3,593**	**2,775**
Total Capital Contribution	**484**	**649**	**736**	**808**	**327**
Total Expenditure, Net	**2,915**	**2,237**	**2,717**	**2,786**	**2,448**

5.4.1.1 Plan vs Actual Variances for the Historical Period

Table 5.4-3: Variance Explanations - 2022 Planned Versus Actuals

Category	2022			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Gross	410	564	38%	The 2022 plan included $100,000 for Highway 148 Upgrades, $93,600 for a 44kV Overhead Line Relocation, and $64,502 for Orchardview Phase 2. The Highway 148 project did not begin until 2023, the 44kV Line Relocation project did not occur due to a change in land ownership, and Orchardview Phase 2 was redesigned and completed in 2025. This category captures externally initiated development projects that can vary significantly year by year.
System Renewal, Gross	1,248	1,980	59%	The plan included $150,000 to replace a failed transformer at Pembroke MS#6. The settlement agreement included $150,000 per year over the 5-year period for a total project cost of $750,000. The actual incurred expenditures in 2022 were $1,082,420, for a total increase of $932,420 compared to the amount included in rates for 2022. Additionally, ORPC increased its metering and transformer replacements by $392,702 due to long supply chain lead times following the pandemic.
System Service, Gross	105	-	-100%	The system service category assumed a budget of $45,000 for SCADA assessments, scouting and configuration and $60,000 for the RTU and relay replacement. Actual SCADA replacements did not begin until 2024 and were categorized as System Renewal. The Pembroke MS#4 RTU replacement originally planned for 2022 occurred in 2024.
General Plant, Gross	139	64	-54%	In its plan for 2022, ORPC included $45,000 for a new e-billing system, $27,000 for eavestrough replacements in

Category	2022			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
				Pembroke and $19,210 for an infrared camera. The actual 2022 expenditures were $22,500 for the e-billing system whereas the eavestrough and infrared camera expenditures did not occur until 2023 and 2025, respectively.
Total Expenditure, Gross	**1,902**	**2,607**	**37%**	
Capital Contributions	**0**	**160**	**-**	
Total Expenditure, Net	**1,902**	**2,447**	**29%**	

Table 5.4-4: Variance Explanations - 2023 Planned Versus Actuals

Category	2023			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Gross	213	1,061	398%	The actual incurred expenditures include $230,279 for the beginning of the Highway 148 Upgrades project which was originally estimated at $100,000 in 2022. Other material expenses in 2023 included $254,185 for a Boundary Road West Subdivision and $161,011 for an industrial park lighting project.
System Renewal, Gross	739	755	2%	Regarding system renewal, the plan included $463,000 for overhead renewal of poles, overhead conductor and transformers. This renewal program did not reach forecasted expenditures due to the significant resource requirements for the Highway 148 System Access project. Material renewal projects did however include $280,069 for the Pembroke MS#1 transformer that experienced a failure and $73,845 in additional renewal costs for the Pembroke MS#6 transformer project that was largely completed in 2022. The Pembroke MS#6 transformer replacement costs were included at

Category	2023			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
				$150,000 per year over the DSP period although all costs were incurred in 2022.
System Service, Gross	162	20	-88%	The system service category included a plan of $162,000 in 2023 compared to $20,326 actually incurred. Planned material projects for system service addressed reliability issues with the current SCADA system installed at ORPC stations.
General Plant, Gross	19	327	1621%	Actual material expenses included $87,574 for ArcGIS and $65,438 for an engine replacement in large vehicle #8. Non-material actual expenses in 2023 included $25,000 for the continuation of the implementation of the new e-billing platform originally planned for 2022, $20,708 for the implementation of the Green Button initiative requirements, $27,739 for the Pembroke eavestrough originally planned for 2022 and $27,801 in miscellaneous computer hardware replacements including laptops, monitors, workstations, and a server.
Total Expenditure, Gross	**1,133**	**2,163**	**91%**	
Capital Contributions	**0**	**343**	**-**	
Total Expenditure, Net	**1,133**	**1,819**	**61%**	

Table 5.4-5: Variance Explanations - 2024 Planned Versus Actuals

Category	2024			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Gross	235	1,174	400%	The actual expenditures include $389,161 for the continuation of the Highway 148 Upgrades project which was originally estimated at $100,000 in 2022. Additionally, 2024 expenditures include $173,214 for the Golfview Subdivision located in Pembroke which was anticipated to connect 96 customers.

Category	2024			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Renewal, Gross	771	994	29%	
System Service, Gross	62	0	-100%	ORPC incurred expenses of $175,342 for the SCADA replacement of Pembroke MS#4 in 2024 and included this in the System Renewal category as the primary driver was to replace obsolete equipment and not to expand the functionality.
General Plant, Gross	30	203	577%	Actual expenditures included $18,213 for the new e-billing platform, $53,518 for the replacement and relocation of a propane generator that was inside one of ORPC's Pembroke offices and not up to code, $11,560 in software expenses for OESP and Net Metering enhancements, $10,158 for new office chairs, $52,110 for a Tandem Axle Pole Trailer to accommodate transportation of pole sizes greater than 55', and $17,684 in Tools, Shop & Garage Equipment, specifically for a 15kV 200 AMP Load Break, crimpers, a grounding elbow and other miscellaneous items.
Total Expenditure, Gross	**1,098**	**2,371**	**116%**	
Capital Contributions	**0**	**295**	**-**	
Total Expenditure, Net	**1,098**	**2,075**	**89%**	

Table 5.4-6: Variance Explanations - 2025 Planned Versus Budget

Category	2025			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Gross	206	795	286%	The actual incurred expenditures include costs of $78,514 for the completion of Highway 148 upgrades and $69,919 for the Golfview Subdivision located in Pembroke. Other material costs included $61,857 for a 3 unit building on Irving Street in Pembroke requiring 4 pole upgrades and 3 50kVa pole mounted transformers, $53,985 for an 8 unit building on Steel Street in Pembroke, and $52,765 for a business customer connection within its Almonte service territory.
System Renewal, Gross	861	1,649	92%	The 2022 approved Distribution System Plan included $150,000 for the MS#6 transformer replacement that occurred in 2022. The cost for the transformer was

Category	2025			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
				spread evenly over 5 years. Additionally, 2025 included unforecasted expenditures of $276,400 for the Almonte MS#2 transformer replacement due to a lightning strike and $331,238 for PCB transformer replacements. The PCB replacements were originally forecasted to occur over the 5 year period, but were condensed into a single year which increased capital expenditures.
System Service, Gross	70	0	-100%	ORPC incurred expenditures of $106,239 for the SCADA replacement of Pembroke MS#8 in 2025 but included this in its System Renewal category as the primary driver was to replace obsolete equipment and not to expand the functionality.
General Plant, Gross	7	254	3330%	Actual incurred material general plant expenditures included $52,214 for a 2023 Ford E-Transit Cargo van and $67,121 for a 2025 Ford F150 XLT which replaced passenger vehicles that experienced engine failures. Other expenditures included $36,096 for computer hardware and equipment, $23,372 for the continuation of the ARCGis migration, $23,648 for various leasehold improvements, and $32,040 for tools, shop, stores, and garage equipment.
Total Expenditure, Gross	**1,144**	**2,698**	**136%**	
Capital Contributions	**0**	**318**	**-**	
Total Expenditure, Net	**1,144**	**2379**	**108%**	

5.4.1.2 Forecast Expenditures

5.4.1.2.1 System Access

Expenditures within the System Access category are driven entirely by external requirements, such as connecting new customer service requests and relocating distribution assets when requested by road or municipal authorities. Investment in this cost category is considered mandatory, and the specific timing of these investments is dictated by external parties.

The majority of the forecasted investments in this category are established using historical averages, supplemented by active planning data and infrastructure development schedules provided by external agencies and municipalities operating within the ORPC service territory.

Table 5.4-7: Forecast System Access Net Expenditures

Project or Program	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
New Services and Service Upgrades	653	673	693	713	735	3,467	100%

Project or Program	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Total Expenditure, Net	**653**	**673**	**693**	**713**	**735**	**3,467**	**100%**

5.4.1.2.2 System Renewal

System Renewal investments involve the systematic replacement of ORPC's system assets. These investments are designed to mitigate asset failure risk, as an unexpected equipment failure can have a significant impact on customers, system reliability, the environment, and safety. ORPC leverages its mature Asset Management Process to rigorously determine the appropriate level and timing of these capital investments.

Table 5.4-8: Forecast System Renewal Net Expenditures

Project or Program	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
SREPs	63	216	138	335	0	753	11%
Capital Renewal and Replacements	669	545	565	587	753	3,120	47%
Substation Buildings & Equipment	619	19	20	676	721	2,055	31%
System Supervisory Equipment	130	134	289	155	0	708	11%
Total Expenditure, Net	**1,481**	**914**	**1,013**	**1,752**	**1,475**	**6,635**	**100%**

5.4.1.2.3 System Service

System Service investments involve targeted modifications to the distribution system to achieve ORPC's operational objectives while proactively addressing anticipated future customer electricity service requirements. System Service investments are designed to provide robust reinforcement to critical supply points, manage emerging capacity or operational constraints, and integrate new communications technologies to ensure that system outages are identified, isolated, and resolved with maximum efficiency. ORPC leverages its mature Asset Management Process to rigorously determine the appropriate level and timing of these capital investments.

Table 5.4-9: Forecast Net System Service Expenditures

Project or Program	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Easements	20	20	20	20	20	100	32%
Station Metering - Almonte MS#1, Almonte MS#4 and Pembroke MS#6					90	90	29%
SCADA Master Data Concentrator				125		125	40%

Project or Program	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Total Expenditure, Net	**20**	**20**	**20**	**145**	**110**	**315**	**100%**

5.4.1.2.4 General Plant

General Plant investments represent modifications, replacements, or the installation of new assets that do not directly deliver electrical supply to customers but are fundamental to supporting ORPC's day-to-day operations. These assets include land, buildings, fleet vehicles, tools, and test equipment, as well as technology hardware and software applications. ORPC leverages its mature Asset Management Process to rigorously determine the appropriate level and timing of these capital investments.

Table 5.4-10: Forecast Net General Plant Expenditures

Project or Program	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Information Technology	28	29	29	30	31	148	5%
Leasehold Improvements	40	41	42	43	45	211	8%
Tools and Equipment	42	43	45	46	47	224	8%
Small Vehicles and Trailers	75	512	50	50	0	687	26%
Large Vehicles	575	5	825	5	5	1,415	53%
Total Expenditure, Net	**760**	**630**	**991**	**175**	**129**	**2,685**	**100%**

5.4.1.3 Comparison of Forecast and Historical Expenditures

Table 5.4-11: Historical and Forecast Capital Expenditures ($ '000)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
System Access	404	718	878	476	566	653	673	693	713	735
System Renewal	1,980	755	994	1,649	857	1,481	914	1,013	1,752	1,475
System Services	0	20	0	0	170	20	20	20	145	110
General Plant	64	327	203	254	733	760	630	991	175	129
Total Expenditure, Net	**2,447**	**1,819**	**2,075**	**2,379**	**2,326**	**2,915**	**2,237**	**2,717**	**2,786**	**2,448**

5.4.1.3.1 Overall Capital Expenditures

Capital expenditures for the historical period from 2022 to 2026 are forecast to be $11.0 million. The capital expenditure forecast for the five-year planning horizon of this Distribution System Plan (DSP) is $13.1 million, representing a 19% increase over the historical baseline. The key drivers necessitating this increase in capital expenditure include:

- Higher number for customer service connections.
- Increased investments within the System Renewal category to proactively mitigate asset failure risks associated with aging and obsolete infrastructure.
- Required renewal of the operational vehicle fleet within the General Plant category to maintain field service capabilities.
- Compounding inflationary pressures affecting both external resource availability and material procurement costs.

An analysis of capital expenditures in the DSP's forecast period as compared to the historical period across the four core cost categories is discussed in the following subsections.

5.4.1.3.2 System Access

Net capital expenditures for the historical period from 2022 to 2026 are forecast to be $3.04 million. The capital expenditure forecast for the five-year planning horizon of this Distribution System Plan (DSP) is $3.47 million, representing a 14% increase over the historical baseline. The foundation of the forecast for the five-year planning period is the annual average actual investment totals during the historical period. The key drivers necessitating this increase in capital expenditure include:

- Higher number for customer service connections.
- Compounding inflationary pressures affecting both external resource availability and material procurement costs.

5.4.1.3.3 System Renewal

Net capital expenditures for the historical period from 2022 to 2026 are forecast to be $6.23 million. The capital expenditure forecast for the five-year planning horizon of this Distribution System Plan (DSP) is $6.63 million, representing a 6% increase over the historical baseline. This moderate increase reflects ORPC ability to secured external federal funding. This funding is provided through Natural Resources Canada's Smart Grid Renewables and Electrification Pathways Program (SREPs), specifically under the Utility Support Stream. The key drivers necessitating this increase in capital expenditure include:

- Increased investments to proactively mitigate asset failure risks associated with aging and obsolete infrastructure.
- Compounding inflationary pressures affecting both external resource availability and material procurement costs.

5.4.1.3.4 System Service

Capital expenditures for the historical period from 2022 to 2026 are forecast to be $0.19 million. The capital expenditure forecast for the five-year planning horizon of this Distribution System Plan (DSP) is $0.32 million, representing a 68% increase over the historical baseline. The key drivers necessitating this moderate increase in capital expenditure include:

- Installation of load totalization meters at key delivery points to collect precise load demand metrics, which will significantly improve long-term system capacity planning and loading forecasting capabilities.

5.4.1.3.5 General Plant

Capital expenditures for the historical period from 2022 to 2026 are forecast to be $1.58 million. The capital expenditure forecast for the five-year planning horizon of this Distribution System Plan (DSP) is $2.69 million, representing a 70% increase over the historical baseline. The key drivers necessitating this increase in capital expenditure include:

- The replacement schedule of ORPC's operational vehicle fleet. A significant portion of the utility's core fleet was originally procured during a single investment window and has collectively reached the end of its useful lifecycle. Because these legacy vehicles remained operational throughout the previous rate period, their mandatory replacement wave is concentrated within the current five-year planning horizon.
- Market-driven inflationary price increases for commercial chassis, specialized utility bodies, and equipment procurement further amplify the capital required to execute this concentrated vehicle renewal cycle.

5.4.2 JUSTIFYING CAPITAL EXPENDITURES

Data, information and analyses to justifying the capital expenditures are detailed in individual investment narratives located in Appendix A – Material Narratives.

APPENDIX A – MATERIAL PROJECT NARRATIVES

A. General Information on the Project/Program

1. Overview

New Service and Service Upgrades enable customers to connect loads and generation to ORPC's distribution system. Investments include connection services and connection assets designed to provide timely, cost-efficient, reliable, and safe access to the distribution system, in accordance with ORPC's Customer service objectives, the Distribution System Code ("DSC"), and applicable legislation.

The Services and Service Upgrades program includes two segments:

- **Load Connections:** This segment enables mandatory connections to the distribution system, including new load connections and modifications to existing load connections.
- **Generation Connections:** This segment includes work necessary to connect distributed energy resources ("DER"), including generation and energy storage, to the distribution system.

Together, these two segments ensure ORPC meets its regulatory obligations while supporting customer growth, regional development, and the integration of emerging technologies.

ORPC's service area continues to experience an increase in residential, commercial, and industrial growth. Customer connection requests have grown in recent historical years due to population growth, housing growth, and continued investments in employment lands. Employment lands are designated areas intended to accommodate major job growth while restricting non-employment uses. These areas include zones for manufacturing, distribution centres, warehousing, and office facilities, thereby supporting economic development and industrial activity. Residential developments in Pembroke, along with numerous new residential developments in Almonte continue into the 2027 to 2031 rate period. These developments align with provincial housing targets and economic policies, including Ontario Regulation 580/22 ("Provincial Priorities") and the 2024 Provincial Policy Statement.

2. Timing

i. Start Date: Ongoing

ii. In-Service Date: Ongoing

iii. Key factors that may affect timing: The timing of new service connections and service upgrades is influenced by several factors, including the volume and complexity of customer connection

requests, availability of distribution system capacity, engineering and design requirements, permitting and approvals, and the procurement and availability of materials and equipment.

3. Historical and Future Capital Expenditures

Table 1 summarizes ORPC's historical capital renewal and replacement expenditures from 2022 to 2024 and projected investment requirements from 2025 to 2031.

Table 1: Historical and future expenditures for New Services and Services Upgrades

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	556	416	568	646	847	944	972	1,001	1,031	1,062
Contributions	38	182	241	558	281	291	299	308	318	327
Capital (Net)	517	234	327	88	566	653	673	693	713	735

ORPC forecasts the total net investment within the New Services and Service Upgrades program to be $3.5M over the 2027 to 2031 period. ORPC forecasts to connect approximately 400 new customers over the 2027 to 2031 rate period. Residential customer growth is expected to average 0.86% annually, while commercial and industrial customer growth is expected to stay relatively consistent to the most recent DSP period. These projections reflect ongoing housing completions, population increases, and economic growth trends throughout the region.

4. Economic Evaluation (Expansion Projects)

In accordance with Section 3.2 of the Distribution System Code, an economic evaluation has been considered for system expansion requirements associated with forecasted customer growth.

ORPC does not forecast any significant business expansion beyond the addition of new customer connections. Future growth within the service territory is therefore expected to be driven primarily by residential and mixed-use development projects. The major developments currently anticipated to contribute to customer growth are summarized below:

Table 2: ORPC Coordinated Development Projects

Project #	Description	Service Territory	Est. Connections
ORPC-26-060	Weavers Way (Phase 1B)	Almonte	60 Residential
ORPC-26-040	Hannan Hills	Almonte	110 Residential
ORPC-26-039	350 International Drive	Pembroke	3 x 16 Unit Residential Buildings (48 Units Total)
ORPC-25-076	Hilan Village	Almonte	115 Residential
ORPC-26-015	Stewart St,	Pembroke	48 Units
ORPC-26-064	127/129 Adelaide St	Almonte	3 x 6 (18 Units)
Total Units		**399 Units**	

During the Development Planning Study (DPS) period, ORPC is actively coordinating with several proposed development projects across its service territories to provide future natural gas service. Based on current project information, these developments are expected to add approximately 399 new residential units to the system over the planning horizon.

Table 3: Approved Development Projects

Project Status	Description	Service Territory	Est. Connections
Approved but not built	Menzie Enclave	Almonte	58 Units
Approved but not built	Golfview Subdivision Project	Pembroke	50 Units
Draft approval	Burcom Developments (Blakely)	Pembroke	10 Units
Approved but not built	Boundary Road W Subdivision Project	Pembroke	25 Units
Approved but not built	Mora Developments Sydenham	Pembroke	8 Units
Approved but not built	Land Beside Supples Landing Land	Pembroke	12 Units
Approved but not built	Seigel Development Bell St	Pembroke	4 Units
Potential Future Development	Infill Lots	Pembroke	30 Units
Total Units		**197 Units**	

In addition to the projects currently under active discussion with ORPC, several municipally approved developments are anticipated to proceed during the DPS period. The projects listed in Table 3 represent developments that are expected to be constructed between 2027 and 2031, contributing an estimated 197 additional residential units within ORPC's service territories.

The customer growth forecast presented below illustrates the projected change in customer accounts over the planning period. Based on the forecast, total customer accounts are expected to increase from

approximately 12,000 customers in 2027 to 12,418 customers by 2031, representing an average annual growth rate of approximately 0.86%.

Table 4: 2027-2031 Customer Growth Estimates

Customer Type	2027	2028	2029	2030	2031
General Service < 50 kW	1267	1265	1263	1261	1259
General Service => 50 kW <= 4,999 kW	133	132	131	130	129
Large User > 4,999 kW	0	0	0	0	0
Residential	10,600	10,706	10,813	10,921	11,030
Total	12,000	12,103	12,207	12,312	12,418
Annual Change %	0.86%				

Note: Customer counts exclude street lighting, sentinel lighting, and unmetered service connections.

Based on the current forecast, growth-related capital investments are expected to be driven primarily by residential development activity and the associated expansion of distribution infrastructure required to connect new customers. No material load growth attributable to existing commercial or industrial customer expansion has been identified at this time.

5. Comparative Historical Expenditure

Where available, historical expenditure information and unit cost comparisons have been reviewed to assess trends in growth-related investment requirements across ORPC's service territory.

Population growth within ORPC's service areas has varied significantly by region between 2016 and 2021, with Almonte experiencing the highest growth rate at 10.2%, reflecting the continued residential development activity occurring within that community. Overall, the ORPC service territory grew by 843 residents (3.6%) during this period, supporting the need for ongoing distribution system expansion to accommodate new customer connections.

Table 5: Population Growth 2016 to 2021

Service Region	Growth (Decline) (#)	Growth (Decline) (%)
Almonte	562	10.2%
Pembroke	368	2.3%
Killaloe	(107)	(18.0%)
Beachburg	20	1.9%
Aggregated	843	3.6%

Historically, investment levels associated with distribution system growth have generally aligned with population growth and development activity, particularly within the Almonte service area. With

population growth driving residential development, gross capital expenditures related to system expansion are expected to increase over the planning period.

The table below compares historical and forecasted growth-related capital expenditures. Gross capital investment is projected to increase from $646 thousand in 2025 to approximately $1.06 million by 2031, reflecting anticipated expenditures required to support new developments and customer connections. A portion of these costs is expected to be offset through customer and developer contributions.

Table 6: Historical and future costs for New Services and Service Upgrades

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	556	416	568	646	847	944	972	1,001	1,031	1,062
Contributions	38	182	241	558	281	291	299	308	318	327
Capital (Net)	517	234	327	88	566	653	673	693	713	735

Net capital expenditures have fluctuated historically based on the timing and magnitude of customer and developer contributions. In 2025, net expenditures are forecast to be relatively low due to the high level of anticipated contributions associated with specific development projects. Beyond 2025, net capital expenditures are expected to stabilize and gradually increase from approximately $566 thousand in 2026 to $735 thousand by 2031, consistent with forecasted customer growth and development activity within ORPC's service territory.

Historical costs were used to estimate annual costs for the 2027–2031 period. Previous spending from the two preceding years was analyzed, including employee hours dedicated to new service connections and service upgrades, applicable labour rates, and average asset-related expenses. These historical costs were escalated using an assumed annual inflation rate of 3% to develop estimated costs for the upcoming five-year period.

6. Investment Priority

The New Services and Service Upgrades program investments are essential to maintain safe, reliable and efficient access to the distribution system while meeting growing customer demand. These investments directly support regional housing and economic policies, enable customers' generation connections and renewable energy and storage initiatives, and ensure that ORPC can continue to meet or exceed customer service standards expected by its customers and prescribed by the OEB.

7. Alternatives Analysis

The New Services and Service Upgrades program is driven by customer requests and ORPC's obligation to provide access to the distribution system. As a result, there is generally limited optionality regarding whether the work proceeds. For each customer request, ORPC evaluates feasible connection and upgrade alternatives and selects the solution that best balances cost, safety, reliability, constructability, and compliance with applicable engineering and regulatory requirements.

Alternatives may include utilizing existing distribution infrastructure where capacity is available, upgrading existing facilities, or extending distribution assets to accommodate customer requirements. The recommended alternative is typically the option that meets customer needs while minimizing overall lifecycle costs and maintaining reliable system performance. This approach ensures that customer connection and service upgrade projects are delivered in a cost-effective manner while supporting the continued safe and reliable operation of the distribution system.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 7: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The investment improves efficiency by expanding system capacity and enabling new customer connections and service upgrades while maintaining reliable system performance. It also supports the installation of assets that meet current efficiency and operational standards, and leverages grid-resiliency technologies and distributed energy resources (DERs) to enhance load management and create additional capacity for electrification and future DER integration.
Customer Value	The investment delivers customer value by helping ORPC meet its customer service objectives for timely connections and ensuring customers are supported throughout the connection process. Customers benefit from access to facilities and connections that comply with current standards and regulatory requirements. In addition, the integration of distributed energy resources provides customers with greater choice, opportunities to participate in greenhouse gas reduction initiatives, lower energy costs, and improved energy efficiency for residential, commercial, and industrial applications.
Reliability	The investment in generation enhances reliability by increasing distribution system capacity to accommodate growth while ensuring the continued dependable operation of the electrical network. Advanced grid technologies and DER integration improve load management, strengthen system resilience, and support the reliable connection of new customers and emerging electrification demands.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	The investment supports safety by ensuring compliance with applicable regulations, codes, and standards governing customer connections. Safety is further enhanced through the completion of Electrical Safety Authority permits and inspections before energizing new or upgraded customer service equipment, helping to protect both customers and the integrity of the distribution system.

2. Investment Need

i. Main Driver:

- Investments are driven by fulfilling customer requests for new service connections and upgrades to existing electrical services.
- Growth in residential, commercial, and institutional development, along with increasing customer electricity demands, continues to drive the need for new connections and service capacity upgrades.

ii. Secondary Drivers:

- Investments are required to fulfill ORPC's obligation to provide customer connections and service upgrades in accordance with applicable regulatory, technical, and safety requirements.
- As a licensed electricity distributor, ORPC must respond to customer requests and provide access to the distribution system in a timely and compliant manner.

3. Investment Justification

Historical customer counts demonstrate steady growth in ORPC's residential customer base, increasing from 10,223 customers in 2022 to 10,367 customers in 2024. Forecast customer counts anticipate continued growth to approximately 11,030 residential customers by 2031, resulting in total customers increasing from 12,000 in 2027 to 12,418 in 2031, representing an average annual growth rate of approximately 0.86%.

Table 8: ORPC Historical Customer Counts

Customer Type	2022	2023	2024	2025	2026
General Service < 50 kW	1274	1267	1271	1273	1269
General Service => 50 kW <= 4,999 kW	141	139	137	133	134
Large User > 4,999 kW	0	0	0	0	0
Residential	10223	10326	10367	10411	10495
Total	11638	11732	11775	11817	11899

Table 9: ORPC Forecast Customer Counts

Customer Type	2027	2028	2029	2030	2031
General Service < 50 kW	1267	1265	1263	1261	1259
General Service => 50 kW <= 4,999 kW	133	132	131	130	129
Large User > 4,999 kW	0	0	0	0	0
Residential	10600	10706	10813	10921	11030
Total	12000	12103	12207	12312	12418
Annual Change %	0.86%				

In addition to these historical trends and forecasted customer counts, ORPC is aware of several residential development projects currently in various stages of planning within its service territory. As summarized in Table 2, these developments represent approximately 333 potential new residential connections. While the timing and ultimate realization of these projects remain uncertain, they account for approximately 80% of the forecasted increase in customers over the DSP period, providing support for the reasonableness of the forecast and indicating continued growth in service requirements.

i. Demonstrating Accepted Utility Practice:

The New Services and Service Upgrades program reflects accepted utility practice by providing customer connections and service upgrades using established engineering, design, construction, and operational standards. Investments are planned and executed to ensure the safe, reliable, and efficient delivery of electricity while maintaining compliance with applicable regulatory, technical, and safety requirements. Standardized equipment and current utility practices are utilized to support a resilient distribution system capable of accommodating customer growth, evolving load requirements, and future electrification initiatives.

ii. Benefit-Cost Analysis:

The New Services and Service Upgrades program is customer-driven and required to meet customer requests for connection to or modification of the distribution system. As such, no investment alternatives were considered. ORPC does evaluate all connection solutions to identify the most practical and cost-effective approach that meets customer requirements while maintaining system reliability, safety, and compliance with applicable standards. The selected solution balances customer needs, operational requirements, and efficient use of utility resources.

iii. Historical Investments & Outcomes Observed:

ORPC has historically invested in customer connections and service upgrades to support residential, commercial, and institutional growth within its service territory. These investments have enabled the

timely connection of new customers, accommodated increased customer load requirements, and maintained compliance with established service standards. Historical experience demonstrates that continued investment in this program is necessary to support ongoing development, customer growth, and changing electricity demands while maintaining reliable service.

iv. Substantially Exceeding Materiality Threshold:

No individual projects within the New Services and Service Upgrades program are expected to substantially exceed the materiality threshold. The program consists of numerous customer-driven connection and service upgrade projects that are generally modest in scope and are completed as requests are received. Should a future project exceed the materiality threshold, ORPC would undertake a detailed business case assessment, including evaluation of alternatives, customer benefits, and short- and long-term cost impacts, consistent with OEB requirements.

4. INNOVATION

i. Assessment of Benefit for Customers:
Not Applicable.

5. ECONOMIC GROWTH

The New Services and Service Upgrades program supports economic growth by enabling residential, commercial, institutional, and mixed-use developments within ORPC's service territory to connect to the distribution system and obtain the electrical service required to operate and expand. Customer requests for new services and service upgrades are directly linked to community growth, business investment, redevelopment activity, and increasing electricity demands associated with population growth and electrification.

The program supports provincial economic growth objectives by facilitating the infrastructure required for housing development, business expansion, and community investment. Timely customer connections and service upgrades help ensure that new developments can proceed as planned, supporting local employment, economic activity, and investment within the communities served by ORPC.

By providing safe and reliable access to electricity for new and expanding customers, the program enables continued growth and development while supporting the evolving energy needs of residential, commercial, and institutional customers throughout ORPC's service area.

A. General Information on the Project/Program

1. Overview

The Capital Renewal and Replacements investment contain any associated work and costs to renew and replace the assets essential to ORPC's distribution network. Two main components of this investment are General Renewal and Replacements, and Cable Rejuvenation and Replacement.

General Renewal and Replacements

Covers distribution assets which require renewal or replacement due to age and condition work and executed under annual programs. These assets include overhead conductors, underground conductors, poles, underground conduits, line transformers, secondary services and meters.

ORCP's 2026 Asset Condition Assessment indicates an ongoing need for capital renewal investment, particularly within the wood pole and overhead conductor asset classes, which contain the largest populations of Poor and Very Poor assets.

ORPC's system age profile highlights an infrastructure asset base requiring timely renewal. Currently, 40% of distribution assets have passed their Typical Useful Life (TUL). In the absence of sustained asset renewal investments, nearly half of ORPC's distribution asset portfolio will exceed its TUL by the end of the 2027–2031 planning horizon, significantly elevating operational and reliability risks.

While most distribution assets remain in Very Good, Good, or Fair condition, targeted renewal and replacement investment is required to address aging infrastructure, mitigate failure risk, and maintain system reliability through a risk-based asset management approach.

This investment component was determined by analyzing historical labour, materials and vehicle spend and extrapolating past work to determine future needs and their costs.

Cable Rejuvenation and Replacement

The Cable Rejuvenation and Replacement cover targeted proactive cable rejuvenation and replacement of cables in Pembroke. The investment aims to extend cable lifespan and improve the reliability of the existing underground (UG) cable network. Aging infrastructure, environmental conditions, and cable degradation necessitate the rejuvenation or replacement of key UG cable segments. Without intervention, the risk of failure will increase, leading to potential service disruptions and higher emergency repair costs.

Cable Rejuvenation and Replacement aligns with ORPC's strategic objectives of enhancing system reliability, ensuring regulatory compliance, and maintaining customer satisfaction by minimizing outage risks associated with aging infrastructure.

The Cable Rejuvenation and Replacement will focus on the following key underground cable segments in Pembroke:

- **Boundary Road** – 0.5 km segment of 50-year-old cable requiring immediate attention. After testing and inspection, it was found that the entire section requires full replacement due to ineligibility for rejuvenation as the cable insulation has been torn out and the cable radii are too small at the termination.

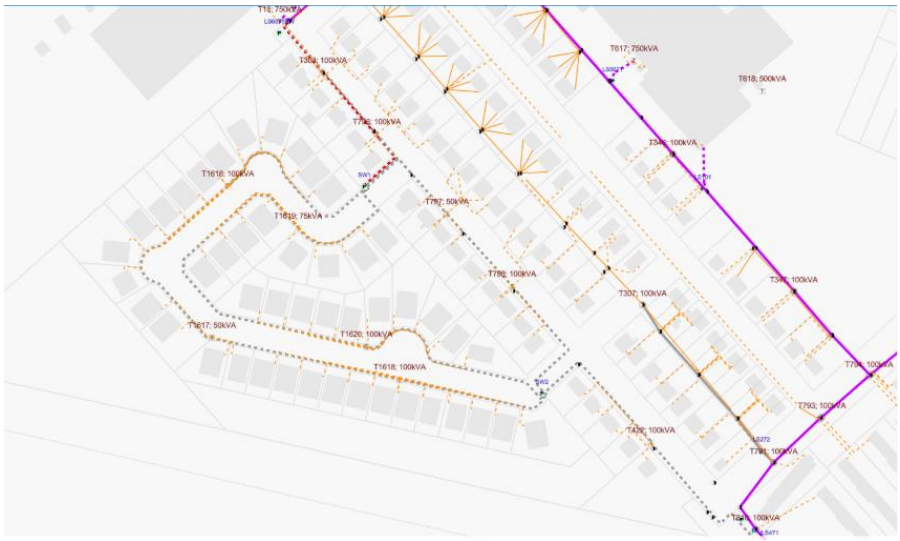


Figure 1: Cable Rejuvenation & Replacement Visualization for Boundary Road

- **Angus Campbell Drive** – Approximately 4 km of UG cable identified for phased rejuvenation and replacement.

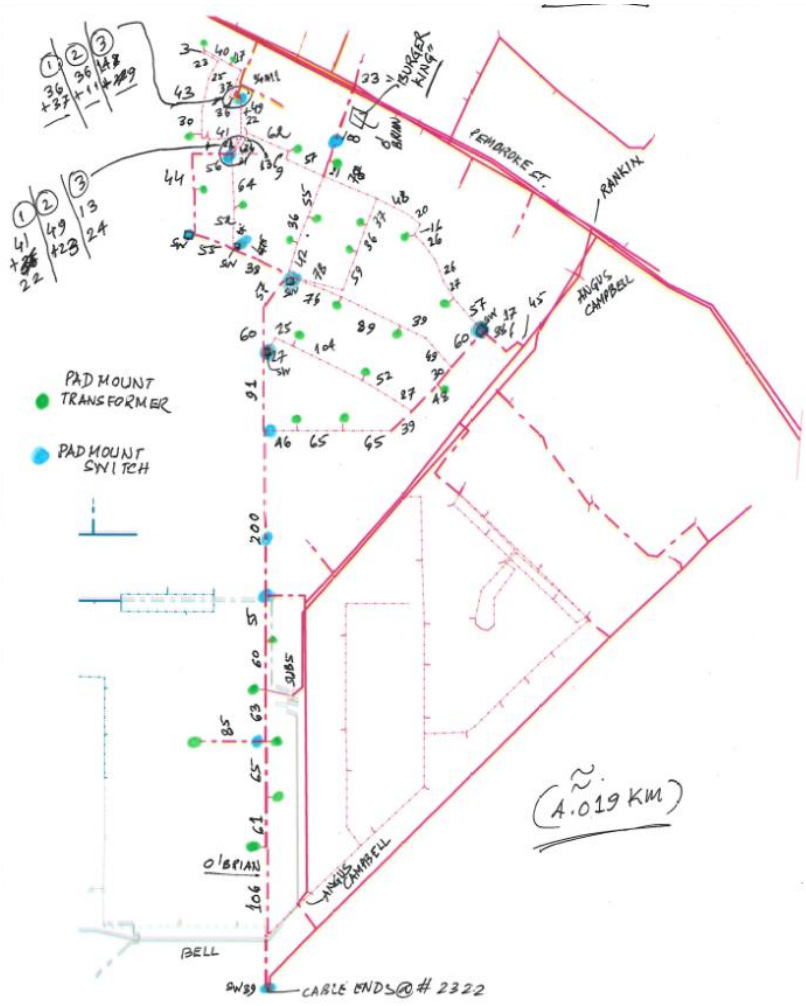


Figure 2: Cable Rejuvenation & Replacement Visualization for Angus Campbell Drive

The projects will involve:

- **Cable Testing and Injection** – Testing existing UG cables for dielectric integrity and injecting rejuvenation fluid into cables that qualify for life extension.
- **Targeted Cable Replacement** – Replacing non-injectable cable sections to ensure network reliability.
- **Preventive Measures** – Deploying monitoring systems to assess future cable health and prevent unexpected failures.

2. TIMING

i. Start Date: Before DSP

ii. Completion Date: Ongoing

iii. Key factors that may affect timing: Timing may be affected by outage scheduling constraints required to minimize customer impacts, availability of qualified contractors and materials, environmental and site conditions, and coordination with municipal or other ORPC projects that may influence construction sequencing.

General Equipment Renewal and Replacements activities occur continuously throughout the DSP period as assets are identified for replacement through ORPC's asset management processes, condition assessments, and lifecycle planning activities. Annual spending levels are based on historical renewal activity and expected replacement requirements for distribution system assets.

The Cable Rejuvenation and Replacement projects are structured as a multi-year phased initiative with planned investments over the 2027-2031 period as follows:

- **2027 – Angus Cambell Rejuvenation:** $75,000
- **2027 – Boundary Road Replacement:** $84,522
- **2028 – Angus Cambell Rejuvenation:** $80,000
- **2029 – Angus Cambell Rejuvenation:** $125,000
- **2030 – Angus Cambell Rejuvenation:** $100,000
- **2031 – Angus Cambell Rejuvenation:** $85,000

This timeline ensures a manageable approach to addressing aging UG cable infrastructure while balancing budgetary constraints.

3. Historical and Future Capital Expenditures

Table 1: Historical and Future Capital Expenditures

Projects	Historical Costs ($ '000)					Future Costs ($'000)				
	2022	2023	2024	2025	2026 (Bridge)	2027 (Test)	2028	2029	2030	2031
Capital Renewal and Replacements	806	238	815	824	657	669	545	565	587	753

Forecast expenditures for the General Renewal and Replacements were developed using historical capital renewal activities completed between October 2023 and September 2025. Historical costs were analyzed and separated into three primary cost drivers: labour, materials, vehicles and contract work. Labour hours,

material usage, vehicle utilization and contracting tasks were reviewed and allocated to specific work activities to determine the portion attributable to capital renewal and replacement work.

The historical primary cost drivers were then used to forecast expenditures. For example, if approximately 20% of technician labour hours were historically dedicated to capital renewal and replacement activities, 20% of forecast technician salaries were allocated to this program. A similar approach was used for material and vehicle costs.

Cable Rejuvenation and Replacement expenditures were forecasted separately based on identified underground cable sections requiring testing, rejuvenation, or replacement during the 2027 to 2031 period. Project costs reflect planned cable testing, rejuvenation injections, targeted cable replacement, contractor services, and project management activities.

While the General Equipment Renewal and Replacements is based on historical renewal activity and expected ongoing asset replacement requirements, Cable Rejuvenation and Replacement consists of projects targeted underground cable assets identified as requiring corrective action through ORPC's asset management and condition assessment processes.

4. Comparative Historical Expenditure

The majority of System Renewal and Replacements capital expenditure is allocated to General Renewal and Replacement activities. Forecasted expenditures for General Renewal and Replacement activities are anchored in historical spending trends, while specific forecasts for Cable Rejuvenation and Replacement incorporate historical unit costs per kilometer, asset condition assessments, and internal technical expertise. Variances between historical expenditures and forecasted investments are driven by project-specific engineering scope, site-specific execution constraints, material price inflation, contractor availability, and system outage scheduling requirements.

5. Investment Priority

The Capital Renewal and Replacements is a high-priority investment category because it directly supports ORPC's obligation to provide safe, reliable, and efficient electricity service.

The General Renewal and Replacements investment addresses the ongoing replacement of aging distribution assets before failures occur. By proactively renewing poles, transformers, conductors, meters, secondary services, and other critical infrastructure, ORPC reduces asset failure risk, limits emergency repair costs, and maintains system reliability.

Table 2 are results of ORPC's 2026 asset condition assessment, showing current condition of wood poles, overhead conductors, overhead switches and pole-mount and pad-mount transformers.

Table 2: 2026 Asset Condition Assessment Results

Asset Category	Population	HI Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	3947	593	50	1031	1741	223	309	93%
Overhead Conductors (km)	389	72	46	128	0	3	140	79%
Pole-Mount Transformers	1047	731	279	34	3	0	0	92%
Pad-Mount Transformers	404	183	91	42	8	0	80	93%
Overhead Switches	446	417	29	0	0	0	0	80%

The asset condition assessment indicates an ongoing need for capital renewal investment, particularly within the wood pole and overhead conductor asset classes, which contain the largest populations of Poor and Very Poor assets. While most distribution assets remain in Very Good, Good, or Fair condition, targeted renewal and replacement investment is required to address aging infrastructure, mitigate failure risk, and maintain system reliability through a risk-based asset management approach.

Figure 3 illustrates the system wide age profile for ORPC overhead and underground distribution system assets. These results are valid as of May 2026.

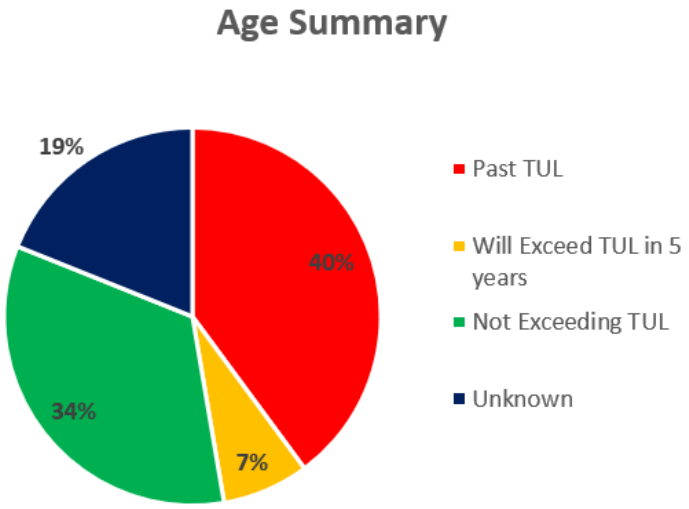


Figure 3: Age Profile of ORPC Distribution Assets

ORPC's system age profile highlights an infrastructure asset base requiring timely renewal. Currently, 40% of distribution assets have passed their Typical Useful Life (TUL). In the absence of sustained asset renewal

investments, nearly half of ORPC's distribution asset portfolio will exceed its TUL by the end of the 2027–2031 planning horizon, significantly elevating operational and reliability risks.

The primary objective of Cable Rejuvenation and Replacement investment is to mitigate the specific risk of UG cable failures and enhance network reliability in Pembroke. The invest will:

- Reduce the frequency and severity of unplanned outages by extending the lifespan of aging UG cables.
- Improve service continuity and reduce the long-term cost of emergency repairs and reactive maintenance.
- Ensure compliance with O. Reg. 22/04 and other regulatory standards governing UG infrastructure.

Together, these investments support ORPC's asset management strategy by balancing reliability improvements, customer impacts, affordability, and long-term lifecycle cost management. This approach is aligned with customer feedback received through ORPC's stakeholder engagement activities, where safe and reliable electricity service was identified as the highest-ranked utility priority.

6. Alternatives Analysis

General Renewal and Replacements

ORPC evaluated three distinct investment alternatives to address the aging infrastructure and reliability risks associated with its distribution assets.

Alternative 1: Do Nothing

This alternative involves maintaining status quo operational maintenance without undertaking proactive capital replacements for aging distribution assets. This approach was rejected because it violates ORPC's statutory obligation to provide safe, adequate, and reliable electrical service to its customers.

While deferring capital investment would temporarily limit rate increases in the near term, it would exponentially increase the likelihood of catastrophic asset failures, extended customer outage events, and elevated safety hazards. Ultimately, the inevitable emergency repairs would cost significantly more than planned replacements, creating an unacceptable impact on service levels and long-term costs for customers.

Alternative 2: Aggressive Renewal and Replacements

Under this alternative, ORPC evaluated accelerating capital investment to materially improve the age and condition profile of the distribution assets.

While this option maximizes long-term system reliability, ORPC determined that the capital investment required would result in an immediate, unacceptable rate impact for customers. For this reason, this alternative was rejected.

Alternative 3: Balanced System Renewal (Recommended)

Under this alternative, ORPC would maintain investment levels at historical levels while accounting for inflation and other cost escalators. This alternative provides an investment that balances system reliability needs against and minimizes customer rate impacts.

Cable Rejuvenation and Replacement:

ORPC evaluated three distinct investment alternatives to address ORPC cables in poor condition:

Alternative 1: Full Cable Replacement

Replacing the entire UG cable network was assessed but deemed cost-prohibitive ($5M+ estimate). Rejuvenation offers an effective and efficient alternative.

Alternative 2: Status Quo / Reactive Maintenance

Continuing to address failures on an as-needed basis would result in higher emergency costs, more service disruptions, and greater risk exposure.

Alternative 3: Targeted Rejuvenation and Replacement (Recommended)

A combination of cable rejuvenation and strategic replacement was selected as the most cost-effective, low-impact, and sustainable approach.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The program improves efficiency by shifting from reactive maintenance to planned asset renewal and replacement activities. General Renewal and Replacements address aging assets before failure, while targeted cable rejuvenation extends asset life at a significantly lower cost than

Primary Criteria for Evaluating Investments	Investment Alignment
	full replacement. Together, these approaches optimize capital spending and reduce emergency repair requirements.
Customer Value	The investment provides customer value by maintaining safe and reliable electricity service while managing long-term costs. Proactive renewal of aging distribution assets and rehabilitation of underground cable infrastructure reduce the likelihood of outages and service disruptions while minimizing the need for more costly future replacements.
Reliability	Reliability is a primary driver of both program components. General Equipment Renewal and Replacements reduce the risk of failures associated with aging poles, transformers, conductors, meters, and other distribution assets. Cable rejuvenation and targeted replacement improve the condition of the underground network, reducing cable failure risk and supporting reliable service over the long term.
Safety	The program enhances safety by replacing aging assets before they create operational or public safety risks. Planned renewal, replacement, and cable rehabilitation activities reduce the likelihood of equipment failures, electrical faults, and emergency repair situations while allowing work to be completed under controlled conditions and in accordance with established safety standards.

2. INVESTMENT NEED

i. Main Driver*:* The primary driver for this investment category is the need to maintain the reliability, safety, and performance of ORPC's aging distribution infrastructure. The underground cable network in Pembroke, particularly along Boundary Road and Angus Campbell Drive, have reached or exceeded their typical useful life. The condition of the cables indicates a high risk of cable failure. To minimize cost cable rejuvenation will be preformed when possible to deferred full cable replacement. The General Renewal and Replacements programs address routine lifecycle replacement requirements for distribution assets that have reached the end of their useful lives or exhibit declining condition.

ii. Secondary Drivers*:*

- System Reliability: Minimizing the probability of equipment failure ensures consistent electricity delivery, reducing disruptions for customers and improving performance metrics such as SAIDI and SAIFI.
- Customer Satisfaction: Customers benefit from a more reliable power supply, with reduced outage incidents and faster recovery times.

- Cost-Effectiveness: Renewal, where possible, is significantly more economical than full asset replacement, optimizing ORPC's capital expenditures while delivering long-term value.

Planned investment is supported by ORPC's asset management processes, including condition assessments, inspection and testing data, asset health indices, and historical performance records across the distribution system. Information from asset inspections, failure history, age-based risk assessments, maintenance records, and lifecycle planning analyses is used to identify assets requiring renewal or replacement and to prioritize investments based on risk and operational impact. This information supports a risk-based, least-cost approach to maintaining system reliability, safety, and long-term asset performance.

3. Investment Justification

i. Demonstrating Accepted Utility Practice: Cable Rejuvenation and Replacements projects represent a strategic investment in the longevity and reliability of ORPC's UG network. By extending the service life of critical infrastructure, reducing the risk of outages, and ensuring compliance with regulatory standards, this initiative aligns with ORPC's commitment to delivering safe, reliable, and cost-effective electricity distribution services.

ii. Benefit-Cost Analysis: The Capital Renewal and Replacements program reflects accepted utility asset management practices by proactively renewing and replacing aging distribution assets based on condition, age, performance history, and risk of failure. The program includes the renewal of poles, transformers, conductors, meters, secondary services, underground infrastructure, and targeted cable rejuvenation and replacement activities. By investing in assets before failures occur, ORPC reduces reliability risks, supports public and worker safety, extends asset life where appropriate, and maintains compliance with regulatory obligations while continuing to provide safe, reliable, and cost-effective electricity distribution services.

iii. Historical Investments & Outcomes Observed: ORPC has consistently invested in the renewal and replacement of aging distribution assets through its annual capital program. Historical investments have included the replacement of poles, transformers, conductors, meters, secondary services, and underground infrastructure, as well as targeted underground cable rehabilitation activities. These investments have supported the continued operation of critical distribution assets, reduced the risk of equipment failures, improved overall system condition, and enabled ORPC to maintain

reliable service to customers. Historical spending patterns and observed asset renewal requirements were used to inform the forecast expenditures proposed throughout the DSP period.

A. General Information on the Project/Program

1. Overview

ORPC operates 12 substations within the Almonte (4) and Pembroke (8) service areas. These stations are the source of electrical supply for the ORPC customers. Substation critical infrastructure consists of power transformers, switchgears, circuit breakers, protective relays, station switches, battery systems, and electrical apparatus.

These substations are the highest-value and most operationally critical assets within the distribution system. Each substation forms the primary interface between the 44 kV supply system and downstream feeders, making substation performance central to reliability, safety, and restoration capability. The loss of an individual distribution substation can result in outages to customers until restoration and switching activities are completed. Substation condition, configuration, and available operational flexibility therefore remain important considerations in overall system performance.

The Station Renewal program is primarily driven by the need to mitigate Failure Risk of critical assets at the substation level. These critical assets have been professionally evaluated to be in poor condition and typically have exceeded to the Typical Useful Life (TUL). These assets will be replaced with the new modern substation equipment that align to industry best practises and current ORPC standards.

Investment Description

The scope of work of this program will consist of:

- General Asset Renewal:
    - Replacement of ad-hoc failed assets found during inspections.
- Pembroke MS#4:
    - Removal of existing legacy oil circuit breakers.
    - Installation of new pad mounted 46kV, 250kV BIL, Outdoor Style Metal-Enclosed Switchgear.
    - New switchgear pad, revised ground electrode system to accommodate switchgear.
    - Removal of legacy equipment.
- Routing of and termination of new MV conductors.

- Almonte MS#3
  - Removal of existing 5kV unit sub and metal enclosed switchgear.
  - Removal of existing 44kV main breaker.
  - Installation of new 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear.
  - Installation of new 44kV main breaker.
  - New switchgear pad, revised ground electrode system to accommodate switchgear.
- Pembroke MS#4
  - Removal of existing legacy 5kV metal enclosed switchgear. Removal of sheet metal ehouse.
  - Installation of new 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear.
  - New switchgear pad, revised ground electrode system to accommodate switchgear.
  - Re-routing or pulling of new main and feeder conductors.
- Pembroke MS#7:
  - Removal of existing legacy air break switches and motor operators.
  - Installation of new 46kV switches, motor operators, and controls.
- Pembroke MS#8:
  - Stabilization of existing power transformer foundation. Installation of new 5kV secondary main conductors.

Table 1 provides the Program Gross Capital Expenditure Plan for the planning period.

Table 1: Program Gross Capital Expenditure Plan ($)

Project	2027	2028	2029	2030	2031
General Asset Renewal	18,772	19,335	19,916	20,513	21,128
Substation Equipment - Pembroke MS#4 - 44KV Renewal	600,000				
Substation Equipment - Almonte MS#3 – 5kV Switchgear				655,000	
Substation Equipment - Pembroke MS#4 – 5kV Switchgear					500,000

Project	2027	2028	2029	2030	2031
Substation Equipment - Pembroke MS#7 - Airbreak Switch					100,000
Substation Equipment - Pembroke MS#8 - TX Foundation					100,000
Total	618,772	19,335	19,916	275,513	721,128

2. TIMING

The pace of investment within this program is designed to strike a balance between the needs of the assets, available resources to execute the work within ORPC as well as customer preferences to keep electricity rates as digestible as possible.

Table 2: Project Timing

Project	In Service Year
General Asset Renewal	2027-2031
Substation Equipment - Pembroke MS#4 - 44KV Renewal	2027
Substation Equipment - Almonte MS#3 – 5kV Switchgear	2030
Substation Equipment - Pembroke MS#4 – 5kV Switchgear	2031
Substation Equipment - Pembroke MS#7 - Airbreak Switch	2031
Substation Equipment - Pembroke MS#8 - TX Foundation	2031

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Table 3: Historical and Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	1,113	516	4	388	4	619	19	20	676	721
Contributions	-	-	-	-	-	-	-	-	-	-
Capital (Net)	1,113	516	4	388	4	619	19	20	676	721

4. COMPARATIVE HISTORICAL EXPENDITURE

During the previous rate period, ORPC's Substation Building and Equipment program was primarily dedicated to transformer replacement projects, driven by age and condition assessments at the time. For the proposed rate period, prioritized capital expenditures shift toward switchgear replacement to address critical end-of-life station equipment and maintain overall system reliability. Consequently, directly comparable historical expenditure baseline figures for the specific projects proposed in this program are not available from the immediate prior rate period.

Historical asset and expenditure records pre-dating the previous rate period were evaluated during the preparation of this plan. However, due to differences in cost tracking granularity and evolving asset data

collection methods, this older historical information was deemed unreliable and not directly comparable to current project scopes. ORPC has instead established the proposed switchgear investment forecasts using updated asset condition assessments, current procurement costs, and industry-standard engineering cost estimates to ensure a prudent and defensible capital budget.

5. Alternatives Analysis

ORPC evaluated three distinct investment alternatives to address the aging infrastructure and reliability risks associated with its substation assets. The evaluation considered asset risk, customer rate impact, and execution feasibility.

Alternative 1: Do Nothing

This alternative involves maintaining status quo operational maintenance without undertaking proactive capital replacements for aging substation assets. This approach was rejected because it violates ORPC's statutory obligation to provide safe, adequate, and reliable electrical service to its customers.

While deferring capital investment would temporarily limit rate increases in the near term, it would exponentially increase the likelihood of catastrophic asset failures, extended customer outage events, and elevated safety hazards. Ultimately, the inevitable emergency repairs would cost significantly more than planned replacements, creating an unacceptable impact on service levels and long-term costs for customers.

Alternative 2: Aggressive System Renewal

A comprehensive condition assessment of ORPC's substation assets identified ten candidate renewal projects based on asset health and failure risk profiles. Under this alternative, ORPC evaluated accelerating capital execution to complete all ten candidate projects within the upcoming planning horizon, thereby addressing all identified substation vulnerabilities immediately.

While this option maximizes long-term system reliability, ORPC determined that executing all ten projects concurrently is infeasible. ORPC lacks sufficient internal resourcing, and system switching flexibility to execute this volume of work without causing severe operational disruptions and extended customer outages during construction. Furthermore, the capital expenditure required would result in an immediate, unacceptable rate impact for customers. For these operational and financial reasons, this alternative was rejected.

Alternative 3: Balanced System Renewal (Recommended)

This alternative establishes a capital program that balances system reliability needs against execution capability and customer rate impacts.

Under Alternative 3, ORPC applied a formal risk-prioritization framework to the ten candidate projects identified in the substation condition assessment. Projects were categorized by risk criticality as High, Moderate, or Low priority:

- High to Moderate Priority Projects: Selected for immediate execution within the proposed planning horizon due to imminent end-of-life condition, elevated risk of failure, and operational criticality.
- Moderate to Low Priority Projects: Deferred to future rate periods, as their ongoing operational risks can be safely managed through targeted monitoring, enhanced inspections, and preventive maintenance.

Boundary conditions were established around overall capital investments limits, system outage windows, and internal project management capacity to ensure the proposed scope is fully executable. Alternative 3 delivers the optimal balance between mitigating critical system risk, maintaining reasonable customer rates, and ensuring reliable execution. Consequently, Alternative 3 is the recommended option proposed in this Distribution System Plan.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 4: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Program Expected Outcomes
Efficiency	This program will lower operational costs and resourcing requirements by proactively removing vulnerable equipment from service before a catastrophic failure occurs. Addressing failed substation assets requires immediate, unplanned emergency intervention that often involves overtime premium rates, significantly escalating internal labor and contractor costs. Unexpected asset failures can also cause extensive collateral damage to adjacent substation equipment, necessitating additional repairs Finally, asset renewal replaces legacy construction layouts and non-standard equipment, which increases staff maintenance efficiency, streamlines supply chain spare parts management.
Customer Value	Substation infrastructure has a tremendous impact on overall system reliability and performance. The systematic replacement of degraded, aging station equipment will succeed in sustaining system reliability

Primary Criteria for Evaluating Investments	Program Expected Outcomes
	while mitigating the operational risks of failure, including prolonged outages and localized safety impacts. Results from the recent ORPC DSP Survey explicitly indicate that reliability remains a critical priority for customers. The execution of this renewal program directly honors that feedback, ensuring that customers continue to receive a safe and dependable electricity supply.
Reliability	Asset renewal supports long-term reliability by preventing equipment failures that would otherwise result in extensive customer service interruptions. The program systematically increases system reliability and resiliency by reducing the volume of obsolete station assets currently operating in poor condition past their typical useful life. Additionally, modern replacement equipment offers improved asset protection, and advanced automation capabilities not found in legacy systems, significantly enhancing the overall resiliency of the electrical system.
Safety	Modern substation equipment incorporates advanced electrical, structural and mechanical safety features not found in legacy designs. Upgrading these installations mitigates the distinct safety hazards associated with unmitigated equipment failure, reducing physical risk profiles for utility field personnel, emergency responders, and the surrounding public.

2. Investment Need

In 2025, ORPC commissioned Rockwood Engineering to perform a comprehensive condition assessment of ORPC's substation assets. This assessment was completed in 2026 and provides the technical foundation for ORPC's capital expenditure planning for the substation renewal program. A copy of the complete substation assessment report is provided in Appendix 1.

The assessment focused on ORPC's distribution substations across the Pembroke (MS #1 through MS #8) and Almonte (MS #1 through MS #4) service territories. Each substation is supplied from 44 kV sub-transmission feeders owned by external utilities or generation entities. ORPC owns and maintains the 44 kV terminal apparatus, including circuit breakers, disconnect switches, lightning arresters, and associated buswork, at the physical point of connection. ORPC ownership extends to all downstream substation facilities, including power transformers, medium-voltage switchgear, station service equipment, protection and control systems, metering, SCADA, communications infrastructure, and associated auxiliary systems required for safe and reliable operation. These critical assets form the core of ORPC's substation infrastructure.

The assessment evaluated all major station components, including:

- Power transformers (typically 44 kV to 12.47 kV or 4.16 kV), associated protection devices, and oil containment systems;
- Medium-voltage switchgear assemblies, including breakers, relays, metering, control wiring, and SCADA and communications systems;
- Instrument transformers, station service supplies, grounding systems, and auxiliary equipment; and
- Civil and structural features influencing reliability, accessibility, or safety (e.g., control buildings, fencing, foundations, and drainage).

i. Primary Driver*:* The primary driver for this program is the mitigation of substation asset failure risk. The catastrophic failure of a substation asset can result in the complete loss of an individual distribution substation, causing widespread customer outages until emergency restoration and system switching activities can be completed. Substation condition, configuration, and available operational flexibility are therefore critical determinants of overall system reliability.

Mitigating the safety hazards associated with unmitigated asset failure is a key consideration. For example, the structural or mechanical failure of electrical apparatus presents an immediate physical hazard to utility personnel and the public. Asset failure also presents significant environmental risks, as a power transformer tank rupture can result in the release of a substantial volume of insulating oil into adjacent soils or local waterways. Furthermore, major substation equipment generally involves long procurement lead times and more difficult execution, necessitating a proactive renewal strategy rather than a reactive run to failure approach.

ii. Secondary Driver: The secondary driver for this program is the elimination of functional obsolescence from the distribution system. The majority of ORPC's substations are legacy installations that utilize outdated substation design and equipment that are functionally obsolete by modern utility engineering standards. These legacy configurations lack the localized reliability, safety features, and operational flexibility inherent to modern substation designs.

Asset renewal enables ORPC to systematically modernize its infrastructure to deliver tangible benefits to customers. Safely accommodating evolving customer demand for electrification, distributed energy resource integration, and enhanced reliability requires a modernized, resilient electrical grid.

3. Investment Justification

3.1 Background

In 2025, ORPC commissioned Rockwood Engineering to perform a comprehensive condition assessment of ORPC's substation assets. This assessment was completed in 2026 and provides the technical foundation for ORPC's capital expenditure planning for the substation renewal program. The assessment methodology integrates multiple information sources and applies professional engineering judgment to evaluate asset condition, system exposure, and relative consequence.

The assessment was informed by the following primary data inputs:

- Non-invasive field inspection observations conducted by Synergy Power Ltd., providing consistent system-wide insight into asset configuration, apparent condition, and observable deficiencies.
- ORPC operational and asset records, including equipment information, historical context, and operational knowledge.
- GIS-derived system data used to evaluate feeder characteristics, overhead and underground exposure, and connected transformer capacity as a proxy for relative load served.
- Regional planning documentation, including relevant Integrated Regional Resource Plans
- (IRRPs), establishing external planning context and coordination considerations.
- Publicly available demographic and electrification indicators used directionally to inform planning context.

3.2 Asset Age

Installation dates were not available for all substation assets. Table 5 shows the approximate age of each substation in ORPC's system. It can be assumed that the majority of critical assets in the substation are around the age shown.

Table 5: Substation Age

Substation Name	Substation Age
Pembroke MS#1	66
Pembroke MS#2	61
Pembroke MS#3	61
Pembroke MS#4	66
Pembroke MS#5	58
Pembroke MS#6	51

Substation Name	Substation Age
Pembroke MS#7	51
Pembroke MS#8	35
Almonte MS#1	17
Almonte MS#2	61
Almonte MS#3	61
Almonte MS#4	7

The majority (9 of 12) of ORPC's substations are 50 years old or older. These legacy installations utilize outdated substation design and equipment that are functionally obsolete by modern utility engineering standards.

3.3 Asset Condition

Table 6 provides the assessed overall condition of each of ORPC's substations.

Table 6: Substation Condition

Substation Name	Substation Condition
Pembroke MS#1	Fair
Pembroke MS#2	Fair
Pembroke MS#3	Fair
Pembroke MS#4	Poor
Pembroke MS#5	Fair
Pembroke MS#6	Good
Pembroke MS#7	Fair
Pembroke MS#8	Fair
Almonte MS#1	Good
Almonte MS#2	Fair
Almonte MS#3	Fair
Almonte MS#4	Good

The assessment observed the following themes regarding the substations:

- Aging outdoor assets were observed at several locations, particularly in transformer and medium-voltage switchgear installations.
- Modernization levels within protection and control systems vary across the system, reflecting differences in age, configuration, and historical investment.
- Supporting systems (i.e. grounding, fencing, and site infrastructure) were generally serviceable, with localized issues at select locations.

Table 7 details specific substation issues identified in the assessment that warrant renewal investment.

Table 7: ORPC Specific Substation Issues

Station	Condition Issues
Pembrook MS#1	• Progressive age-related deterioration across multiple asset classes, particularly affecting outdoor primary equipment, grounding systems, and civil elements. • Legacy SCADA limits system visibility and increases reliance on manual practices. • Safety and compliance deficiencies.
Pembrook MS#2	• Structure risk identified on tower foundation. • Legacy 5kV gear limits operational flexibility and system visibility relative to modern platforms. • Non-functional SCADA system constrains real-time monitoring capability, increasing reliance on local operating practices.
Pembrook MS#3	• Grounding deficiencies. • Progressive external deterioration of transformer and bus structures. • Legacy 5kV gear limits operational flexibility and system visibility relative to modern platforms. • Non-functional SCADA system constrains real-time monitoring capability, increasing reliance on local operating practices.
Pembrook MS#4	• Advanced age-related deterioration across primary switching equipment and supporting station infrastructure, including oil leakage observed on 44 kV breakers, • Bonding deficiencies, corrosion of structural elements, and general site degradation. • Legacy 5kV switchgear and associated control wiring exhibit late-lifecycle behaviour, with operational experience confirming functional reliability concerns, including intermittent interlock issues and control wiring related maloperations during recent work activities.
Pembrook MS#5	• Transformer has reduced dielectric strength. • Non-functional SCADA system constrains real-time monitoring capability, increasing reliance on local operating practices.
Pembrook MS#6	• Grounding deficiencies • Lack of load totalization meter to improve operational visibility and planning data quality.
Pembrook MS#7	• Grounding deficiencies. • Environmental deterioration. • Legacy 44kV air-break switching equipment and associated motor operators exhibit age-related characteristics consistent with increasing maintenance burden and potential variability in operating performance. • SCADA functionality is unreliable or intermittent, limiting real-time monitoring capability and reducing operational visibility.
Pembrook MS#8	• Civil and structural risk related to the main transformer foundation as there is progressive settlement of the transformer foundation toward the adjacent embankment, which has required temporary shimming to maintain acceptable alignment of transformer terminations. This results in long-term risk to mechanical integrity, conductor stress, and future operability. • Minor grounding, labelling, security, and vegetation maintenance items.
Almonte MS#1	• Lack of load totalization meter to improve operational visibility and planning data quality. • Verification of gas monitoring, ventilation, and personnel safety provisions associated with the indoor GIS installation is needed.
Almonte MS#2	• Lack of load totalization meter to improve operational visibility and planning data quality. • Incomplete integration of station monitoring systems resulting in the absence of local data aggregation, load totalization, and full SCADA communications integration.
Almonte MS#3	• Degradation of the unit substation enclosure, 1975-vintage switchgear remains operational but enclosure degradation is now becoming a material lifecycle consideration [Is this the 5/15kV or 44kV] • Grounding deficiencies.

Station	Condition Issues
	• Transformer external condition issues, including oil leakage and surface deterioration. • No SCADA monitoring capability
Almonte MS#4	• Lack of load totalization meter to improve operational visibility and planning data quality.

To prioritize intervention and mitigation of the identified substation issues for a capital expenditure plan the risk associated with each issue was evaluated. Risk is evaluated through the combined consideration of asset condition (as an indicator of relative vulnerability and likelihood of failure) and asset criticality (as an indicator of operational and customer consequence). The assessment did not attempt to quantify absolute risk or develop statistically derived failure probabilities but instead establishes a comparative understanding of relative system exposure.

The following criticality factors described below were considered collectively to establish a relative understanding of substation consequence across ORPC's system. No single factor was applied in isolation; substations were assessed holistically based on combined exposure, load served, and role within the supply network. The resulting classifications support capital prioritization when considered alongside asset condition findings.

- 44kV Sub-Transmission Role: Will an asset failure at the substation, reduce the reliability of the 44kV Sub-Transmission system.
- Medium Voltage Overhead Exposure: Substations supplying extensive overhead MV infrastructure (particularly where a significant portion is three-phase) were therefore assessed as having higher operational consequence in the event of upstream equipment failure.
- Medium Voltage Underground Exposure: Substations supplying extensive underground MV infrastructure (particularly where a significant portion is three-phase) were therefore assessed with increased consideration for outage consequence and restoration complexity.
- Downstream Connected Load: Substations supplying larger connected loads were assessed as having higher potential customer and system impact in the event of an outage, while substations serving smaller or more dispersed loads were assessed as having lower relative consequence.
- Medium Voltage Feeder Redundancy and Network Resilience: Substations supplying predominantly radial feeders with limited or no backfeed capability were assessed as having higher relative consequence, as outages are more likely to result in extended service interruptions.

Table 8 details the result for the risk assessment. A qualitive prioritization of intervention actions to address identified issues.

Table 8: ORCP Prioritized Action Plans for Substation Issues

Station	Action Plan	Priority
PEM MS#4	Replace existing 44 kV switching infrastructure with modern metal-enclosed switchgear.	High
ALM MS#3	Replace existing unit substation and medium voltage switchgear with modern gas-insulated equipment	Moderate
PEM MS#4	Replace legacy 5 kV switchgear with modern GIS equipment.	Moderate
PEM MS#7	Replace legacy 44 kV airbreak switches and motor operators	Moderate
PEM MS#8	Stabilize transformer foundation and renew associated secondary conductor infrastructure	Moderate
Alm MS#2	Reconstruct affected sub-transmission tower foundations	Moderate
PEM MS#1	Replace legacy 5 kV switchgear with modern GIS equipment	Moderate
PEM MS#2	Replace legacy 5 kV switchgear with modern GIS equipment	Moderate
PEM MS#3	Replace legacy 5 kV switchgear with modern GIS equipment	Low
PEM MS#1	Renew 44 kV switching infrastructure	Low

A. General Information on the Project/Program

1. Overview

1.1 Overview of Program

ORPC is planning targeted capital investments to upgrade the Supervisory Control and Data Acquisition (SCADA) system technologies deployed within its substations over the current five-year planning period. A SCADA system is utilized to remotely monitor real-time substation data, including transformer loading and operating temperatures, while enabling power system operators to monitor and remotely operate circuit breaker assets.

Seven of ORPC's twelve substations lack a fully functional modern SCADA arrangement. The current system lacks the advanced functionality required to manage a modern electrical grid and is experiencing regular component failures, leading to prolonged customer disruptions and degraded network reliability.

To address critical asset renewal needs while proactively creating new system efficiencies, the program is structured around two primary areas of focus:

- SCADA and Relay Upgrades: This component prioritizes capital investment toward the SCADA elements most at risk of physical failure and the components that are functionally obsolete. The primary assets addressed include substation Remote Terminal Units (RTUs) and legacy electromechanical relays. These devices will be replaced with modern equivalent intelligent electronic devices (IEDs) that align with utility best practices and current ORPC technical standards.
- Smart Grid Modernization: This component prioritizes capital investments in grid assets that enable faster fault location, isolation, and service restoration. These technologies reduce outage durations, provide advanced situational awareness to operators, and establish a scalable platform for future grid automation and Distributed Energy Resource (DER) integration.

To mitigate the ratepayer impact of these modernization efforts, ORPC has secured external federal funding to offset 50% of the capital costs of this program. This funding is provided through Natural Resources Canada’s Smart Renewables and Electrification Pathways Program (SREPs), specifically under the Utility Support Stream.

1.2 Investment Description

The specific SCADA and relay upgrade configurations will vary by substation; however, the general scope of work across all targeted locations will involve:

- Removal of existing obsolete protective relays and SCADA equipment.
- Installation of protective relays, station meter, communications infrastructure, and associated control wiring.

The specific substations scheduled for SCADA and Relay Upgrades during this planning period are:

- Almonte MS#2
- Almonte MS#3
- Pembroke MS#1
- Pembroke MS#2
- Pembroke MS#3

For the Smart Grid Modernization component of this program, the scope of work encompasses all ORPC service areas (Pembroke, Almonte, Beachburg and Killaloe) and involves the installation of:

- 73 OH Smart Fault Indicators
- 219 OH Visual Fault Indicators
- 25 S&C Trip Savers
- 437 Underground Transformer Indicators
- 1 Recloser Relay
- 10 Pad-mounted Switch Indicators
- Survalent Outage Management System

Table 1 provides the Program Gross Capital Expenditure Plan for the planning period.

Table 1: Program Gross Capital Expenditure Plan ($)

Project	2027	2028	2029	2030	2031
System Supervisory Equipment – Almonte MS#2 - SCADA	130,000				
Smart Grid – Fault Indicators, Trip Savers, Recloser, Outage Management System	256,520	565,911	565,911	824,827	
System Supervisory Equipment - Almonte MS#3 – SCADA		133,900			
System Supervisory Equipment - Pembroke MS#1 - SCADA			144,500		
System Supervisory Equipment - Pembroke MS#2 – SCADA			144,500		
System Supervisory Equipment – Pembroke MS#3 - SCADA				155,100	

2. TIMING

Timing and Project Prioritization

The pace of investment within this program is structured to strike a balance between the need to address obsolete, end-of-life substation SCADA systems, modernizing the grid, the available internal resources required to execute the work safely, and customer preferences to mitigate bill impacts and maintain rate stability.

Furthermore, the proposed timing of these projects directly aligns with the information detailed in ORPC's Technical Planning and Engineering Rationale submission for Natural Resources Canada's Smart Renewables and Electrification Pathways Program (SREPs) under the Utility Support Stream (USS). The executed funding agreement also requires all project installation and commissioning activities to be completed by March 31, 2030.

Table 2 shows the timing of specific projects in program for this planning period.

Table 2: Project Timing

Project	In Service Year
System Supervisory Equipment - Almonte MS#2 - SCADA	2027
Smart Grid – Fault Indicators, TripSavers	2027
System Supervisory Equipment - Almonte MS#3 - SCADA	2028
Smart Grid – Fault Indicators, Recloser	2028
System Supervisory Equipment – Pembroke MS#1 - SCADA	2029

System Supervisory Equipment – Pembroke MS#2 - SCADA	2029
System Supervisory Equipment – Pembroke MS#3 - SCADA	2030
Smart Grid – Fault Indicators, Outage Management System	2030

Program Execution Risk and Risk Mitigation

ORPC proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility manages include:

- Resource Availability – There may be insufficient labor capacity to complete the planned program activities within the designated timelines. This constraint could delay interdependent and downstream work packages, potentially escalating project costs if ORPC is required to retain contracted skilled resources at premium rates. In response, ORPC will implement a structured, long-term resource plan based on projected project activities and establish appropriate cross-training and responsibility overlaps among personnel to minimize the operational impact of staff attrition.
- Outage Planning – Any planned outages required as a consequence of executing this program will be coordinated and communicated to affected parties well in advance. Physical work will be scheduled during periods of low system demand to minimize reliability impacts to customers.
- Unexpected Priority Calls – In the normal course of utility operations, unforeseen events can occur where internal resources must be redirected from planned capital projects to address emergency, reactive system restoration needs. To maintain the established deployment schedule, ORPC utilizes contractor labor where necessary to supplement its internal workforce and ensure overall program delivery stays aligned with the utility's regulatory commitments.

3. Historical and Future Capital Expenditures

Table 3: Historical and Future Capital Expenditures

	Historical Costs ($ '000)				Bridge Year ($'000)	Test Year ($'000)	Future Costs ($ '000)			
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	-	-	175	106	391	387	700	855	980	-
Contributions	-	-	-	-	196	193	350	427	490	-
Capital (Net)	-	-	175	106	195	194	350	428	490	-

The formal SREPs funding agreement establishes a mandatory multi-year execution schedule spanning March 2, 2026, to March 31, 2030. For 2026, the SREP-eligible capital scope focuses specifically on

upgrading the SCADA system at Pembroke MS#7 alongside the deployment of distribution fault indicators and TripSaver devices. Executing this initial scope on schedule is required to maintain compliance with federal funding milestones and secure the corresponding 50% capital cost offset for ratepayers.

4. Comparative Historical Expenditure

ORPC completed two SCADA and Relay Upgrade projects during the prior rate period that can be used as a baseline for unit costs. Actual costs for the upgrades at Pembroke MS#4 were $175,342, and the assets were placed in service in 2024. The actual costs for the upgrades at Pembroke MS#8 were $106,329, and the assets were placed in service in 2025.

Forecast capital expenditures for the five substations scheduled for SCADA and Relay Upgrade during this planning period range from $130,000 to $155,100 per station. The current forecast costs are within the range of the historical capital expenditure. Minor cost variances across the upcoming projects are driven by site-specific scope differences at each individual substation and inflationary impacts on equipment and labour.

ORPC has not completed Smart Grid Modernization in the past, meaning no direct historical cost comparison is available for this component of the program. To ensure cost accuracy and prudence, the capital forecast for the Smart Grid Modernization work stream is built directly from vendor material estimates and subject matter expert assessments of engineering and construction requirements.

5. Alternatives Analysis

ORPC secured external federal funding through NRCan SREPs under the Utility Support Stream. This federal grant directly offsets up to 50 percent of the total capital cost of the SREPs and System Supervisory Equipment investment.

As part of the technical due diligence performed for the funding applications, ORPC evaluated investment options based on their ability to materially reduce outage duration and operational risk, while remaining cost-effective and compatible with existing operations, communications, and SCADA practices.

The criteria for evaluating various alternatives were:

- Reliability impact (expected reduction in time-to-locate and time-to-restore, and reduction in sustained interruptions);
- System integration and interoperability (industry-standard protocols, SCADA/OMS integration, avoidance of vendor lock-in);

- Operational suitability (fit with existing switching and protection philosophies, maintainability, and crew work practices);
- Cyber security and data integrity (secure communications, access control, and network segmentation capabilities);
- Scalability and standardization across multiple feeders and service territories; and
- Total lifecycle cost (capital, installation, spares, and long-term maintenance).

The alternative considered were:

- Status quo / manual fault patrol and manual switching (not acceptable due to restoration time and safety risk).
- Traditional 'wires' solutions (reconductoring, pole replacements, additional switching), valuable for asset condition needs but not a direct substitute for system visibility and rapid fault location at scale.
- Non-wires alternatives (DER, storage, demand-side management) can support capacity and resiliency objectives but does not directly address fault location and restoration time limitations for typical distribution interruptions.
- Manual or fixed-threshold fault indicators at a lower cost but provide limited information and do not adapt to changing load conditions, reduced effectiveness on multi-grounded distribution systems.
- Standalone automation platforms evaluated with preference for solutions that integrate into ORPC's SCADA/OMS environment using standard interfaces.

The selected approach as detailed in this narrative combines monitoring (fault location/indication), targeted lateral reclosing, and control-room tools (SCADA/OMS) to address both outage frequency and outage duration drivers.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 4: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Program Expected Outcomes
Efficiency	SCADA and relay upgrades is expected to significantly reduce the requirement to dispatch field personnel to manually operate substation equipment due to SCADA system failures. Furthermore,

Primary Criteria for Evaluating Investments	Program Expected Outcomes
	transitioning away from obsolete technologies will mitigate the increasing time and maintenance costs associated with sourcing rare spare parts and repairing legacy components. Concurrently, the Smart Grid Modernization work stream will enable localized automated circuit restoration and improve visual fault identification when operator-assisted restoration is required. Together the expect outcome is reduced operational time and physical field effort required to restore customer services following a grid disturbance.
Customer Value	The integration of upgraded SCADA systems and Smart Grid Modernization technologies will significantly reduce the overall outage durations experienced by customers. In addition to experiencing a more resilient power supply, customers will directly benefit from long-term rate stability because of the operational cost efficiencies gained across ORPC's operations.
Reliability	ORPC will achieve a meaningful reduction in customer outage durations, positively impacting system reliability indices. Furthermore, the enhanced SCADA functionality will substantially advance ORPC's real-time operational awareness, enabling operators to closely monitor asset loading profiles and prevent conditions that cause premature equipment degradation, which in turn extends the useful life of major substation assets.
Safety	The deployment of modern SCADA technologies and Smart Grid automation provides an invaluable indirect safety benefit to utility personnel. By introducing automation and reliable remote operating capabilities, ORPC significantly decreases the frequency and duration of time that field personnel must spend in direct physical exposure to high-voltage electrical equipment during switching and fault-isolation activity.

2. INVESTMENT NEED

To maintain the safety, efficiency, reliability, and resiliency of its power delivery system, ORPC must systematically modernize its grid monitoring and control infrastructure. This program establishes a coordinated strategy to renew obsolete substation electronics while simultaneously deploying advanced grid automation technologies across the distribution system.

i. Primary Driver*:* The primary driver for this program is system reliability improvement. The existing SCADA systems in the majority of ORPC's substations have reached the end of their useful lives. These legacy systems are no longer supported by original equipment manufacturers, and replacement spare parts are not readily available in the market. Consequently, this legacy infrastructure has experienced an increasing frequency of component failures, and individual repairs have taken significantly longer to complete because matching replacement components are difficult to obtain.

A SCADA system failure severely impacts utility operations by eliminating real-time system visibility. This visibility loss forces operators to manage the system without real-time data and rely on manual, in-field switching operations rather than safe, efficient remote management from the control room. Operating in this manner significantly delays fault isolation and extends customer outage times. To complement substation upgrades, the Smart Grid Modernization component of this program will deploy proven intelligent devices into the downstream distribution system to enable rapid fault location, isolation, and automatic restoration capabilities, resulting in a demonstrably more resilient system

ii. Secondary Driver: The secondary driver for this program is the realization of measurable operational efficiencies across the distribution system. A modern, fully integrated SCADA platform provides reliable remote monitoring and control capabilities, eliminating unnecessary truck rolls and freeing up qualified field personnel to perform higher-priority system maintenance tasks. Furthermore, a modern SCADA system captures advanced equipment data, providing the foundational metrics required to optimize system loading and extend the operational life of major equipment.

Concurrently, the deployment of smart grid field technologies provides automated fault detection, isolation, and system restoration. By pinpointing line disturbances automatically, these devices minimize line patrolling requirements, reducing the overall time, field resources, and operational costs required to manage and maintain the distribution system.

3. INVESTMENT JUSTIFICATION

SCADA System Condition

In 2025, ORPC commissioned Rockwood Engineering to perform a comprehensive condition assessment of ORPC's substation assets. This assessment was completed in 2026 and provides the technical foundation for ORPC's capital expenditure planning for the substation renewal program. The assessment methodology integrates multiple information sources and applies professional engineering judgment to evaluate asset condition, system exposure, and relative consequence.

The assessment was informed by the following primary data inputs:

- Non-invasive field inspection observations conducted by Synergy Power Ltd., providing consistent system-wide insight into asset configuration, apparent condition, and observable deficiencies.

- ORPC operational and asset records, including equipment information, historical context, and operational knowledge.
- GIS-derived system data used to evaluate feeder characteristics, overhead and underground exposure, and connected transformer capacity as a proxy for relative load served.
- Regional planning documentation, including relevant Integrated Regional Resource Plans (IRRPs), establishing external planning context and coordination considerations.
- Publicly available demographic and electrification indicators used directionally to inform planning context.

Table 5 details the assessment of the SCADA system at each substation.

Table 5: ORPC Specific Substation Issues

Station	Condition Issues
Pembroke MS#1	• Legacy SCADA limits system visibility and increases reliance on manual practices.
Pembroke MS#2	• Non-functional SCADA system constrains real-time monitoring capability, increasing reliance on local operating practices.
Pembroke MS#3	• Non-functional SCADA system constrains real-time monitoring capability, increasing reliance on local operating practices.
Pembroke MS#4	• Protection and SCADA system have been recently modernized, improving system visibility and operability.
Pembroke MS#5	• Non-functional SCADA system constrains real-time monitoring capability, increasing reliance on local operating practices.
Pembroke MS#6	• Protection and SCADA system have been recently modernized. • Lack of load totalization meter to improve operational visibility and planning data quality.
Pembroke MS#7	• SCADA functionality is unreliable or intermittent, limiting real-time monitoring capability and reducing operational visibility.
Pembroke MS#8	• Protection and SCADA system have been recently modernized.
Almonte MS#1	• Substation is a recently modernized indoor installation, including modern gas-insulated switchgear, protection, and monitoring systems.
Almonte MS#2	• Incomplete integration of station monitoring systems resulting in the absence of local data aggregation, load totalization, and full SCADA communications integration.
Almonte MS#3	• No SCADA monitoring capability is currently implemented.
Almonte MS#4	• The station reflects a modern design configuration, including current switching, protection, and monitoring infrastructure • Lack of load totalization meter to improve operational visibility and planning data quality.

The results of the professional assessment indicate seven out of twelve ORPC's substations lack a fully functional modern SCADA arrangement.

Smart Grid Modernization

A review of ORPC's recorded outage events (2022–2024 sample) indicates that defective equipment, foreign interference, and adverse weather are leading drivers of outage frequency. Figure 1 provides a summary of outage events by cause in the 2022–2024 sample.

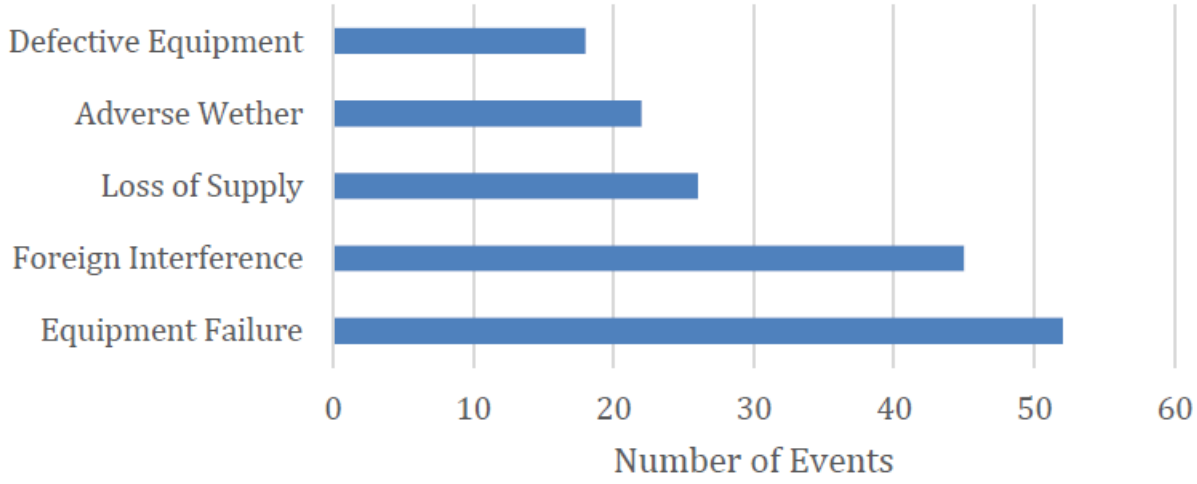


Figure 1: Outage Events by Cause (2022-2024 sample)

These causes are consistent with scenarios where improved fault indication, faster location, and lateral reclosing can reduce restoration time and/or prevent sustained interruptions.

SCADA upgrades are required to integrate new field data sources, improve alarm/event handling, and support OMS functionality. Upgrades focus on standardization, secure communications, and improved operator visibility of feeder and substation conditions.

Project Prioritization

Projects within this program were prioritized based upon:

- The criticality of the station,
- Historical SCADA failure information,
- The number of connected customers to the project assets, who will face resulting outages.

A. General Information on the Project/Program

1. Overview

ORPC's Small/Large Vehicles and Trailers program is organized into three categories: Large Vehicles, Passenger/Light Vehicles, and Other Transportation Equipment. Large Vehicles support distribution system maintenance and capital work, while Passenger/Light Vehicles are used for travel, locates, metering, and minor maintenance tasks. Other Transportation Equipment includes trailers, tensioners and pullers, brush chippers, backhoes, forklifts, and lawn tractors.

Large Vehicles

ORPC has six large vehicles within its fleet that operate across four main service areas, carrying out essential maintenance, supporting capital investment work and responding to emergency outages.

ORPC analyzed the current asset conditions by considering 5 key factors:

i. The age of the large vehicle reaching 15 years by 2031:

- ORPC targets a typical useful life of 15 years for large vehicles. After 8 to 10 years, the vehicles typically experience large increases in maintenance costs which results in extended downtime and ultimately decreased reliability. Large vehicles #1, #3, #8 and #31 have exceeded or will exceed by the end of the DSP period their target typical useful life.

ii. Utilization of large vehicles:

- The average utilization of vehicles with little or no maintenance costs in a given year is approximately 1,120 hours which represents a utilization of 65%. The expected utilization of 65% is deemed reasonable considering ORPC operation department employees spend over 30% of their annual working hours assisting with disconnections during collections periods, cleaning and maintaining vehicles, organizing and counting inventory, training, entering time, completing paperwork, on sick leave or on vacation. ORPC therefore considers any large vehicle below 1,000 utilization hours on average to be under-utilized. Large vehicles #1 and #35 are considered under-utilized according to this parameter. However, both large vehicles are RBDs that are not utilized as frequently during emergencies and outages. Large vehicle #1 is maintained in the event of a breakdown on other vehicles with its utilization largely

depending on the maintenance requirements of other large vehicles. Large vehicle #35 is located within ORPC's Almonte service territory located over 110 kms from the Pembroke service territory. As ORPC maintains 2 operations centres, each requires an RBD.

iii. Average annual cost of non-recurring maintenance:

- Large vehicles are estimated to now cost upwards of $500,000. Over a target typical useful life of 15 years, the annual depreciation would be $33,333. Annual maintenance costs exceeding $33,333 would be justification for immediate replacement. However, downtime where the vehicle is unavailable should also be considered in terms of productivity and emergency and power outage response times. The average per vehicle annual utilization is 862 hours since 2016. In 2024, the average per vehicle utilization was 707 hours, 155 below the average since 2016. At ORPC's calculated rate of $235 per hour including vehicle costs and the cost of 2 journeyperson technicians, this would result in approximately $36,425 of lost productivity per vehicle for 2024. The maintenance costs considered do not include immaterial and recurring repairs and maintenance and wages spent on bringing the vehicles for repairs. ORPC therefore affirms that any amount over $10,000 in annual repairs is considered significant as it brings the total combined cost of lost productivity plus odd and unusual repairs and maintenance above the estimated annual depreciation amount based on the target typical useful life. Large vehicles #8, #11 and #31 currently exceed $10,000 in average per year non-recurring maintenance with vehicle #3 nearing the established threshold as well.

iv. Average non-recurring maintenance cost per hour of utilization:

- This factor combines the average utilization hours of each vehicle with the average non-recurring maintenance costs to determine which vehicles result in more maintenance costs per hour of utilization. A rate of $10/hour in maintenance costs would result in additional maintenance costs of $11,280 based on expected utilization hours which would risk bringing the total costs of lost productivity and non-recurring repairs and maintenance in excess of the annual depreciation. Large vehicles #3, #8 and #11 are currently outside our retention parameters with vehicle #31 very near falling outside of the parameter.

v. Negative utilization and maintenance trend:

- ORPC reviewed the utilization hours and the total non-recurring maintenance costs per year since 2016 on each of its large vehicles and established trends for utilization and maintenance costs. If the utilization trend was decreasing and the maintenance cost trend was increasing, then it was considered as a negative trend as it generally represented that the vehicles were experiencing more and more downtime for repairs and maintenance. Large vehicles #3, #11 and #35 are presently experiencing negative trends with increasing annual maintenance costs and decreasing utilization due to downtime and decreased reliability.

The following summary identifies which vehicles should be considered for replacement, additional monitoring or retention, with red indicating that it has met the criteria for replacement and green indicating that it is still operating within normal parameters for each factor considered:

Table 1: Large Vehicle Replacement Triggers

Unit	Age	Average Utilization	Average Maintenance Costs	Cost per Utilization Hour	Trend	Replace?
#1 - 1994 Freightliner						No
#3 - 2005 International						Yes
#8 - 2008 International						Yes
#11 - 2017 International						Yes
#31 - 2014 International						Yes
#35 - 2019 International						No

Large vehicles #3, #8 and #11 present the most dimensions operating outside of normal parameters and necessitate consideration for replacement with #8 presenting the highest maintenance cost per utilization hour. Large vehicle #31 should also be considered for replacement as its Cost per Utilization hour is close to operating outside of normal parameters. Large vehicles #1 and #35 should be retained according to the parameters mainly due to lower-than-average non-recurring maintenance costs, and costs per utilization hour.

Passenger/Light Vehicles

ORPC has seven passenger and light vehicles ("small vehicles") within its fleet that operate across four main service areas, utilized for meter maintenance and replacements, underground locates, out-of-town

training, property and other essential maintenance, collections, and for identifying distribution system asset repairs when responding to emergency outages.

ORPC analyzed the current asset conditions by considering the same 5 key factors as large vehicles:

The age of the vehicle reaching 15 years by 2031:

- ORPC targets a typical useful life of 15 years for passenger/light vehicles at which point the maintenance costs show upward trends and ultimately decrease reliability. Vehicle #14 has exceeded its target typical useful life while vehicles #4, #5 and #10 will exceed theirs by the end of the DSP period.

Utilization of small vehicles:

- The average utilization of vehicles with little or no maintenance costs in a given year is approximately 780 hours which represents a utilization of 45%. The expected utilization of 45% is deemed reasonable considering ORPC small vehicle users spend over 50% of their annual working hours performing general administration and property maintenance tasks, training, on sick leave or on vacation. ORPC therefore considers any small vehicle below 700 utilization hours on average to be under-utilized. Small vehicle #4 is the only vehicle that is considered under-utilized according to this measure. This vehicle is most often used for administrative and field work, errands by staff, out-of-town training and as a service vehicle when others are not available. Reliable data remains unavailable on vehicles #38 and #39 which were both purchased in 2025.

Average annual cost of non-recurring maintenance:

- Small vehicles are estimated to now cost upwards of $50,000. Over a target typical useful life of 15 years, the annual depreciation would be $3,333. Annual maintenance costs exceeding $3,333 would be justification for immediate replacement. However, downtime where the vehicle is unavailable should also be considered in terms of productivity. The maintenance costs considered do not include immaterial and recurring repairs and maintenance and wages spent on bringing the vehicles for repairs. ORPC therefore affirms that any amount over $2,000 in annual repairs is considered significant as it brings the total combined cost of lost productivity plus odd and unusual repairs and maintenance above the estimated annual depreciation amount based on the target typical useful life. Small vehicle #14 currently exceeds $2,000 in average per year non-recurring maintenance.

Average non-recurring maintenance cost per hour of utilization:

- This factor combines the average utilization hours of each vehicle with the average non-recurring maintenance costs to determine which vehicles result in more maintenance costs per hour of utilization. A rate of $2.78/hour in maintenance costs would result in additional maintenance costs of $2,000 based on expected utilization hours which would risk bringing the total costs of lost productivity and non-recurring repairs and maintenance in excess of the annual depreciation. Vehicle #14 is currently the only vehicle exceeding the normal operating parameter, however #4 is also at risk of exceeding the established parameter.

Negative utilization and maintenance trend:

- ORPC reviewed the utilization hours and the total non-recurring maintenance costs per year since 2016 on each of its small vehicles and established trends for utilization and maintenance costs. If the utilization trend was decreasing and the maintenance cost trend was increasing, then it was considered as a negative trend as it generally represented that the vehicles were experiencing more and more downtime for repairs and maintenance. Vehicles #10 and #14 are presently experiencing negative trends with increasing annual maintenance costs and decreasing utilization due to downtime and decreased reliability.

The following summary identifies which vehicles should be considered for replacement, additional monitoring or retention, with red indicating that it has met the criteria for replacement and green indicating that it is still operating within normal parameters for each factor considered:

Table 2: Small Vehicle Replacement Triggers

Unit	Age	Average Utilization	Average Maintenance Costs	Cost per Utilization Hour	Trend	Replace?
#4 - 2014 Ford C-Max						Yes
#5 - 2013 Ford F150						Yes
#10 - 2015 Dodge Caravan						Yes
#14 - 2011 Chevrolet						Yes
#36 - 2021 Kona EV						No
#38 - 2023 E-Transit Van		N/A				No
#39 - 2025 Ford F150		N/A				No

Small vehicle #14 presents the most dimensions operating outside of normal parameters followed by vehicles #4, #5 and #10. However, vehicles #4, #5 and #10 necessitate consideration for replacement with #4 presenting the highest maintenance cost per utilization hour.

Trailers

ORPC has ten trailers, two tensioners/pullers, one brush chipper, one backhoe, two forklifts and one lawn tractor that operate across four main service areas, utilized for capital projects and distribution system and property maintenance.

Table 3: Other Transportation Equipment Details

Unit	Age (yr)
#17 - 1986 Custom Reel Trailer	40
#18 - 1986 Custom Reel Trailer	40
#19 - 1990 Tensioner/Puller	36
#20 - 1990 Tensioner/Puller	36
#24 - 1999 Pole/Utility Trailer	27
#30 - 2010 Dump Trailer	16
#32 - 2012 Reel Trailer	14
#33 - 2014 Dump Trailer	12
#34 - 2019 Pole Trailer	7
#26 - 2003 Reel Trailer	23
#27 - 2023 Utility Trailer	3
#37 - 2024 Pole Trailer	2
#2 - 2012 Brush Chipper	14
#15 - 2007 Backhoe	19
#21 - 2008 Forklift	18
#23 - 1987 Forklift	39
#25 - 2020 Lawn Tractor	6

Reel trailers #17 and #18 and tensioners/pullers #19 and #20 are the oldest in the fleet reaching 40 years and 36 years of age respectively. The 1987 Forklift has also reached an age of 39 years. The tensioners/pullers have experienced the most issues including exploding mufflers and engine issues resulting in significant downtime and necessitating rescheduling of planned capital works. Annual maintenance costs on #19 and #20 have increased by an approximate average of 42% from 2016 to 2024.

2. TIMING

Not applicable.

3. Historical and Future Capital Expenditures

Table 4 summarizes the overall investment associated with transportation equipment, during the Historical period from 2020 to 2024, the 2025 and 2026 Bridge years, as well as the Forecast period from 2027 to 2031.

Table 4: Historical and Future Capital Expenditures

	Historical Costs ($ '000)				Bridge ($'000)		Future Costs ($ '000)			
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	$-	$68.4	$57.8	$128.3	$608.6	$650.4	$517.0	$875.0	$55.0	$5.0
Contributions	-	-	-	-	-	-	-	-	-	-
Capital (Net)	$-	$68.4	$57.8	$128.3	$608.6	$650.4	$517.0	$875.0	$55.0	$5.0

To ensure that ORPC is able to continue to maintain assets and respond to issues in the distribution system, investments in new large vehicles will be required in 2027 and 2029, small vehicles will be required in 2027, 2028, 2029 and 2030 and a puller and tensioner will be required in 2028. This will allow ORPC to continue to carry out its routine maintenance activities, support capital investment projects, as well as respond to any emergencies as required. Table 5 below outlines the investments to occur from 2027 onwards to 2031.

Table 5: Transportation Equipment Five-Year Projects and Cost

Project	2027	2028	2029	2030	2031
Posi-Plus 50' Single Bucket	$550				
Posi-Plus 55' Double Bucket			$820		
2011 Chevrolet Replacement	$70				
2013 Ford F150 Replacement		$70			
2014 Ford C-Max Replacement			$50		
2015 Dodge Caravan Replacement				$50	
Tensioner and Puller		$442			
Allowance for Component Replacements	$5	$5	$5	$5	$5
Total	**$625**	**$517**	**$875**	**$55**	**$5**

Should an unplanned operational conflict arise such that an investment cannot be completed as scheduled, a decision will be made to defer projects or components of this project to a later date. Unplanned conflicts may include unscheduled investments of a higher priority.

4. Economic Evaluation (Expansion Projects)

Not applicable.

5. Comparative Historical Expenditure

Not applicable.

6. Investment Priority

To ensure that ORPC is able to continue to maintain assets and respond to issues in the distribution system, investments in new large vehicles will be required in 2027 and 2029, small vehicles will be required in 2027, 2028, 2029 and 2030 and a puller and tensioner will be required in 2028. This will allow ORPC to continue to carry out its routine maintenance activities, support capital investment projects, as well as respond to any emergencies as required.

7. Alternatives Analysis

When considering alternatives in the forecast period, ORPC has considered different options including:

i. Preferred Option: Purchasing New Equipment

- Purchasing new Large Vehicles, Passenger/Light Vehicles, and a new Tensioner/Puller remains the most reliable and cost-effective approach to support ORPC's maintenance, capital, and emergency response activities. New units provide improved reliability, reduced downtime, enhanced safety features, and lower operating and maintenance costs compared to aging equipment. Proactive replacement also allows ORPC to manage procurement lead times effectively and avoid reliance on rentals or neighbouring utilities. For Passenger/Light Vehicles, timely replacement ensures continuity of daily tasks such as travel, locates, metering, and minor maintenance. Across all equipment types, purchasing new assets ensures fleet readiness, operational efficiency, and long-term sustainability.

ii. Hiring or Renting from Third-Party Providers or Neighbouring Utilities

- ORPC has historically shared large vehicles with neighbouring utilities for major projects or storm response; however, access to these assets is limited. The nearest utility has only two

large vehicles, and their availability cannot be guaranteed. Renting large vehicles from third-party providers is possible but costly—often exceeding $1,000 per week plus mileage—and would introduce coordination delays that negatively affect planned work and emergency restoration times.

- For the Tensioner/Puller, no nearby utilities have the required equipment available. Renting from a third-party provider is feasible but comes at high cost and would likely delay capital projects or emergency tasks.
- For Passenger/Light Vehicles, rental vehicles are available but introduce logistical challenges, cost inefficiencies, and lack the specialized outfitting required for field tasks.

iii. Repair and Refurbishment of Existing Equipment

- Refurbishing Large Vehicles is not a practical alternative due to the complexity of major components such as engines, exhaust systems, and booms. Vendor options for full refurbishment are limited, and the process would take the vehicle out of service for an extended period, requiring ORPC to rely on costly rentals or third-party services. In many cases, the scale of refurbishment required is substantial and not economical given the remaining useful life of the vehicles.
- Similarly, refurbishing Passenger/Light Vehicles is not cost-effective. Significant mechanical repairs would create extended downtime and still fail to provide the long-term reliability needed for daily operations. ORPC continues to complete minor repairs where practical, but the units identified for replacement would require extensive work to remain viable, making replacement the more efficient option.

iv. Green Emissions Alternatives

- ORPC evaluated hybrid and electric options across vehicle categories. While some Large Vehicle EV or hybrid models exist, current market offerings are not feasible due to the long travel distances between service territories and significantly higher capital costs. For Passenger/Light Vehicles, green alternatives may offer fuel, maintenance, and carbon cost savings; ORPC will assess their feasibility at the time of purchase as the technology evolves. ORPC remains committed to monitoring the market and pursuing green emissions options where operationally and financially viable.

8. Innovative Nature of the Project

Not applicable.

9. Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The main Small/Large Vehicles and Trailers Program risks include:

- Long lead times or vendor delays postponing vehicle delivery, creating gaps in maintenance and capital schedules.
- Supply chain volatility may increase costs for chassis, specialized equipment, or upfitting.
- Transition and failure risk, where retiring or failing old vehicles before new ones arrive disrupts maintenance and capital work schedules.

Ensuring that vehicles are replaced at the end of their typical useful lives mitigates risks related to lead times, supply chain delays, and transition disruptions by allowing ORPC to plan procurement proactively rather than reactively. Proactive replacement provides sufficient scheduling flexibility to accommodate extended manufacturing or upfitting timelines without affecting maintenance or capital work. It also prevents unexpected in-service failures of aging vehicles, reducing the likelihood that essential equipment will be unavailable when needed. By replacing vehicles before reliability declines, ORPC can avoid costly emergency rentals or third-party services and maintain continuity in both planned and emergency operations.

Table 6: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The reliability of vehicles and equipment in the fleet impact several areas including supporting maintenance activities, supporting capital projects, performing underground locates, attending training and events and supporting response time to emergency calls. Equipment availability directly impacts productivity and scheduled replacements reduces the risk of unplanned vehicle and equipment failures. ORPC will also be able to reduce its maintenance costs through new purchases. New vehicles and equipment have lower maintenance tasks and costs associated in their younger years which will require less maintenance to be performed.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	ORPC will continue to maintain and improve response times to outages and emergency locates, and improve crew effectiveness and productivity.
Reliability	ORPC will be able to continue to maintain, operate and respond in a safe, timely and efficient manner. The purchase of new vehicles and related equipment ensures that ORPC can continue to maintain its business operations.
Safety	Not applicable.

2. INVESTMENT NEED

i. Main Driver:

The primary driver of this program is system maintenance support, as this program will allow ORPC to continue to carry out its maintenance activities, support capital projects, and respond to emergency outages. To do this, ORPC uses its trailers, tensioners, pullers and other equipment. Replacing the tensioners and pullers will permit ORPC to reliably carry out its capital project. Not replacing the tensioners and pullers will result in decreasing reliability of the equipment with continued impacts on planned work.

These vehicles are a critical part of OPRC's fleet. Through purchasing the new large vehicles, the reliability of large vehicles will increase, ensuring that critical maintenance can continue to be carried out. In addition, as ORPC plans to undertake a significant number of capital projects, the vehicles will play a critical role in supporting their execution by serving as material handlers. If ORPC did not invest in new vehicles, vehicles would have to be rented from nearby utilities or hired from third-party services when required, which presents additional risks and cost increases. It would also introduce delays to restoration times for emergency work, as well as cause issues with coordination of planned works.

Additionally, small vehicles allow ORPC crews can carry out its regular maintenance activities, support capital projects and support staff training. If the health and number of vehicles are not maintained, then this could induce issues with coordination efforts on planned work and human resources activities. Furthermore, ORPC uses its trailers, tensioners, pullers and other equipment to support system maintenance. Replacing the tensioners and pullers will permit ORPC to reliably carry out its capital project. Not replacing the tensioners and pullers will result in decreasing reliability of the equipment with continued impacts on planned work.

ii. Information Used to Justify the Investment:

The Small/Large Vehicles and Trailers program is designed to ensure ORPC crews can respond efficiently, timely and safely to emergency power outages, as well as carry out its regular maintenance activities and support capital projects. If the health and number of vehicles are not maintained then this could induce delays in restoration times and emergency work, as well as causing issues with coordination efforts on planned work.

This program is primarily driven by the need to renew and invest in vehicles to carry out critical system maintenance activities, support capital investment projects, and respond to emergency power outages.

3. Investment Justification

i. Demonstrating Accepted Utility Practice:

Not applicable.

ii. Benefit-Cost Analysis:

Not applicable.

iii. Historical Investments & Outcomes Observed:

Large Vehicles

ORPC proposes the purchase of 2 large vehicles in the forecast period including a single bucket large vehicle in 2027 and a double bucket large vehicle in 2029 to replace the existing 2008 and 2014 large vehicles. Both vehicles will have reached their maximum typical useful lives of 15 years in the intended year of replacement, and both vehicles have shown upward trending non-recurring maintenance costs since 2016. The additional maintenance costs on these large vehicles are also accompanied by productivity loss as a result of the vehicles being out of service for extended periods of time. The Small/Large Vehicles and Trailers program is designed to equip ORPC with a fleet of vehicles such that the utility can continue to provide safe, reliable, and effective services to its customers. Total program spending from 2027 onwards to 2031 is $1.3M which is an increase to estimated actual capital spending of $795K over the previous DSP period from 2022 to 2026. This is mainly due to ORPC needing to replace two large vehicles in the next five-year period.

Large vehicle #8 (a Posi-Plus 400-50) will require replacement in 2027. Large vehicle #8 is a material handling aerial device and is used as a person lift for service work and as material handler on capital and maintenance projects. In addition, it is used to restore power during outages. The vehicle was purchased in 2008 and has been used 1,066 hours per year on average. It has 174,653 km and 14,339 engine hours. In addition to having

reached its end of 15-year life, the vehicle has experienced multiple failures, with an engine rebuild being carried out in 2015, an exhaust and emissions system failure in 2018 and cracking of pistons in 2023. This has led to increased maintenance costs year on year compared to other vehicles and the vehicle has also been out of service for extended periods of time, averaging non-recurring maintenance costs of $22,562 per year since 2016. The vehicle will be replaced with a Posi-Plus 50' Single Bucket Hydraulic Over Center Material Handling Device similar to the vehicle in Figure 1.



Figure 1: Posi Pluss 400-50 Truck

Large vehicle #31 (a Posi-Plus 500-55) has also been identified for replacement in 2029. Large vehicle #31 is a material handling aerial device and is used as a person lift for service work and as a material handler on capital and maintenance projects. It is also used to restore power during outages. The vehicle was purchased in 2014 and has been used 1,262 hours per year on average. It has 123,774 km. In addition to having reached its end of 15-year life, the vehicle has experienced multiple failures including an exhaust manifold replacement in 2023 and EGR valve, Control Module and Turbocharger replacements in 2025. This has led to increased maintenance costs year on year compared to other vehicles and the vehicle has also been out of service for extended periods of time, averaging non-recurring maintenance costs of $11,314 per year since 2016. The vehicle will be replaced with a Posi-Plus 55' Double Bucket Deck-Mounted Elevator Hydraulic Over Center Material Handling Aerial Device similar to the vehicle in Figure 2. The double-bucket large vehicle #31 is considered a priority over the RBD large vehicle #11

experiencing similar maintenance costs due to #31's capability to respond to emergencies and it being the only large vehicle capable of reaching 44kV circuits on 65' and 70' poles.



Figure 2: Posi Plus 500-55 Truck

OPRC has also allocated $5,000 each year to allow for capital spend on their fleet to ensure they keep operating safely and efficiently. This will enable ORPC staff to carry-out all its essential activities with minimal disruption to its operations.

Small Vehicles

ORPC proposes the purchase of four small vehicles in the forecast period to replace vehicles #4, #5, #10 and #14. All vehicles will have reached their maximum typical useful lives of 15 years in the intended years of replacement and have shown upward trending non-recurring maintenance costs since 2016. These small vehicles are essential in supporting maintenance activities, supporting capital projects, performing underground locates, attending training and events, site visits, travel between operations centres, and supporting response time to emergency calls.

Small vehicle #14 will require replacement in 2027. This vehicle is a passenger vehicle mainly used in essential maintenance and capital works and in responding to emergency calls. The vehicle was purchased

new and has been used an average of 780 hours per year. It has 203,848 km. It has reached the end of its useful life and maintenance costs are trending towards $4,000 per year. The vehicle has experienced issues with the doors in 2021, 2022 and 2025 and holes in the floor were repaired in 2022 due to issues with rust. This vehicle will be replaced with a similar model, to be determined based on availability at the time of purchase.

Small vehicle #5 will require replacement in 2028. This vehicle is a passenger vehicle mainly used in essential maintenance and capital works and in responding to emergency calls at the Pembroke operations centre. The vehicle was purchased new and has been used an average of 839 hours per year. It has 269,129 km and is beginning to show significant rust. It will have reached the end of its typical useful life in 2028 and maintenance costs are trending upwards of $2,300 per year. This vehicle will be replaced with a similar model, to be determined based on availability at the time of purchase.

Small vehicle #4 will require replacement in 2029. This vehicle is a hybrid vehicle that discontinued production in 2019. Its primary purpose is for underground locates, maintenance activities and attending out-of-town training events at the Pembroke operations centre. The vehicle was purchased new and has been used approximately 750 hours per year on average. It has 167,088 km in addition to reaching the end of its typical useful life in 2029. The maintenance costs on this vehicle have steadily increased since 2016 trending upwards of $1,500 per year on average. This vehicle will be replaced with a small hybrid or electric vehicle similar to #36 (2021 Hyundai Kona EV) which is appropriate for transporting locate and metering equipment and is a green alternative.

Small vehicle #10 will require replacement in 2030. This vehicle is a passenger vehicle utilized in ORPC's Almonte service territory mainly for underground locates, metering and maintenance activities at the Almonte operations centre. The vehicle has been used an average of 763 per year since 2016 with 181,103 km. It will reach the end of its expected typical useful life in 2030. The maintenance costs on this vehicle are trending towards $1,500 per year by 2027 and the vehicle is experiencing a negative trend of declining usage and increasing maintenance costs due to extended repair periods. This vehicle will be replaced with a small hybrid or electric vehicle similar to #36 (2021 Hyundai Kona EV) which is appropriate for transporting locate and metering equipment and is a green alternative.

Trailers

The existing tensioner and puller were purchased in 1990 and have experienced multiple engine and exhaust issues in recent years, including one incident where the muffler exploded, often resulting in

delays to planned capital projects. The equipment has significantly exceeded the target typical useful life on transportation equipment of 15 years. ORPC intends to purchase a Timberland DPT30B Trailer-Mounted Tensioner and a Timberland DPT30B Trailer Mount Puller including accessory kits, reels, covers, grounds and lines, similar to the tensioner in Figure 3.



Figure 3: Timberland DPT30B Trailer Mounted Tensioner

iv. Substantially Exceeding Materiality Threshold:

Not applicable.

4. INNOVATION

i. Assessment of Benefit for Customers:

Not applicable.

5. ECONOMIC GROWTH

Not applicable.

APPENDIX B – ACA REPORT (DISTRIBUTION)

ORPC

Asset Condition Assessment

Pembroke, Ontario

Technical Report

ACA Report

August 05, 2026

Final Report

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Client Project No.: 79690002-002

Asset Condition Assessment
Technical Report
ACA Report

2026-08-05
Final Report



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REVISION HISTORY

Revision	Document Status – Revision Description	Date
0	Final Report	2026-08-05

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Executive Summary

Context of the Study

Ottawa River Power Corporation ("ORPC") is an electricity distributor serving over 11,800 customers in the Almonte, Beachburg, Killaloe and Pembroke areas. ORPC engaged BBA E&C Inc. ("BBA"), formerly METSCO Energy Solutions Inc., to prepare a comprehensive Asset Condition Assessment ("ACA") study for the major assets comprising ORPC'S distribution system. The ACA is one of the key inputs in the preparation of ORPC'S five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

Scope of the Study

BBA's work included consultations with ORPC subject matter experts to define the Health Indices ("HI") appropriate for the asset types, review and consolidation of the client's data sets, analysis of ORPC's asset records to calculate the HI values, and preparation of the final document. In total, BBA assessed the following asset classes:

- Poles (Wood, Concrete, Steel);
- Overhead ("OH") Conductors;
- Underground ("UG") Cables;
- Pole-mount Transformers
- Pad-Mount Transformers; and
- Overhead ("OH") Switches.

All data used in the study is maintained by ORPC as part of its regular asset management practices and was collected by ORPC or its contractors in compliance with Distribution System Code requirements. Data used in this study are valid as of May 2026.

Methodology and Findings

For all asset classes that underwent assessment, BBA used a consistent scale of asset health from "Very Good" to "Very Poor". The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions recommended for the asset management team at ORPC.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal or no maintenance
[70-85)	Good	Significant Deterioration of some components	Normal or no maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed, depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on the assessment

Using this scale, BBA calculated Health Indices for every asset class in the scope of its assessment using a selected HI model. The HI for each asset class is made up of available and relevant "Degradation Factors" – individual characteristics of the state of an asset's components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall HI made up by the parameter. BBA's findings for each asset class were developed using this methodology, as described in more detail in Section 4. The consolidated results of the ORPC's ACA are summarized in Table 0-2.

For each asset class, the following details are listed: total population, average Data Availability Index ("DAI"), and the HI distribution. A DAI is a percentage of Degradation Factor data available for an asset or asset class, weighted by their contributions to the HI formulation. A DAI of 100% for an asset indicates that all data is available. As discussed in Section 2.3, if the DAI for an asset is less than 70%, a valid HI cannot be calculated.

Table 0-2: ORPC'S Health Index Results

Asset Category	Population	HI Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	3947	593	50	1031	1741	223	309	93%
Overhead Conductors (km)	389	72	46	128	0	3	140	79%
Pole-Mount Transformers	1047	731	279	34	3	0	0	92%
Pad-Mount Transformers	404	183	91	42	8	0	80	93%
Overhead Switches	446	417	29	0	0	0	0	80%

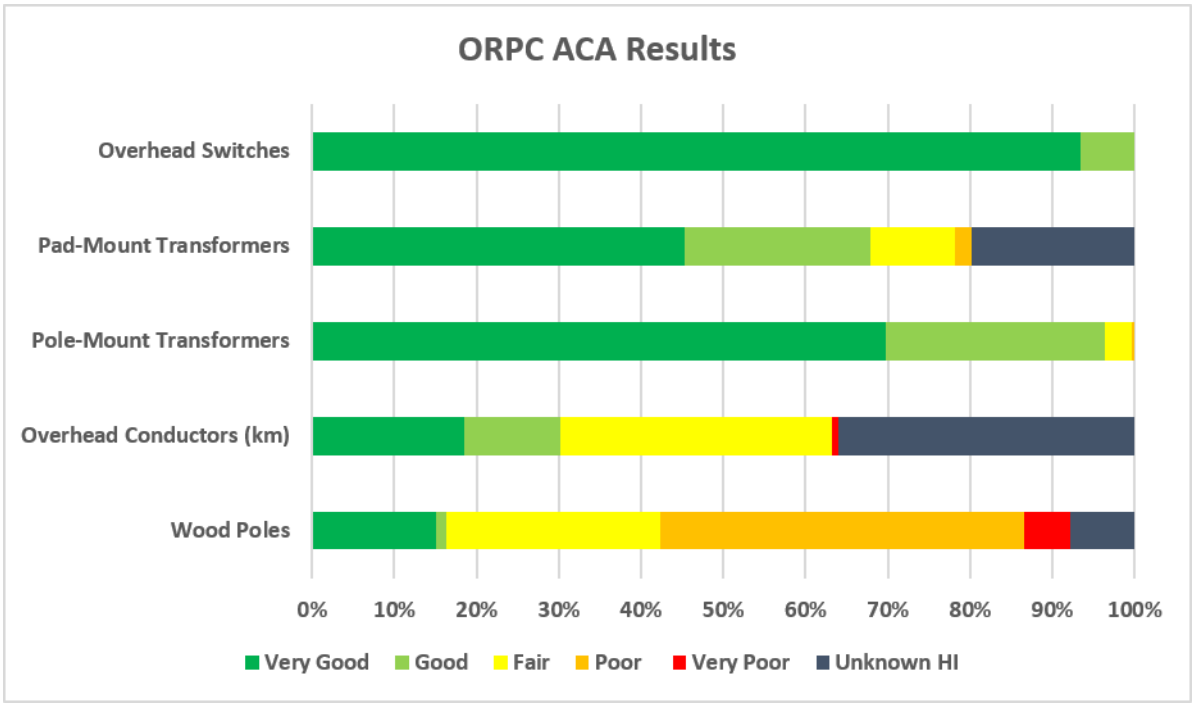


Figure 0-1: Health Index Results

As the table and figure above indicate, most of ORPC's assets with known HI results were found to in either Very Good or Poor condition. Most of ORPC's Pole-mount Transformers and OH Switches are in Very Good to Good condition. While Most of ORPC's Wood Poles are between Fair to Poor condition. Some asset classes like OH Conductors and UG Cables had significant data availability issues which resulted in assets with Unknown HI. HI results were not calculated for UG Cables due to data availability issues, as such it was not shown in Table 0-2 or Figure 0-1.

ORPC'S Current Health Index Maturity and Continuous Improvement

Overall, ORPC's asset data collection practices would benefit from some improvement in GIS data availability and inspection data availability. Section 5 of this report identifies further opportunity for HI and data availability improvements.

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LIST OF ACRONYMS

Acronym	Description
ACA	Asset Condition Assessment
AM	Asset Management
BBA	BBA E&C Inc.
DAI	Data Availability Index
EOL	End of Life
GIS	Geographic Information System
HI	Health Index
IR	Infrared
ISO	International Organization for Standardization
OEB	Ontario Energy Board
ORPC	Ottawa River Power Corporation
PD	Partial Discharge
SAMPs	Strategic Asset Management Plans

1. Introduction

This report summarizes the results of an Asset Condition Assessment ("ACA") carried out by BBA E&C Inc. ("BBA"), formerly METSCO Energy Solutions Inc., on behalf of Ottawa River Power Corporation ("ORPC"). BBA is an industry expert in ACA and Asset Management ("AM") practices, with extensive experience conducting ACAs, developing AM plans, and implementing AM frameworks for organizations across North America. BBA's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions.

ORPC is an electricity distributor operating in the Almonte, Beachburg, Killaloe and Pembroke areas, serving over 11,800 customers. ORPC engaged BBA to prepare a comprehensive Asset Condition Assessment ("ACA") study for the major assets comprising ORPC'S distribution system. The ACA is one of the key inputs in the preparation of ORPC'S five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

To assist ORPC with further asset condition data integration efforts, Section 5 of this report contains a set of recommendations for the utility's management to consider going forward.

The asset classes covered in the report include the following:

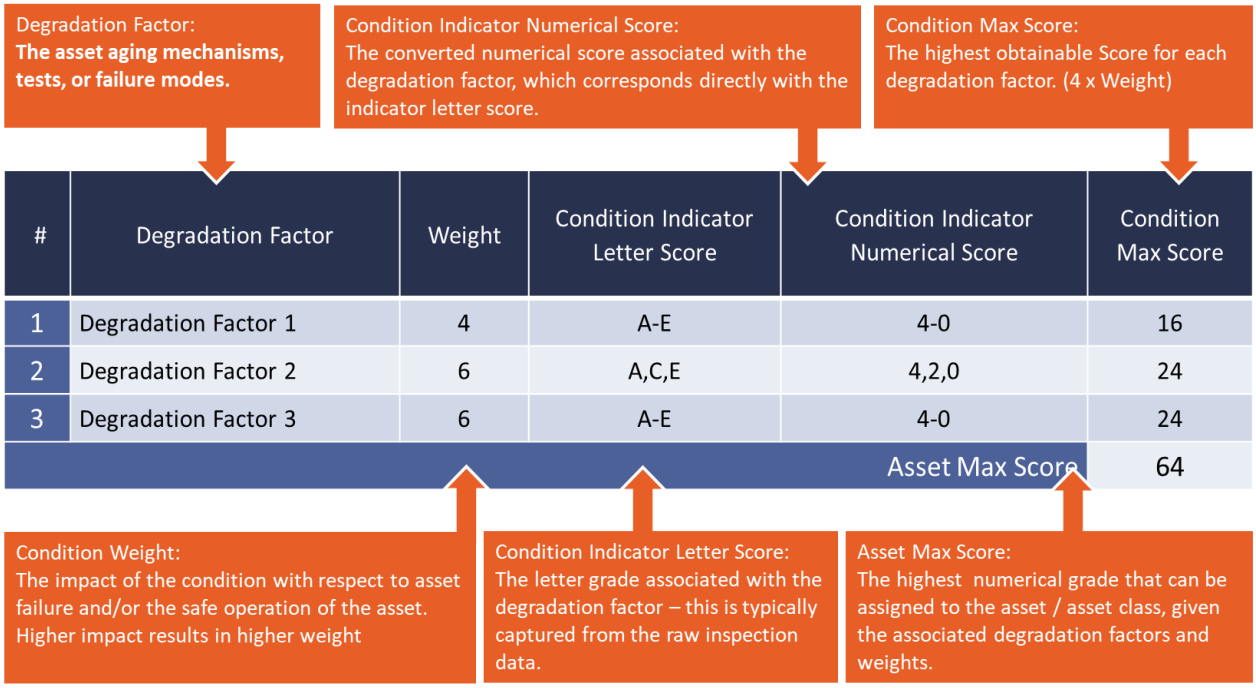
- Poles (Wood, Concrete, Steel);
- Overhead Conductors;
- Underground Cables;
- Pole-mount Transformers
- Pad-Mount Transformers; and
- Overhead Switches.

2. Asset Condition Assessment Methodology

2.1 Degradation Factors

To determine the overall HI for an asset, formulations are developed based on "Degradation Factors" that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each Degradation Factor to indicate the amount of influence the condition has on the overall health of the asset. Figure 2-1 provides an example of an HI formulation table.

Figure 2-1: HI Formulation Components



Degradation Factors of the asset are characteristic properties that are used to derive the overall HI. They are specific and uniquely graded to each asset class. Additionally, some Degradation Factors can be comprised of "Sub-Degradation Factors". For example, the Degradation Factor "Oil Quality" for power transformers includes multiple Sub-Degradation Factors: "Interfacial Tension", "Dielectric strength", and "Water Content". In this case, the lowest Sub-Degradation Factor score is used as the score for the Degradation Factor.

The scale used to determine an asset's score for a Degradation Factor is called the "Condition Indicator". Each Degradation Factor is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a Condition Indicator of 4 represents the best grade, whereas a Condition Indicator of 0 represents the worst grade.

The conversion from alphabetic ranking to numerical grade and a brief characteristic description of the grade is provided below:

Table 2-1: HI Score Grading

A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\% \quad (1)$$

where *i* corresponds to the Degradation Factor, and the HI is a percentage representing the remaining life of the asset.

2.2 Health Index Interpretation

BBA's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset. To assign each asset into one of the categories, BBA constructs numerical HI for each asset class that captures information on individual Degradation Factors contributing to that asset's declining condition over time. Condition Indicators assigned to each Degradation Factor are expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual Condition Indicators, with each of the five condition categories ("Very Good", "Good", "Fair", "Poor", "Very Poor") corresponding to a numerical band that are roughly equivalent to the percentage of remaining useful life for the given asset. For example, the condition score of Very Good indicates assets with HI between 100% and 85%, whereas the condition score of Very Poor indicates assets with calculated HI between 0% and 30%.

Generating an HI provides a succinct measure of the long-term health of an asset. Table 2-2 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing, or replacing the asset prior to failure.

Table 2-2: HI Ranges and Corresponding Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal or no maintenance
[70-85)	Good	Significant Deterioration of some components	Normal or no maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

2.3 Data Availability

BBA supplemented its HI findings with the calculation of a Data Availability Index ("DAI"), which is a measure of the availability of Degradation Factor data for a specific asset scaled by their weights in the HI formulation. The DAI is determined by comparing the sum of the weights of the Degradation Factors available to the total weight of the Degradation Factors used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\% \quad (2)$$

where *i* corresponds to the Degradation Factor number and *a* is the availability of coefficient (*a* =1 when datum is available *a* =0 when datum is unavailable).

An asset with all Degradation Factor data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. In the case where the DAI for an asset is less than 70%, a valid HI cannot be calculated. Additionally, HI scores cannot be calculated based solely on the age of the asset. For assets with only age data available no HI was calculated. Instead, an age analysis with a typical useful life comparison has been performed. This analysis can then be used to help inform investments needed for these assets.

2.4 Project Execution

The HI formulations calculated in this study are based only on available data provided by ORPC. BBA's execution path in completing the ACA study can be separated into four phases described below:

1. *Initial Information Gathering* – including initial interviews with ORPC staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with ORPC subject matter experts through a series of interviews.

2. *Database Construction* – activities to construct a database of condition-related information for each ORPC asset amongst the in-scope asset classes using the provided data sources. This includes consolidation of ORPC's asset inspection and maintenance records, databases containing results of technical tests performed by ORPC and its contractors.

3. *HI and DAI Calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, BBA calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from ORPC to improve the accuracy of the asset health calculation, where applicable.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3. Input Data

To assess the demographics and establish the unit population of ORPC's distribution system assets, BBA was provided with ORPC's available asset demographics from their current Geographic Information System ("GIS"), asset inspection and maintenance records, and copies of test reports. This dataset contained the last calculated degradation score for a particular asset as well as the most recent test results which were translated to a score and ultimately a HI. Most of this data came from sources such as equipment inspection forms completed by ORPC staff or contractors or results of specific technical tests.

Additionally, BBA was provided with historical operating data for assets that required operating information for the HI calculation. An example of operating data used includes historical loading information for transformers.

3.1 Continuous Improvement

The application of rigorous AM processes can provide several benefits to an organization including but not limited to: realized financial savings; better classified and managed risk among assets; better-informed investment decisions; demonstrated compliance to standards and mandates among the asset base; increased public and worker safety; as well as working towards corporate reliability targets.

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant stakeholders. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical expertise, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor. [1]

Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency to effectively manage its distribution infrastructure. With time, the goal of any AM system

[1] ISO 55000 – Asset management – Overview, principles and terminology

is to continually improve and realize benefits within the organization through better management of its asset portfolio, continuous improvement in the quantity and quality of asset data and data collection procedures, SAMPs, and further integration into all aspects of an organization's activities as it grows and evolves over time.

4. Asset Condition Assessment Results

This section presents the current HI Formulation, Age Demographics, and HI Results for each asset class.

4.1 Poles

Poles are an integral part of ORPC's overhead distribution system. They support the majority of overhead distribution lines, overhead transformers, switches, streetlights, and majority of ORPC's underground system. Poles under this assessment are made of wood, steel and concrete.

The HI for poles is estimated by considering a combination of EOL criteria summarized in Table 4-1.

Table 4-1: Pole HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Overall Condition	4	A,C,D,E	4,2,1,0	16
Out of Plumb	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				32

ORPC owns 3947 poles within its service territory. Service date is known for approximately 93% of the total in-service population. Figure 4-1 presents the age distribution for ORPC in-service poles.

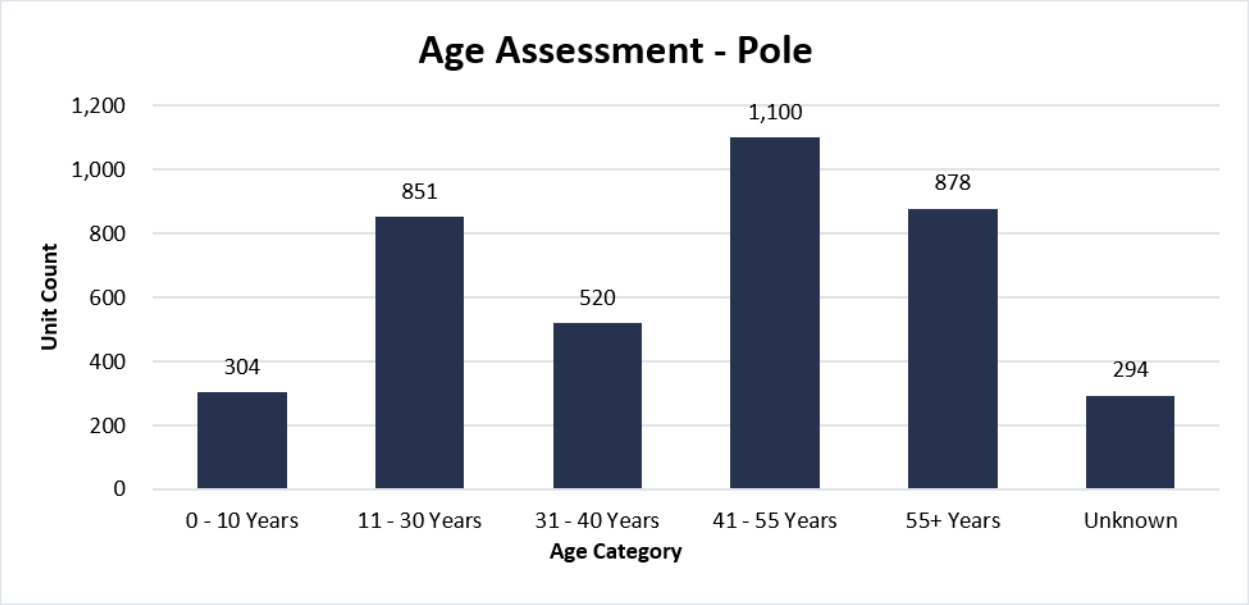


Figure 4-1: Pole Age Demographics

ORPC's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-1. The average DAI for the asset class is 93%.

A valid HI was calculated for 92% of the poles. HI distribution for the poles is presented in Figure 4-2. Most of ORPC poles with valid HI results are between Fair to Poor condition.

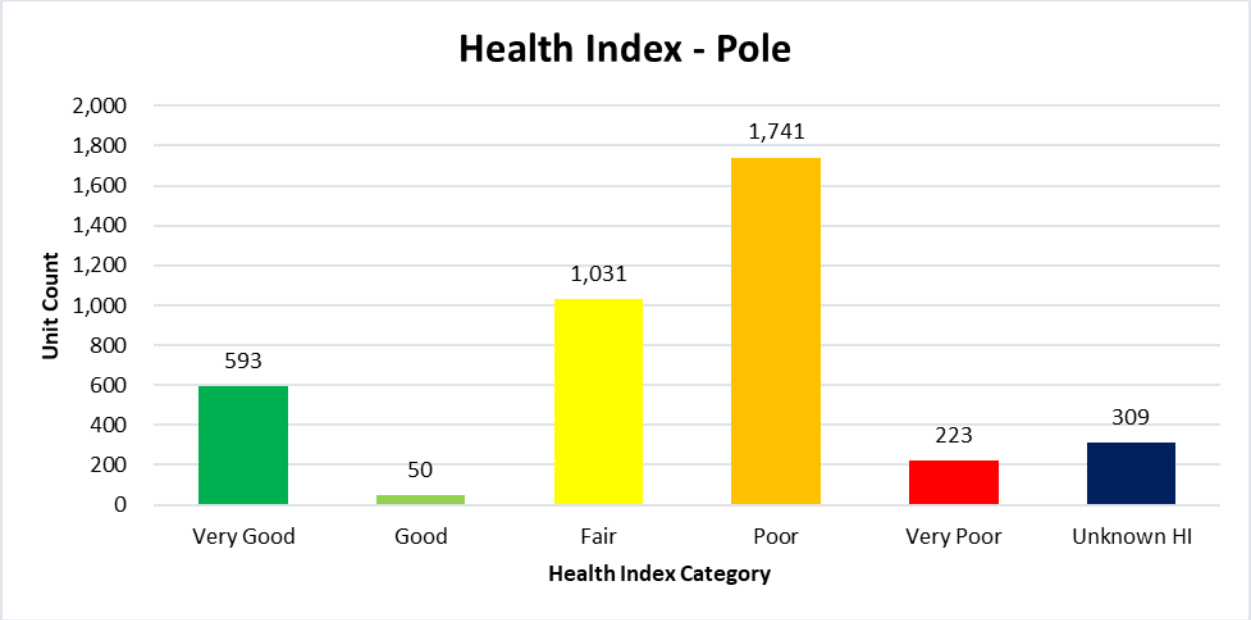


Figure 4-2: Pole HI Results

4.2 Overhead Conductors

Overhead ("OH") Conductors are an important component of an overhead system; however, there is almost no inspection or maintenance undertaken. Conductor assets tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons.

The HI for OH Conductors is calculated by considering a combination of EOL criteria, as summarized in Table 4-2.

Table 4-2: OH Conductors HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Small Conductor Risk	1	A,E	4,0	4
			Total score	8

The main recognized conductor risk is the tendency for small copper conductors to age at an accelerated rate and become brittle, as such small conductor risk is weighted the most. Service age is another degradation factor considered in the HI calculation.

ORPC owns 389km of OH Conductors within its service territory. Figure 4-3 presents the age distribution for OH Conductors. Service age is known for 64% of OH Conductors.

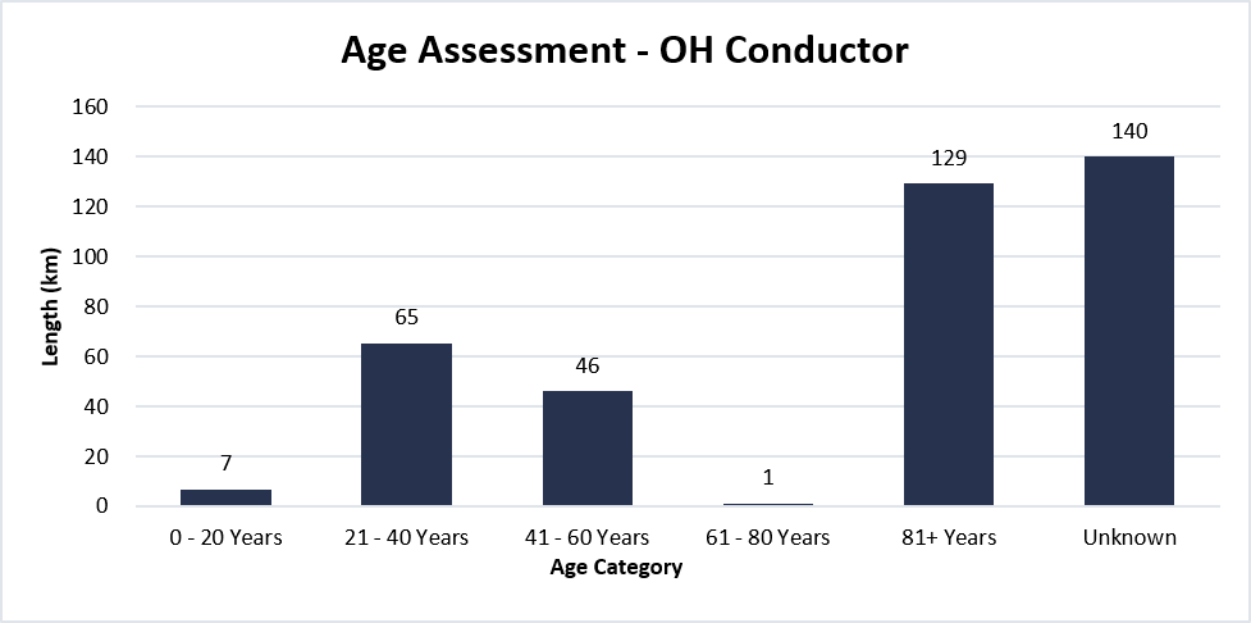


Figure 4-3: OH Conductor Age Demographics

ORPC's demographics data was used to calculated HI results for OH Conductors. The average DAI for this asset class is 79%.

HI results for ORPC's OH Conductors are summarized in Figure 4-4. A valid HI was calculated for 64% of assets. Most OH conductors are in Very Good to Fair condition.

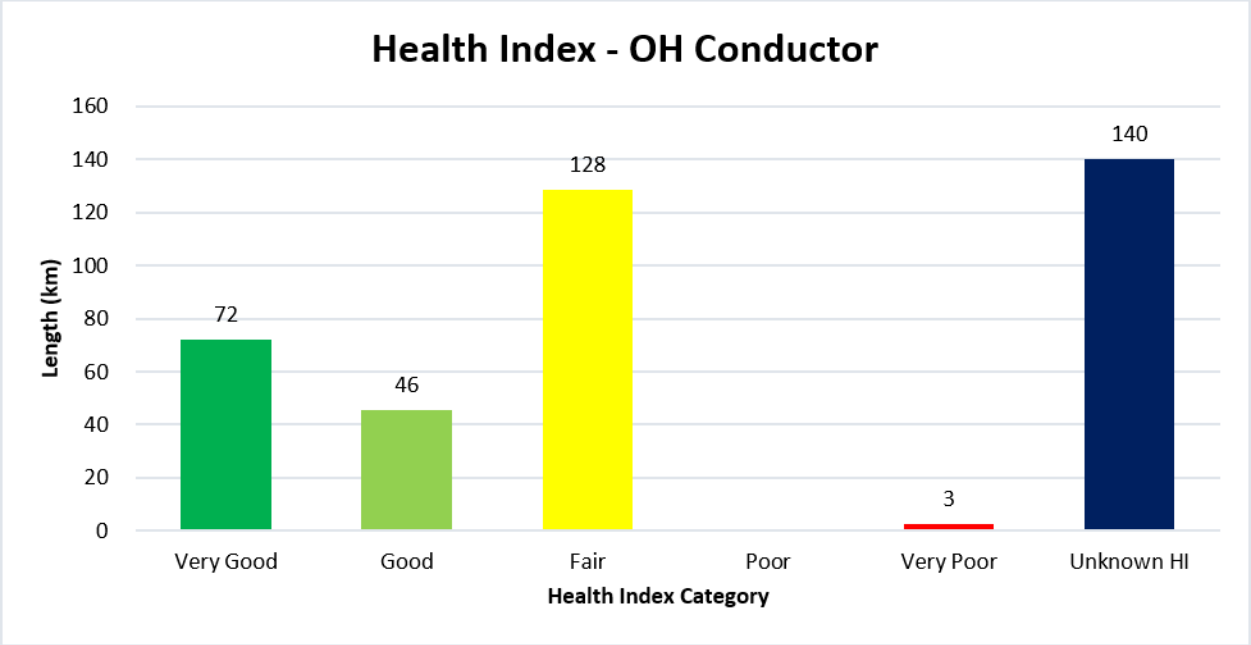


Figure 4-4: OH Conductors HI Results

4.3 Underground Cables

Underground ("UG") Primary Cables are one of the most challenging assets on electricity systems from a condition assessment and AM viewpoint. Although a number of test techniques, such as partial discharge ("PD") testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables.

ORPC owns 84km of UG Cables within its service territory. Figure 4-5 presents the age distribution for UG cables. Age is known for all Underground Cables.

Due to limited data available, only an age assessment was performed for UG Cables and HI results were not calculated.

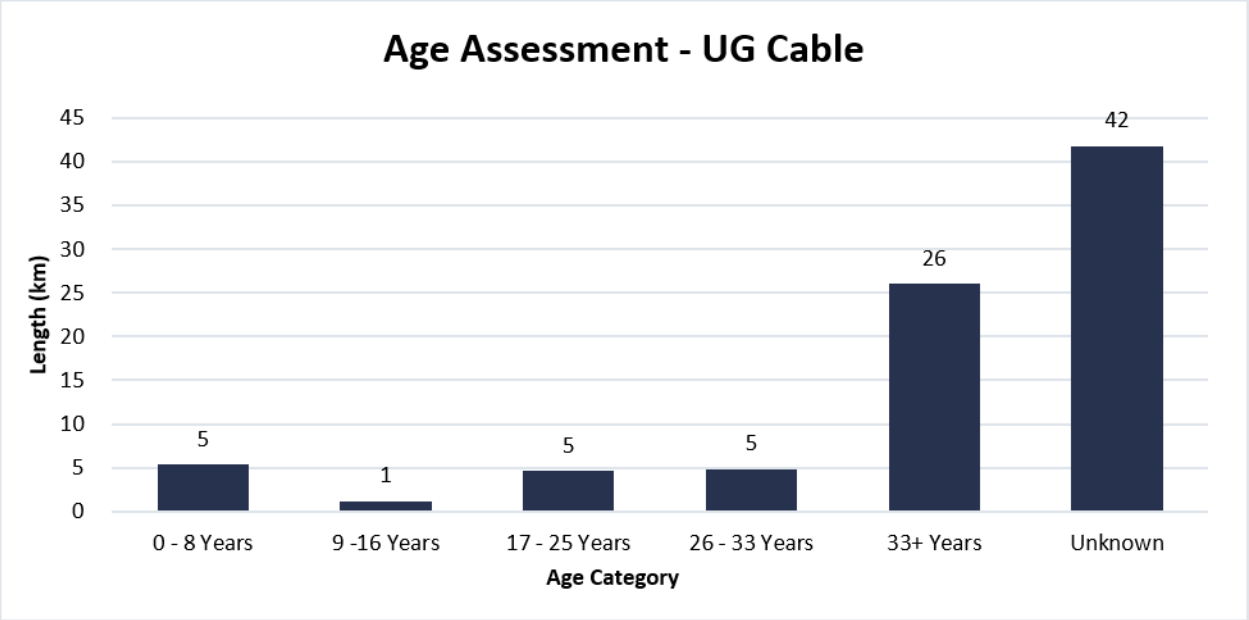


Figure 4-5: UG Cables Age Demographics

4.4 Pole-mount Transformers

Pole-mount distribution transformers are installed on service poles above ground with the primary function to step down distribution voltage to the final secondary voltage for the end-user (customer). The HI for pole-mount transformers is calculated by considering a combination of EOL criteria summarized in Table 4-3.

Table 4-3: Pole-mount Distribution Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	3	A,C,E	4,2,0	12
			Total score	32

IR scanning results provide an important Degradation Factor for condition assessment of the overhead transformers since they identify hotspots (i.e., high temperatures) on the asset. Transformers operating continuously at high temperatures beyond their normal operating state can cause accelerated degradation of the insulation oil, which may lead to premature failure.

ORPC owns 1047 pole-mounted transformers within its service territory. Installation dates are known for 69% of the transformers. Figure 4-6 presents the age distribution for pole-mounted transformers.

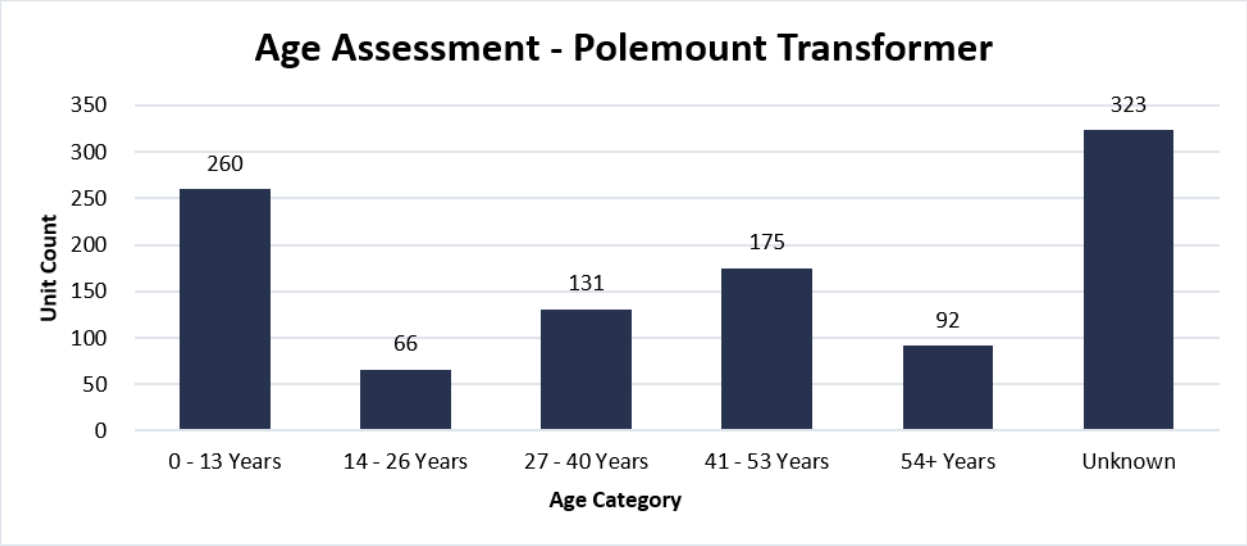


Figure 4-6: Pole-mount Transformer Age Demographics

ORPC's transformer maintenance records, nameplate information, and IR data were used to calculate the HI based on the criteria provided in Table 4-3. If visual inspections and IR results were unavailable for a given asset it was assumed that no deficiencies were noted and the condition parameters were given a score of A. The average DAI for this asset class is 92%.

A valid HI was calculated for all overhead transformers. The overall HI distribution is presented in Figure 4-7. Most of ORPC's pole-mounted transformers are in Very Good or Good condition.

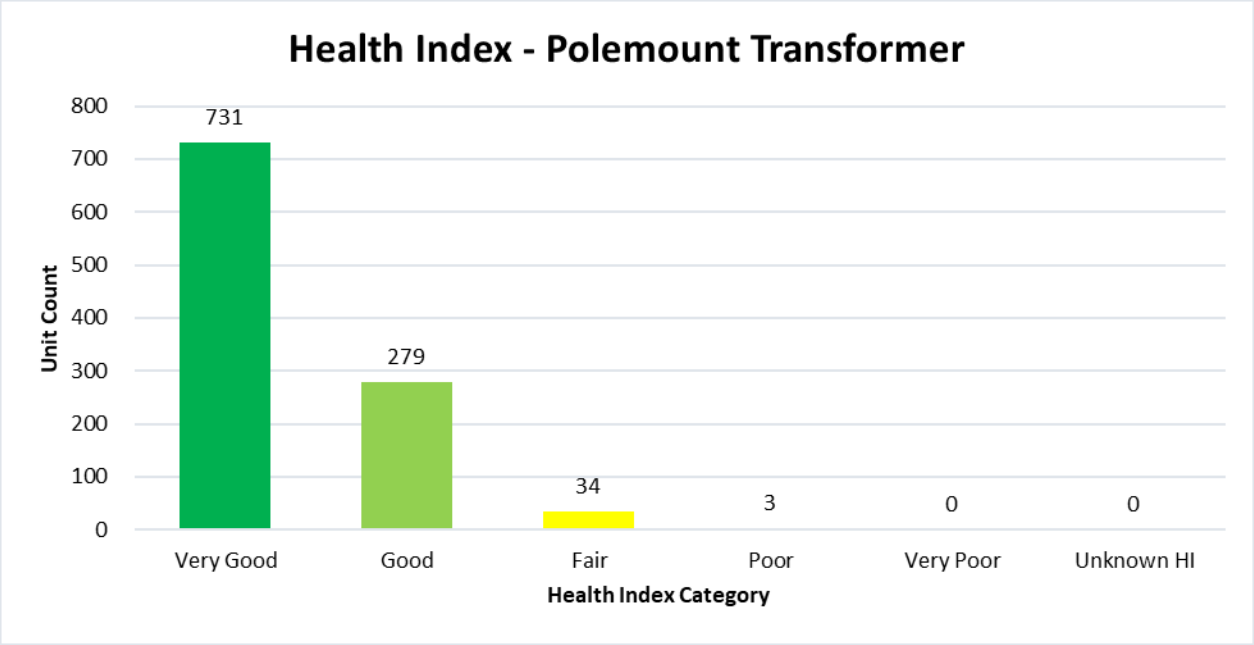


Figure 4-7: Pole Mount Transformer HI Results

4.5 Pad-mount Transformers

Pad-mount distribution transformers are used to step down power from the medium-voltage distribution system to the secondary voltage required by customers. These transformers are located at ground level and are a specific type of underground distribution transformer assessed within this report. In general, the useful life of a transformer is determined by its overall condition, which is largely influenced by loading, temperature, and the presence of oxygen and moisture in the oil. The HI for pad-mount transformers is calculated by considering a combination of EOL criteria, as summarized in Table 4-4.

Table 4-4: Pad-mount Distribution Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
IR Scan	2	A,B,C,D,E	4,3,2,1,0	8
Visual Inspection	4	A,C,E	4,2,0	16
			Total score	36

ORPC owns 404 pad-mount transformers within its service territory. Figure 4-8 presents the age distribution of transformers.

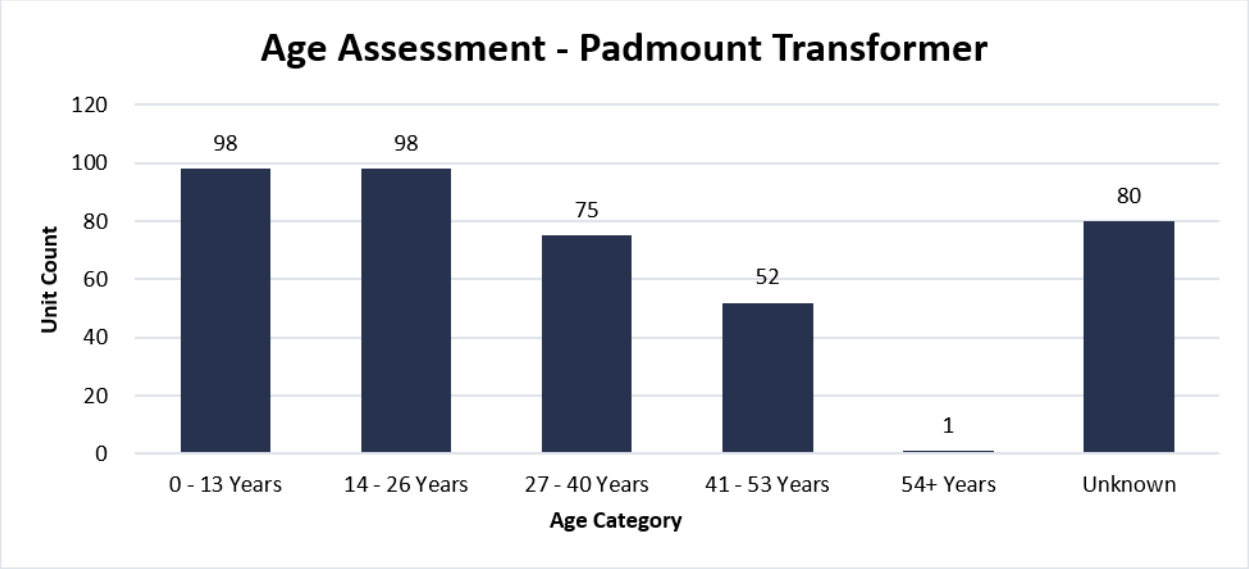


Figure 4-8: Pad-mount Transformer Age Demographics

ORPC transformer maintenance records, nameplate information, and operating data were used to calculate the HI based on the criteria outlined in Table 4-4. If visual inspections and IR results were unavailable for a given asset, it was assumed that no deficiencies were noted, and the condition parameters were given a score of A. The average DAI for this asset class of ORPC is 93%.

The overall HI distribution for pad-mount transformers of ORPC is presented in Figure 4-9. A valid HI was calculated for approximately 80% of the pad-mount transformers. Most of ORPC's pad-mount transformers are in Very Good condition.

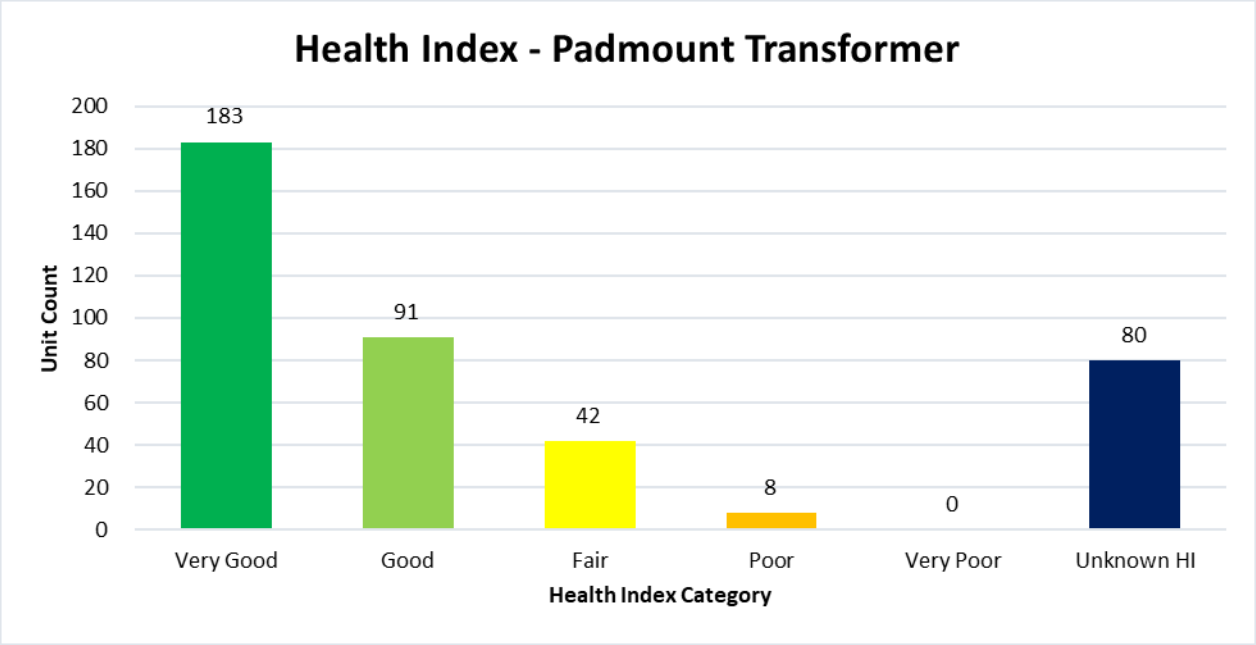


Figure 4-9: Pad-mount Transformer HI Results

4.6 Overhead Switches

OH Switches are essential components of distribution systems, providing load disconnection and isolation for various equipment configurations. This section encompasses both single-phase and three-phase overhead switches, each serving distinct purposes within the distribution network. OH Switches are diverse in type and function, ranging from single-phase switches serving lateral and transformer connections to three-phase switches crucial for distribution infrastructure.

Single-phase switches are comprised of fused switches, solid-blade disconnects, and others, primarily face degradation from physical corrosion, insulator tracking, and heat due to loose connections. For three-phase switches, which include gang-operated, pole-mounted, and load interrupter variants, inspection focuses on identifying dirt, corrosion, and "hot" connections through visual inspections and IR scans.

Table 4-5 summarizes the methodologies to generate the HI for the overhead switches.

Table 4-5: Overhead Switches HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Infrared Scan	2	A,B,C,D,E	4,3,2,1,0	8
Visual Condition	3	A,C,E	4,2,0	12
			Total score	28

ORPC owns 446 overhead switches;

Figure 4-10 presents their age distribution. Age was known for 29% of assets.

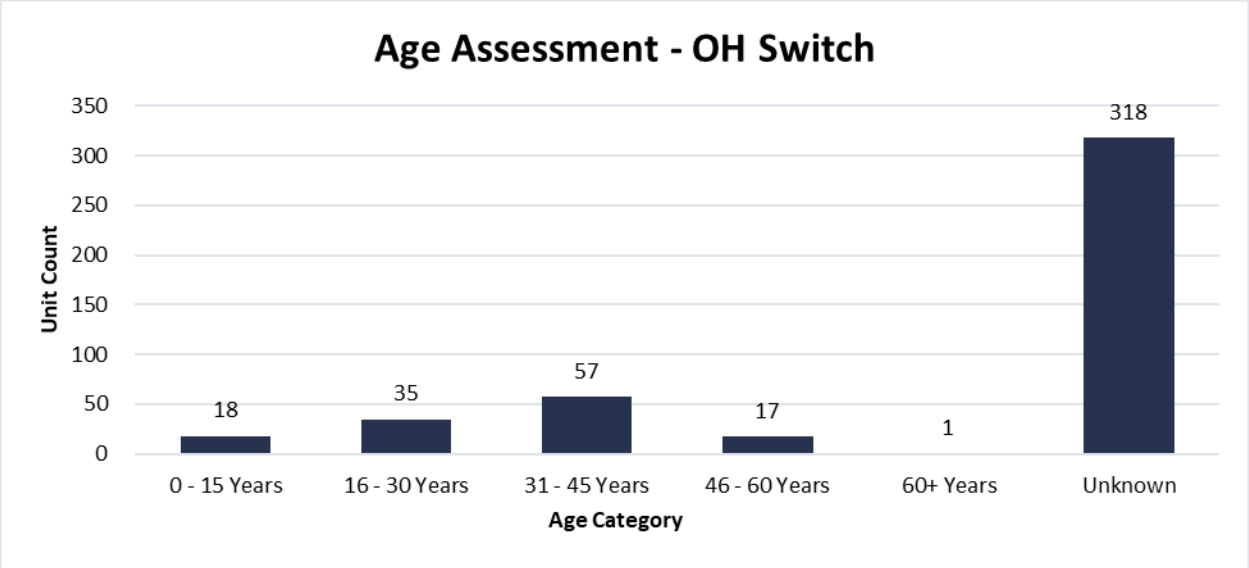


Figure 4-10: Overhead Switches Age Demographics

The HI for overhead switches was calculated using ORPC's demographics, visual inspection, and IR Scan results. IR scanning is an important Degradation Factor as it detects overheated connections due to loosened connectors. Additional degradation factors include visual inspection results, which provide information on asset deficiencies such as insulator chipping and corrosion.

If visual inspections and IR results were unavailable for a given asset, it was assumed that no deficiencies were noted, and the condition parameters were given a score of A. The average DAI for this asset class of ORPC is 79%.

Figure 4-11 illustrates the HI distribution for ORPC's Overhead Switches. A valid HI was calculated for all assets. Most assets with are in Very Good condition.

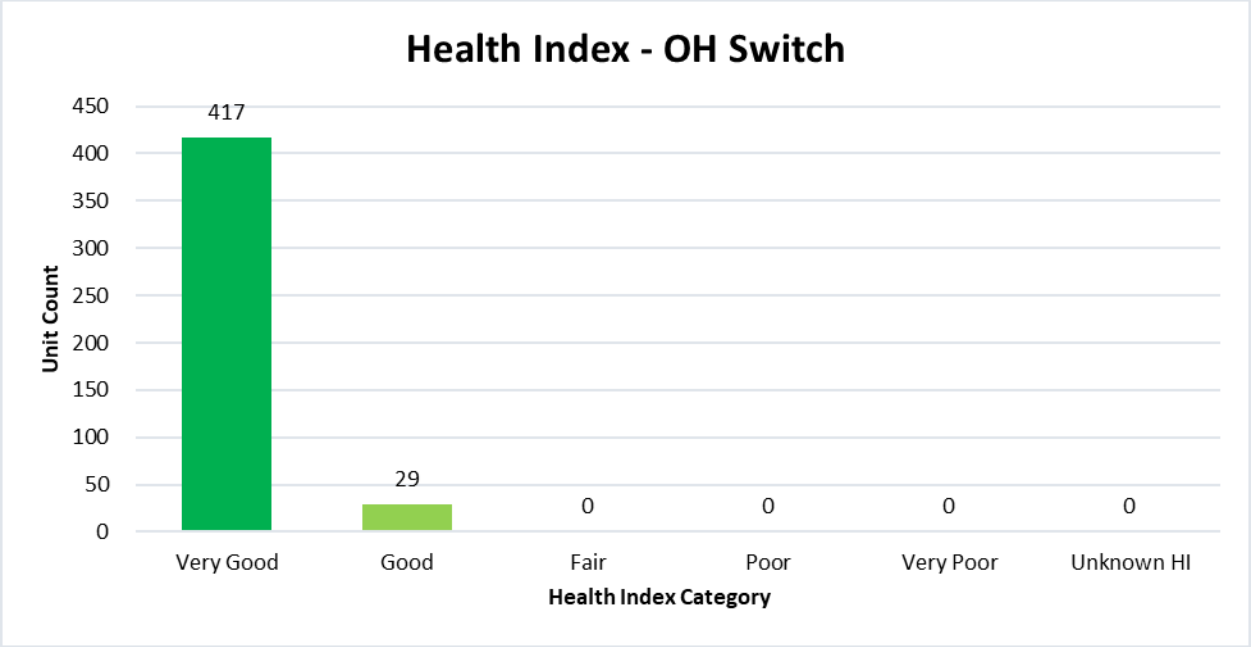


Figure 4-11: Overhead Switches HI Results

5. Recommendations

A complete ACA framework for ORPC represents an integral component of its broader asset management framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows ORPC to make informed investment decisions. There are further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

This section breaks down BBA's recommendations into the following categories:

- HI improvement; and
- Data availability improvements.

5.1 Health index improvements

For select asset classes, a recommended HI formulation was used for ORPC's ACA framework. The following set of recommendations target additional Degradation Factors that can be incorporated for specific asset classes to improve the HI formulation and provide ORPC with additional data to refine its asset condition calculations. The recommendations are based on the "Ideal" ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted. The priority of each recommendation depends on the relative weight of the Degradation Factor that it addresses. Data collection should be performed on a frequency consistent with Annex C – Minimum Inspection Requirements of the OEB's Distribution System Code [1]. It is however, recommended that if an LDC observes more failure or issues with certain assets, then these could be inspected more frequently, but is not a requirement. If implemented these inspections and/or tests should be planned and performed for all assets in each asset class.

5.1.1 Poles

Pole asset data provided to BBA was separated by region. The data was then subsequently compiled for this study. BBA recommends that ORPC maintain a consolidated database for all their asset classes.

Overall Condition for Poles was recorded using a four-point grading scheme (See Appendix A). BBA recommends ORPC adopt a consistent five-point scheme when grading visual inspection results (Ex: "Very Good", "Good", "Fair", "Poor", "Very Poor").

Lastly, ORPC should consider assessing Wood Poles, Concrete Poles, and Steel Poles into individual asset classes for future ACAs.

5.1.2 OH Conductors

HI results for Overhead Conductors were calculated using Service Age and Small Conductor risk, which provides a comprehensive HI Formulation. Service Age was unknown for 36% of the total population by length. BBA recommends ORPC update the age data for this asset.

If available, ORPC can consider the following additional visual inspection parameters for future ACAs:

- Conductor Condition;
- Damper Condition; and
- Sleeve Condition.

5.1.3 Underground Cables

Valid HI results were not available for any of ORPC's Underground Cables. Even though an age assessment was performed, only 50% of the cables have a known service age. BBA recommends ORPC update the age data for this asset.

BBA recommends the following condition parameters for future ACAs:

- Visual Inspection of Splices;
- Cable Loading History; and
- Failure Rates.

5.1.4 Pole-mount and Pad-mount Transformers

Asset data submitted to BBA was organised by region and subsequently consolidated for this study. However, discrepancies were noted in the column headers across regions. BBA

recommends that ORPC establish a unified database encompassing all asset classes to enhance consistency. Furthermore, pole-mount transformers are referenced by location number and pole number in the IR report, yet the asset data lacked pole numbers for identification purposes. It is advisable to include the relevant pole number in future asset records.

For future ACAs, BBA recommends ORPC include Loading History as an additional condition parameter for both pole-mount and pad-mount transformers.

5.1.5 OH Switches

BBA received asset data divided by region and later combined it for this study. BBA advises ORPC to keep a single, unified database covering all asset categories. Many OH Switches lack information on installation dates or manufacturing years. BBA recommends ORPC take steps to improve their demographics data.

5.2 Data availability

Data availability is critical in being able to produce prudent, accurate and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA study, each asset class included a breakdown of data available for each Degradation Factor collected. For Degradation Factors with data availability below 70%, BBA recommends that ORPC continue collecting the information related to these data points to reach the 70% data availability threshold.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the Degradation Factors used in the HI formulation. As part of future improvement opportunities, it is recommended that ORPC continue capturing asset data for Degradation Factors that are currently available for a small proportion of the asset population, such that valid Health Indices can be produced across the population. It is expected that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

This report provides ORPC with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance it's AM analytics.

Keeping records of asset condition is good practice, as it may assist in planning and assessing the quality of assets being replaced in-service. BBA recommends collecting and keeping condition records consistent for all assets inspected. BBA recommends that ORPC tracks all contractor assessments through a central system, such as GIS, as part of their process improvements between Asset Management and GIS. This will help ORPC in both standardizing inspection results and quickly identifying and flagging issues within the system. Obtaining and organizing more comprehensive condition data records would establish a stronger baseline of the asset health indices and more robust, multi-parameter, HI formulations can be used that are in-line with standardized practice in the industry.

6. Conclusions

As Table 6-1 indicates, for most of ORPC's OH Switches and Distribution Transformers analyzed are in Fair condition or better, with a significant portion of asset populations in Good or Very Good condition. This can indicate ORPC has taken the necessary steps to manage its asset health and performance for the benefit of its customers. ORPC's poles require attention in the coming years where a material number of assets are in or are approaching Poor or Very Poor condition. ORPC's OH Conductors and UG Cables had significant data availability issues which resulted in assets with Unknown HI.

BBA recommends that ORPC continue their work to mitigate the gaps in the existing data so that more degradation parameters can be assigned actual grades, expanding the sample size of valid HI and capturing all possible degradation of the evaluated assets. As well, ORPC should work to expand the types of data captured as to best represent each assets degradation to the greatest accuracy.

Table 6-1: Health Index Results

Asset Category	Population	HI Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	3947	593	50	1031	1741	223	309	93%
Overhead Conductors (km)	389	72	46	128	0	3	140	79%
Pole-Mount Transformers	1047	731	279	34	3	0	0	92%
Pad-Mount Transformers	404	183	91	42	8	0	80	93%
Overhead Switches	446	417	29	0	0	0	0	80%

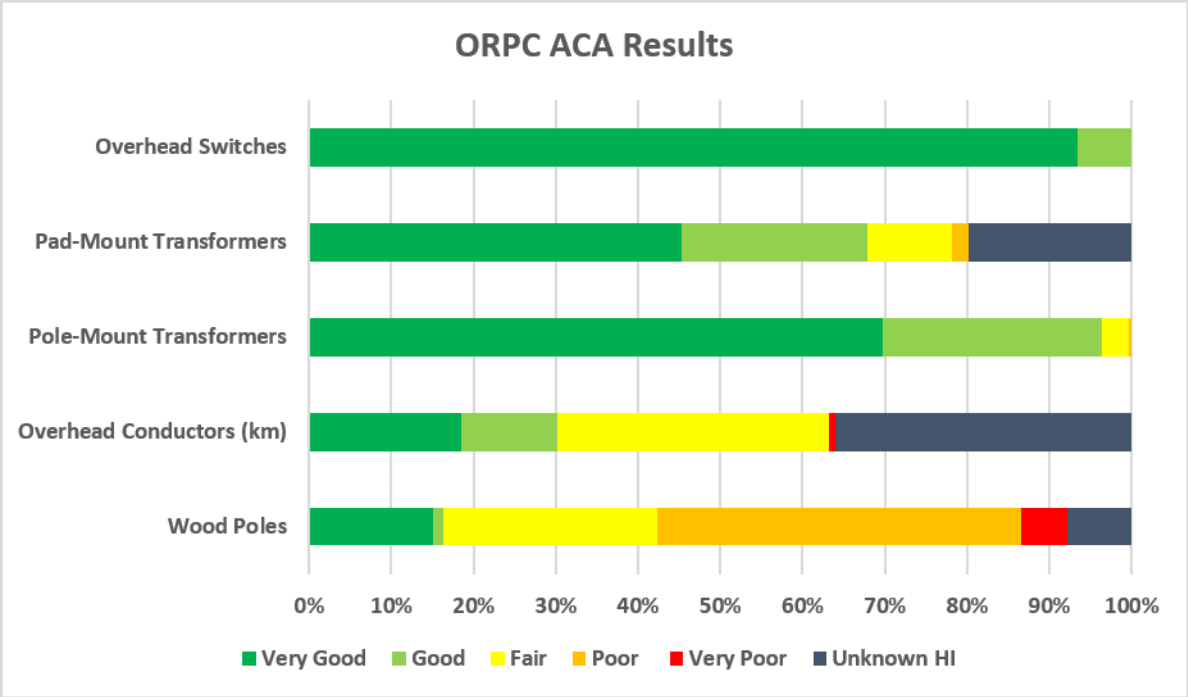


Figure 6-1: Health Index Results

Replacement Recommendations

BBA recommends that any assets with a valid HI that are in poor or very poor condition be considered for replacement within the next five-year period. In addition, assets in Fair condition should be further assessed and considered for replacement when they are critical to ORPC's operation.

This concludes BBA's ACA report for ORPC's major distribution assets. We thank ORPC's staff and management for the opportunity to participate in this complex study and for their ongoing support throughout its development.

7. References

[1] Ontario Energy Board, "Dustribution System Code," Ontario Energy Board, Toronto, 2025.

Appendix A: Condition Parameter Grading Tables

A.1 Poles

Table A-1: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0-10 years
B	11-30 years
C	31-40 years
D	41-55 years
E	55+ years

Table A-2: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Good
C	Fair
D	Fair-Poor
E	Poor

Table A-3: Criteria for Out of Plumb

Condition Rating	Corresponding Condition
A	No
E	Yes

A.2 Overhead Conductors

Table A-4: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0-20 years
B	21-40 years
C	41-60 years
D	61-80 years
E	80+ years

Table A-5: Criteria for Small Conductor Risk

Condition Rating	Corresponding Condition
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

A.3 Pole-mount and Pad-mount Transformers

Table A-6: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0-13 years
B	14-26 years
C	27-40 years
D	41-53 years
E	54+ years

Table A-7: Criteria for Visual Inspections

Condition Rating	Corresponding Condition
A	Good
C	Average
E	Poor

Table A-8: Criteria for IR Scanning

Condition Rating	Severity Response
A	No Report
B	Low
C	Medium
D	High
E	Immediate

A.4 OH Switches

Table A-9: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0-15 years
B	16-30 years
C	16-45 years
D	46-60 years
E	60+ years

Table A-10: Criteria for Visual Inspections

Condition Rating	Corresponding Condition
A	Good
C	Average
E	Poor

Table A-11: Criteria for IR Scanning

Condition Rating	Severity Response
A	No Report
B	Low
C	Medium
D	High
E	Immediate

APPENDIX C – ACA REPORT (SUBSTATION)

OTTAWA RIVER POWER CORPORATION – SUBSTATION DISTRIBUTION SYSTEM PLAN

REVISION TABLE

REVISION #	DATE OF RELEASE	DESCRIPTION	RELEASED BY
0	2026-04-01	CLIENT RELEASE	MDENIS
1	2026-06-03	CLIENT RELEASE	MDENIS

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Appendices

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- **Appendix B:** Regional Planning and Electrification Context
- **Appendix C:** GIS Derived Feeder & Substation Data
- **Appendix D:** Substation Capital Project Summaries
- **Appendix E:** Preventative and Predictive Maintenance Framework

1 Introduction

This Distribution System Plan (DSP) presents Ottawa River Power Corporation's (ORPC's) strategic, risk informed framework for managing and reinvesting in its substation and associated feeder infrastructure.

The DSP establishes a forward-looking planning horizon of 2027–2031, aligned with ORPC's next cost-of-service test year. The year 2026 represents a transition period between the expiry of the current rate order and implementation of the next approved capital plan; capital activity in 2026 is therefore expected to consist primarily of committed work and continuation of existing programs. Investment recommendations in this DSP are focused on the 2027–2031 period.

This DSP focuses on ORPC's twelve distribution substations — Pembroke Substations 1 through 8 and Almonte Substations 1 through 4 — which form the backbone of the medium-voltage distribution network. These assets are evaluated through a structured, condition and risk-based framework drawing on recent field assessments, load concentration indicators, and system performance information to support renewal and maintenance prioritization.

This document is not intended to serve as a full utility-wide DSP. It is a targeted substation asset management framework designed to support and inform ORPC's next comprehensive DSP filing. The primary objectives are to:

- Identify and prioritize renewal and upgrade needs based on technical and operational criteria;
- Support capital planning decisions and future rate-filing evidence with transparent, defensible data; and
- Align substation investment decisions with OEB expectations for prudent, risk informed planning.

Through this focused DSP, ORPC demonstrates a proactive commitment to reliability, safety, and fiscal responsibility in managing the most complex and highest-value assets within its distribution system.

The level of detail presented is commensurate with the planning objectives of the DSP and supports timely, risk informed capital decision-making.

1.1 Executive Summary

This substation-focused Distribution System Plan (DSP) presents Ottawa River Power Corporation's (ORPC's) planning level assessment of substation asset condition, system risk, and capital investment priorities over the 2027–2031 planning horizon. It supports ORPC's upcoming cost of service filing and establishes a transparent, defensible framework for future substation investment decisions.

The assessment focuses on ORPC's twelve distribution substations—Pembroke Substations MS#1 through MS#8 and Almonte Substations MS#1 through MS#4—which form the backbone of the medium-voltage distribution system. These substations are the utility's highest-value and most operationally critical assets and are central to system reliability, safety, and restoration capability.

The DSP applies a structured, engineering-based methodology integrating asset condition assessment, system criticality evaluation, and needs identification to support risk informed capital prioritization. Condition was evaluated using non-invasive field inspections, available asset records, and professional engineering judgment informed by industry experience with comparable equipment. Criticality was assessed based on the consequence of asset or substation loss, including 44 kV supply role, downstream feeder exposure, connected load, and restoration flexibility. Needs were defined in terms of underlying technical drivers (capacity, condition and reliability, safety and compliance, and operational flexibility) without prescribing detailed design solutions.

Overall, ORPC's substation risk profile is manageable but materially influenced by asset age and legacy infrastructure, particularly within portions of the Pembroke system. Several substations contain aging equipment that remains operable but is increasingly susceptible to unplanned outages, maintenance challenges, and condition-driven reliability events. In contrast, the Almonte system includes a higher proportion of newer infrastructure but faces stronger growth and electrification pressures that warrant continued monitoring and adaptive planning.

Capital investment priorities reflect a balanced response to these conditions. Near-term emphasis is placed on safety and compliance risks, condition-driven reliability exposure at higher-criticality substations, and improving operational flexibility where configuration limitations amplify outage impact. At the same time, the DSP advances System Service and enabling investments, particularly in protection, control, communications, and SCADA modernization as a core component of the capital strategy.

These enabling investments deliver immediate operational and restoration benefits while strengthening ORPC's ability to prioritize, scope, and time future capital and maintenance activities. Improved system visibility, data quality, and operational insight support more targeted, risk-based decision-making as asset condition evolves and electrification pressures increase.

The DSP is not a comprehensive, utility-wide DSP and does not establish approved project scopes, costs, or implementation schedules. It provides a focused framework to support capital planning discussions, future DSP updates, and project-specific evaluation processes. Detailed engineering, validation, and cost refinement will occur as individual investments advance.

In summary, ORPC's substation system is fundamentally serviceable but aging, with risk concentrated in specific asset groups and locations. By combining disciplined condition assessment, consequence-based prioritization, and early investment in enabling capabilities, ORPC is positioned to manage substation risk prudently while preserving flexibility to adapt to future system change.

1.2 Scope and Objectives

This assessment focuses on ORPC's distribution substations in the Pembroke (MS #1 through MS #8) and Almonte (MS #1 through MS #4) service territories.

The scope is limited to equipment and systems within each substation's fenced boundary, representing assets under ORPC's ownership and operational control. Each substation is supplied from 44 kV sub-transmission feeders owned by external utilities or generation entities. Within the fence, ORPC owns and maintains the 44 kV terminal apparatus, including circuit breakers, disconnect switches, lightning arresters, and associated buswork at the point of connection.

ORPC ownership extends to all downstream substation facilities, including power transformers, medium-voltage switchgear, station service equipment, protection and control systems, metering, SCADA and communications infrastructure, and associated auxiliary systems required for safe and reliable operation. These assets form the core of ORPC's substation infrastructure and are the focus of this assessment.

The assessment considers all major station components, including:

- Power transformers (typically 44 kV to 12.47 kV or 4.16 kV), associated protection devices, and oil containment systems;

- Medium-voltage switchgear assemblies, including breakers, relays, metering, control wiring, and SCADA and communications systems;
- Instrument transformers, station service supplies, grounding systems, and auxiliary equipment; and
- Civil and structural features influencing reliability, accessibility, or safety (e.g., control buildings, fencing, foundations, and drainage).

The purpose of this study is to provide a structured evaluation of substation condition, functionality, and risk to support ORPC's asset-management and capital-planning framework within the DSP.

The previous 2022–2026 DSP was reviewed during development of this assessment and provided important planning context. The current DSP builds upon many of the same underlying planning themes, including asset renewal, operational reliability, protection and SCADA modernization, and risk-informed investment prioritization. However, given the narrower substation-focused scope of this assessment, a detailed comparison to the previous utility wide DSP was not undertaken.

Specific objectives are to:

- Document the present condition and configuration of ORPC's substation assets using field inspection data provided by Synergy Power Ltd. and available ORPC records;
- Identify renewal, refurbishment, or replacement needs arising from asset age, deterioration, condition, or obsolescence;
- Develop a preliminary engineering framework for prioritizing substation and feeder renewal needs based on relative asset criticality and operational exposure to support risk informed decision making;
- Support coordination with regional planning initiatives and system studies conducted by external system owners and the IESO, as applicable; and
- Provide a consistent technical basis for future detailed engineering assessments and system studies.

The outcomes of this assessment inform the asset condition evaluation and capital prioritization presented in Sections 4 and 7.

1.3 Utility Overview

ORPC is a licensed local distribution company serving portions of eastern Ontario, with primary service territories centered on the City of Pembroke and the Town of Mississippi Mills (Almonte). The service area includes a mix of urban, semi-urban, and adjacent rural communities and supplies a predominantly residential customer base, with additional commercial, institutional, and light industrial load.

ORPC's distribution system is supplied at 44 kV through a combination of ORPC-owned and upstream-owned sub-transmission infrastructure, depending on location and point of supply. Bulk power is transformed within ORPC-owned substations to serve downstream medium-voltage networks operating primarily at the 5 kV (4.16 kV nominal) and 15 kV (12.47 kV nominal) voltage classes. Although ORPC owns portions of its 44 kV supply infrastructure, upstream system performance and configuration continue to influence operational flexibility, outage coordination, and substation capital planning.

ORPC operates twelve distribution substations: eight in the Pembroke area (MS #1 through MS #8) and four in the Almonte area (MS #1 through MS #4). These substations are the highest-value and most operationally critical assets within the distribution system. Each substation forms the primary interface between the 44 kV supply system and downstream feeders, making substation performance central to reliability, safety, and restoration capability.

The Pembroke and Almonte service areas exhibit differing characteristics that influence substation planning. The Pembroke system includes a mix of 5 kV and 15 kV infrastructure developed over multiple periods, with asset age, configuration, and condition varying by location and feeder. Feeders serve both compact urban areas and more geographically dispersed load. The Almonte system has experienced comparatively stronger population growth and development and includes a combination of newer infrastructure and older unit substations that continue to serve established urban load pockets.

Across both territories, the distribution network is characterized by a moderate system scale and a range of feeder configurations that influence restoration practices and operational flexibility. While feeder interconnections and alternate supply paths exist in portions of the system, the extent of available transfer capability varies by location and operating conditions. As a result, the loss of an individual distribution substation can, in some cases, result in localized outage impacts until

restoration and switching activities are completed. Substation condition, configuration, and available operational flexibility therefore remain important considerations in overall system performance and capital planning.

This substation-focused DSP places specific emphasis on ORPC's substations as critical system nodes. This overview establishes baseline context for the service area, system structure, and operating environment to support the asset condition assessment, risk evaluation, and capital planning framework presented in subsequent sections.

1.4 Methodology

This substation-focused DSP was developed using a structured, engineering-based methodology intended to support comparative assessment, risk informed prioritization, and forward-looking capital planning for ORPC's distribution substations over the 2027–2031 horizon.

The methodology integrates multiple information sources and applies professional engineering judgment to evaluate asset condition, system exposure, and relative consequence in a consistent and transparent manner.

The original project scope contemplated development of a comparative Probability of Failure (PoF) and Consequence of Failure (CoF) style assessment framework, including matrix-based prioritization concepts. During development of the DSP, it became evident that the available asset condition, loading, operational, and historical performance information was not sufficiently complete or consistently quantitative to support defensible probabilistic modelling or numerically calibrated risk scoring without introducing a level of implied precision that could not be reliably substantiated.

Accordingly, the methodology was refined toward a qualitative engineering assessment framework that incorporates the underlying principles of probability and consequence evaluation through comparative condition and criticality groupings informed by inspection findings, operational context, asset age and technology considerations, available performance information, and professional engineering judgment.

The level of analysis is proportionate to the planning objectives of the DSP and does not attempt detailed design, formal probabilistic failure modelling, or project-level engineering.

1.4.1 Data Sources

The DSP is informed by the following primary data inputs:

- Non-invasive field inspection observations conducted by Synergy Power Ltd., providing consistent system-wide insight into asset configuration, apparent condition, and observable deficiencies.
- ORPC operational and asset records, including equipment information, historical context, and operational knowledge.
- GIS-derived system data used to evaluate feeder characteristics, overhead and underground exposure, and connected transformer capacity as a proxy for relative load served.
- Regional planning documentation, including relevant Integrated Regional Resource Plans (IRRPs), establishing external planning context and coordination considerations.
- Publicly available demographic and electrification indicators used directionally to inform planning context rather than develop deterministic forecasts.

Where data availability or consistency varied across substations, reasonable assumptions were applied to enable comparative evaluation. These assumptions are noted where relevant and reflect accepted utility planning practice.

1.4.2 Planning Level Assessment Approach

The methodology follows a sequential planning framework:

a) **Asset Inventory and Configuration** – Establishes a system-level understanding of substation assets, voltage classes, configurations, and approximate vintage (Section 3).
b) **Asset Condition Assessment** – Interprets inspection observations, asset age, and known performance characteristics to develop qualitative condition ratings by asset group (Section 4).
c) **Risk and Criticality Evaluation** – Assesses the relative consequence of asset or substation loss based on system role, downstream exposure, redundancy, and connected load (Section 5).
d) **Needs Identification** – Translates condition and criticality findings into underlying system needs without prescribing specific solutions (Section 6).
e) **Capital Prioritization and Planning** – Integrates condition, consequence, and system needs to support relative prioritization and planning level investment sequencing (Sections 7 and 8).

Risk is considered in a comparative planning context, reflecting the interaction between asset condition and system consequence rather than formal probabilistic failure modelling or

quantitatively calibrated risk scoring. Within this framework, comparative asset condition considerations function as a proxy for relative likelihood of failure, while criticality considerations reflect relative operational and customer consequence exposure.

1.4.3 Use of Engineering Judgement

Professional engineering judgment is applied throughout the DSP to interpret inspection findings, normalize condition assessments across substations, and integrate multiple planning inputs. Inspection observations are evaluated alongside asset vintage, configuration, known degradation mechanisms, and industry experience with comparable equipment, recognizing that observed deficiencies do not always translate directly to condition or capital urgency.

1.4.4 Alignment with Regulatory Expectations

The methodology aligns with Ontario Energy Board expectations for prudent, risk informed distribution system planning. It emphasizes transparency, proportionality, and defensibility while distinguishing between planning level assessment and implementation level decision making.

The DSP establishes a structured framework for future detailed engineering, validation, and capital approval processes without predetermining project scope, cost, or execution timing.

1.4.5 Limitation and Intended Use

This DSP supports strategic planning and prioritization at the substation level. It does not replace detailed engineering studies, condition diagnostics, or project specific evaluations undertaken as individual investments advance.

The results should be interpreted as indicators of relative condition, exposure, and priority suitable for informing capital planning discussions and regulatory filings, rather than definitive determinations of asset life or immediate replacement need.

2 Planning Context

This section establishes the external, regulatory, and system level context for ORPC's substation planning decisions. It outlines the regional planning environment, local growth and electrification drivers, and key data considerations informing ORPC's approach to managing and reinvesting in its distribution substations.

2.1 Regional Planning and Policy Drivers

ORPC's distribution substations operate within a broader context shaped by Ontario's regional electricity planning process, local growth patterns, and accelerating electrification trends. This DSP therefore considers not only internal asset condition and operational needs, but also external drivers influencing the timing, sequencing, and coordination of substation investments over the 2027–2031 horizon.

2.1.1 Regional Planning Context and Coordination

Regional electricity planning in Ontario is conducted through Integrated Regional Resource Plans (IRRPs), which assess long-term electricity needs and identify recommended actions and coordination requirements for transmitters, distributors, and the IESO. ORPC's service territories intersect two relevant planning areas: the Renfrew region, which informs the planning context for Pembroke-area substations, and the Greater Ottawa / Ottawa Area sub-region, which provides broader eastern Ontario context, including growth and electrification assumptions applied by upstream system owners.

The IESO released the Renfrew Region IRRP in December 2022, covering the 2021–2042 study period. It identifies emerging capacity needs driven by forecast growth, electrification, and configuration constraints, and recommends advancing these needs through a subsequent Regional Infrastructure Plan (RIP) led by the upstream system owner. The IRRP highlights capacity considerations in the Pembroke supply area, with further technical definition and implementation timing to be refined during the RIP stage. It also emphasizes the need for coordinated planning among Hydro One Transmission, Hydro One Distribution, ORPC, and the IESO as recommended actions progress.

From ORPC's perspective, the Renfrew Region IRRP establishes key planning assumptions for Pembroke area substations and signals the likelihood of upstream work that may introduce coordination requirements related to outage windows, commissioning activities, and interface arrangements at ORPC's 44 kV connection points.

Regional planning for the Ottawa Area Sub-Region was completed in July 2025, with the IRRP and supporting appendices published by the IESO. The Ottawa Area IRRP emphasizes electrification-driven demand growth, including electric vehicles, electrified heating, and other decarbonization initiatives, and incorporates these drivers into regional forecasting methodologies. While ORPC's substations are distribution-level assets, the IRRP underscores the importance of coordinated

planning across system owners to manage growth, maintain reliability, and sequence infrastructure investments.

ORPC's substation capital planning must therefore remain responsive to upstream planning signals and coordination requirements that may influence supply arrangements, outage windows, protection interfaces, and construction sequencing. This includes maintaining alignment with upstream renewal or reinforcement initiatives identified through IRRP and RIP processes, even as detailed scope and timing continue to evolve.

ORPC has participated in regional planning engagement activities led by the IESO and upstream system owners, including the Renfrew and Ottawa Area processes. ORPC will continue to engage as recommendations advance through subsequent study and implementation stages, ensuring substation renewal and modernization activities remain compatible with broader system development while retaining flexibility to adjust timing and scope as upstream plans evolve.

2.1.2 Population Growth and Development Patterns

Local growth patterns differ materially between ORPC's service territories and influence load growth, system expansion, and electrification impacts. Recent census data indicate that the City of Pembroke experienced modest population growth from 2016 to 2021 (approximately +3.5%), while Mississippi Mills (Almonte area) grew more strongly over the same period (approximately +12.0%).

These differing trajectories suggest that planning emphasis should vary by service area:

- In Pembroke, investment drivers may be weighted toward condition, reliability, modernization, and operational resilience.
- In Almonte/Mississippi Mills, planning should remain attentive to growth associated needs, subdivision development, and electrification uptake that may accelerate loading changes and operational requirements.

2.1.3 Electrification and EV Adoption as Emerging Demand Drivers

Electrification trends, particularly electric vehicle adoption and the electrification of space and water heating, are increasingly relevant drivers of electricity demand growth in Ontario. At the provincial level, the IESO continues to identify electrification as a key long-term contributor to incremental demand growth, with implications for both peak demand characteristics and overall system utilization.

At the regional level, the Ottawa Area IRRP and supporting appendices incorporate assumptions related to electric vehicles, electrified heating, and broader decarbonization initiatives within regional demand forecasting methodologies. These assumptions establish an important planning context for ORPC's service territories, even where localized impacts are not yet directly observable in measured substation loading data.

At the local level, observable indicators of electrification activity are present within both ORPC service territories. In Pembroke, publicly accessible electric vehicle charging infrastructure has been installed at municipal and institutional locations, including civic facilities and health-care sites. Recent additions of Level 2 and Level 3 charging infrastructure at the Pembroke Regional Hospital further reflect ongoing adoption of electric transportation.

Similarly, in the Almonte / Mississippi Mills area, municipal investment in publicly accessible charging infrastructure provides evidence of early electric mobility uptake. While these installations remain modest in scale, they are consistent with broader population growth and development trends within the service area.

Taken together, these provincial, regional, and local indicators support electrification as an emerging planning consideration within ORPC's substation DSP. Their principal relevance at this stage lies less in quantifying immediate load impacts and more in reinforcing the importance of maintaining operational flexibility, system visibility, and planning margin as electrification continues to evolve over the planning horizon.

2.1.4 Climate Adaptation and Resilience Considerations

Regional planning methodologies emphasize system performance under extreme weather and peak stress conditions. For ORPC's substations, this reinforces the value of investments that improve restoration capability, maintainability, and system visibility—particularly where redundancy is limited and manual switching remains a significant component of restoration practice.

2.2 ORPC Distribution System Context

ORPC operates a medium-voltage system supplied from external 44 kV sub-transmission sources. These supplies are transformed within ORPC owned substations to serve downstream networks operating primarily at nominal 5 kV (4.16 kV) and 15 kV (12.47 kV) voltage classes.

The system serves a mix of urban and semi-urban areas and supplies residential, commercial, and institutional customers. Feeder characteristics vary in length, geographic dispersion, and the proportion of overhead and underground construction. In general, 15 kV feeders serve larger geographic areas with longer line lengths, while 5 kV feeders are more compact and concentrated in denser areas; however, these characteristics vary by location and substation.

ORPC's substations form the primary interface between the regional 44 kV supply network and the local medium-voltage system. Each substation supplies multiple downstream feeders and plays a central role in reliability, operational control, and restoration capability. Operational flexibility varies across the system based on feeder configuration, available tie points, and local operating practices.

Detailed documentation of individual substations, asset configurations, and operating characteristics is presented in Section 3.

2.3 Planning Data Context and Assumptions

The analyses and conclusions in this DSP are based on available documentation, field inspection observations, Geographical Information System (GIS) derived information, and professional engineering judgment.

Substation condition information is informed primarily by visual, non-invasive inspections conducted by Synergy Power Ltd., supplemented by ORPC records. These inspections provide consistent system wide insight into asset configuration, apparent condition, and observable deficiencies but do not include intrusive testing, detailed diagnostics, or remaining life analysis.

System configuration, feeder characteristics, and downstream exposure were evaluated using ORPC's GIS data. GIS information supports comparative assessment of feeder length, construction type, and connected load but does not represent real-time operating conditions.

Measured loading and reliability data were reviewed where available; however, availability and consistency varied across substations and feeders. Connected load and system configuration were therefore used as primary indicators of relative exposure and planning margin, with measured data informing engineering judgment rather than serving as definitive indicators of peak or seasonal loading.

Growth related assumptions inform relative prioritization over the planning horizon and are not intended as precise forecasts.

3 Asset Inventory and Configuration

This section establishes a system-level inventory of ORPC's substations and major station components, documenting configuration, voltage class, capacity, and approximate age profile. The inventory establishes a baseline reference describing asset composition, system arrangement, and the functional role of each substation within the network.

The information presented characterizes asset composition and system structure. Where historical records were unavailable, engineering judgment was applied to estimate equipment vintage using nameplate data, design characteristics, and observed configuration.

3.1 Asset Inventory Assumptions

Installation dates were not available for all substation assets. Where documentation was unavailable, equipment vintage was estimated using nameplate information, manufacturer identification, design characteristics, and observed configuration. Approximate vintage bands are shown using year-only notation or "pre-year" estimates (e.g., <1975) to reflect uncertainty while maintaining consistency across the system inventory.

Sub	44kV Supply Config.	44kV Circuit Breaker Qty(Vintage)	44kV Switching Device Qty(Vintage)	Power Transformer MVA(Vintage)	MV SWGR (kV Rating /Vintage)	MV Feeder Count	Notes
Pembroke Substations							
MS#1	Loop	2(1965)	2(1982) 1(1965)	5MVA(1976)	5kV(1960)	4	Urban, Mixed OH & UG
MS#2	Loop to radial	-	3(2013)	6MVA(<1970)	5kV(<1965)	5	Urban, Mixed OH & UG
MS#3	Loop	-	3(<1965)	5MVA(1967)	5kV(<1960)	4 (2 in service)	Yard is shared with MS#7, Urban, OH dominant
MS#4	Loop	3(<1960)	4(<1985)	5MVA(1963)	5kV(<1965)	5(4 in service)	Main incoming 44kV to Pembroke, Urban,

Sub	44kV Supply Config.	44kV Circuit Breaker Qty(Vintage)	44kV Switching Device Qty(Vintage)	Power Transformer MVA(Vintage)	MV SWGR (kV Rating /Vintage)	MV Feeder Count	Notes
							Mixed OH & UG
MS#5	Loop to radial	-	3(<1975)	3MVA(1968)	5kV(<1975)	4(1 in service)	Urban, Mixed OH & UG
MS#6	Loop	-	3(<1985)	10MVA(1990) 10MVA(2023)	15kV(1975)	4	Urban/Rural, Mixed OH & UG
MS#7	Loop	-	3(<1965)	10MVA(1974)	15kV(1975)	2	Urban, Mixed OH & UG
MS#8	Loop	-	4(<1995)	10MVA(1991)	15kV(1991)	2	Urban, Mixed OH & UG

Sub	44kV Supply Config.	44kV Circuit Breaker Qty(Vintage)	44kV Switching Device Qty(Vintage)	Power Transformer MVA(Vintage)	MV SWGR (kV Rating /Vintage)	MV Feeder Count	Notes
Almonte Substations							
MS#1	Loop	-	1(<1985)	5MVA(2003)	15kV*(2009)	3	Urban, OH
MS#2	Loop	-	1(<1985)	5MVA(1989)	5kV(<1975)	3	Urban, Mixed OH & UG
MS#3	Radial	-	1(<1975)	3MVA(1965)	5kV(<1975)	2	Urban, Mixed OH & UG
MS#4	Radial	-	1(2018)	5MVA(2019)	15kV*(2019)	2	Urban, Mixed OH & UG

*MS#1 and MS#4 switchgear has been replaced. The new gas insulated switchgear is 15kV rated and is operating on the 5kV distribution system.

3.2 Configuration and Interconnection

ORPC's substations are supplied from 44 kV sub-transmission sources and step down to medium-voltage distribution operating at either the 5 kV class (4.16 kV nominal) or the 15 kV class (12.47 kV nominal). The 44 kV supply arrangements are generally straightforward and reflect typical utility practice for systems of this size, consisting primarily of radially fed transformer connections with fused primary disconnects. In some cases, looping switches are provided within the substation yard to support alternate supply arrangements; however, the 44 kV system does not function as a complex distribution network within the substation footprint.

At the 44 kV level, each substation operates independently. Pembroke MS#3 and MS#7 share a common physical yard but are functionally independent (MS#3 services 4.16kV circuits, MS#7 services 12.47kV circuits), with no operational interdependence between their transformer or distribution systems. All other substations are physically and operationally distinct.

At the medium-voltage level, configurations vary across the system. Most substations employ simple bus arrangements appropriate to their size and role within the network. Feeder interconnection and transfer capability exists to varying degrees and includes a mix of intra-substation ties and ties between adjacent substations. While interconnections are identifiable at a system level through GIS

records, available transfer capability within individual substations depends on local configuration and operating practices.

Redundancy and restoration flexibility vary across ORPC's substation portfolio. In some locations, loss of individual components can be mitigated through feeder transfers or alternate supply paths, subject to capacity and loading conditions. In others, restoration feasibility is more constrained and dependent on the equipment affected and prevailing system loading. These configuration characteristics provide context for the assessment of system criticality and operational flexibility discussed in later sections.

3.3 Inspection Findings and Condition Themes

Field inspections of ORPC's substations were conducted by Synergy Power Ltd. to document observable asset condition and identify notable configuration or maintenance issues. Inspections were visual and non-invasive and focused on major asset classes, including power transformers, medium-voltage switchgear, protection and control equipment, and supporting station systems. The scope was applied consistently across substations to provide a common baseline for planning purposes.

At a system level, inspections indicate that ORPC's substation portfolio includes a mix of legacy and more recently installed equipment. Aging outdoor assets were observed at several locations, particularly in transformer and medium-voltage switchgear installations. Modernization levels within protection and control systems vary across the system, reflecting differences in age, configuration, and historical investment. Supporting systems (ie. grounding, fencing, and site infrastructure) were generally serviceable, with localized issues at select locations.

Detailed condition interpretation, comparative assessment, and identification of renewal drivers are addressed in Section 4.

3.4 Operational Overview

This section provides a high-level operational overview of ORPC's substations, focusing on system characteristics that influence restoration complexity, operational exposure, and relative scale. The overview draws on GIS derived feeder data, connected transformer information, and qualitative operational knowledge to describe how each substation functions within the system.

Because measured loading and reliability data vary in availability and consistency across substations, the discussion emphasizes relative comparisons and system structure rather than quantitative performance metrics.

3.4.1 Pembroke Substations – Operational Characteristics

The Pembroke substations serve a mix of urban and semi-urban areas with both overhead and underground medium-voltage distribution. The system includes 5 kV (4.16 kV class) and 15 kV (12.47 kV class) feeders, with the 15 kV network generally supplying longer and more geographically dispersed circuits.

Primary feeder exposure varies across the Pembroke substations, reflecting differences in service area size, feeder density, and network configuration. Substations supplying longer overhead feeder lengths typically exhibit greater restoration complexity and increased operational exposure during fault or outage conditions, particularly where redundancy is limited.

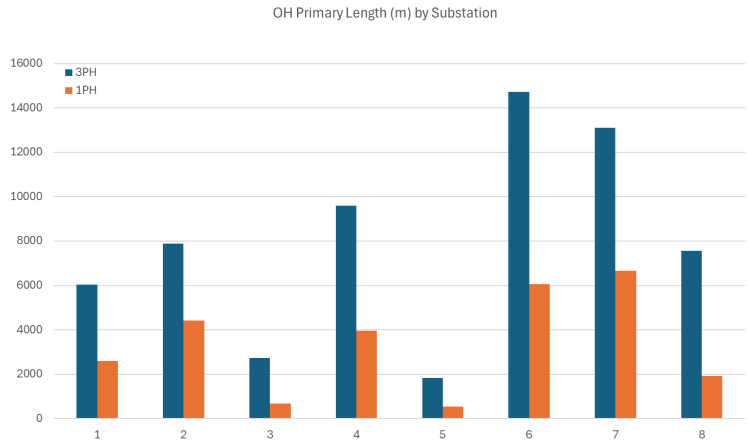


Figure 1 - Pembroke Substations - Overhead Primary Feeder Length by Substation

Underground feeder exposure also varies across the Pembroke system and is generally concentrated in more urbanized areas. While underground circuits can reduce exposure to weather related interruptions, they may introduce additional complexity in fault location and restoration, particularly where feeder segmentation or alternate supply options are limited.

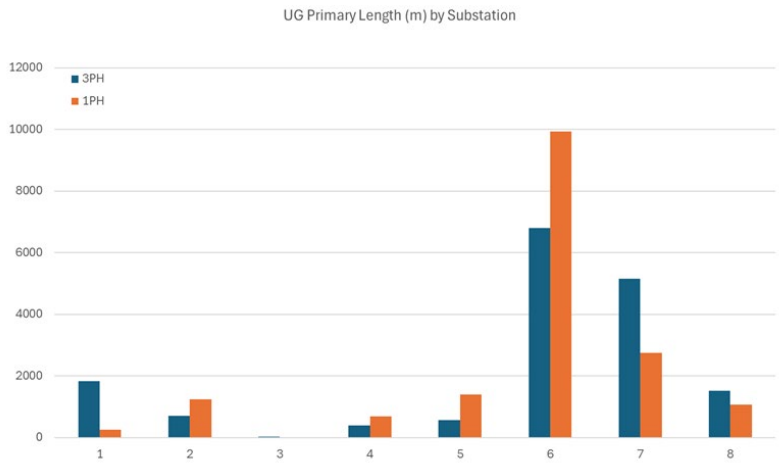


Figure 2 - Pembroke Substations - Underground Primary Feeder Length by Substation

The relative scale of load served by each Pembroke substation was assessed using connected transformer capacity as a proxy for load magnitude. This provides a consistent basis for comparison in the absence of uniform measured demand data. It does not represent actual peak loading or utilization, but rather the relative size of each substation's downstream system.

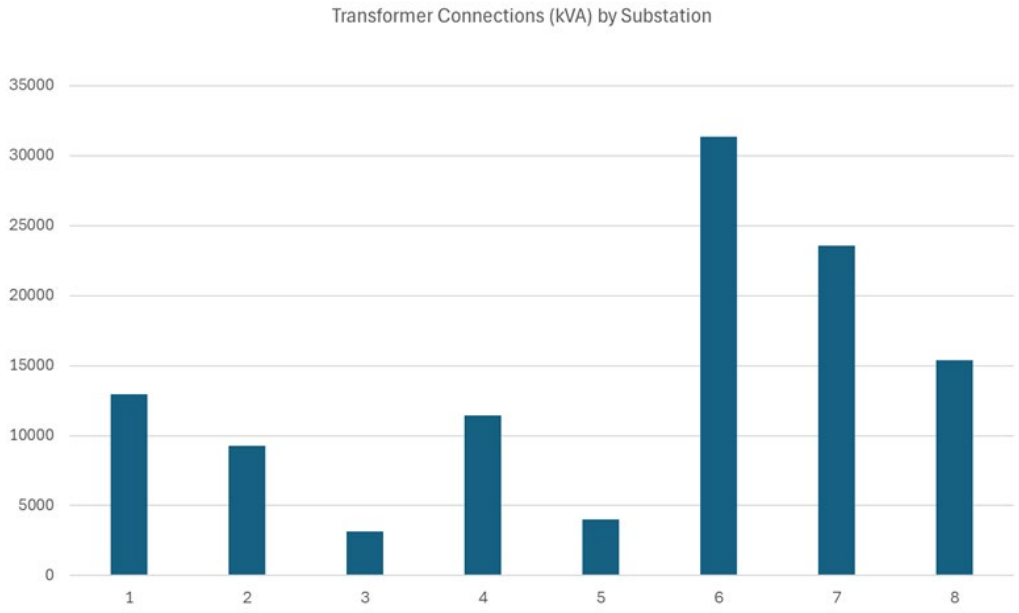


Figure 3 - Pembroke Substations - Connected Transformer Capacity by Substation

Restoration activities across the Pembroke system rely predominantly on manual switching, with limited remote control capability at select locations. Protection schemes follow standard utility reclosing practices. Based on the information available at the planning level, no pronounced seasonal

loading effects or broader system-level performance concerns were evident; however, this observation should be interpreted in the context of variable availability and consistency of measured loading and reliability data across substations.

3.4.2 Almonte Substations – Operational Characteristics

The Almonte substations serve primarily urban areas with both overhead and underground distribution. As in Pembroke, the system includes 5 kV and 15 kV feeders, with the higher-voltage feeders generally serving larger and more dispersed load areas.

Variation in overhead primary feeder length reflects differences in service territory extent and feeder configuration. Substations with longer overhead exposure may experience increased restoration effort during outages, particularly where feeder ties or alternate supply paths exist outside the substation fence.

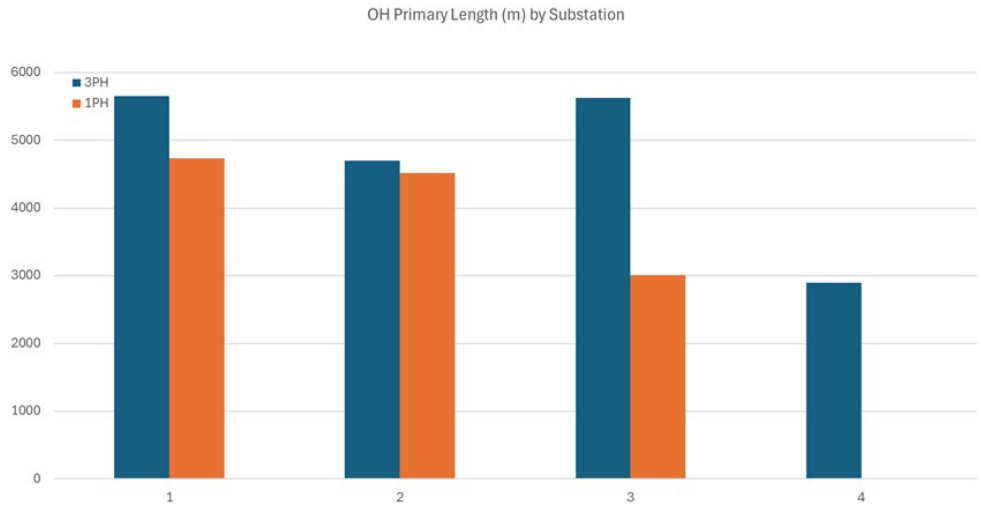


Figure 4 - Almonte Substations - Overhead Primary Feeder Length by Substation

Underground feeder exposure is more prominent at select Almonte substations, reflecting higher load density and urban development patterns. While underground infrastructure can improve reliability under some conditions, it introduces operational considerations related to fault isolation and restoration duration.

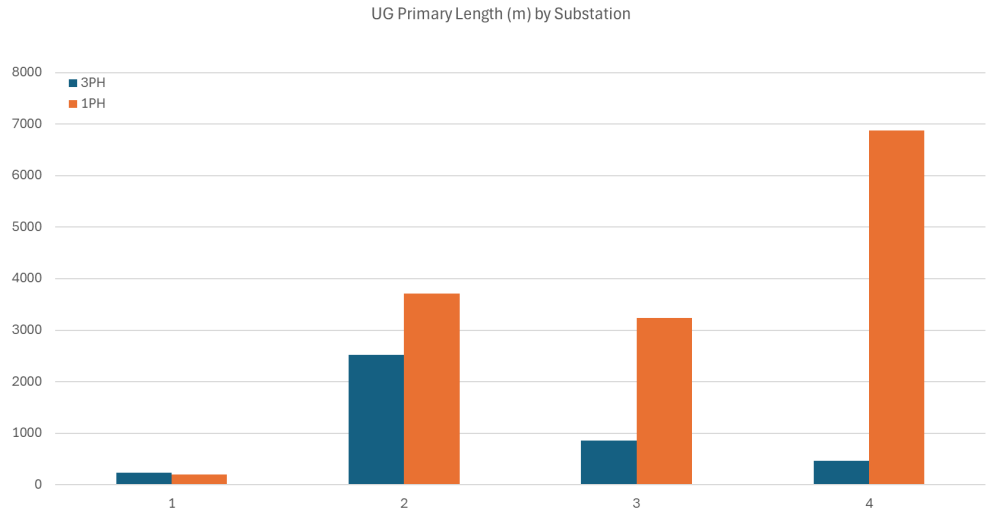


Figure 5 - Almonte Substations - Underground Primary Feeder Length by Substation

Connected transformer capacity was used as a proxy indicator of substation scale within the Almonte system. Differences in connected capacity highlight variation in the size and importance of individual substations within the broader network.



Figure 6 - Almonte Substations - Connected Transformer Capacity by Substation

As in the Pembroke system, detailed and consistent reliability indices and measured loading data were not available for all Almonte substations. Restoration activities rely primarily on manual switching supported by conventional protection schemes. Based on available planning-level

information, no pronounced seasonal loading effects or broader near-term operational concerns were evident; however, this observation is subject to the availability and consistency of measured loading and reliability data across substations

4 Asset Condition Assessment

This section summarizes the observed condition of ORPC's substations based on field inspections, available records, and engineering judgment. Asset condition is presented by major asset group to highlight dominant drivers of deterioration and operational concern. The summaries support comparative assessment across substations and inform subsequent evaluation of system risk and investment needs.

4.1 Interpretation of Inspection Findings and Asset Condition Ratings

Asset condition ratings in this DSP reflect a planning level assessment informed by field inspection findings, asset age and technology vintage, observed performance history, and the known degradation characteristics of comparable substation equipment in broader utility applications. Detailed inspection reports prepared by Synergy Power identify discrete deficiencies and observed conditions at the time of inspection. These findings are key inputs to the assessment; however, inspection-level observations are interpreted in context and are not carried forward directly as planning level classifications.

Condition ratings represent a normalized view of relative asset health across ORPC's substation portfolio and are applied to support risk informed capital planning rather than maintenance prioritization. Asset condition is expressed using qualitative ratings to enable consistent comparison across substations as follows;

A '**Good'** rating indicates assets performing as intended with only minor signs of aging and no material reliability or safety concerns. A '**Fair'** rating reflects aging or localized deficiencies that may require increased monitoring or future renewal. A '**Poor'** rating indicates condition issues likely to impact reliability or safety and that may warrant prioritized corrective action.

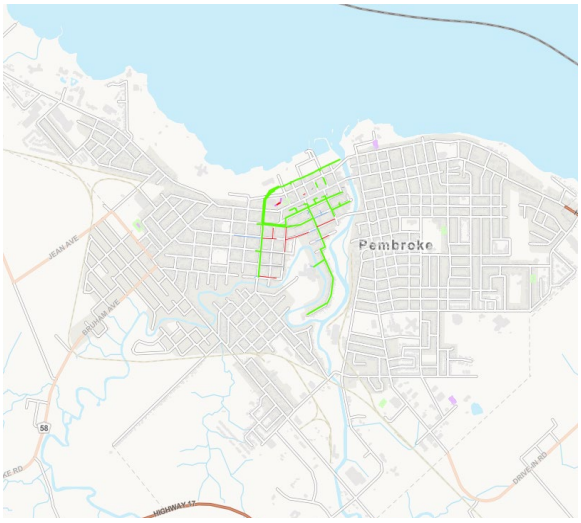
The following sections apply this rating framework by major asset group to summarize observed condition across ORPC's substations.

4.2 Pembroke Substation Condition Summaries

Substation Condition Summary Report			
Substation:	**Pembroke – MS#1**		
Voltage Class:	**5kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Pembroke MS#1 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results identify progressive age-related deterioration across multiple asset classes, particularly affecting outdoor primary equipment, grounding systems, and civil/clearance elements. While the station remains operable, these conditions reflect increasing maintenance complexity and exposure to condition-related risk.

The indoor 5 kV switchgear and associated protection systems are of legacy design generation, introducing growing limitations in maintainability and long-term supportability. Sub-transmission switching equipment exhibits typical aging characteristics; however, looped system configuration moderates near-term reliability consequence.

Transformer condition indicators, including DGA and oil testing, confirm stable internal condition with no evidence of active deterioration, supporting continued operation under routine monitoring.

Operationally, SCADA obsolescence limits system visibility, increasing reliance on manual practices, while recent DC system renewal improves auxiliary reliability.

Overall, the station exhibits progressive lifecycle risk exposure across multiple asset groups without imminent failure, with identified safety and compliance deficiencies largely addressable through targeted corrective work.

Path Forward:

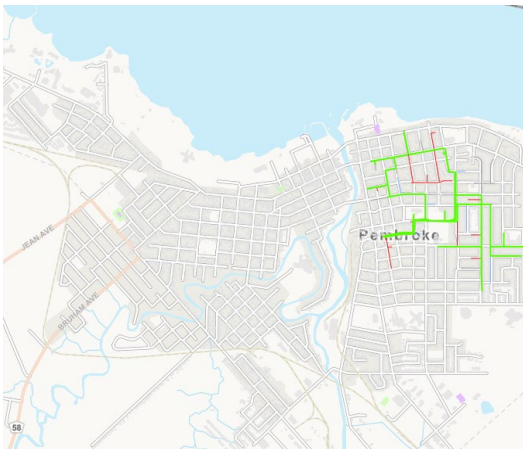
A phased, risk-informed modernization approach is appropriate. Near-term priorities include grounding, bonding, and clearance remediation, along with restoration of monitoring capability through SCADA modernization. Medium-term investment should target renewal of legacy medium-voltage switchgear and protection systems, while sub-transmission switching renewal can be deferred to the longer-term horizon given manageable near-term risk.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#2**		
Voltage Class:	**5kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Pembroke MS#2 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Inspection results indicate generally stable condition across primary electrical equipment, with condition concerns primarily associated with localized civil infrastructure deterioration and aging medium-voltage switchgear. The identified tower foundation issues represent a site-specific structural risk rather than a systemic deficiency in core electrical assets.

Substation Feeder Map



The indoor 5 kV switchgear and associated protection systems reflect legacy design generation, introducing increasing lifecycle management complexity and reduced long-term supportability. While these systems remain operable, they limit operational flexibility and system visibility relative to modern platforms.

Transformer condition indicators, including DGA and oil testing, confirm stable internal condition with no evidence of active deterioration, supporting continued operation under routine monitoring practices.

Operationally, non-functional SCADA infrastructure constrains real-time monitoring capability, increasing reliance on local operating practices, while grounding systems and primary equipment remain in satisfactory condition.

Overall, the station exhibits localized condition deficiencies combined with emerging lifecycle considerations for legacy equipment, while core functionality remains intact and condition-related risks are manageable through targeted intervention.

Path Forward:

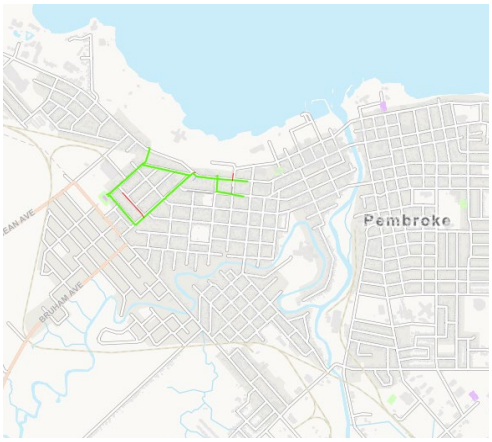
A phased, risk-informed approach is appropriate. Near-term efforts should focus on targeted civil remediation of tower foundation deficiencies and restoration of monitoring capability through SCADA modernization. Medium-term investment should address renewal of legacy medium-voltage switchgear and protection systems, aligned with increasing obsolescence and supportability constraints, while no immediate primary equipment replacement is required.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#3**		
Voltage Class:	**5kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Pembroke MS#3 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Inspection results indicate generally stable primary electrical equipment condition, with condition concerns primarily associated with localized grounding compliance deficiencies and progressive external deterioration of transformer and bus structures. These issues are asset-specific and reflect typical aging and environmental exposure rather than systemic functional limitations.

Substation Feeder Map



The indoor 5 kV switchgear and associated protection systems reflect legacy design generation, introducing increasing lifecycle management complexity and reduced long-term supportability. While operable, these systems limit operational flexibility and system visibility relative to modern digital platforms.

Transformer condition indicators, including DGA and oil testing, confirm stable internal condition with no evidence of active deterioration, with observed aging consistent with equipment of this vintage and supporting continued operation under routine monitoring.

Operationally, non-functional SCADA infrastructure constrains monitoring capability, increasing reliance on local operating practices. Grounding system upgrades completed in 2016 have improved overall system integrity, with remaining deficiencies considered localized and addressable.

Overall, the station exhibits localized condition deficiencies combined with progressive lifecycle considerations for legacy equipment, while core functionality remains intact and condition-related risks are manageable through targeted intervention.

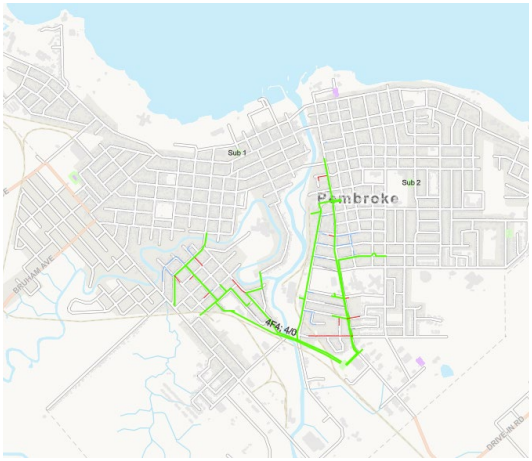
Path Forward:

A phased, risk-informed approach is appropriate. Near-term efforts should focus on targeted remediation of grounding deficiencies and equipment surface deterioration, along with restoration of monitoring capability through SCADA modernization. Medium-term investment should address renewal of legacy medium-voltage switchgear and protection systems, aligned with increasing obsolescence and supportability constraints, with no immediate requirement for primary equipment replacement.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#4**		
Voltage Class:	**5kV**	**Assessed Condition:**	**POOR**

The condition assessment for Pembroke MS#4 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results identify advanced age-related deterioration across primary switching equipment and supporting station infrastructure, including oil leakage observed on 44 kV breakers, bonding deficiencies, corrosion of structural elements, and general site degradation. These findings indicate a station experiencing broad-based asset aging rather than isolated deficiencies.

At the distribution level, the legacy 5 kV switchgear and associated control wiring exhibit late-lifecycle behaviour, with operational experience confirming functional reliability concerns, including intermittent interlock issues and control wiring-related misoperations during recent work activities. These observed events provide direct evidence of increasing operational risk beyond that inferred from inspection alone.

Protection and SCADA systems have been recently modernized, improving system visibility and operability; however, these upgrades do not mitigate the underlying condition concerns associated with aging primary switching equipment and legacy control wiring.

Transformer condition indicators, including DGA and oil testing, confirm no evidence of active internal deterioration, supporting continued operation under routine monitoring practices.

Overall, the station exhibits advanced lifecycle degradation combined with demonstrated operational reliability concerns, resulting in materially increased risk exposure across primary switching and control systems.

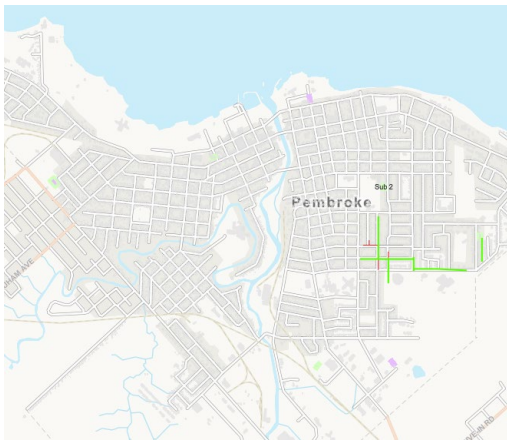
Path Forward:

A prioritized renewal approach is appropriate. Near-term efforts should continue to address discrete safety and compliance deficiencies through maintenance; however, capital investment should focus on replacement of aging 44 kV switching infrastructure and renewal of medium-voltage switchgear, addressing demonstrated reliability concerns. Recent protection and SCADA upgrades support improved operability, but core switching asset renewal remains the primary driver within the near- to medium-term planning horizon.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#5**		
Voltage Class:	**5kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Pembroke MS#5 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results indicate generally stable condition across primary electrical equipment, with condition concerns primarily associated with grounding deficiencies, localized corrosion, and general site condition, as well as aging protection and control infrastructure. These findings reflect typical condition characteristics for a station of this vintage and do not indicate systemic degradation of core electrical assets.

The medium-voltage switchgear, while of legacy design, is of comparatively later vintage relative to peer stations and remains serviceable with continued component supportability, moderating near-term renewal urgency.

Transformer condition indicators, including oil testing, support continued operation, with no evidence of active faulting. Reduced dielectric strength suggests a need for maintenance intervention (e.g., oil processing) rather than asset replacement, with continued monitoring recommended.

Operationally, non-functional SCADA limits system visibility, and legacy protection and control systems reduce operational flexibility relative to modern platforms. These factors represent the primary drivers of condition and operational risk, rather than degradation of primary equipment.

Overall, the station exhibits manageable lifecycle risk primarily associated with control system obsolescence and localized condition deficiencies, while core functionality remains intact and primary equipment is generally serviceable.

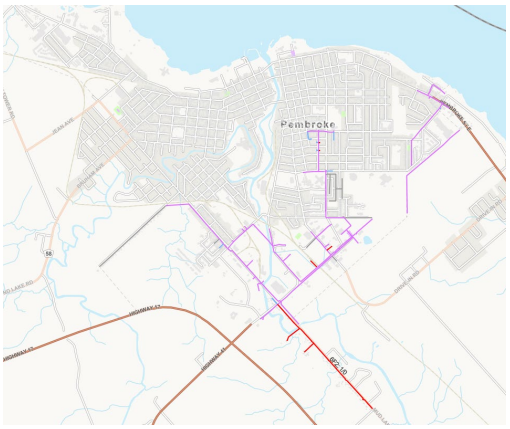
Path Forward:

A targeted modernization approach is appropriate. Near-term efforts should focus on grounding remediation, site condition improvements, and restoration of monitoring capability through SCADA modernization. Maintenance intervention for transformer oil condition should be completed as required. Medium-term investment should prioritize renewal of legacy protection and control systems, while deferring major primary equipment replacement given stable condition and continued supportability.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#6**		
Voltage Class:	**15kV**	**Assessed Condition:**	**GOOD**

The condition assessment for Pembroke MS#6 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results indicate generally sound condition across primary electrical equipment, with condition concerns limited to localized structural and grounding deficiencies and minor environmental deterioration. These issues are discrete in nature and do not indicate systemic degradation of core station assets.

The medium-voltage switchgear, while of legacy design generation, remains operationally serviceable with no significant deterioration identified, and does not represent a near-term renewal driver.

Protection and SCADA systems have been recently modernized, materially improving operational visibility, reliability, and lifecycle supportability relative to other stations in the portfolio.

Transformer condition indicators, including DGA and oil testing, support continued normal operation, with minor oil quality considerations addressable through maintenance intervention as required.

Operationally, the absence of load totalization represents a functional limitation in monitoring capability, affecting data granularity rather than indicating a condition-driven risk.

Overall, the station exhibits low lifecycle risk with stable primary equipment condition and modernized control infrastructure, with identified deficiencies manageable through routine maintenance.

Path Forward:

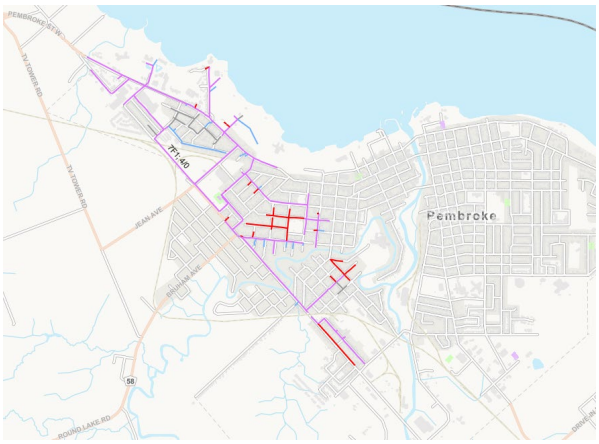
A maintenance-focused approach is appropriate. Near-term efforts should address localized structural and grounding deficiencies and complete minor maintenance activities as required. Capital investment is limited to installation of a load totalization meter to improve operational visibility and planning data quality. No major equipment renewal is required within the planning horizon.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#7**		
Voltage Class:	**15kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Pembroke MS#7 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Inspection results indicate generally stable condition across primary electrical equipment, with condition concerns primarily associated with localized grounding deficiencies, environmental deterioration, and aging outdoor switching equipment. These issues are consistent with station vintage and do not indicate systemic degradation of core assets.

Substation Feeder Map



The medium-voltage switchgear remains serviceable with no significant deterioration identified, moderating near-term renewal requirements. In contrast, legacy 44 kV air-break switching equipment and associated motor operators exhibit age-related characteristics consistent with increasing maintenance burden and potential variability in operating performance over time.

Transformer condition indicators, including DGA and oil testing, support continued normal operation, with no evidence of active internal deterioration.

Operationally, SCADA functionality is unreliable or intermittent, limiting real-time monitoring capability and reducing operational visibility. Protection and control systems are of legacy design, contributing to reduced operational flexibility and supportability.

Overall, the station exhibits moderate lifecycle risk driven by aging control, monitoring, and switching interfaces, while primary equipment remains serviceable and condition-related risks are manageable within the planning horizon.

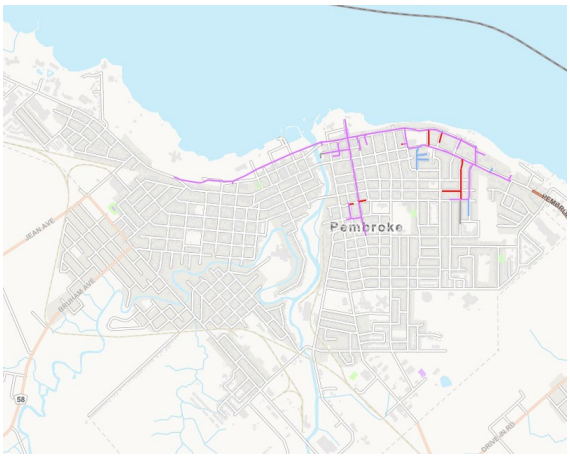
Path Forward:

A targeted modernization approach is appropriate. Near-term efforts should focus on restoration of monitoring capability through SCADA modernization and targeted remediation of grounding and site deficiencies. Medium-term investment should address renewal of aging 44 kV air-break switching equipment and associated motor operators, along with modernization of legacy protection systems, while deferring medium-voltage switchgear replacement given current serviceability.

Substation Condition Summary Report			
Substation:	**Pembroke – MS#8**		
Voltage Class:	**15kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Pembroke MS#8 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results indicate generally stable condition across core electrical equipment, with condition concerns primarily associated with localized civil and structural risk related to the main transformer foundation, together with minor grounding, labelling, security, and vegetation maintenance items.

The principal planning consideration is progressive settlement of the transformer foundation toward the adjacent embankment, which has required temporary shimming to maintain acceptable alignment of transformer terminations. While this condition does not presently affect transformer internal performance, it introduces increasing long-term risk to mechanical integrity, conductor stress, and future operability if left unaddressed.

Protection and SCADA systems have been recently modernized and are functioning as intended, and the medium-voltage switchgear remains of comparatively later vintage and serviceable within the planning horizon.

Transformer condition indicators, including DGA and oil testing, confirm stable internal condition with no evidence of active deterioration, supporting continued operation under routine monitoring and maintenance practices.

Overall, the station exhibits manageable near-term risk exposure driven primarily by localized civil infrastructure concerns, while core electrical systems remain generally serviceable and recently modernized.

Path Forward:

A targeted corrective approach is appropriate. Near-term capital focus should be on permanent stabilization of the transformer foundation and associated secondary conductor renewal to mitigate escalating structural risk. Localized grounding, labelling, security, and site maintenance deficiencies should continue to be addressed through routine corrective work programs.

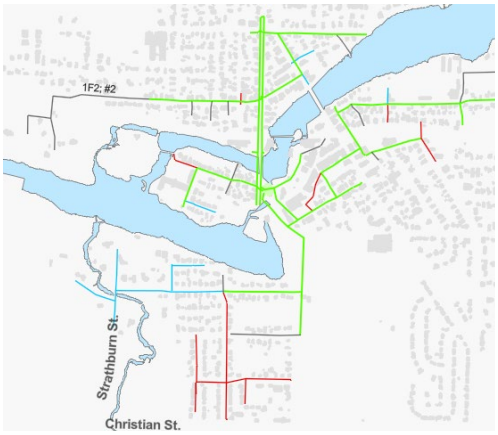
4.3 Almonte Substation Condition Summaries

Substation Condition Summary Report			
Substation:	**Almonte – MS#1**		
Voltage Class:	**5kV**	**Assessed Condition:**	**GOOD**

The condition assessment for Almonte MS#1 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Inspection results indicate generally stable condition across primary electrical equipment, consistent with a recently modernized indoor installation, including modern gas-insulated switchgear, protection, and monitoring systems. Identified civil and structural deterioration is localized in nature and does not presently affect electrical operability.

Substation Feeder Map



The primary planning consideration is not asset condition, but rather completion of operational monitoring standardization, specifically the absence of a substation load totalization meter, which limits alignment with current ORPC monitoring standards and reduces system-level visibility for planning and operational analysis.

A further planning-level requirement is the verification of gas monitoring, ventilation, and personnel safety provisions associated with the indoor GIS installation, as part of modernization completion and prudent asset stewardship. This is considered a standards-alignment and verification activity rather than a condition-driven deficiency.

Transformer condition indicators support continued normal operation under routine monitoring practices. While elevated ethane concentration warrants continued trending, available diagnostic evidence does not indicate active internal fault mechanisms or the need for immediate corrective intervention.

Overall, the station exhibits low lifecycle risk with stable, recently modernized electrical systems, with remaining items limited to monitoring standardization and minor facility maintenance.

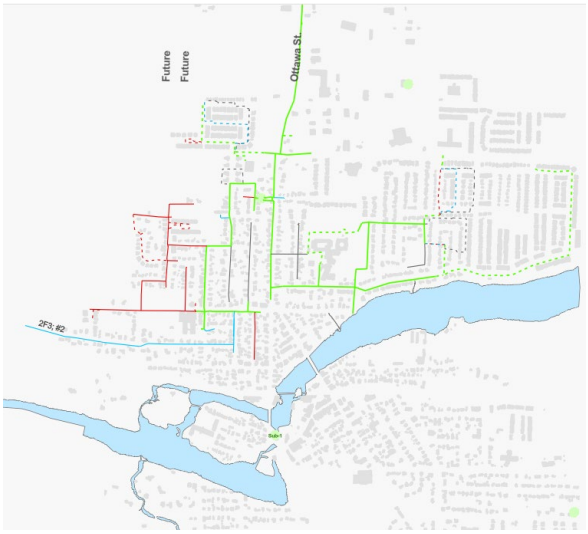
Path Forward:

A completion and maintenance-focused approach is appropriate. Near-term capital efforts should focus on installation of a load totalization meter and associated instrumentation, together with engineering verification of indoor GIS safety provisions. Localized civil deficiencies should be addressed through routine corrective maintenance. No major primary equipment renewal is required within the planning horizon.

Substation Condition Summary Report			
Substation:	**Almonte – MS#2**		
Voltage Class:	**5kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Almonte MS#2 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results indicate generally stable condition across primary electrical equipment, with condition concerns primarily associated with localized civil infrastructure deterioration affecting the sub-transmission tower foundations. This represents the principal condition driver and introduces increasing long-term structural reliability risk if not addressed through corrective intervention.

The indoor medium-voltage switchgear remains serviceable and operationally stable, and does not presently represent a condition-driven renewal requirement within the planning horizon.

A key operational consideration is the incomplete integration of station monitoring systems. While protective relaying has been modernized, the absence of local data aggregation, load totalization, and full SCADA communications integration limits operational visibility and reduces alignment with current ORPC monitoring standards.

Transformer condition indicators, including DGA and oil testing, support continued normal operation under routine monitoring practices, with no evidence of active internal deterioration.

Overall, the station exhibits moderate lifecycle risk driven by localized structural deficiencies and incomplete monitoring modernization, while core electrical systems remain generally stable and serviceable.

Path Forward:

A phased corrective and modernization approach is appropriate. Near-term capital efforts should focus on reconstruction of deteriorated tower foundations to restore long-term structural integrity, together with completion of station monitoring modernization, including local data aggregation, load totalization metering, and SCADA communications integration. No medium-voltage switchgear renewal is required within the current planning horizon.

Substation Condition Summary Report			
Substation:	**Almonte – MS#3**		
Voltage Class:	**5kV**	**Assessed Condition:**	**FAIR**

The condition assessment for Almonte MS#3 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Inspection results indicate generally stable condition across core electrical equipment, with condition concerns primarily associated with degradation of the unit substation enclosure, localized grounding deficiencies, and transformer external condition issues, including oil leakage and surface deterioration. These deficiencies are localized but introduce increasing maintenance burden and long-term reliability concerns if left unaddressed.

Substation Feeder Map



The principal planning driver is the progressive deterioration of the unit substation enclosure, which introduces exposure pathways that may affect the long-term reliability and maintainability of the installed medium-voltage switchgear and associated systems. While the 1975-vintage switchgear remains operational, enclosure degradation is now becoming a material lifecycle consideration.

Protection and control systems remain of legacy design, and no SCADA monitoring capability is currently implemented, limiting real-time operational visibility and reducing alignment with current portfolio-wide monitoring standards.

Transformer condition indicators, including DGA and oil testing, support continued normal operation under routine monitoring practices, with no evidence of active internal deterioration.

Overall, the station exhibits elevated lifecycle risk driven by enclosure deterioration and incomplete operational modernization, while core electrical functionality remains intact and generally serviceable.

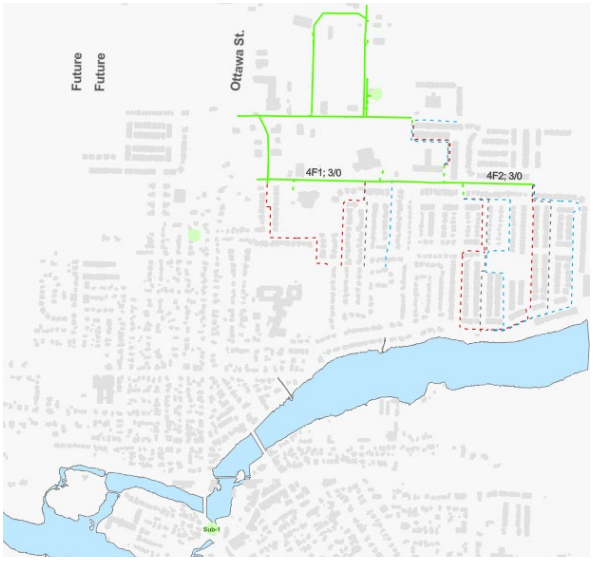
Path Forward:

A structured renewal and modernization approach is appropriate. Capital investment should focus on replacement of the existing unit substation and medium-voltage switchgear with a modern gas-insulated configuration, together with modernization of protection, control, and SCADA systems to restore operational visibility and improve long-term supportability. Localized grounding, transformer external condition, and site deficiencies should continue to be addressed through targeted corrective work programs.

Substation Condition Summary Report			
Substation:	**Almonte – MS#4**		
Voltage Class:	**5kV**	**Assessed Condition:**	**GOOD**

The condition assessment for Almonte MS#4 is informed by inspection findings (Synergy Power), field observations, transformer DGA and oil quality testing, and ORPC operational feedback, providing a consolidated planning-level view of asset condition and lifecycle risk.

Substation Feeder Map



Inspection results indicate like-new condition across primary electrical and supporting infrastructure systems, with no material deficiencies or code-related concerns identified. Primary equipment, including the transformer, switchgear, and reclosers, is in good operating condition consistent with a recently constructed and commissioned station.

The station reflects a modern design configuration, including current switching, protection, and monitoring infrastructure, resulting in minimal lifecycle risk exposure relative to the broader substation portfolio.

The only planning-level consideration identified is the absence of a substation load totalization meter, which represents a minor functional gap relative to current ORPC monitoring standards and affects planning visibility rather than asset condition.

Transformer condition indicators, including DGA and oil testing, confirm normal in-service performance with no evidence of active deterioration, fully consistent with expectations for a relatively new installation.

Overall, the station exhibits low lifecycle risk with near-new electrical and supporting infrastructure, requiring only routine monitoring and maintenance activities within the planning horizon.

Path Forward:

A monitoring-completion and routine maintenance approach is appropriate. Capital activity is limited to installation of a load totalization meter to align with current system monitoring standards and improve operational visibility. No additional capital renewal is required within the current planning horizon.

5 Risk and Criticality Assessment

This section presents the framework utilized for evaluating the relative risk associated with ORPC's substations and feeders by considering asset condition, operational exposure, and system criticality.

Building on the asset condition assessment in Section 4, the framework identifies substations and feeders whose loss or degradation would have the greatest impact on system reliability, safety, and restoration performance.

5.1 Criticality Framework and Interpretation

For this DSP, risk is evaluated through the combined consideration of asset condition (as an indicator of relative vulnerability and likelihood of failure) and asset criticality (as an indicator of operational and customer consequence). The assessment does not attempt to quantify absolute risk or develop statistically derived failure probabilities, but instead establishes a comparative understanding of relative system exposure associated with the loss or degradation of individual substations and their feeders.

The intent is to support comparative prioritization rather than deterministic prediction. When interpreted alongside the asset condition findings in Section 4, the framework provides a planning level view of relative system exposure suitable for capital decision making.

5.2 Criticality Framework Structure

The criticality evaluation considers:

- each substation's role within the 44 kV sub-transmission network
- the extent and nature of downstream infrastructure
- the degree of feeder redundancy and backfeed capability
- the magnitude of load and customers served

These factors represent the primary drivers of outage severity and restoration complexity in ORPC's system.

Criticality is assessed on a relative basis, with substations compared to identify assets with higher, moderate, or lower consequence in the event of loss or degradation. The resulting classifications

inform prioritization and sequencing of capital investments when considered alongside asset condition findings.

5.3 Criticality Factors Considered

The factors described below were selected based on engineering judgment and the availability of consistent planning level data and were applied uniformly across ORPC's substations to support relative comparison.

While feeder and breaker level data were reviewed where appropriate, criticality conclusions are presented at the substation level to align with the planning objectives of this DSP.

5.3.1 44kV Sub-Transmission Role and Criticality

The role of each substation within the 44 kV sub-transmission network is a primary driver of criticality, as loss of the 44 kV supply typically represents the most consequential outage scenario at a station.

Across ORPC's system, 44 kV networks are configured using a combination of looped and radial arrangements. Substations supplied from looped circuits benefit from alternate supply paths and sectionalizing capability, resulting in lower relative consequence at the sub-transmission level. Substations supplied radially, or through intermediate switching elements that represent a single point of failure, were assessed as having higher relative consequence in the event of a 44 kV outage.

In the Pembroke area, the 44 kV system forms a loop originating at Pembroke MS#4. Intermediate substations are equipped with air-break switches that allow sectionalizing and provide inherent redundancy. As the loop source, the breakers and switching devices at MS#4 were assessed as having elevated criticality due to their potential to affect a larger portion of the downstream network. Substations supplied via radial taps from the loop, where present, were assessed as having higher localized consequence due to single-point-of-failure exposure.

In the Almonte area, MS#1 and MS#2 form part of a looped 44 kV arrangement and were assessed similarly with respect to sub-transmission criticality. MS#4 is supplied via a radial tap from the loop and was assessed as having higher consequence due to loss of loop redundancy. MS#3 is supplied radially from the Hydro One 44 kV system; although the upstream Hydro One network is presumed looped, the ORPC-facing supply remains radial and was assessed accordingly.

Overall, differentiation across ORPC's 44 kV system is driven by supply topology and source-point function, and this factor was applied consistently as a key input to the substation criticality assessment.

5.3.2 Medium Voltage Overhead Exposure

The extent of downstream medium-voltage (MV) overhead infrastructure supplied by each substation is a significant contributor to criticality, reflecting both outage likelihood and restoration effort. Substations supplying greater quantities of overhead primary conductor are exposed to increased risk from weather, vegetation, and third-party contact, which can lead to higher outage frequency and longer restoration durations.

Overhead exposure was evaluated using GIS derived feeder data reviewed at the breaker level and summarized at the station level. In addition to total overhead circuit length, differentiation was made between three-phase and single-phase distribution. Three-phase overhead circuits represent a larger fault exposure and are more susceptible to multi-conductor outages during adverse conditions. They are also more likely to supply higher density load areas, larger customers, and critical facilities, increasing restoration consequence and complexity.

Single-phase overhead circuits remain subject to environmental risk but typically serve lower density load and smaller customer groupings, resulting in lower relative consequence compared to equivalent three-phase exposure.

Substations supplying extensive overhead MV infrastructure (particularly where a significant portion is three-phase) were therefore assessed as having higher operational consequence in the event of upstream equipment failure. This factor was applied consistently as a key input to the overall substation criticality assessment.

5.3.3 Medium Voltage Underground Exposure

The extent of downstream medium-voltage (MV) underground infrastructure supplied by each substation represents a distinct criticality consideration. Although underground circuits generally experience fewer outage events due to reduced exposure to weather and external contact, failures are typically more complex to locate and repair, resulting in longer outage durations and increased restoration effort.

Underground exposure was evaluated using GIS derived feeder data reviewed at the breaker level and summarized at the station level. As with overhead infrastructure, differentiation was made between three-phase and single-phase underground distribution. Three-phase underground circuits are more often associated with higher-capacity feeders, greater customer density, and larger or more critical loads. As a result, outages on three-phase underground circuits carry higher consequence and restoration complexity than comparable single-phase exposure.

Single-phase underground circuits typically serve lower density areas and smaller customer groupings, and while repair durations may still be significant, the overall consequence of failure is generally lower.

Substations supplying extensive underground MV infrastructure (particularly where a significant portion is three-phase) were therefore assessed with increased consideration for outage consequence and restoration complexity. This factor was applied consistently as part of the overall substation criticality assessment.

5.3.4 Downstream Connected Load

The magnitude of downstream connected load supplied by each substation is a key indicator of outage impact and system criticality. In the absence of consistent real-time or historical loading data across all feeders, connected load (based on the aggregate rating of downstream distribution transformers) was used as a proxy for relative load served.

Substations supplying larger connected loads were assessed as having higher potential customer and system impact in the event of an outage, while substations serving smaller or more dispersed loads were assessed as having lower relative consequence. At the scale of ORPC's system, connected load provides a sufficient representative indicator of relative impact for planning purposes.

5.3.5 Medium Voltage Feeder Redundancy and Network Resilience

The degree of medium-voltage feeder redundancy and network meshing downstream of each substation was considered as an additional criticality factor due to its influence on outage duration and restoration capability. Substations supplying feeders with multiple tie points, alternate source paths, or the ability to transfer load to adjacent substations were assessed as having reduced consequence in the event of equipment failure or feeder outages.

Substations supplying predominantly radial feeders with limited or no backfeed capability were assessed as having higher relative consequence, as outages are more likely to result in extended service interruptions. This factor reflects the practical operational flexibility available during restoration rather than failure likelihood and was assessed qualitatively based on known feeder interconnections and system configuration.

5.3.6 Use of GIS Derived System Data

Data supporting the criticality assessment (including feeder routing, conductor type, and connected transformer information) were obtained from ORPC's GIS. These data were considered appropriate for planning level evaluation of system exposure and were applied consistently across all substations to support comparative assessment.

5.3.7 Summary of Factor Application

The criticality factors described above were considered collectively to establish a relative understanding of substation consequence across ORPC's system. No single factor was applied in isolation; substations were assessed holistically based on combined exposure, load served, and role within the supply network. The resulting classifications support capital prioritization when considered alongside asset condition findings, rather than representing absolute measures of system risk.

5.4 Relative Criticality Classification

Based on the criticality factors described in Section 5.3, ORPC's substations were assessed and grouped into qualitative classifications to support capital prioritization. The classifications reflect the relative consequence of substation or feeder loss considering 44 kV supply role, downstream medium-voltage exposure, available redundancy and restoration flexibility, and connected load.

Substations were reviewed comparatively across the system using engineering judgment informed by GIS derived data and feeder level exposure summarized at the station level. Rather than assigning numeric scores or calibrated PoF/CoF values, substations were grouped into qualitative bands to reflect meaningful differences in outage impact, operational exposure, and relative system consequence.

The classifications inform prioritization and sequencing of renewal investments when considered alongside the asset condition findings in Section 4.

For this DSP, substations were grouped into the following categories:

High Criticality — Substations whose loss would result in significant outage impact due to their role in the 44 kV supply network, extent of downstream exposure, and magnitude of connected load. These stations typically represent single points of transformation for large portions of the system or supply extensive overhead or underground infrastructure.

Moderate Criticality — Substations with material customer and system impact, but with some operational flexibility, reduced downstream exposure, or lower relative connected load.

Lower Criticality — Substations serving smaller or less exposed portions of the system, or those with lower outage consequence due to limited downstream exposure or reduced load.

Pembroke Stations		
Substation	**Relative Criticality**	**Primary Criticality Drivers**
Pembroke MS#1	Moderate	44kV role, connected load
Pembroke MS#2	Low	Strong redundancy, moderate exposure
Pembroke MS#3*	Moderate	44kV role
Pembroke MS#4	High	44kV role
Pembroke MS#5	Low	Low loading, low exposure
Pembroke MS#6	High	High load, high exposure
Pembroke MS#7*	High	High load, high exposure, 44kV role
Pembroke MS#8	Moderate	Moderate loading, moderate exposure

*****Pembroke MS#3 and MS#7 occupy a shared physical site. While the 44 kV criticality weighting is equivalent for both substations, the downstream medium-voltage distribution systems are assessed separately and treated as independent.

Almonte Stations		
Substation	**Relative Criticality**	**Primary Criticality Drivers**
Almonte MS#1	Low	Strong redundancy, moderate exposure
Almonte MS#2	Moderate	High loading, moderate exposure
Almonte MS#3	Moderate	Moderate loading, moderate exposure
Almonte MS#4	High	44kV role

5.5 Limitations and Intended Use

This assessment is based on available documentation, site observations, GIS system data, and professional engineering judgment and is intended to support comparative evaluation and long-term capital planning at a system level.

Information availability and consistency varied across substations. Where necessary, reasonable assumptions were applied to enable consistent relative comparison. The results should therefore be interpreted as indicators of relative condition and system consequence rather than precise measures of asset health, failure probability, or remaining service life.

The assessment is planning level in nature and is not intended to replace project-specific investigations, validation, or detailed engineering undertaken at the implementation stage.

6 Needs Identification

This section identifies system needs arising from the asset condition assessment and criticality evaluation in Sections 4 and 5. These needs represent the underlying technical drivers for substation renewal, refurbishment, or replacement and form the basis for capital investment prioritization within ORPC's DSP.

Needs are identified in a manner consistent with OEB expectations for risk informed planning and reflect asset condition, system configuration, operational constraints, and safety considerations. The focus is on why investment is required, rather than prescribing detailed design solutions or project-specific implementation approaches.

6.1 Capacity Needs

Capacity needs arise where substation equipment operates with limited planning margin relative to connected load, or where system configuration provides limited tolerance for future growth or contingency conditions. Within ORPC's system, substations supplying higher relative connected load or relying on single major transformation components may be more sensitive to capacity-related exposure over the planning horizon.

Capacity considerations were screened by comparing connected transformer capacity to installed ratings and reviewing system configuration and operational context. This screening approach is intended to provide a high-level indication of relative exposure rather than a detailed assessment of

peak or seasonal loading performance. Consistent, time-series loading data is not presently available across all substations at a level sufficient to support a comprehensive capacity study.

Improving measured system visibility is a recognized planning objective and is aligned with ORPC's planned protection, control, and SCADA modernization initiatives. As these upgrades are implemented, future planning cycles are expected to incorporate more data driven capacity analysis.

Accordingly, capacity considerations identified in this DSP are treated as screening level indicators that inform monitoring priorities and future study needs, rather than definitive findings of constraint. This approach preserves planning flexibility while acknowledging the importance of enhanced system data in supporting future capacity evaluation.

6.2 Condition and Reliability Needs

Condition and reliability driven needs reflect the physical state and performance history of substation assets, including age, deterioration, and deficiencies observed during field inspections. Assets exhibiting advanced age, degraded condition, or recurring operational issues present elevated risk of unplanned outages and increased maintenance burden.

These needs are most significant where condition concerns coincide with higher system criticality, magnifying the consequence of failure. Addressing condition and reliability issues supports long-term system stability, reduces reactive maintenance, and mitigates service interruption risk.

6.2.1 Transformer Lifecycle Planning Considerations

Several of ORPC's distribution substations contain power transformers that are of advanced age, with a number of units installed between the 1960s and 1970s. The age profile of these assets was considered during development of this DSP and is recognized as an important long-term asset management consideration. However, the assessment did not conclude that broad transformer replacement should be advanced as a priority within the 2027–2031 planning horizon based on age alone.

Unlike many distribution assets, transformer service life is not determined primarily by chronological age. Long-term transformer performance is strongly influenced by factors including historical loading, thermal aging of insulation systems, moisture content, maintenance practices, fault exposure, and overall internal condition. As a result, transformers of similar age can exhibit materially different remaining service lives and risk profiles.

Available transformer condition information reviewed as part of this assessment included dissolved gas analysis (DGA), oil quality testing, field inspection observations, and operational feedback from ORPC personnel. Across the transformer fleet, these indicators generally supported continued operation and did not identify evidence of widespread active internal deterioration requiring near-term replacement. While individual maintenance or corrective actions may be appropriate as condition evolves, the available evidence did not support a conclusion that the oldest transformers had reached a clearly demonstrable end-of-life condition.

The assessment also considered operational consequence and system criticality. The potential impact of transformer failure varies significantly between substations depending on connected load, feeder configuration, available transfer capability, restoration options, and overall system role. These considerations were incorporated into the broader condition, criticality, and capital prioritization framework presented within this DSP.

A further consideration is the limited availability of consistent historical loading and utilization data. Transformer insulation aging is closely linked to thermal loading history; however, sufficient long-term loading information was not available across the substation portfolio to support robust estimation of accumulated loss of life, remaining insulation life, or replacement timing. In the absence of such information, reliance on age alone would introduce a level of uncertainty not considered appropriate for recommending major capital replacement.

Accordingly, the current DSP adopts a risk-informed monitoring and lifecycle management approach rather than a broad age-based replacement strategy. This approach emphasizes continued condition assessment, oil testing, operational monitoring, and the advancement of SCADA, metering, and data collection improvements intended to strengthen future lifecycle decision-making.

This conclusion should not be interpreted as indicating that transformer replacement will not be required during future planning horizons. Rather, it reflects the assessment's determination that the currently available evidence does not provide a sufficiently defensible basis for recommending widespread transformer replacement within the 2027–2031 period. As additional condition information, loading history, and operational data become available, transformer replacement timing and lifecycle strategies should be re-evaluated through future DSP updates and asset management planning activities.

6.3 Safety and Compliance Needs

Safety and compliance needs arise where substation infrastructure does not fully align with current safety standards, regulatory requirements, or applicable codes. Examples include elevated arc-flash exposure, grounding deficiencies, or non-conformance with electrical safety and operating standards.

Addressing these issues is fundamental to protecting personnel, maintaining regulatory compliance, and ensuring safe operation of ORPC's substations. Safety driven needs may warrant priority consideration independent of asset age or capacity constraints due to their potential impact on workers and operational risk.

6.4 Operational Flexibility Needs

Operational flexibility needs reflect limitations in substation configuration or system arrangement that restrict ORPC's ability to maintain, isolate, or restore equipment without service interruption. Substations with rigid bus configurations, limited maintenance bypass capability, or constrained feeder transfer options may experience prolonged outages during planned maintenance or fault conditions.

These needs are directly tied to system resilience and restoration performance, particularly where medium voltage feeder redundancy is limited. Improving operational flexibility can reduce outage duration, enhance maintainability, and support effective response to both planned and unplanned events, consistent with ORPC's reliability objectives.

7 Capital Investment Prioritization

This section outlines ORPC's approach to prioritizing substation capital investments by integrating asset condition, system criticality, operational needs, and regional planning considerations.

7.1 Prioritization Objectives

ORPC's capital investment prioritization process is guided by the objective of maintaining a safe, reliable, and resilient distribution system while allocating capital in a disciplined and prudent manner. Generally, investments are directed toward needs that most effectively manage system risk across the substation portfolio.

Priority is placed on addressing safety and compliance issues, particularly where infrastructure presents elevated risk to personnel or does not align with applicable codes, standards, or operating practices. Investments that mitigate safety exposure or support regulatory compliance are considered foundational to system operation.

The prioritization process also seeks to reduce outage consequence by addressing assets and substations whose failure would have the greatest impact on customers, operations, or restoration capability. This includes consideration of asset condition, system criticality, and downstream exposure as identified in earlier sections of this DSP.

Capital planning further supports system reliability and resilience by targeting investments that improve maintainability, restoration performance, and operational flexibility during both planned and unplanned events. Consideration is given to how configuration, protection and control capability, and system visibility influence ORPC's ability to operate and restore the system efficiently.

Finally, ORPC recognizes the value of investments that strengthen future planning. Enhancements to monitoring, protection, control, and communications improve system visibility and data quality, supporting more informed prioritization and more effective deployment of subsequent capital.

In summary, ORPC's capital prioritization objectives are to:

- Address safety and regulatory compliance risks
- Reduce system risk and outage consequence
- Support system reliability, resilience, and restoration capability
- Maintain operational flexibility and adaptability
- Enable informed, risk based capital and maintenance decisions
- Align substation investments with regional planning requirements

7.2 Inputs to Capital Investment Prioritization

Capital investment prioritization for ORPC's substations is informed by a defined set of technical, operational, and planning inputs developed through this DSP. Together, these inputs provide the evidentiary basis for comparing relative investment needs and support transparent, risk informed decision making.

The primary technical input is the asset condition assessment in Section 4. Field inspection findings, observed deficiencies, and equipment age and configuration establish the physical condition of major assets and identify where deterioration or obsolescence may warrant capital intervention.

Criticality classifications from Section 5 provide a second key input by characterizing the relative consequence of asset or substation failure. These classifications reflect each substation's role within the 44 kV supply network, downstream exposure, available feeder redundancy and restoration capability, and connected load served.

The system needs identified in Section 6 translate condition and criticality findings into underlying technical drivers for investment. Capacity exposure, condition and reliability concerns, safety and compliance requirements, and operational flexibility limitations are considered collectively to understand where investment is required.

Capital prioritization is also informed by regional planning and coordination considerations, including IESO initiatives, anticipated upstream developments, and coordination requirements with host utilities. These factors may influence the timing or sequencing of investments to maintain alignment with broader system development.

Operational experience and professional engineering judgment are applied to integrate these inputs and resolve competing priorities. This includes consideration of constructability, maintainability, system interdependencies, and opportunities to coordinate or bundle investments where appropriate.

7.3 Capital Investment Prioritization Framework

ORPC's capital investment prioritization framework translates identified system needs into relative priorities across the substation portfolio in a consistent and transparent manner. The framework integrates technical and operational considerations rather than relying on a single metric or scoring model.

In applying the framework, asset condition is evaluated alongside system consequence. Assets exhibiting advanced age, deterioration, or known deficiencies are assessed in the context of their role within the system, recognizing that similar condition issues may warrant different priority depending on operational impact.

Criticality is a central element of prioritization. Substations and assets whose loss would result in greater outage impact, reduced restoration capability, or heightened operational complexity are assigned higher relative priority than assets serving less exposed portions of the system.

The nature of the underlying system need also influences prioritization. Safety and compliance issues are given particular weight due to their implications for personnel protection and regulatory obligations. Reliability, capacity, operational flexibility, and enabling considerations are assessed in combination, recognizing that these drivers often interact.

Interdependencies between assets and system functions are considered to ensure investments address root causes rather than isolated symptoms. This includes how equipment, protection and control systems, communications infrastructure, and operating practices interact to support overall system performance.

Practical implementation factors are incorporated into the framework, including constructability, opportunities to coordinate related work, outage requirements, and alignment with regional planning activities. Professional engineering judgment is applied to integrate these considerations and resolve competing priorities.

7.4 Enabling and Foundational Investments

While reported within the OEB capital categories in Section 8, ORPC separately recognizes enabling and foundational investments as an important internal planning lens for prioritization.

In addition to investments driven by asset condition or localized system risk, ORPC's capital strategy recognizes the importance of enabling investments that strengthen system performance and planning capability. These investments improve operational effectiveness, system visibility, and decision making quality, and enhance the value of other capital projects across the distribution system.

A primary enabling focus is modernization of protection, control, and communications infrastructure, including SCADA enhancements and relay upgrades. These improvements support more effective monitoring, remote operation, and faster restoration, while reducing reliance on manual intervention during both planned and unplanned events.

Enabling investments also improve ORPC's ability to prioritize, scope, and time future capital and maintenance activities by providing higher quality system data and operational insight. Advancing protection, control, and communications upgrades early in the planning horizon is intended to deliver immediate operational benefits and support more targeted deployment of subsequent capital.

Standardization and modular design initiatives are also recognized as enabling measures. Consistent protection and control designs and repeatable implementation practices reduce execution risk, improve maintainability, and support safer and more efficient delivery of future projects. These benefits apply across the substation portfolio independent of specific asset condition issues.

Improvements in system monitoring, asset information, and supporting infrastructure further strengthen ORPC's planning and asset management capability by improving the quality and availability of technical data used in decision making. While enabling investments may not always correspond to immediate deficiencies, they provide system wide benefits that reinforce condition driven capital planning and are treated as an integral part of ORPC's prioritization framework.

7.5 Priority Classification Categories

To support clear communication of capital priorities, ORPC groups identified investment needs into qualitative classifications that organize relative urgency across the substation portfolio. These categories reflect the combined consideration of asset condition, system criticality, identified system needs, and enabling factors described in preceding sections.

The classifications are intended to distinguish relative project impact and urgency. They do not represent fixed thresholds or prescriptive timelines, but provide a structured way to compare investment needs.

For this DSP, capital needs are grouped as follows:

High Priority Investments

Address needs that present elevated risk to system reliability, safety, or operational performance, particularly where condition concerns coincide with higher system criticality or limited flexibility. These investments typically warrant earlier consideration within the planning horizon.

Moderate Priority Investments

Address needs with material system impact but lower relative consequence or greater operational flexibility. These investments remain important to long term reliability and performance but may be sequenced later in the planning horizon.

Lower Priority or Monitor Investments

Address needs that currently present lower relative risk or system impact, or where uncertainty exists regarding timing or scope. These items are monitored and may advance in priority as conditions evolve.

7.6 Application of the Prioritization Framework

The prioritization framework described above was applied across ORPC's substation portfolio to identify relative investment priorities.

Substations and associated asset classes were reviewed by considering observed asset condition, relative system criticality, and the system needs identified in Section 6. This approach recognizes that similar condition issues may warrant different prioritization depending on consequence of failure, operational flexibility, and each substation's role within the broader system.

Condition findings, criticality classifications, and identified needs were integrated to understand how multiple factors intersect at individual substations. Higher priority was generally assigned where condition concerns coincided with greater system consequence, safety or compliance exposure, or limited ability to mitigate impacts through operational measures.

Regional planning considerations and practical constraints were also incorporated, including coordination requirements with upstream system owners, relevant regional initiatives, outage requirements, constructability, and opportunities to coordinate related work.

7.7 Relationship to Capital Planning and Phasing

The prioritization outcomes inform ORPC's capital planning and sequencing over the DSP horizon.

Higher priority needs are generally aligned with near term planning due to their urgency and potential impact on reliability, safety, or operational performance. Advancement remains subject to coordination requirements, funding availability, and implementation readiness.

Moderate priority needs inform medium term planning. These investments remain important to system performance and resilience but may be advanced as conditions evolve or coordination opportunities arise.

Lower priority or monitor needs are tracked and reconsidered as system conditions change, risks increase, or efficiencies can be achieved by coordinating with other capital work. Ongoing monitoring supports adaptive planning without premature capital commitment.

Capital phasing is further influenced by regional planning considerations, coordination with upstream system owners, funding constraints, outage requirements, and constructability.

7.8 Limitations and Use of Prioritization Results

The prioritization results reflect a planning level application of ORPC's framework based on available asset information and professional engineering judgment. They support relative comparison and sequencing of investment needs rather than defining project scope, cost, or implementation timing.

The framework is intended to be adaptive and may be refined as new information becomes available through future planning cycles. The results inform capital planning discussions and regulatory transparency but do not replace project specific engineering or implementation level analysis.

8 Capital Investment Plan

This section summarizes proposed substation capital investments over the DSP planning horizon. The plan reflects a risk informed approach to addressing identified system needs while balancing reliability, safety, operational performance, and implementation practicality.

8.1 Overview of the Capital Investment Plan

The plan is informed by the asset condition assessment (Section 4), criticality evaluation (Section 5), identified system needs (Section 6), and prioritization framework (Section 7). Together, these inputs establish a structured basis for determining which investment categories warrant attention and how they may be sequenced at a planning level.

The capital plan identifies investment categories and relative timing considerations. Individual projects will be refined and validated through detailed engineering, coordination with external system owners, and future regulatory filings as required.

Investments are organized by asset class and category to provide transparency into the drivers and objectives underlying ORPC's substation strategy. The summary table in Section 8.4 presents planned investments by category and indicative planning period.

8.2 Capital Investment Categories

To support clarity and consistency in capital planning, ORPC organizes substation investments in accordance with the Ontario Energy Board's standard capital investment categories. These categories provide the primary framework for grouping planned work and communicating how capital resources respond to identified system needs.

System Access

This category includes investments required to support new customer connections, system expansions, load transfers, and configuration changes associated with customer growth or third-party infrastructure interfaces. Given the substation-focused scope of this DSP, investments in this category are expected to be limited and primarily driven by external connection requirements.

System Renewal

This category includes renewal, refurbishment, or replacement of substation assets that have reached advanced service life or exhibit condition-related deficiencies. Typical drivers include asset age, deterioration, obsolescence, failure risk, end-of-life equipment, and civil or structural degradation.

System Service

This category includes investments intended to improve system reliability, safety, operational flexibility, restoration capability, protection performance, SCADA visibility, and capacity support. This category captures many modernization and operational improvement initiatives identified through the DSP.

General Plant

This category includes support systems, operational tools, communications infrastructure, engineering data capability, and other non-process facilities that support the safe and effective operation of the substation portfolio.

8.3 Planning Horizon and Phasing Approach

ORPC considers substation investments over the DSP horizon using defined planning bands that reflect relative timing and sequencing rather than fixed implementation schedules. The bands support structured capital planning while preserving flexibility to respond to evolving system conditions.

For this DSP, the planning horizon is organized into the following indicative bands:

- **Nearer term (2027–2028)** — Investments aligned with higher priority needs that address safety, reliability, system risk, or provide enabling benefits across the portfolio
- **Mid term (2029–2030)** — Investments addressing material system needs that may follow higher priority actions or advance as supporting engineering and system readiness progresses
- **Longer term (2031)** — Investments associated with lower priority or emerging needs that are monitored and advanced as conditions evolve

Assignment to planning bands reflects the prioritization framework in Section 7 together with considerations of system readiness and practical implementation.

Some projects may enter the capital plan before detailed engineering is complete. In these cases, planning and prioritization proceed while scope development and implementation planning continue in parallel.

Enabling investments, including protection, control, and system visibility improvements, may be advanced earlier where they provide system wide benefits or strengthen the effectiveness of other capital work.

8.4 Summary of Planned Investments by Category and Planning Considerations

The capital investment plan is summarized at a category level to provide an at a glance view of the types of substation investments anticipated over the DSP horizon and the factors that influence their relative sequencing.

Table 1 organizes investments by category and highlights typical drivers and planning considerations that influence how work within each category may be phased. Individual investments may advance

at different points in the planning horizon based on priority, readiness, and coordination requirements.

Investment Category	Typical Drivers	Planning Horizon Considerations
System Access	Customer connection requirements, new load requests, system configuration changes required to support customer growth or third-party infrastructure interface	Generally project-specific and driven by customer timing, external development schedules, or connection commitments
System Renewal	Asset condition, aging infrastructure, obsolescence, failure risk, end-of-life equipment, civil deterioration	Prioritized based on condition risk, criticality, and prudent lifecycle replacement timing
System Service	Reliability improvement, safety, protection and control modernization, SCADA visibility, system operability, resiliency, capacity support	May be phased over the planning horizon based on risk reduction benefit, operational need, and coordination with renewal projects
General Plant	Support systems, operational tools, communications infrastructure, non-process facilities, engineering data and planning capability	Typically sequenced based on enabling value, operational efficiency, and alignment with field modernization activities

Table 1 - Capital Investment Categories and Planning Considerations

8.5 System Service and Enabling Investments within the Capital Plan

In addition to condition-driven renewal work, ORPC's capital investment plan includes System Service investments that strengthen overall system capability. These investments support operational flexibility, system visibility, restoration performance, and planning effectiveness across the substation portfolio.

Enabling and foundational investments include protection and control modernization, SCADA and communications enhancements, and improvements to system monitoring and data quality. These initiatives are evaluated based on their system wide benefit rather than their association with a single asset deficiency.

Some enabling investments may be advanced earlier in the planning horizon because of their broad operational impact. Improvements in control, visibility, and communications capability can reduce

outage duration, enhance restoration performance, and support safer and more efficient operation across multiple substations, particularly where redundancy or operational flexibility is limited.

These investments also strengthen ORPC's asset management and planning capability by improving the quality and availability of system information. Enhanced monitoring and data support more informed prioritization, reduce uncertainty in future planning cycles, and improve coordination between capital and maintenance programs.

By incorporating enabling and foundational investments into the capital plan, ORPC maintains a balanced strategy that addresses immediate needs while building the capabilities required for long term reliability, resilience, and adaptive planning.

8.6 Alignment with Regional Planning and Coordination Requirements

ORPC's substation capital investment plan is developed with awareness of the broader regional planning environment in which its distribution system operates, including upstream supply arrangements and coordination requirements with external system owners whose facilities interface with ORPC substations.

Substation investments may be influenced by external system developments such as upstream configuration changes, regional load growth, or reinforcement initiatives. Where relevant, these factors are considered when sequencing investments to ensure compatibility with the surrounding network.

Coordination with upstream system owners and other stakeholders is particularly important where outages, supply interfaces, or shared infrastructure affect constructability or implementation. The capital plan maintains flexibility to accommodate these coordination requirements as they are identified through ongoing planning and operational engagement.

8.7 Capital Plan Implementation Context

The substation capital investment plan provides a planning level framework for organizing potential investments over the DSP horizon. It informs strategic planning and regulatory discussion but does not define detailed project scope, schedules, or funding approvals.

Investment priorities and timing may be refined over time as system conditions, operational experience, and external requirements evolve. Individual projects will undergo detailed engineering

and coordination prior to implementation. The capital plan supports future business case development and cost of service filings by linking identified system needs to proposed investments while preserving flexibility at the project level.

9 Section 9 – Financial Overview

This section provides a financial overview of the substation capital investments identified in this DSP. Its purpose is to illustrate the order of magnitude scale, distribution, and sequencing of anticipated investments over the 2027–2031 horizon and confirm alignment between system needs, prioritization outcomes, and capital planning.

Estimates are provided at an order of magnitude level to support planning discussions and internal coordination. Advancement of individual projects remains subject to scope refinement, engineering validation, coordination, funding availability, and ORPC governance and regulatory processes.

This section is limited to aggregate and categorical financial information. Project level details, including indicative costs and timing assumptions, are presented in Appendix D.

9.1 Aggregate Capital Outlook by Planning Window

Based on application of the prioritization framework in Section 7, anticipated substation capital investments are distributed across the DSP horizon to reflect relative urgency, system consequence, and implementation readiness.

At a planning level, investments are grouped into near term, mid term, and longer term windows. Higher priority projects, including safety, compliance, and enabling investments, are concentrated in earlier periods. Moderate and lower priority work is sequenced into later windows to allow refinement as system conditions evolve.

The resulting capital profile shows earlier spending focused on risk mitigation and foundational system improvements, with later periods retaining flexibility to address emerging needs and coordination opportunities.

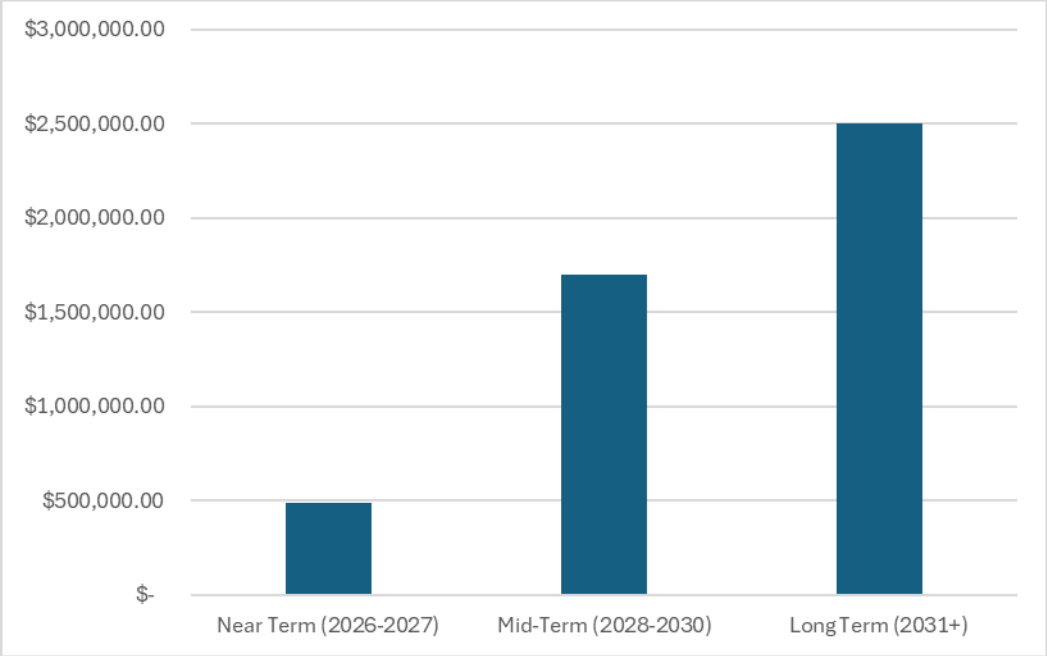


Figure 7 - Indicative Substation Capital Outlook by Planning Window

Each bar in the figure represents the aggregate planning level capital outlook for the window.

The larger total shown in the longer term window reflects the inclusion of contingent and monitor level projects intentionally deferred for future refinement, rather than an accumulation of unresolved near term risk.

9.2 Capital Distribution by Investment Category

Planned substation investments are distributed across the OEB capital categories identified in Section 8: System Access, System Renewal, System Service, and General Plant.

At an aggregate level, the distribution reflects the system needs identified in Sections 4 through 6, while recognizing that not all needs require capital intervention. A significant portion of anticipated investment is associated with System Renewal, consistent with condition findings that identified advanced age, deterioration, and obsolescence across several major asset groups., consistent with condition findings that identified advanced age, deterioration, or obsolescence across several major asset groups, including medium voltage switchgear, grounding systems, civil and structural elements, and certain 44 kV equipment.

Safety and compliance needs are primarily reflected within System Service and, where asset replacement is required, System Renewal. In the assessment; however, many inspection related

issues are more appropriately addressed through maintenance and corrective programs rather than capital work. Capital in this category is focused on needs that require asset replacement, configuration change, or permanent infrastructure modification, such as clearance remediation, grounding upgrades, or integration of safety improvements within broader renewal projects.

Investments related to protection, control, SCADA modernization, and system visibility are primarily classified as System Service, reflecting their role in improving reliability, operational flexibility, and restoration performance. These investments support improved prioritization, maintenance targeting, and execution of future renewal and enhancement projects.

Capacity and performance-related investments are primarily reflected within System Service and, where customer-driven, System Access. These investments remain subject to refinement as additional system information becomes available and as regional planning and load evolution are clarified.

9.3 Alignment with Priority and Risk

The financial outlook is designed to align with the qualitative priority classifications established in Section 7.

The placement of enabling and foundational investments in earlier windows reflects their role in improving protection, control, communications, and system visibility. These improvements support asset monitoring, event diagnosis, and restoration coordination, and contribute to more effective deployment of future capital and maintenance activity.

Overall, the financial profile is consistent with the relative distribution of system risk and consequence identified in earlier sections and reflects the sequencing approach applied across the substation portfolio.

9.4 Cost Basis and Uncertainty

Cost estimates used for planning are derived from ORPC historical project experience, recent substation work, industry benchmarks, and professional engineering judgment applied at a conceptual level. The estimates reflect indicative scopes developed for comparative planning and prioritization rather than detailed, execution ready definitions.

The estimates represent order of magnitude expectations and are subject to uncertainty. Actual costs will vary as scope is refined, asset specific conditions are confirmed, and detailed engineering is completed.

Final cost and timing will also depend on constructability, outage and coordination requirements, market conditions, and alignment with upstream system owner activities. The distinction between capital and maintenance work may further influence project scope and cost allocation as projects advance.

These factors will be resolved through subsequent engineering, budgeting, and capital approval processes prior to implementation.

9.5 Relationship to Capital Planning and Future Filings

This financial overview supports ORPC's broader capital planning and regulatory transparency. The DSP provides planning context but does not replace future capital planning processes, rate applications, or project specific justification as investments advance.

Project scope, cost, and timing will be refined through detailed engineering and governance processes. The financial outlook may be updated in future planning cycles as system conditions and priorities evolve.

10 Coordination and Stakeholder Considerations

This section summarizes coordination considerations relevant to ORPC's substation planning, with emphasis on system interfaces, upstream system owners, and external dependencies that may influence the scope or sequencing of capital investments. The purpose is to describe how coordination is incorporated into prudent planning rather than to prescribe specific outcomes or commitments.

10.1 Coordination with Upstream System Owners

ORPC's distribution substations interface with upstream 44 kV systems owned by external entities including Hydro One Transmission, Brookfield, and Hydro Québec. These interfaces require coordination related to outages, protection, construction sequencing, and system access.

Although ORPC owns portions of its 44 kV infrastructure, coordination with upstream system owners is necessary to execute substation work safely and efficiently. In most cases these requirements are

routine and do not materially limit ORPC's ability to advance prioritized investments. Planning activities account for interface considerations to maintain alignment with upstream operations and avoid conflicts with external work.

A limited number of substations include more complex interface arrangements. In particular, Pembroke MS #4 includes 44 kV tie-in breakers that introduce shared interface considerations and may require enhanced coordination with upstream system owners when planning capital modifications. These interface characteristics are reflected in planning level assessments of scope and sequencing where relevant.

10.2 Protection, Outage, and Construction Coordination

Substation capital projects may require planned outages, temporary reconfiguration, or protection and control adjustments. ORPC incorporates these requirements into planning, recognizing that outage and commissioning activities involve coordination with internal stakeholders and, where applicable, upstream system owners.

In most cases, outage and protection coordination does not alter relative investment priority. Where substation work coincides with major distribution or externally driven projects, coordination considerations may influence preferred timing or sequencing to reduce operational disruption and construction complexity.

10.3 Alignment with Regional Planning Initiatives

ORPC monitors relevant regional planning initiatives, including Integrated Regional Resource Plans, as contextual inputs to substation planning. These processes are used to identify potential coordination requirements and circumstances where upstream developments could affect the scope or timing of ORPC owned investments.

In limited cases, regional considerations may influence project scope to maintain compatibility with anticipated upstream system changes or to avoid premature investment. However, these factors do not supersede asset condition, safety, or operational risk drivers identified through ORPC's internal assessments.

10.4 Municipal and Local Coordination Considerations

Municipal coordination can influence substation planning where projects extend beyond existing station footprints or involve site access, civil works, or adjacent infrastructure. These considerations are more prominent in the Almonte service area, where development activity and growth pressures are comparatively higher.

Where work is confined to existing facilities and established boundaries, municipal coordination requirements are typically limited. Projects involving expansion, reconfiguration, or external works are planned with awareness of municipal processes and development timelines to maintain compatibility with local planning objectives and permitting requirements.

10.5 Internal Coordination and Integration with Maintenance Planning

Effective substation planning relies on coordination between ORPC's operations and maintenance functions. Condition assessments, inspection findings, and operational experience are shared across internal groups to ensure issues are addressed through the appropriate mix of maintenance, corrective repair, or capital investment.

This coordination aligns capital planning with maintenance programs and helps ensure capital resources are focused on needs that cannot be managed through routine maintenance alone. Integration of operational insight also supports more accurate scoping and timing of investments as projects advance.

10.6 Implications for Capital Timing and Flexibility

Coordination considerations described in this section may influence the timing and sequencing of individual substation investments but generally do not prevent ORPC from addressing higher-priority system needs. In some cases, projects may be deferred or advanced to align with major distribution line capital work or upstream system activities, even where asset condition or system risk would otherwise support earlier implementation.

These considerations reinforce the need to maintain flexibility within planning windows and to avoid rigid scheduling assumptions at the DSP stage. ORPC's planning approach is structured to accommodate coordination requirements while preserving the ability to respond to emerging system needs and changing external conditions.

11 Conclusions and Next Steps

11.1 Conclusions

This substation-focused DSP provides a structured, planning level assessment of ORPC's distribution substations over the 2027–2031 planning horizon. The DSP applies a qualitative, risk informed approach to asset condition, system criticality, and needs identification, and establishes a defensible framework for prioritizing substation investments.

The assessment indicates that ORPC's substation risk is manageable, but that a significant portion of the substation asset base is aging and increasingly susceptible to condition-related degradation, obsolescence, and unplanned failures. In several cases, asset age and configuration increase the likelihood that deterioration will manifest as operational disruptions rather than gradual performance decline. These findings underscore the importance of proactive planning and timely intervention to reduce the risk of unplanned outages and escalating maintenance burden.

The DSP also confirms that not all identified needs require capital investment. Many safety- and condition-related observations can be, and are appropriately, addressed through ORPC's maintenance and corrective repair programs. Capital investment is therefore focused on needs that cannot be effectively mitigated through maintenance alone, including asset renewal, permanent safety and compliance remediation, configuration improvements, and enabling system upgrades.

Clear differences between ORPC's service areas further inform planning conclusions. The Pembroke substations reflect a broader mix of asset vintages and system configurations, with condition and reliability considerations playing a more prominent role in prioritization. In contrast, the Almonte substations are influenced by comparatively stronger growth and development pressure, warranting continued monitoring of capacity, configuration flexibility, and future load evolution, including potential electrification-driven demand changes.

A central conclusion of this DSP is the importance of enabling and foundational investments, particularly in protection, control, and SCADA systems. These investments are not only operationally beneficial, but also critical to improving system visibility, data quality, and diagnostic capability. Advancing these upgrades early supports more informed prioritization, more effective maintenance targeting, and greater confidence in future capital planning decisions.

Overall, the DSP establishes a coherent, proportionate, and defensible basis for substation capital planning, aligned with ORPC's operating realities and external coordination requirements.

11.2 Recommended Next Steps

To carry forward the outcomes of this DSP, the following recommended actions and anticipated activities are identified:

- **Advance detailed engineering and design for protection, control, and SCADA upgrades**, with priority placed on initiatives that improve system visibility, event diagnostics, and asset performance data. These upgrades will support more data-driven planning and asset management in future DSP cycles while complementing the planning level analysis presented in this report.
- **Proceed with refinement and validation of higher-priority capital projects** through detailed engineering, constructability review, and coordination with operations and maintenance groups, recognizing that project scope and timing may evolve as additional information becomes available.
- **Continue coordination with upstream system owners and external stakeholders**, including regular engagement to align outage planning, protection coordination, and construction sequencing, particularly where substation projects interface with externally owned 44 kV infrastructure.
- **Monitor growth and electrification trends**, with particular attention to the Almonte service area, to identify emerging capacity or configuration needs and to inform future planning updates as development patterns and load characteristics evolve.
- **Enhance asset information and data integration**, leveraging improvements enabled through protection and SCADA modernization to support more granular condition assessment, performance monitoring, and future risk evaluation.

Supporting technical detail, including asset inventories, inspection summaries, and system data used to inform the condition, criticality, and planning assessments, is provided in the appendices to this report.

11.3 Relationship to Future Planning

The findings and framework established through this substation-focused DSP are intended to inform future capital planning, detailed engineering activities, and subsequent DSP updates. As projects advance toward implementation, they will be subject to ORPC's internal governance processes, detailed scope definition, and applicable capital approval mechanisms.

The DSP provides a foundation for adaptive planning. As system conditions, asset performance, data availability, and regional planning outcomes evolve, the prioritization and capital outlook described herein may be refined through future planning cycles, studies, and filings. This approach supports prudent system stewardship while maintaining flexibility to respond to changing conditions and emerging needs.

APPENDIX A – SUPPORTING ASSET CONDITION DOCUMENTATION

Relationship Between Supporting Documentation and DSP Condition Assessments

The documents included in this appendix provide the technical basis for the asset condition assessments presented in this Distribution System Plan and include:

- Traceability Summary Tables
- Engineering Evaluation Summaries prepared by Rockwood Engineering
- Field inspection reports prepared by Synergy Power Ltd.
- Transformer oil sample and dissolved gas analysis (DGA) reports

Together, these documents form the evidentiary basis used to support the planning-level condition and risk assessments within the DSP.

The Synergy Power inspection reports provide detailed, component-level visual observations of substation equipment and site conditions at the time of inspection. These reports document observed deficiencies, equipment condition indicators, and site-specific issues identified through non-invasive field review.

The oil sample and DGA reports provide diagnostic information specific to transformer internal condition and oil quality and are used to inform assessment of transformer health, maintenance requirements, and potential degradation mechanisms.

The Engineering Evaluation Summaries prepared by Rockwood Engineering serve as the primary synthesis layer between these technical inputs and the planning-level conclusions presented in the DSP. These evaluations integrate the Synergy inspection findings, oil test results, available ORPC records, asset age and configuration, operational context, and relevant utility engineering experience to establish a consistent planning-level view of asset condition and lifecycle risk for each substation.

To improve traceability and auditability of the planning conclusions, Appendix A also includes concise Traceability Summary Tables prepared by Rockwood Engineering for each substation assessment. These tables provide a simplified line of sight between key inspection

observations, diagnostic information, engineering interpretation, and the resulting operational, maintenance, or capital planning response reflected within the DSP.

The asset condition ratings and capital planning conclusions presented in the main body of this DSP are based primarily on the integrated engineering synthesis documented in the Engineering Evaluation Summaries, rather than on any individual inspection observation or diagnostic result in isolation.

The DSP reflects a portfolio level planning assessment derived from the Engineering Evaluation Summaries, which bridge detailed field observations and supporting diagnostic data into a consistent framework for comparative condition assessment, risk evaluation, and capital prioritization across ORPC's substation portfolio.

Discrete deficiencies identified within the supporting documentation may be addressed through operations and maintenance programs, targeted corrective work, or localized capital projects independent of broader asset renewal timing.

APPENDIX A – TRACEABILITY SUMMARY TABLES

PEMBROKE – MS#1						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Legacy protection, control, and SCADA systems provide limited operational visibility and are increasingly difficult to support and integrate with modern utility monitoring practices	Engineering Evaluation Summary / ORPC Operational Feedback	Improved system visibility, operational awareness, and data collection capability are required to support effective operations and future asset management decisions	Reduced operational visibility, limited system monitoring capability, and increasing obsolescence of protection and control infrastructure	Modernize protection, control, SCADA, and communications systems (STN001)	Enabling Modernization	High
Existing 44 kV oil circuit breakers and associated switching equipment exhibit age-related deterioration, oil leakage, and declining maintainability	Synergy Inspection / Engineering Evaluation Summary	Aging high-voltage switching infrastructure presents increasing lifecycle and maintenance challenges; however, system consequence is moderated by the station's looped supply configuration	Increasing maintenance burden, reduced long-term supportability, and elevated risk of future equipment failure	Renew 44 kV switching infrastructure (STN011)	Capital Renewal	Low
Legacy 5 kV switchgear remains in service and exhibits increasing obsolescence, maintenance burden, and declining long-term supportability	Engineering Evaluation Summary / Synergy Inspection	Modernization would improve reliability, safety, maintainability, and operational flexibility while reducing reliance on aging equipment	Increased maintenance complexity, reduced availability of replacement components, and elevated long-term lifecycle risk	Replace legacy 5 kV switchgear with modern GIS equipment (STN012)	Capital Renewal	Moderate
Transformer oil testing and DGA results do not indicate active internal deterioration	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation within the planning horizon	No evidence of active internal degradation requiring immediate intervention	Continue routine oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor
Localized grounding, site condition, and station maintenance deficiencies were identified during inspection	Synergy Inspection	Deficiencies are localized in nature and do not presently drive major capital investment requirements	Potential for gradual deterioration of safety, reliability, or maintainability if not addressed through routine work programs	Complete corrective maintenance and ongoing inspection activities as required	Corrective Maintenance	Moderate

APPENDIX A – TRACEABILITY SUMMARY TABLES

PEMBROKE – MS#2						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Legacy 5 kV switchgear remains in service and exhibits increasing obsolescence, maintenance burden, and declining long-term supportability	Engineering Evaluation Summary / Synergy Inspection	Aging switchgear infrastructure presents increasing lifecycle risk and reduced long-term maintainability	Increased maintenance complexity, reduced equipment supportability, and elevated long-term reliability risk	Replace legacy 5 kV switchgear with modern GIS equipment (STN013)	Capital Renewal	Moderate
Localized deterioration of tower foundations and supporting civil infrastructure was identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Civil deterioration represents the most significant non-electrical condition concern at the station	Progressive deterioration may increase maintenance requirements and structural risk if left unaddressed	Complete targeted corrective maintenance and civil remediation activities	Corrective Maintenance	Moderate
Legacy protection, control, and SCADA systems provide limited operational visibility and are increasingly difficult to support and integrate with modern utility monitoring practices	Engineering Evaluation Summary / ORPC Operational Feedback	Modern operational monitoring, protection functionality, and system visibility are required to support reliable operation and future asset management decisions	Reduced operational awareness, limited event visibility, reduced data availability, and increasing obsolescence risk	Modernize protection, control, SCADA, and communications systems (STN002)	Enabling Modernization	High
Transformer oil testing and DGA results indicate acceptable oil quality and no evidence of active internal fault mechanisms	DGA Reports / Engineering Evaluation Summary	Transformer remains suitable for continued service within the planning horizon	No indication of active internal deterioration requiring capital intervention	Continue routine oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor
Primary transformer and grounding systems were found to be generally satisfactory for continued operation	Synergy Inspection / Engineering Evaluation Summary	Core station functionality remains stable despite localized infrastructure deficiencies	No significant reliability concerns presently identified for primary equipment systems	Continue routine inspection and maintenance activities	Operations & Maintenance	Lower / Monitor

APPENDIX A – TRACEABILITY SUMMARY TABLES

PEMBROKE – MS#3						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Existing protection, control, and SCADA systems are of legacy vintage and station SCADA is non-functional	Engineering Evaluation Summary / ORPC Feedback	Modern operational monitoring and control capabilities are required to improve system visibility, operational supportability, and future asset management decision making	Reduced operational awareness, limited monitoring capability, and increasing obsolescence of control infrastructure	Modernize protection, control, SCADA, and communications systems (STN003)	Enabling Modernization	High
Legacy indoor 5 kV switchgear remains operable but is approaching the later stages of its service life, resulting in increasing lifecycle management complexity and reduced long-term supportability	Engineering Evaluation Summary	Aging switchgear infrastructure presents increasing lifecycle and maintainability challenges typical of equipment of this vintage	Increased maintenance complexity, declining equipment supportability, and elevated long-term lifecycle risk	Replace legacy 5 kV switchgear with modern GIS equipment (STN014)	Capital Renewal	Low
Localized grounding and bonding deficiencies associated with transformer installation were identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Progressive exterior deterioration of transformer tank surfaces and associated bus structures was identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Deterioration is primarily external in nature and does not presently indicate internal transformer condition concerns	Continued deterioration may increase future maintenance requirements and corrosion-related repair needs	Complete targeted surface rehabilitation, corrosion control, and maintenance activities	Corrective Maintenance	Moderate
Transformer dissolved gas analysis and oil quality testing indicate stable internal condition and normal aging characteristics	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation within the planning horizon	No evidence of active internal deterioration or abnormal fault development	Continue routine oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor

APPENDIX A – TRACEABILITY SUMMARY TABLES

PEMBROKE – MS#4						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Legacy 44 kV oil circuit breakers exhibit oil leakage, evidence of low oil level conditions, and deterioration of legacy control wiring has contributed to breaker misoperation during operation	Engineering Evaluation Summary / ORPC Feedback	Observed condition and operational performance issues indicate advanced lifecycle degradation of critical 44 kV switching infrastructure supporting a primary supply function	Increasing probability of breaker failure, reduced operational reliability, increased maintenance burden, and elevated restoration risk associated with aging high-voltage switching equipment	Replace existing 44 kV switching infrastructure with modern metal-enclosed switchgear (STN015)	Capital Renewal	High
Legacy 5 kV switchgear has experienced intermittent mechanical interlock failures resulting in extended troubleshooting and restoration delays during recent operational activities	Engineering Evaluation Summary / ORPC Feedback	Demonstrated operational reliability concerns confirm increasing lifecycle risk associated with aging medium-voltage switchgear infrastructure	Increased restoration complexity, declining reliability, increased maintenance intervention requirements, and elevated long-term lifecycle risk	Replace legacy 5 kV switchgear with modern GIS equipment (STN016)	Capital Renewal	Moderate
Localized grounding and bonding deficiencies were identified on transformers and primary switching equipment during inspection	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Visible external deterioration of transformer surfaces, tower structures, and station infrastructure was identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Deterioration is primarily external in nature and does not presently indicate significant loss of equipment functionality	Continued deterioration may increase future maintenance requirements and corrosion-related repair needs	Complete targeted corrosion mitigation, surface rehabilitation, and maintenance activities	Corrective Maintenance	Moderate
Vegetation encroachment was observed within portions of the station yard	Synergy Inspection	Vegetation management deficiencies represent routine station maintenance requirements	Potential interference with access, inspection activities, and long-term asset preservation if not addressed	Complete vegetation removal and ongoing yard maintenance activities	Corrective Maintenance	Lower / Monitor
Safety compliance deficiencies including expired emergency equipment and labeling deficiencies were identified during inspection	Synergy Inspection	Deficiencies are administrative and compliance-related rather than indicative of broader asset condition concerns	Localized safety and compliance exposure if corrective action is delayed	Update emergency equipment, signage, and labeling through routine maintenance activities	Corrective Maintenance	Moderate
Transformer dissolved gas analysis and oil quality testing indicate normal internal condition; however, dielectric breakdown strength is below recommended limits	DGA Reports / Engineering Evaluation Summary	Diagnostic information supports continued operation, although oil maintenance may improve long-term dielectric performance	Reduced insulation margin if oil condition continues to deteriorate without corrective maintenance	Consider oil processing or dehydration and continue routine oil testing and DGA monitoring	Monitoring & Assessment	Moderate

APPENDIX A – TRACEABILITY SUMMARY TABLES

PEMBROKE – MS#5						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Existing protection, control, and SCADA systems are of legacy vintage and station SCADA is non-functional	Engineering Evaluation Summary / ORPC Feedback	Modern operational monitoring and control capabilities are required to improve system visibility, operational supportability, and future asset management decision making	Reduced operational awareness, limited monitoring capability, increased restoration complexity, and growing obsolescence of control infrastructure	Modernize protection, control, SCADA, and communications systems (STN004)	Enabling Modernization	High
Grounding and bonding deficiencies were identified during inspection requiring corrective action to maintain safety compliance	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Localized corrosion and external deterioration were observed on station structures and equipment surfaces	Synergy Inspection / Engineering Evaluation Summary	Deterioration is primarily external in nature and does not presently indicate significant equipment condition concerns	Continued deterioration may increase future maintenance requirements and corrosion-related repair needs	Complete targeted corrosion mitigation, surface rehabilitation, and maintenance activities	Corrective Maintenance	Moderate
General station housekeeping and vegetation management deficiencies were noted during inspection	Synergy Inspection	Housekeeping observations represent routine maintenance requirements rather than asset condition concerns	Potential interference with access, inspections, and long-term asset preservation if not addressed	Complete vegetation management and routine station maintenance activities	Corrective Maintenance	Lower / Monitor
Transformer oil testing indicates acceptable overall condition with no evidence of active internal fault mechanisms; however, dielectric breakdown strength is below recommended limits	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation, although maintenance intervention is warranted to improve dielectric performance	Reduced insulation margin if oil condition continues to deteriorate without corrective maintenance	Perform oil processing, filtration, or dehydration as required and continue routine oil testing and DGA monitoring	Monitoring & Assessment	Moderate
Legacy 5 kV switchgear remains serviceable and supportable, with condition and supportability superior to several peer stations in the portfolio	Engineering Evaluation Summary	Continued component availability and absence of significant deterioration moderate the need for near-term renewal investment	Increasing lifecycle management complexity over the longer term, but no immediate renewal driver identified	Continue condition monitoring and lifecycle assessment as part of future planning cycles	Monitoring & Assessment	Lower / Monitor

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PEMBROKE – MS#6						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Absence of a station load totalization meter limits station-level monitoring and loading visibility	Engineering Evaluation Summary	Improved station-level monitoring is required to support operational awareness, loading assessment, and future planning activities	Reduced monitoring granularity, reduced confidence in loading assessments, and limitations in planning data quality	Install station load totalization metering (STN005)	Enabling Modernization	Moderate
Localized structural deterioration associated with pole-mounted primary equipment supports was identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Condition issue is localized and does not presently indicate broader infrastructure degradation	Progressive deterioration may increase future maintenance requirements and structural repair needs if left unaddressed	Complete targeted structural repairs and maintenance activities	Corrective Maintenance	Moderate
Grounding and bonding deficiencies requiring remediation were identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Minor environmental deterioration of transformer surfaces and secondary bus duct was observed	Synergy Inspection / Engineering Evaluation Summary	Deterioration is primarily cosmetic and external in nature with no indication of significant equipment condition concerns	Continued deterioration may increase future maintenance requirements and corrosion-related repair needs	Complete targeted corrosion mitigation, surface rehabilitation, and maintenance activities	Corrective Maintenance	Lower / Monitor
Transformer dissolved gas analysis and oil quality testing indicate normal internal condition; however, dielectric breakdown strength is below recommended limits	DGA Reports / Engineering Evaluation Summary	Diagnostic information supports continued operation, although oil maintenance may improve long-term dielectric performance	Reduced insulation margin if oil condition continues to deteriorate without corrective maintenance	Consider oil processing or dehydration and continue routine oil testing and DGA monitoring	Monitoring & Assessment	Moderate
Indoor 5 kV switchgear remains serviceable and in good overall condition with no significant inspection-identified deterioration	Synergy Inspection / Engineering Evaluation Summary	Existing switchgear remains operationally supportable and does not presently represent a renewal driver	No material near-term lifecycle or reliability concern identified	Continue routine maintenance, monitoring, and lifecycle assessment	Monitoring & Assessment	Lower / Monitor
Recently modernized protection and SCADA infrastructure is functioning as intended	ORPC Feedback / Engineering Evaluation Summary	Recent modernization materially improves operational visibility, reliability, and long-term supportability	No significant operational or lifecycle concerns identified	Continue routine maintenance and monitoring	Monitoring & Assessment	Lower / Monitor

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PEMBROKE – MS#7						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Existing protection, control, and SCADA systems are of legacy vintage and station SCADA is unreliable	Engineering Evaluation Summary / ORPC Feedback	Modern operational monitoring and control capabilities are required to improve system visibility, operational supportability, and future asset management decision-making	Reduced operational awareness, limited monitoring capability, increased reliance on manual intervention, and growing obsolescence of control infrastructure	Modernize protection, control, SCADA, and communications systems (STN006)	Enabling Modernization	High
Legacy 44 kV air-break switches and associated motor operators exhibit age-related mechanical degradation and environmental exposure consistent with increasing lifecycle risk	Engineering Evaluation Summary	Aging switching infrastructure presents increasing operability, maintainability, and long-term supportability concerns	Increased maintenance burden, reduced switching reliability, potential restoration delays, and elevated operational risk during contingency events	Replace legacy 44 kV air-break switches and motor operators (STN017)	Capital Renewal	Moderate
Grounding and bonding deficiencies were identified, including missing transformer bonding and perimeter bonding concerns	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues, particularly given the grounding system renewal completed in 2016	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Environmental deterioration of transformer surfaces including fading paint and surface corrosion was observed during inspection	Synergy Inspection / Engineering Evaluation Summary	Deterioration is primarily external in nature and does not presently indicate internal transformer condition concerns	Continued deterioration may increase future maintenance requirements and corrosion-related repair needs	Complete targeted corrosion mitigation, surface rehabilitation, and maintenance activities	Corrective Maintenance	Moderate
Minor condition issues were identified on pole-mounted primary equipment, including insulator contamination	Synergy Inspection / Engineering Evaluation Summary	Localized equipment condition concerns are manageable through routine maintenance activities	Potential increase in maintenance requirements and reduced equipment performance if deterioration progresses	Complete targeted cleaning, inspection, and corrective maintenance activities	Corrective Maintenance	Lower / Monitor
Station housekeeping and safety equipment compliance deficiencies were identified during inspection	Synergy Inspection	Deficiencies are administrative and maintenance-related rather than indicative of broader asset condition concerns	Localized safety and compliance exposure if corrective action is delayed	Correct deficiencies through routine maintenance and compliance programs	Corrective Maintenance	Moderate
Transformer dissolved gas analysis and oil quality testing indicate normal internal condition and acceptable oil quality	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued transformer operation within the planning horizon	No evidence of active internal deterioration or abnormal fault development	Continue routine oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor
Indoor medium-voltage switchgear remains serviceable and operationally supportable with no significant inspection-identified deterioration	Synergy Inspection / Engineering Evaluation Summary	Existing switchgear remains operationally supportable and is not presently a renewal driver	No material near-term lifecycle or reliability concern identified	Continue routine maintenance, monitoring, and lifecycle assessment	Monitoring & Assessment	Lower / Monitor

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PEMBROKE – MS#8						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Progressive settlement of the main transformer foundation toward the adjacent embankment has required temporary shimming to maintain acceptable transformer termination alignment	Engineering Evaluation Summary / ORPC Feedback	Foundation instability represents a localized but significant civil infrastructure risk affecting a critical station asset	Increasing risk to transformer mechanical integrity, conductor stress, equipment alignment, and long-term operational reliability if settlement continues	Stabilize transformer foundation and renew associated secondary conductor infrastructure (STN018)	Capital Renewal	Moderate
Localized grounding and bonding deficiencies associated with station structures were identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Perimeter security and labeling deficiencies typical of aging outdoor installations were identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Deficiencies are localized and administrative in nature rather than indicative of broader asset condition concerns	Localized safety, security, and compliance exposure if corrective action is delayed	Update labeling, signage, and perimeter security measures through routine maintenance activities	Corrective Maintenance	Moderate
Transformer external condition indicators require preventative maintenance attention	Synergy Inspection / Engineering Evaluation Summary	Observed deterioration is external in nature and does not presently indicate internal transformer condition concerns	Continued deterioration may increase future maintenance requirements and corrosion-related repair needs	Complete targeted surface rehabilitation, corrosion control, and preventative maintenance activities	Corrective Maintenance	Moderate
Vegetation management and minor civil maintenance requirements were identified during inspection	Synergy Inspection	Observations represent routine maintenance requirements rather than asset condition concerns	Potential interference with access, inspections, and long-term asset preservation if not addressed	Complete vegetation management and routine civil maintenance activities	Corrective Maintenance	Lower / Monitor
Transformer dissolved gas analysis and oil quality testing indicate normal internal condition and expected aging characteristics	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued transformer operation within the planning horizon	No evidence of active internal deterioration or abnormal fault development	Continue annual oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor
Protection and SCADA systems have been recently modernized and remain operationally supportable	Engineering Evaluation Summary / ORPC Feedback	Recent modernization materially improves operational visibility, reliability, and lifecycle supportability	No significant operational or lifecycle concerns identified	Continue routine maintenance, monitoring, and lifecycle assessment	Monitoring & Assessment	Lower / Monitor

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ALMONTE – MS#1						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Absence of a substation load totalization meter limits alignment with current operational monitoring standards and constrains system level visibility	Engineering Evaluation Summary	Improved station-level monitoring is required to support operational awareness, loading assessment, and future planning activities across the substation portfolio	Reduced monitoring granularity, reduced confidence in loading assessments, and limitations in planning data quality	Install substation load totalization metering and associated instrumentation (STN007)	Enabling Modernization	Moderate
Indoor gas-insulated switchgear installation requires verification that gas monitoring, ventilation, alarm integration, and personnel safety provisions remain aligned with current industry standards	Engineering Evaluation Summary	Verification supports ongoing asset stewardship and modernization completion activities associated with indoor GIS installations	Potential operational and safety risks if supporting systems are not maintained consistent with applicable standards	Complete engineering review of GIS monitoring, ventilation, alarm integration, and operational response provisions	Monitoring & Assessment	Moderate
Localized civil and structural deterioration consistent with environmental exposure was observed during inspection	Synergy Inspection / Engineering Evaluation Summary	Deterioration is localized in nature and does not presently affect electrical operability	Continued deterioration may increase future maintenance requirements and localized repair needs	Complete targeted civil repairs and corrective maintenance activities	Corrective Maintenance	Moderate
Transformer dissolved gas analysis indicates elevated ethane concentration; however, diagnostic indicators remain consistent with normal insulation aging and no active fault development	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation while warranting continued trending and monitoring	Potential for emerging thermal-related issues if gas concentrations increase over time	Continue periodic DGA monitoring and review transformer loading, cooling performance, and oil circulation condition	Monitoring & Assessment	Lower / Monitor
Primary electrical equipment, protection systems, and monitoring infrastructure are generally consistent with a recently modernized installation and remain serviceable	Synergy Inspection / Engineering Evaluation Summary	Recent modernization materially reduces lifecycle risk exposure relative to other substations in the portfolio	No significant operational or lifecycle concerns identified	Continue routine maintenance, monitoring, and lifecycle assessment	Monitoring & Assessment	Lower / Monitor

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ALMONTE – MS#2						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Station lacks fully integrated SCADA monitoring capability, including local data aggregation, load totalization metering, and communications integration	Engineering Evaluation Summary	Modern operational monitoring capabilities are required to improve system visibility, operational supportability, and future asset management decision-making	Reduced operational awareness, limited monitoring capability, reduced planning data quality, and increased reliance on manual monitoring activities	Implement local data aggregation, load totalization metering, and SCADA communications integration (STN008)	Enabling Modernization	High
Significant deterioration of sub-transmission tower foundations was identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Progressive deterioration of structural support infrastructure represents the most significant condition-related risk at the station	Increasing structural reliability risk, potential impacts to equipment support systems, and elevated long-term operational risk if deterioration continues	Reconstruct affected sub-transmission tower foundations (STN021)	Capital Renewal	Moderate
Indoor medium-voltage switchgear remains serviceable and operationally supportable with no significant inspection-identified deterioration	Synergy Inspection / Engineering Evaluation Summary	Existing switchgear remains operationally supportable and does not presently represent a renewal driver	No material near-term lifecycle or reliability concern identified	Continue routine maintenance, monitoring, and lifecycle assessment	Monitoring & Assessment	Lower / Monitor
Primary transformer and grounding systems were observed to be in satisfactory condition	Synergy Inspection / Engineering Evaluation Summary	Available inspection findings support continued operation within the planning horizon	No significant condition-related risk identified	Continue routine maintenance and condition monitoring practices	Monitoring & Assessment	Lower / Monitor
Transformer dissolved gas analysis and oil quality testing indicate stable internal condition with no evidence of active fault mechanisms; however, dielectric strength remains below preferred thresholds	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation while warranting continued monitoring of oil condition	Reduced insulation margin if oil quality continues to deteriorate without maintenance intervention	Continue routine oil testing, DGA monitoring, and maintenance surveillance	Monitoring & Assessment	Moderate
Overall station configuration reflects a legacy physical design generation but core electrical equipment remains generally stable and serviceable	Engineering Evaluation Summary	Legacy station design contributes to lifecycle management considerations but does not presently drive additional renewal requirements	Long-term maintainability considerations typical of stations of similar vintage	Continue routine maintenance, monitoring, and lifecycle planning activities	Monitoring & Assessment	Lower / Monitor

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ALMONTE – MS#3						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Protection and control systems remain of legacy design generation and no SCADA monitoring capability is currently implemented at the station	Engineering Evaluation Summary / ORPC Feedback	Modern operational monitoring and control capabilities are required to improve system visibility, operational supportability, and future asset management decision-making	Reduced operational awareness, limited monitoring capability, increased reliance on manual intervention, and growing obsolescence of control infrastructure	Modernize protection, control, communications, and SCADA systems (STN009)	Enabling Modernization	High
Existing unit substation enclosure has deteriorated, creating exposure pathways that may affect long-term equipment condition, reliability, and maintainability	Engineering Evaluation Summary	Enclosure deterioration introduces increasing lifecycle risk and reduces long-term supportability of the existing medium-voltage switchgear installation	Increased exposure of equipment to environmental conditions, increased maintenance requirements, and declining long-term reliability	Replace existing unit substation and medium-voltage switchgear with modern gas-insulated equipment (STN019)	Capital Renewal	Moderate
Grounding and bonding deficiencies were identified, including insufficient transformer bonding and fence/gate bonding issues	Synergy Inspection / Engineering Evaluation Summary	Grounding deficiencies represent discrete safety and compliance concerns rather than systemic grounding system issues	Localized personnel safety and compliance concerns if deficiencies remain uncorrected	Complete targeted grounding remediation and corrective maintenance activities	Corrective Maintenance	Moderate
Transformer condition concerns including conservator oil leakage, corrosion, and deteriorated nameplate were identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Findings represent localized equipment condition concerns requiring maintenance attention but do not presently indicate systemic asset deterioration	Increased maintenance requirements and potential progression of equipment deterioration if left unaddressed	Complete targeted transformer maintenance and corrective repair activities	Corrective Maintenance	Moderate
Perimeter security deficiencies including fencing deterioration and improperly oriented barbed wire were identified during inspection	Synergy Inspection / Engineering Evaluation Summary	Security deficiencies represent localized infrastructure concerns rather than primary asset condition issues	Reduced site security and increased compliance exposure if deficiencies remain uncorrected	Complete fencing repairs and perimeter security improvements	Corrective Maintenance	Moderate
General environmental deterioration was observed across outdoor station infrastructure	Synergy Inspection / Engineering Evaluation Summary	Deterioration is primarily external in nature and does not presently affect core station functionality	Continued deterioration may increase future maintenance requirements and repair costs	Complete targeted corrosion mitigation, rehabilitation, and maintenance activities	Corrective Maintenance	Moderate
Transformer dissolved gas analysis and oil quality testing indicate stable internal condition with no evidence of active fault mechanisms	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation within the planning horizon	No evidence of active internal deterioration or abnormal fault development	Continue routine oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor
Existing indoor medium-voltage switchgear remains operational and serviceable despite enclosure deterioration concerns	Engineering Evaluation Summary	Core switchgear functionality remains intact, although enclosure condition creates increasing lifecycle risk	No immediate operability concerns, but long-term supportability is affected by enclosure degradation	Continue maintenance and condition monitoring pending planned replacement	Monitoring & Assessment	Lower / Monitor

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ALMONTE – MS#4						
INSPECTION/OPERATIONAL OBSERVATION	**SOURCE**	**PLANNING SIGNIFICANCE**	**RISK/OPERATIONAL IMPACT**	**PLANNING RESPONSE**	**PROGRAM TYPE**	**PRIORITY**
Absence of a substation load totalization meter limits alignment with current operational monitoring standards and constrains system-level visibility	Engineering Evaluation Summary	Improved station-level monitoring is required to support operational awareness, loading assessment, and future planning activities across the substation portfolio	Reduced monitoring granularity, reduced confidence in loading assessments, and limitations in planning data quality	Install substation load totalization metering and associated instrumentation (STN010)	Enabling Modernization	Moderate
Primary electrical equipment, including transformer, switchgear, and reclosers, is in good condition and consistent with a recently commissioned installation	Synergy Inspection / Engineering Evaluation Summary	Recent installation and commissioning materially reduce lifecycle risk exposure relative to the broader substation portfolio	No significant operational or lifecycle concerns identified	Continue routine maintenance, monitoring, and lifecycle assessment	Monitoring & Assessment	Lower / Monitor
Grounding, perimeter security, and vegetation management systems were observed to be in satisfactory condition	Synergy Inspection / Engineering Evaluation Summary	Supporting infrastructure systems are functioning as intended and do not present material condition concerns	No significant operational, safety, or compliance risks identified	Continue routine inspection and maintenance activities	Monitoring & Assessment	Lower / Monitor
Transformer dissolved gas analysis and oil quality testing indicate normal internal condition and expected performance for a relatively new transformer	DGA Reports / Engineering Evaluation Summary	Available diagnostic information supports continued operation within the planning horizon	No evidence of active internal deterioration or abnormal fault development	Continue routine oil testing, DGA monitoring, and condition assessment	Monitoring & Assessment	Lower / Monitor
Overall station condition is consistent with a recently constructed and commissioned facility with modern switching, protection, and monitoring infrastructure	Engineering Evaluation Summary	Modern station configuration minimizes lifecycle risk exposure and supports long-term asset reliability	No material condition-driven risks identified	Continue routine maintenance and asset management practices	Monitoring & Assessment	Lower / Monitor

ENGINEERING EVALUATION SUMMARY	PEM MS#1
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– accumulated aging indicators across outdoor primary and structural assets – grounding and bonding deficiencies requiring targeted remediation – environmental deterioration consistent with station vintage and exposure – legacy electrical clearance constraints associated with original air-insulated station configuration – indoor switchgear remaining generally serviceable – overall station operability maintained despite condition deficiencies
Planning Relevant Observations:	
	The indoor 5 kV switchgear installation reflects a legacy design generation typical of substations of similar vintage within the ORPC system. While the equipment remains operational and has not demonstrated immediate functional deficiency, continued reliance on aging mechanical operating mechanisms and legacy protection integration introduces increasing maintenance burden and variability in switching performance over time. Associated protection and control systems are of comparable vintage and are based on earlier technology platforms with limited functionality relative to modern digital systems. Although presently serviceable, this configuration constrains system visibility, restoration flexibility, and long-term supportability as component availability declines and integration requirements evolve. At the sub-transmission level, the 44 kV switching infrastructure exhibits age-related condition indicators consistent with prolonged service exposure. However, the station's position within a looped supply configuration moderates immediate system consequence, allowing operational risk to be managed through maintenance and established operating practices in the near term. Collectively, these factors indicate a station characterized by progressive lifecycle risk exposure across multiple asset classes, without evidence of imminent functional inadequacy. This profile supports a structured, risk-informed renewal approach aligned with broader asset management objectives rather than reactive capital intervention.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate normal gas concentrations and stable trending across all key diagnostic gases, with no evidence of active fault development or abnormal thermal or electrical deterioration mechanisms.

	Diagnostic methods including Rogers Ratio, Duval Triangle, and Duval Pentagon were not applicable due to gas levels remaining within expected background ranges. Carbon monoxide and carbon dioxide concentrations are consistent with normal insulation aging processes, and furans testing indicates a high degree of polymerization and minimal paper degradation, suggesting that the transformer insulation system remains in satisfactory condition for continued service. Oil quality parameters, including moisture content, dielectric strength, acidity, and interfacial tension, were within acceptable limits for in-service equipment, further supporting the conclusion that the transformer is not presently experiencing accelerated aging or internal fault activity. Overall, the DGA results support continued routine monitoring and maintenance-based asset management, with no immediate indication of condition-driven renewal requirement for the transformer within the near-term planning horizon.
ORPC Feedback:	
	ORPC has advised that the station SCADA system at MS-1 is currently not functioning and is considered obsolete, resulting in limited real-time monitoring capability and increased reliance on local operational practices. ORPC further indicated that the station DC battery bank and associated control equipment have been recently renewed and are considered to be in good condition.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-1 exhibits progressive age-related condition degradation across several asset classes, including outdoor primary equipment, grounding systems, and legacy control infrastructure. Identified safety and compliance deficiencies are generally localized and are considered addressable through targeted remediation and maintenance activities in the near term. Legacy electrical clearance constraints associated with the original air-insulated station configuration were identified during inspection. ORPC has established operational work protection practices and switching procedures to manage these conditions in accordance with applicable safety requirements. While these legacy configuration constraints do not presently constitute an immediate reliability or compliance risk, future station modernization initiatives are expected to incorporate design corrections to ensure that new installations meet current engineering and safety standards. Condition indicators associated with the indoor 5 kV switchgear and protection systems reflect legacy design generation and increasing lifecycle management complexity, particularly with respect to maintainability, operational consistency, and long-term supportability. Operational feedback further indicates that station monitoring capability is presently constrained due to non-functional and obsolete

	SCADA systems, while recent renewal of the DC supply system has improved auxiliary system reliability. Transformer condition indicators, including dissolved gas analysis and oil quality testing, are consistent with stable internal condition and normal insulation aging for equipment of comparable vintage, supporting continued operation under routine monitoring practices.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, operational feedback, and system configuration considerations, MS-1 is assessed as being in Fair overall condition relative to the substation portfolio. The station exhibits progressive lifecycle risk exposure associated with aging infrastructure and legacy equipment platforms; however, core functionality remains intact and condition deficiencies are generally manageable through targeted corrective actions and planned renewal interventions. System configuration and established contingency supply arrangements further moderate immediate reliability consequence. Accordingly, a structured and risk-informed approach to modernization is appropriate, with priority focus on addressing identified safety remediation requirements and modernizing control and protection infrastructure, while major primary equipment renewal can be sequenced within the medium-term planning horizon.
Resulting Capital Strategy:	
	The capital response strategy for MS-1 reflects a phased approach to addressing identified safety, operational, and lifecycle considerations. Discrete condition deficiencies identified through inspection, including grounding, bonding, and site condition issues, are expected to be addressed through ongoing maintenance and targeted corrective work programs in the near term. Capital investment focus is directed toward modernization of legacy control and protection infrastructure to improve system visibility and operational supportability, followed by renewal of aging medium-voltage switching equipment within the medium to long-term planning horizon. Modernization of sub-transmission switching infrastructure is sequenced to a later planning period, reflecting moderated system consequence and the continued ability to manage condition-related risk through established maintenance and operational practices.

ENGINEERING EVALUATION SUMMARY	PEM MS#2
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– localized civil infrastructure degradation associated with tower foundation condition – legacy medium-voltage switchgear exhibiting age-related functional wear – primary transformer and grounding systems generally in satisfactory condition – overall station equipment condition largely consistent with vintage outdoor installation
Planning Relevant Observations:	
	The station configuration reflects a legacy design generation consistent with other substations of similar vintage within the ORPC system. While the indoor 5 kV switchgear remains operable, the equipment is approaching the later stages of its service life, introducing increasing lifecycle management complexity and reduced long-term supportability. Associated protection and control systems are of comparable vintage, limiting system visibility and operational flexibility relative to modern digital platforms. At the sub-transmission level, the principal condition driver identified through inspection relates to deterioration of structural civil components supporting outdoor equipment. This condition represents a localized infrastructure risk rather than a systemic primary equipment deficiency.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate normal gas concentrations and stable trending across key diagnostic parameters, with no indication of active fault mechanisms or abnormal insulation deterioration. Diagnostic methods including Rogers Ratio and Duval analysis were not applicable due to gas levels remaining within expected background ranges. Oil quality indicators, including moisture, dielectric strength, and acidity, remain within acceptable limits for continued in-service operation. Overall, results support routine monitoring and maintenance-based asset management for the transformer within the planning horizon.
ORPC Feedback:	
	ORPC has advised that the existing SCADA system at MS-2 is not currently functional, resulting in limited real-time monitoring capability and increased reliance on local operational practices.

Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-2 exhibits generally stable electrical equipment condition with localized infrastructure deficiencies affecting structural support systems. Identified issues related to tower foundation integrity represent the most significant condition concern, while primary transformer and grounding systems remain in satisfactory condition for continued operation. Legacy medium-voltage switchgear and associated protection systems reflect increasing lifecycle management challenges typical of equipment of this generation, particularly with respect to long-term supportability and operational flexibility. Operational feedback further indicates constrained monitoring capability due to non-functional SCADA infrastructure.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, operational feedback, and system configuration considerations, MS-2 is assessed as being in Fair overall condition relative to the substation portfolio. While localized civil infrastructure deterioration introduces elevated maintenance requirements and legacy control infrastructure limits operational visibility, core station functionality remains intact and primary equipment condition is generally stable. These factors support a structured renewal approach aligned with lifecycle risk exposure rather than immediate system reliability concern.
Resulting Capital Strategy:	
	The capital response strategy for MS-2 reflects a phased approach to addressing identified operational and lifecycle considerations. Localized infrastructure deficiencies, including tower foundation condition, are expected to be addressed through targeted maintenance or corrective civil works programs. Capital investment focus is directed toward modernization of legacy protection and control systems to restore monitoring capability and improve operational supportability, followed by renewal of aging medium-voltage switchgear within the medium to long-term planning horizon.

ENGINEERING EVALUATION SUMMARY	PEM MS#3
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– grounding and bonding deficiencies associated with transformer installation – progressive exterior deterioration of transformer tank and associated bus structures – aging station identification and labeling systems – indoor medium-voltage switchgear generally serviceable for age – overall station condition consistent with legacy outdoor installation exposure
Planning Relevant Observations:	
	The station reflects a legacy design configuration typical of substations of similar vintage within the ORPC system. While the indoor 5 kV switchgear remains operable, the equipment is approaching the later stages of its service life, introducing increasing lifecycle management complexity and reduced long-term supportability. Associated protection and control systems are of comparable vintage and provide limited operational visibility and system flexibility relative to modern digital platforms. Inspection findings indicate that the principal condition considerations at this station relate to localized safety compliance issues and progressive external deterioration of primary equipment surfaces rather than systemic functional limitations.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate normal gas concentrations and stable trending across key diagnostic gases, with no evidence of active fault development or abnormal internal deterioration mechanisms. Diagnostic methods including Rogers Ratio and Duval analysis were not applicable due to gas levels remaining within expected background ranges. Oil quality indicators, including moisture content, dielectric strength, acidity, and interfacial tension, remain within acceptable limits for continued in-service operation. Furans analysis indicates moderate insulation aging consistent with equipment of this vintage, with an estimated degree of polymerization supporting continued service under routine monitoring practices. Overall results support maintenance-based asset management within the planning horizon.
ORPC Feedback:	

	ORPC has advised that the station SCADA system at MS-3 is not currently functional, resulting in limited real-time monitoring capability and increased reliance on local operational practices. ORPC further noted that the station grounding system was renewed in 2016, and that currently identified grounding issues are considered localized deficiencies requiring targeted corrective action rather than systemic grounding condition concerns.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-3 exhibits progressive age-related condition degradation primarily associated with localized grounding compliance deficiencies and external deterioration of transformer surfaces. Grounding system renewal completed in 2016 has improved overall system integrity, and remaining deficiencies are considered discrete and addressable through targeted remediation and maintenance interventions in the near term. Legacy medium-voltage switchgear and associated protection systems reflect increasing lifecycle management challenges typical of equipment of this generation, particularly with respect to long-term supportability and operational flexibility. Operational feedback further confirms that station monitoring capability is constrained due to non-functional SCADA infrastructure. Transformer condition indicators, including dissolved gas analysis and oil quality testing, are consistent with stable internal condition and normal aging processes, supporting continued operation under routine monitoring practices.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, operational feedback, and system configuration considerations, MS-3 is assessed as being in Fair overall condition relative to the substation portfolio. While localized safety compliance deficiencies and legacy control infrastructure introduce increasing lifecycle management considerations, core station functionality remains intact and primary equipment condition is generally stable. These factors support a structured renewal approach aligned with progressive asset aging rather than immediate reliability concern.
Resulting Capital Strategy:	
	The capital response strategy for MS-3 reflects a phased approach to addressing identified operational and lifecycle considerations. Discrete safety and compliance deficiencies, including grounding and equipment surface condition issues, are expected to be addressed through ongoing maintenance and targeted corrective work programs. Capital investment focus is directed toward modernization of legacy protection and control systems to restore monitoring capability and improve operational

	supportability, followed by renewal of aging medium-voltage switchgear within the medium- to long-term planning horizon.

ENGINEERING EVALUATION SUMMARY	PEM MS#4
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– transformer bonding deficiencies identified, including missing bond connection – visible external deterioration of transformer surfaces including rust and paint degradation – oil leakage observed on multiple 44 kV oil circuit breakers – evidence of low oil level condition on breaker bushing – localized bonding deficiencies on primary switching equipment – external corrosion observed on tower structures and station perimeter infrastructure – vegetation encroachment within the station yard – safety compliance items including expired emergency equipment and labeling deficiencies These observations reflect condition issues identified during visual inspection and referenced against Ontario Electrical Safety Code requirements.
Planning Relevant Observations:	
	MS-4 exhibits multiple indicators of advanced asset aging affecting both primary switching infrastructure and associated control systems. While inspection findings primarily identify localized condition deficiencies, operational experience during recent protection upgrade work has demonstrated functional reliability concerns consistent with late-lifecycle equipment behaviour. Intermittent failures of mechanical interlock systems within the legacy 5 kV switchgear resulted in extended troubleshooting prior to restoration of normal station configuration. In addition, deterioration of legacy field control wiring contributed to ground faults and misoperation of 44 kV circuit breakers. These events provide direct operational evidence of increasing lifecycle risk exposure beyond that inferred from visual inspection alone. Collectively, inspection observations and operational performance experience indicate that continued reliance on legacy switching and control infrastructure is expected to result in increasing maintenance burden and restoration complexity over the planning horizon.
Dissolved Gas Analysis Interpretation:	
	Available dissolved gas analysis results indicate normal gas levels with no indication of internal electrical, thermal, or insulation-related fault activity.

	Diagnostic evaluation confirms normal transformer operation with routine annual resampling recommended. General oil quality parameters are broadly acceptable for in-service operation; however, dielectric breakdown strength is below recommended limits, indicating reduced insulating margin. Maintenance intervention such as oil processing or dehydration may be considered to restore dielectric performance and support long-term asset reliability.
ORPC Feedback:	
	ORPC has advised that renewal of the station DC supply system is scheduled for 2026 as part of planned lifecycle maintenance activities. Operational experience during recent protection upgrade work identified intermittent failures of mechanical interlock systems within the legacy 5 kV switchgear, resulting in extended troubleshooting prior to restoration of normal station configuration. Additionally, deterioration of legacy control wiring not included in the upgrade scope contributed to ground faults and misoperation of 44 kV circuit breakers.
Engineering Interpretation:	
	Inspection findings and operational performance evidence collectively indicate that MS-4 is exhibiting advanced lifecycle degradation affecting both primary switching equipment and associated control infrastructure. While individual inspection-identified deficiencies are generally localized, recent operational events provide direct confirmation of emerging functional reliability concerns consistent with late-lifecycle asset behaviour. Observed switching performance variability and control system integrity issues introduce increasing operational risk exposure, particularly with respect to restoration performance and safe switching operations. Although continued operation can be supported through maintenance intervention in the near term, the demonstrated failure mechanisms are expected to become more prevalent over time as equipment deterioration progresses.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection findings, operational performance evidence, and asset lifecycle considerations, MS-4 is assessed as being in Poor overall condition relative to the substation portfolio. The station exhibits both advanced asset aging and demonstrated operational reliability concerns affecting primary switching infrastructure and control system performance. These factors materially increase lifecycle risk exposure and support prioritization of renewal investment.
Resulting Capital Strategy:	

	The capital response strategy for MS-4 is focused on renewal of aging primary switching infrastructure and associated control systems to mitigate demonstrated operational reliability risks. Planned investment includes replacement of legacy 44 kV oil circuit breakers with modern metal-enclosed switchgear and renewal of aging medium-voltage switchgear infrastructure. Discrete condition deficiencies identified through inspection will continue to be addressed through targeted maintenance activities, while scheduled DC system renewal in 2026 supports interim operational reliability.

ENGINEERING EVALUATION SUMMARY	PEM MS#5
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– grounding and bonding deficiencies identified requiring corrective action to maintain safety compliance – localized corrosion and external deterioration observed on station structures and equipment surfaces – general station housekeeping and vegetation management considerations noted – legacy protection and control installation observed – station monitoring capability constrained due to non-functional SCADA system
Planning Relevant Observations:	
	Station condition risk is primarily associated with legacy protection, control, and monitoring infrastructure rather than degradation of primary electrical plant. The absence of functional SCADA reduces operational visibility and restoration support capability. The medium-voltage switchgear installation, while of legacy design, is of comparatively later vintage (circa 1975) relative to other stations in the portfolio. Continued availability of replacement components and absence of significant inspection-identified deterioration suggest that near-term degradation-driven failure risk remains moderate. Primary equipment condition appears consistent with continued serviceability within the planning horizon, with identified localized deficiencies considered manageable through routine maintenance or minor corrective work. Legacy station configuration includes overhead 44 kV conductor routing in proximity to the e-house structure. While no clearance deficiencies were explicitly identified in the inspection report, the configuration reflects historical design practice and may introduce operational constraints or maintenance considerations typical of stations of similar vintage.
Dissolved Gas Analysis Interpretation:	
	Available transformer oil testing indicates normal dissolved gas levels with no evidence of active internal faulting. General oil quality parameters are broadly acceptable for continued service; however, dielectric breakdown strength is below recommended limits. This condition suggests the need for maintenance intervention such as oil processing, filtration, or dehydration to restore dielectric strength and improve

	long-term insulation performance. The limited number of historical test results constrains assessment of condition trend; continued monitoring is recommended.
ORPC Feedback:	
	ORPC has confirmed that station SCADA is currently not functional, limiting operational monitoring capability. No additional significant operational concerns have been identified.
Engineering Interpretation:	
	Overall station condition is influenced more by control system obsolescence and loss of monitoring capability than by degradation of primary electrical infrastructure. Transformer condition indicators support continued operation with maintenance intervention as required. The relative vintage and supportability of the medium-voltage switchgear moderates immediate renewal need compared to other stations within the portfolio. Renewal of legacy protection, control, and monitoring systems is therefore considered the primary near-term capital requirement.
Planning Level Condition Outcome:	
	MS-5 is assessed to be in Fair condition, reflecting the presence of legacy protection and control infrastructure and loss of monitoring capability associated with non-functional SCADA, while primary electrical equipment remains generally serviceable. The comparatively later vintage and continued supportability of the medium-voltage switchgear moderates near-term renewal urgency relative to peer stations. Overall risk exposure is considered manageable within the planning horizon through targeted maintenance and prioritized modernization of control systems.
Resulting Capital Strategy:	
	MS-5 is assessed to be in Fair condition, reflecting the presence of legacy protection and control infrastructure and loss of monitoring capability associated with non-functional SCADA, while primary electrical equipment remains generally serviceable. The comparatively later vintage and continued supportability of the medium-voltage switchgear moderates near-term renewal urgency relative to peer stations. Legacy overhead conductor routing in proximity to station structures is recognized as a characteristic of original station design. These configurations are generally managed through established operational work practices and do not presently constitute a primary driver for capital intervention. Future modernization or renewal activities would be expected to incorporate updated physical layout and clearance arrangements consistent with contemporary engineering standards. Overall risk exposure is considered manageable within the planning horizon through targeted maintenance and prioritized modernization of control systems.

PEM MS#5: Asset Condition Assessment – Engineering Review

ENGINEERING EVALUATION SUMMARY	PEM MS#6
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– localized structural deterioration associated with pole-mounted primary equipment support – grounding and bonding deficiencies requiring targeted remediation – minor environmental deterioration of transformer surfaces and secondary bus duct – indoor switchgear observed to be in good overall condition – protection and SCADA systems recently modernized with no inspection concerns noted
Planning Relevant Observations:	
	Station condition risk is limited and primarily associated with discrete civil and grounding deficiencies rather than systemic degradation of primary electrical infrastructure. The medium-voltage switchgear installation, while of legacy design generation (circa 1975), remains operationally supportable with no significant inspection-identified deterioration. Protection and SCADA infrastructure have recently been modernized, materially improving operational visibility, reliability performance, and lifecycle supportability relative to peer stations within the portfolio. The absence of a station load totalization meter represents a functional limitation relative to current ORPC operational standards. This constraint affects system monitoring granularity and planning data quality rather than representing a condition-driven asset risk. Primary transformer condition indicators, including dissolved gas analysis and oil quality testing, support continued normal operation under routine monitoring practices.
Dissolved Gas Analysis Interpretation:	
	Available dissolved gas analysis results indicate normal gas levels with no indication of internal electrical or thermal fault activity. Diagnostic evaluation confirms normal transformer operation with routine resampling recommended. General oil quality parameters are broadly acceptable for in-service operation; however, dielectric breakdown strength is below recommended limits, indicating reduced insulating margin. Maintenance intervention such as oil processing or

	dehydration may be considered to restore dielectric performance and support long-term asset reliability. (Oil sample only available for transformer T2 - S/N A32S008 - 1990 Vintage)
ORPC Feedback:	
	No specific operational concerns have been identified by ORPC. Protection and SCADA systems are understood to be recently upgraded and functioning as intended.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-6 is generally in sound operating condition, with localized deficiencies primarily associated with civil structures and grounding components rather than degradation of primary electrical equipment. Recent modernization of protection and SCADA systems materially improves station operability and reduces lifecycle risk relative to other legacy substations. The medium-voltage switchgear installation, while of older design generation, remains serviceable and does not presently represent a near-term renewal driver. Identified deficiencies are considered addressable through targeted maintenance or minor corrective work programs. The absence of load totalization capability represents an operational data limitation rather than a condition-driven reliability risk.
Planning Level Condition Outcome:	
	MS-6 is assessed to be in Good condition, reflecting generally serviceable primary equipment, recently modernized protection and control infrastructure, and limited condition-related risk exposure. Localized structural and grounding deficiencies are not considered indicative of systemic asset deterioration and are expected to be addressed through routine maintenance activities. Overall station risk exposure is considered low within the planning horizon.
Resulting Capital Strategy:	
	Capital investment is limited to installation of a station load totalization meter to align with current operational monitoring standards and support improved system performance tracking. Localized civil, grounding, and equipment surface condition deficiencies are expected to be addressed through targeted maintenance or corrective work programs. Medium-voltage switchgear renewal is not identified as a planning requirement within the current horizon.

ENGINEERING EVALUATION SUMMARY	PEM MS#7
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– grounding and bonding deficiencies requiring corrective action, including missing transformer bonding and perimeter bonding concerns – environmental deterioration of transformer surfaces including fading paint and surface corrosion – minor condition issues associated with pole-mounted primary equipment and insulator contamination – indoor medium-voltage switchgear observed to be in generally good working condition – station housekeeping and safety equipment compliance deficiencies identified
Planning Relevant Observations:	
	Overall station condition risk is primarily associated with legacy protection, control, and switching infrastructure rather than degradation of primary transformer assets. The medium-voltage switchgear lineup (circa 1975) remains operationally supportable and exhibits no significant inspection-identified deterioration, representing comparatively moderate near-term renewal risk within the portfolio. Legacy 44 kV air-break switching equipment and associated motor operators exhibit condition characteristics typical of advanced service age and environmental exposure. While not explicitly identified as deficient in the inspection report, observed weathering and mechanical aging are consistent with increasing maintenance burden and operational performance variability over time. Grounding system renewal completed in 2016 materially reduces systemic grounding risk; remaining deficiencies identified during inspection are localized and considered addressable through targeted remediation. Operational feedback indicates that station SCADA capability is presently unreliable or non-functional, limiting system monitoring and operational visibility.
Dissolved Gas Analysis Interpretation:	
	Available dissolved gas analysis results indicate normal gas concentrations with no indication of active internal electrical or thermal fault mechanisms. Diagnostic methods including Rogers Ratio and Duval analysis are not applicable due to low gas levels, consistent with normal transformer operation. Oil quality indicators are broadly acceptable for continued service. Dielectric breakdown strength meets minimum in-service acceptance criteria based on the

	most recent sample, supporting continued operation under routine monitoring practices.
ORPC Feedback:	
	ORPC has indicated that station SCADA functionality is unreliable or intermittent, resulting in reduced operational monitoring capability. No additional significant operational concerns have been reported.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-7 remains generally operable, with condition risk primarily associated with aging protection, control, and monitoring systems rather than deterioration of primary electrical plant. Legacy protection systems and non-functional SCADA reduce operational supportability and limit real-time system visibility, increasing reliance on manual monitoring and operational intervention. The medium-voltage switchgear installation remains serviceable and is not presently a primary renewal driver. However, legacy 44 kV air-break switching equipment and associated motor operators represent an emerging lifecycle risk due to age-related mechanical degradation and long-term exposure to environmental stressors. Overall station risk exposure is considered manageable within the planning horizon through targeted maintenance and planned modernization of control and switching infrastructure.
Planning Level Condition Outcome:	
	MS-7 is assessed to be in Fair condition, reflecting serviceable primary electrical equipment moderated by legacy protection and monitoring infrastructure and aging outdoor switching systems. Grounding system renewal has mitigated broader safety exposure, and remaining inspection-identified deficiencies are localized. Overall lifecycle risk exposure is considered moderate within the planning horizon.
Resulting Capital Strategy:	
	Capital investment focus is directed toward modernization of legacy protection and SCADA systems to restore monitoring capability and improve operational supportability, together with renewal of aging 44 kV air-break switching equipment and associated motor operators to address emerging operability and maintenance risks. Localized grounding and environmental condition deficiencies are expected to be addressed through routine maintenance and targeted corrective work programs. Medium-voltage switchgear renewal is not identified as a near-term planning requirement.

ENGINEERING EVALUATION SUMMARY	PEM MS#8
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– localized grounding and bonding deficiencies associated with station structures – perimeter security and labelling issues typical of aging outdoor installations – transformer external condition indicators requiring preventative maintenance attention – vegetation management and minor civil maintenance requirements – indoor switchgear and protection systems recently modernized and operational
Planning Relevant Observations:	
	Station risk exposure is primarily associated with localized civil and structural condition affecting the main power transformer foundation rather than degradation of primary electrical equipment. ORPC has identified progressive foundation settlement toward the adjacent embankment, requiring temporary shimming to maintain alignment of transformer terminations. While this condition does not presently affect transformer internal performance, it introduces increasing long-term risk to mechanical integrity, conductor stress, and future operability if not addressed. Protection and SCADA systems have been recently modernized and are functioning as intended, and the medium-voltage switchgear installation is of comparatively later vintage (circa 1991), supporting continued serviceability within the planning horizon. Inspection-identified deficiencies related to grounding, labelling, security, and vegetation are considered localized and manageable through targeted maintenance programs.
Dissolved Gas Analysis Interpretation:	
	Available dissolved gas analysis results indicate normal gas levels with no evidence of active internal fault development or abnormal thermal or electrical deterioration mechanisms. Cellulose degradation indicators remain within expected limits for equipment of comparable age, and oil quality parameters are generally consistent with continued in-service operation under routine monitoring practices. Continued annual oil testing and external condition maintenance are recommended to support long-term asset performance.
ORPC Feedback:	

	ORPC has identified progressive settlement of the main transformer foundation toward the adjacent embankment. Temporary shimming measures have been implemented to maintain acceptable termination alignment pending permanent corrective works.
Engineering Interpretation:	
	MS-8 is assessed to be in Fair condition, driven primarily by localized civil infrastructure risk associated with transformer foundation stability rather than degradation of core electrical assets. Recent modernization of protection and SCADA systems has improved station operability and monitoring capability, and the medium-voltage switchgear remains consistent with continued serviceability expectations. Inspection-identified deficiencies related to grounding, labelling, and site maintenance are not considered primary drivers of capital intervention and can be addressed through routine maintenance programs. However, progressive foundation settlement introduces increasing long-term risk to transformer mechanical integrity and associated conductor systems. Timely stabilization is required to prevent escalation of condition risk and to maintain acceptable operational reliability.
Planning Level Condition Outcome:	
	MS-8 is classified as Fair condition, reflecting the presence of localized civil infrastructure risk associated with transformer foundation stability while core electrical systems remain generally serviceable and recently modernized. Overall risk exposure is considered manageable in the near term but requires corrective intervention within the near- to medium-term planning horizon to prevent progression of condition-related operational risk.
Resulting Capital Strategy:	
	Capital planning for MS-8 is focused on stabilization of the existing transformer foundation and associated secondary conductor renewal to address localized structural risk. Inspection-identified deficiencies related to grounding, labelling, security, and vegetation management are expected to be addressed through targeted maintenance and corrective work programs.

ENGINEERING EVALUATION SUMMARY	ALM MS#1
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– modern indoor gas-insulated switching installation observed – localized civil and structural deterioration consistent with environmental exposure – primary electrical equipment generally observed to be in serviceable condition – overall station configuration consistent with recently modernized indoor installation
Planning Relevant Observations:	
	The station reflects a recently modernized design configuration relative to other substations within the ORPC system, including replacement of legacy switching, protection, and monitoring infrastructure. As a result, lifecycle risk exposure associated with primary electrical plant is comparatively reduced. Despite this modernization, the absence of a substation load totalization meter limits alignment with current operational monitoring standards adopted across the broader substation portfolio and constrains system-level visibility for planning and operational analysis purposes. The indoor installation of gas-insulated switchgear introduces a planning-level requirement to verify that gas monitoring, ventilation, and personnel safety provisions are consistent with contemporary industry standards for indoor GIS installations. Follow-up engineering review should confirm alignment with applicable guidance such as IEC 62271-203 and IEEE C37.122, including assessment of gas detection, ventilation effectiveness, alarm integration, and operational response procedures. This verification activity is considered part of modernization completion and asset stewardship rather than a condition-driven deficiency or independent capital driver.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate elevated ethane concentration relative to typical background values; however, overall gas ratios and associated diagnostic indicators remain consistent with normal insulation aging and do not suggest active fault development. The ethane presence is most commonly associated with low-energy thermal processes or historical gas accumulation typical of equipment of comparable vintage. Oil quality parameters remain within acceptable operating limits.

	Continued periodic dissolved gas monitoring is recommended, with follow-up review of transformer loading profile, cooling performance, and oil circulation condition to confirm stable thermal operating behaviour. No immediate corrective intervention is indicated based on available test results.
ORPC Feedback:	
	No additional operational concerns were identified by ORPC at this station.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-1 exhibits generally stable electrical equipment condition consistent with recent modernization of switching, protection, and monitoring systems. Observed civil and structural deterioration is localized in nature and does not presently affect electrical operability. Transformer condition indicators support continued in-service operation under routine monitoring practices. While elevated ethane concentrations warrant continued trending, available diagnostic evidence does not indicate the presence of active internal fault mechanisms. The primary planning consideration at this station relates to completion of monitoring system standardization and verification of modern installation provisions associated with indoor gas-insulated equipment.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, and station configuration considerations, MS-1 is assessed as being in Good overall condition relative to the substation portfolio. Recent modernization of primary electrical systems materially reduces lifecycle risk exposure, while identified civil deterioration and monitoring enhancements represent manageable asset management considerations within the planning horizon.
Resulting Capital Strategy:	
	The capital response strategy for MS-1 is focused on completion of operational monitoring standardization through installation of a substation load totalization meter and associated instrumentation. Localized civil deficiencies are expected to be addressed through routine maintenance or minor corrective works programs. No major primary equipment renewal is indicated within the planning horizon based on current condition evidence.

ENGINEERING EVALUATION SUMMARY	ALM MS#2
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– significant civil deterioration identified at sub-transmission tower foundation – indoor medium-voltage switchgear observed to be in serviceable operating condition – primary transformer and grounding systems generally observed to be in satisfactory condition – overall station condition largely consistent with vintage outdoor installation
Planning Relevant Observations:	
	The station configuration reflects a legacy physical design generation consistent with other substations of similar vintage within the ORPC system. While the indoor medium-voltage switchgear installation remains operable and serviceable, the station lacks fully integrated SCADA monitoring capability despite modernization of protective relaying. The absence of local data aggregation and load totalization functionality limits real-time system visibility and alignment with current operational monitoring standards adopted across the substation portfolio. The most significant condition driver identified through inspection relates to deterioration of structural civil components supporting outdoor sub-transmission equipment. Progressive degradation of tower foundations represents a localized infrastructure risk that may affect long-term structural stability and operational reliability if not addressed through corrective intervention. Completion of monitoring system modernization through installation of local data aggregation capability, load totalization metering, and communications integration is therefore aligned with broader operational performance and planning objectives.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate generally normal gas concentrations across key diagnostic parameters, with no evidence of active internal fault mechanisms. Diagnostic methods including Rogers Ratio and Duval analysis were not applicable due to gas levels remaining within expected background ranges. Oil quality indicators remain broadly acceptable for continued in-service operation, although dielectric strength remains below preferred threshold levels and should continue to be monitored as part of routine maintenance surveillance. Overall results support continued operation under enhanced monitoring practices consistent with laboratory recommendations.

ORPC Feedback:	
	No additional operational concerns were identified by ORPC for this station.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-2 exhibits generally stable electrical equipment condition with localized infrastructure deficiencies affecting structural support systems. The deterioration of tower foundations represents the most significant condition concern and introduces increasing long-term structural reliability risk if not addressed through corrective civil intervention. While protection systems have been modernized, the absence of integrated SCADA monitoring capability reduces operational visibility and limits alignment with contemporary system monitoring practices. Primary electrical equipment, including medium-voltage switchgear, remains serviceable and does not presently represent a condition-driven renewal requirement.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, and station configuration considerations, MS-2 is assessed as being in Fair overall condition relative to the substation portfolio. Localized civil infrastructure deterioration introduces elevated structural risk exposure, while incomplete monitoring system integration constrains operational visibility. Core station functionality remains intact and primary equipment condition is generally stable, supporting a structured renewal approach aligned with lifecycle risk management objectives.
Resulting Capital Strategy:	
	The capital response strategy for MS-2 reflects a phased approach to addressing both condition-driven and operational modernization needs. Structural deficiencies associated with sub-transmission tower foundations will be addressed through a dedicated capital project involving reconstruction of affected tower footings to restore long-term structural integrity. Capital investment is also directed toward completion of station monitoring modernization through implementation of local data aggregation capability, installation of a load totalization meter, and communications integration with the SCADA master system to improve operational visibility and planning support. Medium-voltage switchgear renewal is not identified as a planning requirement within the current horizon.

ENGINEERING EVALUATION SUMMARY	ALM MS#3
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– grounding and bonding deficiencies identified, including insufficient transformer bonding and fence/gate bonding issues – transformer condition concerns including oil leakage at conservator, corrosion, and deteriorated nameplate – localized deterioration of enclosure structures including switchgear housing condition – perimeter security deficiencies including improperly oriented barbed wire and fencing deterioration – general environmental deterioration across outdoor station infrastructure
Planning Relevant Observations:	
	The station reflects a legacy design configuration consistent with other substations of similar vintage within the ORPC system. The indoor medium-voltage switchgear is of 1975 vintage and remains operable; however, degradation of the unit substation enclosure has resulted in exposure pathways that may affect long-term equipment condition and reliability if not addressed. Protection and control systems remain of legacy design generation, and no SCADA monitoring capability is currently implemented at the station. This results in limited operational visibility and reduced alignment with current system monitoring standards adopted across the substation portfolio. Transformer-related condition findings, including oil leakage and grounding deficiencies, represent localized equipment and safety concerns that require corrective maintenance but do not currently indicate systemic failure of the asset.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate normal gas concentrations across all key diagnostic parameters, with no indication of active fault mechanisms or abnormal insulation deterioration. Diagnostic methods including Rogers Ratio and Duval analysis are not applicable due to gas levels remaining within expected background ranges. Cellulose insulation indicators remain within normal limits, with no evidence of paper degradation or internal fault involvement. Oil quality parameters are generally acceptable for continued in-service operation, although dielectric breakdown strength is below preferred thresholds and should be monitored as part of routine maintenance practices.

	Overall results support continued operation under routine monitoring and maintenance-based asset management practices.
ORPC Feedback:	
	ORPC has indicated that no SCADA system is currently implemented at this station, resulting in limited real-time monitoring capability.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-3 is generally in stable operating condition, with localized deficiencies primarily associated with grounding, transformer condition, and site infrastructure rather than degradation of primary electrical equipment. The indoor medium-voltage switchgear remains operational; however, degradation of the unit substation enclosure introduces increasing exposure risk to installed equipment and reduces long-term reliability and maintainability if left unaddressed. Protection and control systems remain of legacy design, and the absence of SCADA monitoring capability limits operational visibility and alignment with current system monitoring practices. Identified deficiencies are considered addressable through targeted maintenance or corrective work programs. Overall station condition risk is therefore driven primarily by enclosure condition and limitations in monitoring capability rather than systemic equipment deterioration.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, and station configuration considerations, MS-3 is assessed as being in Fair to Poor overall condition relative to the Almonte substation portfolio. While localized deficiencies introduce increased maintenance requirements and the unit substation enclosure presents an emerging reliability consideration, core station functionality remains intact and primary electrical equipment is generally serviceable. These factors support a structured renewal approach aligned with lifecycle risk exposure and operational modernization needs.
Resulting Capital Strategy:	
	The capital response strategy for MS-3 reflects a coordinated approach to addressing both asset condition and operational modernization requirements. Capital investment is directed toward replacement of the existing unit substation and medium-voltage switchgear with a modern gas-insulated configuration, addressing enclosure degradation and improving long-term asset supportability. Modernization of protection and control systems, including implementation of SCADA monitoring capability, will restore operational visibility and align the station with portfolio-wide monitoring standards.

	Localized deficiencies related to grounding, transformer condition, and site infrastructure are expected to be addressed through targeted maintenance and corrective work programs.

ENGINEERING EVALUATION SUMMARY	ALM MS#4
Purpose of Evaluation: This summary report consolidates and describes how inspection observations, field photographs, dissolved gas analysis, and ORPC feedback informed the planning level condition assessment and associated project decisions.	
Inspection Themes Noted:	
	– station identified as like-new with no code violations or material deficiencies – primary electrical equipment, including transformer, switchgear, and reclosers, observed to be in good condition – grounding, perimeter security, and vegetation management systems in satisfactory condition – overall station condition consistent with recent installation and commissioning
Planning Relevant Observations:	
	The station reflects a recently constructed and commissioned design configuration, with modern switching, protection, and monitoring infrastructure in place. As a result, lifecycle risk exposure associated with primary electrical equipment is minimal relative to other stations within the portfolio. The absence of a substation load totalization meter represents a functional gap relative to current operational monitoring standards adopted across the system and limits system-level visibility for planning and operational analysis purposes.
Dissolved Gas Analysis Interpretation:	
	Recent dissolved gas analysis results indicate normal gas concentrations across all key diagnostic parameters, with no indication of active fault mechanisms or abnormal insulation deterioration. Diagnostic methods including Rogers Ratio and Duval analysis are not applicable due to gas levels remaining within expected background ranges. Oil quality indicators, including moisture content, dielectric strength, and acidity, are within acceptable limits for in-service operation. Overall results are consistent with expected performance for a relatively new transformer and support continued routine monitoring practices.
ORPC Feedback:	
	No additional operational concerns were identified by ORPC for this station.
Engineering Interpretation:	
	Inspection findings and supporting technical inputs indicate that MS-4 is in sound operating condition, with no material deficiencies identified across primary electrical or supporting infrastructure systems.

	The station reflects a modern design configuration with minimal lifecycle risk exposure. Identified condition considerations are limited to routine monitoring and maintenance practices typical of newly commissioned assets. The absence of load totalization capability represents a minor functional limitation rather than a condition-driven concern.
Planning Level Condition Outcome:	
	Based on the synthesis of inspection observations, technical condition indicators, and station configuration considerations, MS-4 is assessed as being in Good overall condition relative to the substation portfolio. Primary electrical equipment and supporting infrastructure are in near-new condition, and overall risk exposure is considered low within the planning horizon.
Resulting Capital Strategy:	
	The capital response strategy for MS-4 is limited to installation of a substation load totalization meter to support alignment with current system monitoring standards and improve operational visibility. No additional capital investment is indicated within the planning horizon based on current condition evidence. Routine maintenance and monitoring activities will support continued reliable operation.

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-1
107 Frank Nighbor St.
Pembroke, ON.

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-1 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-1 Substation
  - **Location:** 107 Frank Nighbor St., Pembroke, ON
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation serving 4160/2400 V feeders 1-1, 1-2, 1-3, and 1-4
  - **Last Inspection:** October 7, 2025

- **Inspection Summary**

  In the inspection conducted on October 7, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Barbed wire not properly bonded (OESC 36-312)**
  - **Barbed wire falling out of brackets and not properly tensioned**
  - **A2 switch handle not properly bonded (OESC 36-200 2) b)**
  - **Breaker A2 appears to be leaking oil and paint faded**
  - **Breaker A3 appears to be leaking oil and paint faded**
  - **Breaker A3 control cabinet very rusty**
  - **Potential transformers paint peeling away and very rusty**
  - **Concrete across station is cracked and uneven**
  - **Multiple tripping hazards from uneven surfaces, conduits no longer being used, and debris**
  - **Tower structure rusting, particularly where it meets the concrete**
  - **Fading nameplates and labels across all equipment in the station**
  - **Transformer bond not connected (OESC 36-302)**
  - **Clearances between 44kV bus structure and building less then 3m (OESC 36-110, Table 33)**
  - **Light rusting on transformer**
  - **Dirty insulators**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Critical	Bond not connected, light rust forming
Switchgear (Indoor)	Low	Appears to be in good condition for its age
Pole/Tower Equipment	Medium	Dirty insulators, 44kV bus has very little clearance from tower structure in some areas.
Perimeter Security	Low	Fence in good condition
Grounding	Critical	Bond not secured on transformer, no bond on barbed wire, bond secured with #8 wire on switch handle
Vegetation Management	Low	Very little spaces for vegetation to grow.
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Reconnect bond on transformer**
  - **Connect bond on A2 switch handle with proper clamp**
  - **Bond barber wire in accordance with code**
  - **Repair oil leaks on both oil filled breakers**
  - **Mark or remove any tripping hazards located in station**

- **Preventative Maintenance:**
  - Remove rust, seal, and paint all equipment
  - Replace Fading nameplates and labeling across station
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue with annual oil testing

Regards,



Douglas Charron
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SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-2
392 Fraser St.
Pembroke, ON.

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-2 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-2 Substation
  - **Location:** 392 Fraser St., Pembroke, ON
  - **Voltage Levels:** 44kV Primary / 4.16 kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation supplying 4160/2400 V feeders 2-1, 2-2, 2-3, 2-4, and 2-5
  - **Last Inspection:** October 7,2025

- **Inspection Summary**

  In the inspection conducted on October 7, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Name-plate on transformer severely faded and not legible**
  - **Transformer paint faded and starting to rust**
  - **Transformer only bonded at one point (OESC 36-302)**
  - **Switch handle (AB2) not properly bonded, it is recommended bond be above switch handle**
  - **Eye wash bottle found to be expired**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	**Severity Scale**	**Notes**
Outdoor Transformer	Critical	Missing bond, Faded paint, rusting, nameplate unable to be read due to fading
Switchgear (Indoor)	Low	Appears to be in good condition for its age
Pole Equipment	Low	Equipment on pole appears as-new
Perimeter Security	medium	Gaps seen under large gate on fence, allow pests easy access
Grounding	Critical	Second transformer tank bond is needed, switch handle bond to be moved above handle
Vegetation Management	Low	Very little vegetation, meets code guidelines
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Apply a second transformer tank bond**
  - **Relocate switch bond to above the switch handle**
  - **Apply new nameplate to transformer**

- **Preventative Maintenance:**
  - Fix gaps under fence to prevent pests from gaining easy access
  - Seal and paint transformer to prevent further rusting and improve life span
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue to do annual oil sampling

Regards,



Douglas Charron
Operation Manager, Service & Maintenance
Tel: (519) 245-4900
Cell: (519) 476-3448
dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-3
756 Fischer St.
Pembroke, ON.

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-3 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-3 Substation
  - **Location:**756 Fischer St., Pembroke, ON
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution Substation supplying 4160/2400 V feeders 3-2 and 3-4. (3-1 and 3-3 not in use)
  - **Last Inspection:** October 7, 2025

- **Inspection Summary**
  In the inspection conducted on October 7, 2025, we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Only one bond found on transformer (OESC 36-302)**
  - **Nameplate faded and unreadable**
  - **Paint faded and rust forming on TX and busway**
  - **Fading labeling of Motor operated switches**
  - **Missing bond on barbed wire (OESC 36-312)**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Critical	Only one bond present on transformer, paint fading, rust forming, water gathering on ledge leading to further rusting, nameplate illegible
Switchgear (Indoor)	Low	Very little clearance behind switchgear
Pole Equipment	Low	Appears to be in good condition, labeling starting to fade/ letters peeling off
Perimeter Security	Low	Wall in good condition
Grounding	Critical	Missing bond on Transformer, missing bond on barbed wire
Vegetation Management	Low	Very little vegetation present
SCADA/Protection System	Low	No issues indicated by ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Attach second bond to transformer tank**
  - **Barbed wire on station wall needs to be bonded**
  - **Remove rust, seal, and paint transformer to stop and prevent future fust**

- **Preventative Maintenance:**
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue with annual oil sampling
  - Replace equipment labelling
  - Install new transformer nameplate

Regards,



Douglas Charron
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dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS4
940 MacKay St.
Pembroke, ON.

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-4 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-4 Substation
  - **Location:** 940 MacKay St., Pembroke, ON
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution Substation supplying 4160/2400 V to feeders 4-1, 4-2, 4-4, 4-5 (4-3 not in use)
  - **Last Inspection:** October 7, 2025

- **Inspection Summary**

  In the inspection conducted on October 7, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Only one bond found on transformer (OESC 36-302)**
  - **Transformer paint fading**
  - **Transformer rusting**
  - **Breakers 6M2P, B3, and 6M1P-B all appear to have oil leaks**
  - **Breakers 6M2P, B3, and 6M1P-B all have faded paint and rust forming**
  - **Bushing on breaker 6M1P-B appears to be low on oil**
  - **Breaker 6M1P-B has a disconnected bond (OESC 36-302)**
  - **Switch B1 bonded below handle, it is recommended the bond is above the handle**
  - **Tower structure shows rust**
  - **Fading label on switch B-3**
  - **Barbed wire facing wrong direction**
  - **Eye wash expired**
  - **Fence and barbed wire are beginning to rust**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Critical	Transformer only has one bond (2 required), Paint fading, and rust starting
Switchgear (Indoor)	Low	Good condition, maintenance done last year
Pole/Tower Equipment	Low	Appears to be in good condition
Perimeter Security	Medium	Barbed wire facing wrong direction
Grounding	Critical	Transformer missing bond, B1 switch bonded below handle, Breaker 6M1P-B bond disconnected.
Vegetation Management	Medium	Vegetation growth covering 15% of station
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Attach second bond to transformer**
  - **Repair oil leaks on Breakers 6M2P, B3, and 6M1P-B**
  - **Repair/ Top up 6M1P-B bushing**
  - **Reconnect bond on breaker 6M1P-B**
  - **Replace label for switch B-3**
  - **Attach bond on switch B1 above the handle**

- **Preventative Maintenance:**
  - Remove rust, seal, and paint transformer
  - Remove rust and paint all other outdoor equipment
  - Remove vegetation
  - Paint fence and barbed wire to prevent further rusting
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue annual oil sampling

Regards,



Douglas Charron
Operation Manager, Service & Maintenance
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dcharron@synergypower.tech

SYNERGY POWER

TO:	SITE:
Ottawa River Power Corp.	MS-5
283 Pembroke St. W.	505 O'Brien St.
Pembroke, ON. K8A 6Y6	Pembroke, ON.

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-5 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-5 Substation
  - **Location:** 505 O'Brien St., Pembroke, ON
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation supplying 4160/2400 V to feeder 5-4 (feeders 5-1, 5-2, 5-3 spare/ not in use)
  - **Last Inspection:** October 7, 2025

- **Inspection Summary**

  In the inspection conducted on October 7, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Unsealed Conduits coming into basement of building (2-128)**
  - **Unsealed conduits going into switchgear (2-128)**
  - **Pole structure IL254 not properly labeled**
  - **Appears to be rodents living under transformer pad**
  - **Eyewash station expired**
  - **Moss and light weeds growing on over 50% of station (OESC 36-304)**
  - **Gravel in station does not meet code requirements (OESC 36-304)**

- **Asset Condition Rating**

  Severity Scale Definition

  Low → Good condition; no immediate action required.

  Medium → Minor/moderate issues; plan corrective maintenance.

  High → Significant deficiencies; corrective action required soon.

  Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	**Severity Scale**	**Notes**
Outdoor Transformer	Low	Asset appears to be in good condition
Switchgear (Indoor)	High	Ensure conduits to switchgear and building are sealed to prevent moisture and rodents
Pole Equipment	Critical	Signage not displayed on pole
Perimeter Security	Low	Wall in good condition
Grounding	Low	Grounding is satisfactory
Vegetation Management	High	Lots of small vegetation growth, Gravel does not meet code requirements
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Apply signage to pole to be able to identify IL254**
  - **Replace gravel in station to meet code compliance**
  - **Seal conduits coming into building and switchgear**

- **Preventative Maintenance:**
  - Seal off rodent hole(s) to prevent damage to ground under transformer pad
  - Replace eyewash station
  - Maintain and ensure spare breakers are in working condition in needed
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue annual oil sampling

Regards,



Douglas Charron
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dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-6
Quarry Rd.
Pembroke, ON.

October 21, 2025

Dear Atul,

This letter serves as an asset management record for the MS-6 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-6 Substation
  - **Location:** Quarry Rd., Pembroke, ON
  - **Voltage Levels:** 44kV Primary/ 12.47kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation supplying 12470/7200 V to feeders 6-1, 6-2, 6-3, and 6-4
  - **Last Inspection:** October 7, 2025

- **Inspection Summary**

  In the inspection conducted on October 7, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Pole supporting lines to T2 severely cracked, starting to rot**
  - **Conduits in basement of building not sealed (2-128)**
  - **No bond on building doorframe (OESC 10-700)**
  - **Anchors pulling out on basement guardrail**
  - **Eyewash expired**
  - **Eyewash stored in close proximity to batteries**
  - **Power bus way off T1 is open, allowing rodents easy access**
  - **T2 and secondary bus duct paint fading and rusting**
  - **Fading signage primarily on B-26**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Medium	Paint fading and rusting on T2,Bus way on T1 open
Switchgear (Indoor)	Low	Appears to be in good condition
Pole Equipment	High	Pole cracked, some rotting around crack
Perimeter Security	Low	Fence in good condition and properly bonded
Grounding	High	Building doorframe needs bond
Vegetation Management	Low	Very little vegetation
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Replace pole supporting T2 primary lines**
  - **Apply bond to building doorframe**
  - **Replace any fading/ missing signage**
  - **Repair power bus way to prevent rodents**

- **Preventative Maintenance:**
  - Repair any rusting and re-paint T2 transformer and bus duct
  - Repair basement guardrail
  - Move eyewash to different location and replace
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue annual oil sampling

Regards,

Douglas Charron
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dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-7
756 Fischer St.
Pembroke, ON.

October 21, 2025

Dear Atul,

This letter serves as an asset management record for the MS-7 Substation, documenting the results of inspections conducted on October 7, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Pembroke MS-7 Substation
  - **Location:** 756 Fischer St., Pembroke, ON
  - **Voltage Levels:** 44kV Primary / 12.47kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation supplying 12470/7200 V feeders 7-1 and 7-2
  - **Last Inspection:** October 7, 2025

- **Inspection Summary**

  In the inspection conducted on October 7, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **No bond on barbed wire (OESC 36-312)**
  - **Only one bond found on transformer (OESC 36-302)**
  - **Fading paint and rust forming on transformer**
  - **Fading signage**
  - **Eyewash expired and located in close proximity to batteries**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Medium	Paint fading and rust forming
Switchgear (Indoor)	Low	All appears to be working
Pole Equipment	Medium	Some insulators are dirty, structure in good condition
Perimeter Security	Low	Gaps are tight, fence in good condition
Grounding	Critical	Add another bond to transformer tank, bond barbed wire
Vegetation Management	Low	Very little vegetation in station
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Add another bond to transformer tank**
  - **Bond barb wire**

- **Preventative Maintenance:**
  - Repair rust, seal and paint transformer and busway
  - Establish a preventative maintenance program with annual testing and servicing

Regards,



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SYNERGY POWER

TO:	SITE:
Ottawa River Power Corp.	MS-8
283 Pembroke St. W.	Nelson St
Pembroke, ON. K8A 6Y6	Pembroke, ON. K8B 1A1

September 23, 2025

Dear Atul,

This letter serves as an asset management record for the MS-8 Substation, documenting the results of inspections and maintenance conducted on September 8, 2025, and the relay upgrades completed during the planned outage. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** MS-8 Substation
  - **Location:** Nelson Street, Pembroke, ON
  - **Voltage Levels:** 44 kV Primary / 13.8 kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation serving 12470/7200 V feeders 8-1 and 8-2
  - **Last Inspection:** September 8, 2025
  - **Last Commissioning Activity:** September 2025 (SEL relay upgrades)

- **Inspection and Testing Summary**

  Maintenance Performed:
  - **Transformer**: Testing and inspection of outdoor main power transformer
  - **Switchgear**: Indoor 13.8 kV distribution switchgear inspected and tested
  - **Protection & Control**: SEL 751 and 735 relays installed; RTAC integration for SCADA; point-to-point and secondary injection testing performed
  - **Breaker Testing**: Functional tests completed

- **Key Findings (OESC Referenced):**
  - Faded/missing pole switch labelling (OESC 2-306)
  - Rusted barbed wire fencing (OESC 26-306)
  - Lack of labelling on motorized 44 kV switches A28 & B28
  - Overgrown vegetation inside the substation (OESC 36-304, Item 5)
  - Gap between brick wall and perimeter fence (OESC 26-312 3)
  - Loose conduits on 44 kV switch pole
  - Unreadable label (AB-8) due to placement behind conduits
  - Improper bonding on pole switch AB-8 and A1S1P-SUB 8: ground conductor connected at lower spot from operating handle, it's recommended to connect above operating handle
  - 44 kV bus proximity to doorway creates minimum approach distance hazard (OESC 36-110, Table 33; Ontario Building Code 3.1.19.1)
  - Transformer lid corrosion and water ingress risk
  - Unsealed conduit entry in building wall (OESC 2-128)
  - Unbonded metal doors and frames (OESC 10-700, 10-802)

- **Asset Condition Rating**

  Severity Scale Definition

  Low → Good condition; no immediate action required.

  Medium → Minor/moderate issues; plan corrective maintenance.

  High → Significant deficiencies; corrective action required soon.

  Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Medium	Surface corrosion, requires sealing and coating
Switchgear (Indoor)	Low	Operational, tested, relays upgraded
Pole Equipment	Medium	Labelling, bonding, conduit issues noted
Perimeter Security	Medium	Barbed wire rusted, wall gap allows for intrusion
Grounding	Critical	No bonding on doors of elec. room
Vegetation Management	Low	Requires clearing and regular maintenance
SCADA/Protection System	Low	SEL relays installed and tested; SCADA functional

- **Relay Upgrade Summary**
  - Installed SEL 751 relays for feeders 8-1 & 8-2
  - Installed SEL 735 metering relay for main feed
  - RTAC (SEL 3505-3) integrated for SCADA and logic control
  - Verified SCADA points, relay protection elements, and reclosing functionality

Recommendations

- **Urgent Repairs (High Priority):**
  - Correct bonding issues on pole switches – connect to switch frame above handle (OESC 10-700)
  - Restore or install all equipment labels in visible and code-compliant locations (OESC 2-306)
  - Seal building conduits and bond all metal doors/frames (OESC 10-700, 10-802)
  - Address approach distance violation at door near 44 kV bus (OESC 36-110, Table 33; OBC 3.1.19.1)

- **Preventative Maintenance:**
  - Remove vegetation/add gravel to restore code compliance (OESC 36-304)
  - Implement a vegetation control program
  - Replace barbed wire and seal perimeter gap
  - Clean and coat transformer top to prevent further rusting / full external painting
  - Continuing annual oil sampling (ASTM/DGA)
  - Establish a preventative maintenance program with annual testing

Regards,

Douglas Charron
Operations Manager, Service & Maintenance
Tel: (519) 245-4900
Cell: (519) 476-3448
dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-1
51 Main St. W.
Mississippi Mills, ON

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the Almonte MS-1 Substation, documenting the results of inspections conducted on October 8, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Almonte MS-1 Substation
  - **Location:** 51 Main Street West, Mississippi Mills, ON
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution Station serving 4160/2400 V feeders 1F1, 1F2, 1F3
  - **Last Inspection:** October 8, 2025

- **Inspection Summary**

  In the inspection conducted on October 8, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Heavy Rust forming on Transformer**
  - **Switch ILS43 Has no visible labeling at base of pole**
  - **Terminations on transformers secondary side are very dirty**





- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	High	Paint chipping and rust forming around transformer including radiators.
Indoor Equipment	Low	Indoor Equipment appears to be in good condition.
Pole Equipment	Critical	Labeling on switch ILS43.
Perimeter Security	Low	Fence is secure and properly bonded.
Grounding	Low	Everything appears to be properly bonded including Transformer, Switches, tower structure, building, and fence.
Vegetation Management	Low	Appears to be new gravel with very little vegetation growth.
SCADA/Protection System	low	No concerns from ORPC staff with these systems.

Recommendations

- **Urgent Repairs (High Priority):**
  - **Apply signage to switch ILS43**

- **Preventative Maintenance:**

  - Remove and seal rust on transformer, so no further damage is done
  - Clean secondary terminations to improve longevity
  - Establish a preventative maintenance program with annual testing and servicing
  - Continue annual oil sampling

Regards,



Douglas Charron
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dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-2
309 Victoria St.
Almonte, ON

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-2 Substation, documenting the results of inspections conducted on October 8, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Almonte MS-2 Substation
  - **Location:** 309 Victoria St., Almonte, ON
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution Station serving 4160/2400 feeders 2F1, 2F2, and 2F3
  - **Last Inspection:** October 8, 2025

- **Inspection Summary**

  In the inspection conducted on October 8, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced where applicable):**
  - **Concrete securing tower structure severely cracked**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Low	Good condition
Switchgear (Indoor)	Medium	Handle broken on metering/ incoming cell door
Tower Equipment	Critical	Concrete securing tower structure severely cracked
Perimeter Security	Low	Wall and barbed wire in good condition
Grounding	Low	Bonding meets code requirements
Vegetation Management	Low	Very little vegetation growth
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Repair or pour a new concrete foundation in which tower structure is fixed to.**

- **Preventative Maintenance:**
  - Repair handle on indoor switchgear
  - Implement a preventative maintenance program with annual cleaning and testing of devices
  - Continue annual oil sampling

Regards,



Douglas Charron
Operation Manager, Service & Maintenance
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dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-3
424 king St.
Almonte, ON

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-3 Substation, documenting the results of inspections conducted on October 8, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Almonte MS-3 Substation
  - **Location:** 424 King St., Almonte, ON.
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation serving feeders 3F1 and 3F2
  - **Last Inspection:** October 8, 2025

- **Inspection Summary**

  In the inspection conducted on October 8, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced):**
  - **Transformer only has one bond (OESC 36-302)**
  - **Rust and fading paint on transformer**
  - **Fading name plate on transformer**
  - **Conservator on transformer leaking oil**
  - **Barber wire on fencing facing wrong direction, shows light rusting**
  - **Bonds on fencing not properly weaved through fabric (OESC 36-312)**
  - **Bond clamp on gate loose, not a secure connection (OESC 36-312)**
  - **Tower structure displays light rust**
  - **Rusting on top rail of fence**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Critical	Transformer shows light rust, fading paint, and fading nameplate. Conservator appears to be leaking at level gauge. Transformer only has one bond.
Switchgear (Indoor)	Medium	Paint on metal clad enclosure fading, spaces for rodents to get in.
Pole/Tower Equipment	Low	Equipment appears to be in good condition, light rusting on tower structure
Perimeter Security	Medium	Barbed wire on fencing facing wrong direction, barbed wire and fencing shows light rust
Grounding	Critical	Multiple bonds incorrectly installed on fence and gate. Transformer only has one bond
Vegetation Management	Low	Very little vegetation growth
SCADA/Protection System	Low	No concerns from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**
  - **Repair leak on oil conservator**
  - **Repair fence & gate bonding to meet code requirements**
  - **Add another bond to transformer tank**

- **Preventative Maintenance:**
  - Remove current rusting, seal and paint transformer
  - Install new transformer nameplate to ensure it continues to be legible
  - Paint switchgear building
  - Paint fencing and barbed wire

Regards,



Douglas Charron
Operation Manager, Service & Maintenance
Tel: (519) 245-4900
Cell: (519) 476-3448
dcharron@synergypower.tech

SYNERGY POWER

TO:
Ottawa River Power Corp.
283 Pembroke St. W.
Pembroke, ON. K8A 6Y6

SITE:
MS-4
92 Industrial Dr.
Almonte, ON. K0A 1A0

October 20, 2025

Dear Atul,

This letter serves as an asset management record for the MS-4 Substation, documenting the results of inspections conducted on October 8, 2025. It outlines current asset condition, safety code compliance, and recommendations for sustaining asset integrity, aligned with the Ontario Electrical Safety Code (OESC) and NETA standards.

- **Asset Overview**
  - **Asset Name:** Almonte MS-4 Substation
  - **Location:** 92 Industrial Dr., Almonte, ON.
  - **Voltage Levels:** 44kV Primary / 4.16kV Secondary
  - **Ownership/Operator:** Ottawa River Power Corp.
  - **Function:** Distribution substation serving 4160/2400 V to feeders 4F1 & 4F2
  - **Last Inspection:** October 8, 2025
  - **Last Commissioning Activity:**

- **Inspection Summary**

  In the inspection conducted on October 8, 2025 we visually, from ground level, viewed equipment on the SLD to get accurate condition. Name-plate data was gathered when accessible. Binoculars were used to assess condition of equipment on tower structures and poles.

- **Key Findings (OESC Referenced):**
  - **Station is Like-new, no code violations or concerns**

- **Asset Condition Rating**

Severity Scale Definition

- Low → Good condition; no immediate action required.
- Medium → Minor/moderate issues; plan corrective maintenance.
- High → Significant deficiencies; corrective action required soon.
- Critical → Urgent non-compliance or safety risk; immediate attention required.

Component	Severity Scale	Notes
Outdoor Transformer	Low	Very minor rust, not a concern
Switchgear (Outdoor)	Low	Good condition
Reclosure's	Low	Good condition
Pole Equipment	Low	Good condition
Perimeter Security	Low	Good condition
Grounding	Low	No grounding issues found
Vegetation Management	Low	No vegetation issues
SCADA/Protection System	Low	No comments from ORPC staff

Recommendations

- **Urgent Repairs (High Priority):**

- **Preventative Maintenance:**
  - Develop an annual preventative maintenance program for testing and servicing equipment
  - Continue annual oil sampling

Regards,



Douglas Charron
Operation Manager, Service & Maintenance
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dcharron@synergypower.tech

APPENDIX B – REGIONAL PLANNING AND ELECTRIFICATION CONTEXT

This appendix provides reference material supporting the regional planning, electrification, and demand context summarized in Section 2. Materials are reproduced in excerpted form for reference and are not restated in full within the DSP.

B.1 RENFREW REGION INTEGRATED REGIONAL RESOURCE PLAN – ORPC INTERPRETATION

The following external planning documents were reviewed and considered as contextual inputs in the development of the Renfrew Region planning discussion in Section B.0.1:

- Independent Electricity System Operator (IESO). *Renfrew Region Integrated Regional Resource Plan (IRRP)*. December 22, 2022.

The Independent Electricity System Operator (IESO) released the Renfrew Region Integrated Regional Resource Plan (IRRP) in December 2022, covering a 2021–2042 planning horizon. The IRRP was developed through Ontario's coordinated regional electricity planning process involving the IESO, Hydro One Transmission, Hydro One Distribution, and embedded local distribution companies, including ORPC.

The Renfrew IRRP identifies emerging electricity system needs within the region driven by a combination of modest demand growth, electrification trends, and transmission system configuration constraints. While the region has historically experienced relatively low growth, the IRRP notes that electricity demand is increasingly approaching the capacity limits of portions of the existing transmission system, with station capacity issues identified in the Pembroke supply area, as well as in Petawawa and Laurentian Valley. The IRRP recommends that these capacity-related needs be advanced through a subsequent Regional Infrastructure Plan (RIP) process led by the upstream system owner, with further technical definition and option development to occur in that stage of planning.

From ORPC's perspective, the Renfrew Region IRRP establishes important upstream planning assumptions that frame the operating context for Pembroke-area distribution substations. The IRRP identifies ORPC as an embedded distributor at Pembroke Transformer Station, supplying predominantly residential load, while upstream transmission assets and the majority of

industrial load remain under Hydro One ownership and control. As such, ORPC does not own or control the upstream transmission facilities addressed in the IRRP; however, the regional planning outcomes signal the potential for future upstream infrastructure changes, operational constraints, and coordination requirements that may influence outage planning, construction sequencing, and interface arrangements at ORPC's 44 kV points of connection.

The IRRP also highlights broader regional trends relevant to ORPC's substation planning, including residential development pressures in certain communities, increasing electrification of space heating and transportation, and the growing importance of maintaining system performance under peak and extreme-weather conditions. The IRRP explicitly distinguishes between near term, medium term, and long term planning horizons and emphasizes the need to avoid premature commitment to long-term infrastructure solutions given forecast uncertainty, instead identifying near-term actions and monitoring activities to inform subsequent planning cycles.

Accordingly, ORPC's substation-focused DSP reflects awareness of the Renfrew IRRP as contextual planning input rather than a directive investment plan. ORPC's capital priorities are developed based on asset condition, system criticality, and relative risk within ORPC-owned substations, while remaining attentive to regional planning signals that may affect supply arrangements, permissible outage windows, and coordination with upstream asset renewal or reinforcement initiatives as IRRP recommendations advance through future RIP and implementation stages over the 2027–2031 planning horizon.

B.2 GREATER OTTAWA REGION REGIONAL PLANNING – ALMONTE CONTEXT AND ORPC INTERPRETATION

The following external planning documents were reviewed and considered as contextual inputs in the development of the Greater Ottawa / Almonte planning discussion in Section B.0.2:

- Independent Electricity System Operator (IESO). *Greater Ottawa Region – Third Cycle Regional Needs Assessment*. December 20, 2022.
- Independent Electricity System Operator (IESO). *Ottawa Area Integrated Regional Resource Plan (IRRP)*. July 31, 2025.
  (Referenced for regional planning framework and methodological context only; not relied upon for asset- or substation-specific conclusions applicable to the Almonte service area.)

The Independent Electricity System Operator (IESO), in coordination with Hydro One Transmission, Hydro One Distribution, and embedded local distribution companies, completed the Greater Ottawa Region 3rd Cycle Regional Needs Assessment in December 2022. The Needs Assessment forms part of Ontario's coordinated regional electricity planning process and evaluates electricity system conditions and emerging needs across the broader Ottawa region over a long-term planning horizon.

For the purposes of regional planning, the Greater Ottawa Region is subdivided into multiple sub-regions, including the Outer Ottawa – Western Area, which encompasses the Almonte Transformer Station supply area. Within this context, Ottawa River Power Corporation (ORPC) is identified as an embedded distributor supplying customers from Almonte TS via Hydro One Distribution-owned upstream facilities. While ORPC does not own or operate the upstream transmission or sub-transmission assets addressed in the regional planning process, the Greater Ottawa regional planning outcomes establish the upstream operating and coordination context within which ORPC's Almonte-area distribution substations function.

The Greater Ottawa Region Needs Assessment identifies that, while portions of the broader Ottawa area are experiencing more pronounced growth and electrification pressures, outer

areas such as the Western Area are subject to more moderate and variable demand growth, with planning emphasis placed on maintaining reliability, asset condition, and coordination readiness rather than near-term major infrastructure expansion. The Needs Assessment confirms that certain needs within the Greater Ottawa Region require regional coordination and subsequent planning stages, while other areas may be addressed through continued monitoring and distributor-level planning as conditions evolve.

From ORPC's perspective, the Greater Ottawa regional planning materials provide contextual upstream planning assumptions rather than prescriptive direction for distribution-level investments at Almonte. The regional documents signal the importance of maintaining awareness of upstream system constraints, outage coordination requirements, and longer-term regional development trends, particularly as electrification and decarbonization policies continue to influence demand patterns across Eastern Ontario. However, the regional planning outcomes do not identify specific transmission-driven capacity deficiencies or mandatory infrastructure reinforcements directly affecting ORPC-owned substation assets in the Almonte service area within the near-term planning horizon.

The Greater Ottawa regional planning framework also emphasizes the importance of managing forecast uncertainty through staged planning, monitoring, and adaptive decision-making. This approach aligns with ORPC's treatment of Almonte-area substation needs within the DSP, where investment priorities are informed by asset condition, operational flexibility, safety considerations, and relative system criticality, rather than by long-range demand forecasts alone.

Accordingly, ORPC's substation-focused DSP reflects the Greater Ottawa regional planning documents as contextual reference material that informs awareness of upstream system conditions and regional planning posture. ORPC's capital planning for Almonte-area substations remains grounded in the condition and performance of ORPC-owned assets, with flexibility retained to coordinate with upstream planning outcomes should future regional studies or implementation activities introduce constraints or opportunities affecting outage planning, sequencing, or points of interconnection over the 2027–2031 planning horizon.

APPENDIX C – GIS DERIVED FEEDER & SUBSTATION DATA

C.1 OVERVIEW AND DATA USE NOTES

This appendix presents supporting feeder-level data used to inform the substation condition, criticality, and needs assessments summarized in Sections 4 through 6 of this Distribution System Plan. The tables included herein provide a consolidated view of feeder characteristics associated with ORPC-owned distribution substations, including feeder counts, approximate feeder lengths, overhead and underground exposure, and general configuration attributes.

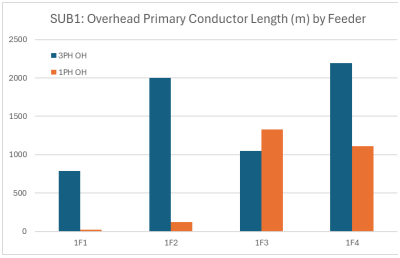
The data presented in this appendix are intended to support comparative, planning-level assessments rather than detailed engineering analysis. Feeder attributes are used as proxies for relative exposure, operational complexity, and restoration considerations, and are not intended to represent precise as-built conditions, peak loading values, or real-time operational constraints.

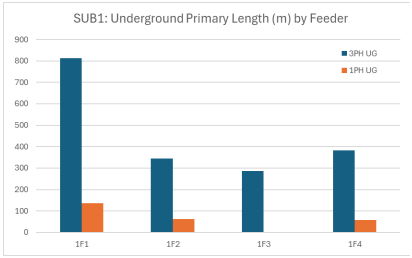
Feeder information has been derived from available GIS datasets and internal records and has been processed to provide consistent, substation-level summaries suitable for planning application. As such, the data are used to inform relative risk, criticality, and operational flexibility considerations across substations, consistent with the qualitative, risk-informed planning approach adopted in this DSP.

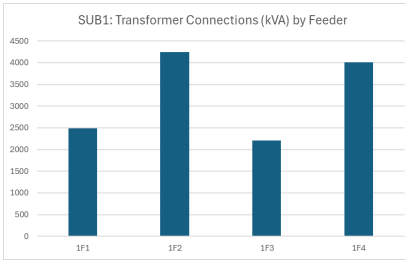
The tables in this appendix are referenced where relevant in the body of the report but are not reproduced in full within the main text in order to maintain clarity and focus on planning conclusions.

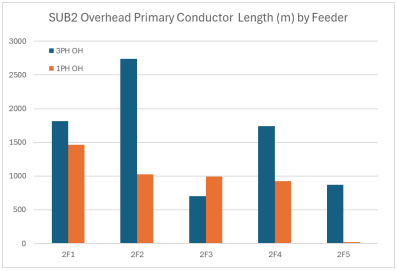
C.2 Pembroke-Area Substation Feeder Summary Tables

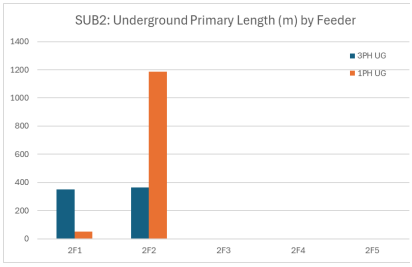
Note: '3PH' refers to 'three phase', '1PH' refers to 'single phase'

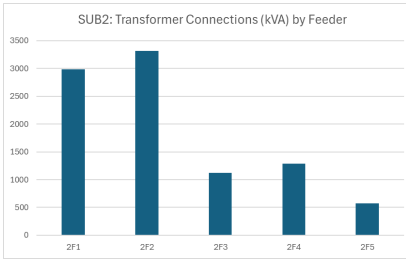


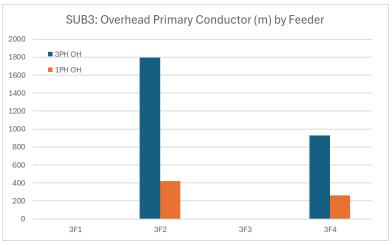


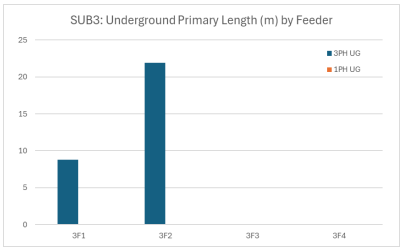


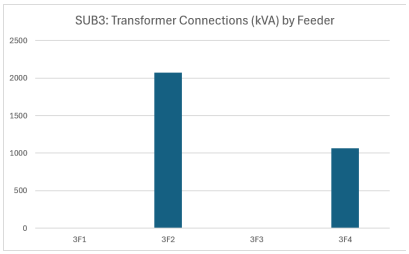


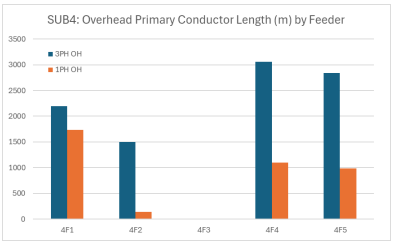


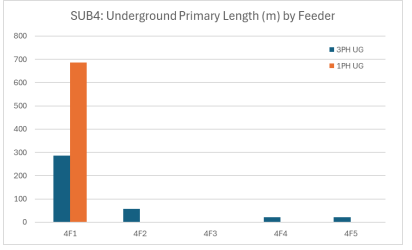


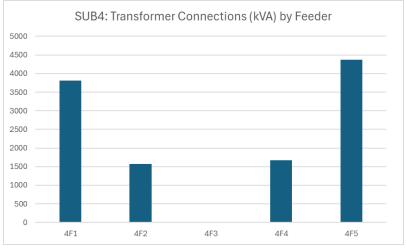


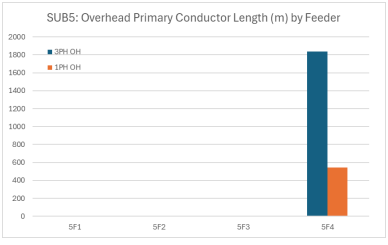


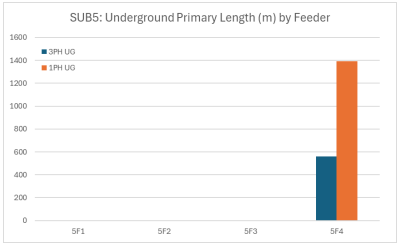


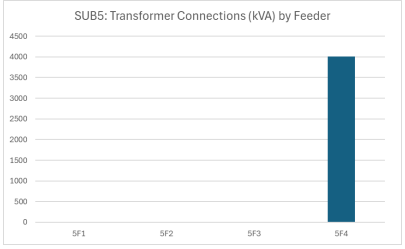


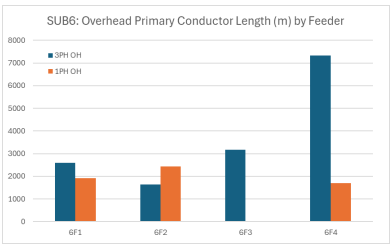


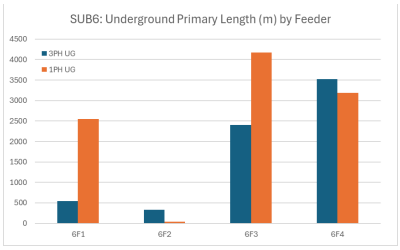


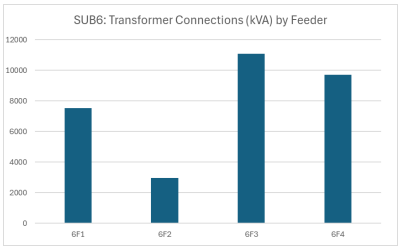


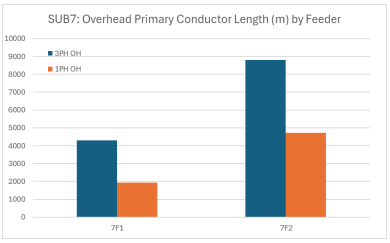


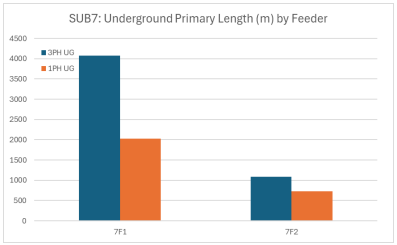


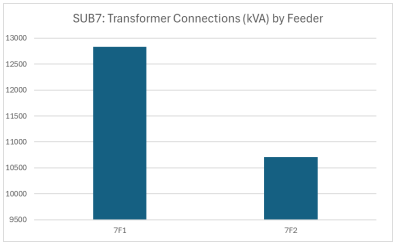

SUB6: Overhead Primary Conductor Length (m) by Feeder
3PH OH
1PH OH
6F1
6F2
6F3
6F4

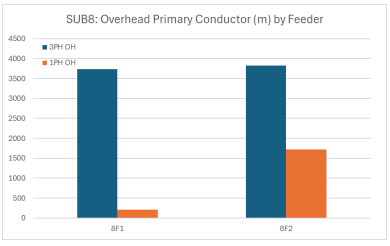

SUB6: Underground Primary Length (m) by Feeder
3PH UG
1PH UG
6F1
6F2
6F3
6F4

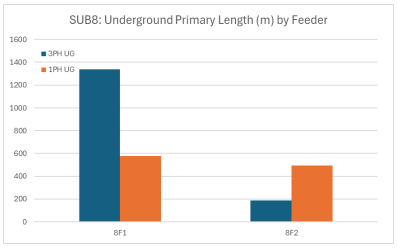

SUB6: Transformer Connections (kVA) by Feeder
6F1
6F2
6F3
6F4

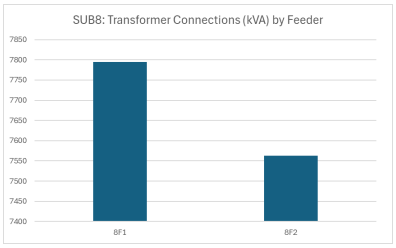

SUB7: Overhead Primary Conductor Length (m) by Feeder
3PH OH
1PH OH
7F1
7F2

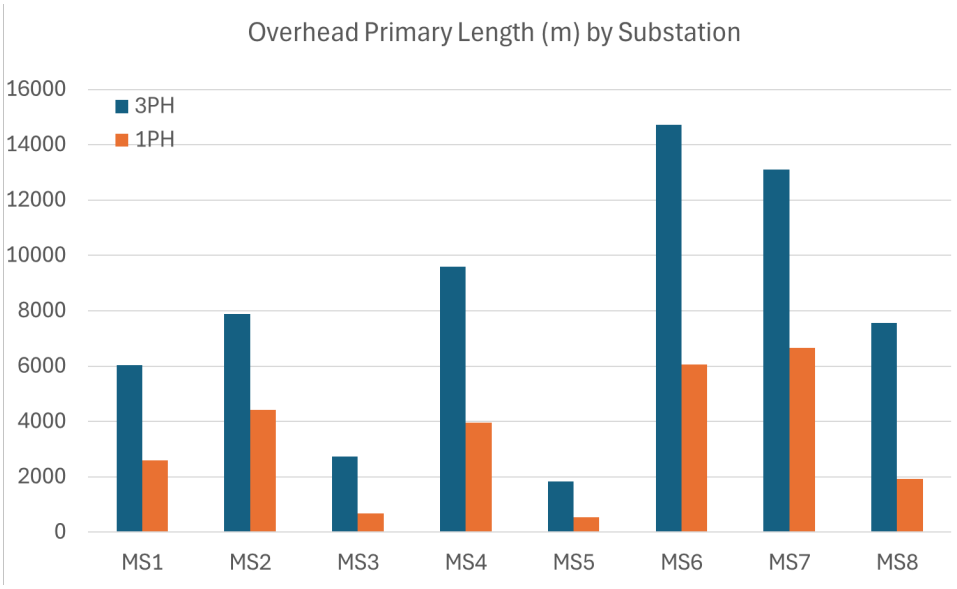

SUB7: Underground Primary Length (m) by Feeder
3PH UG
1PH UG
7F1
7F2

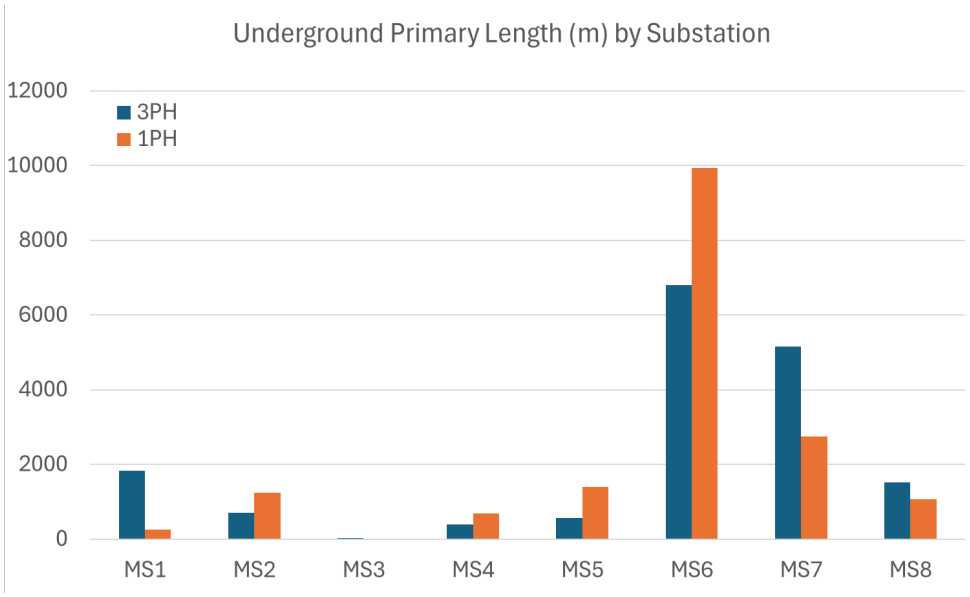

SUB7: Transformer Connections (kVA) by Feeder
7F1
7F2

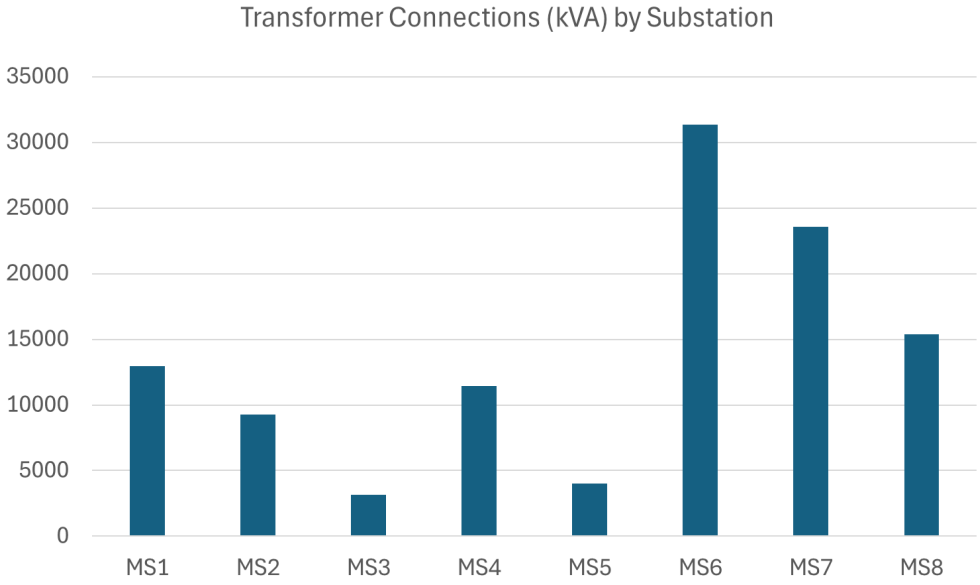

SUB8: Overhead Primary Conductor (m) by Feeder
3PH OH
1PH OH
8F1
8F2


SUB8: Underground Primary Length (m) by Feeder
3PH UG
1PH UG
8F1
8F2


SUB8: Transformer Connections (kVA) by Feeder
8F1
8F2

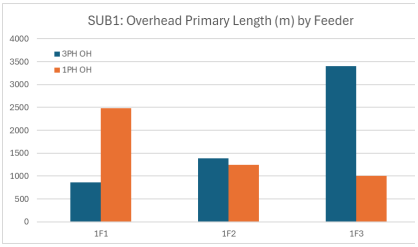

Overhead Primary Length (m) by Substation
3PH
1PH
MS1
MS2
MS3
MS4
MS5
MS6
MS7
MS8

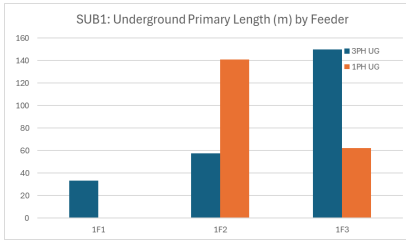

Underground Primary Length (m) by Substation
12000
10000
8000
6000
4000
2000
0
3PH
1PH
MS1
MS2
MS3
MS4
MS5
MS6
MS7
MS8

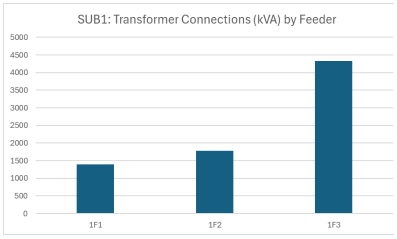

Transformer Connections (kVA) by Substation
35000
30000
25000
20000
15000
10000
5000
0
MS1
MS2
MS3
MS4
MS5
MS6
MS7
MS8

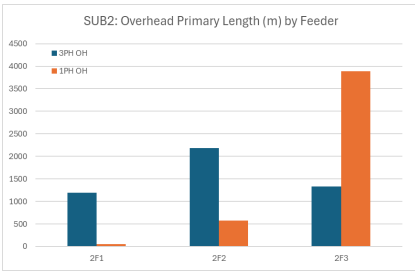
C.3 Almonte-Area Substation Feeder Summary Tables

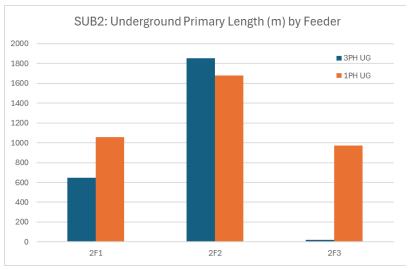
Note: '3PH' refers to 'three phase', '1PH' refers to 'single phase'

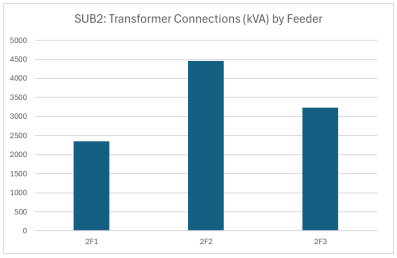


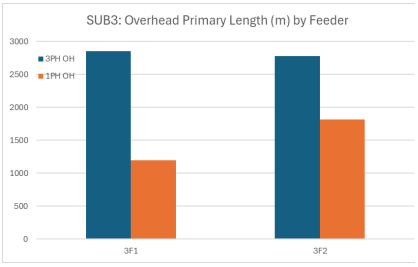


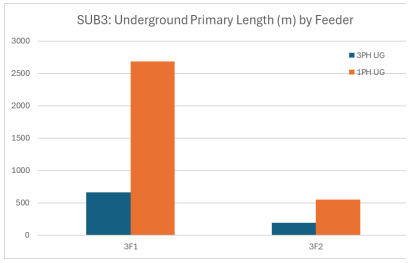


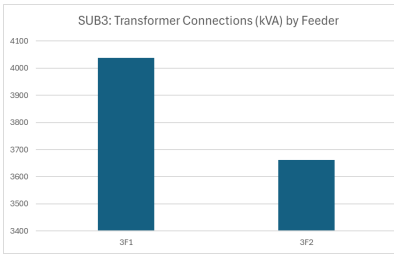


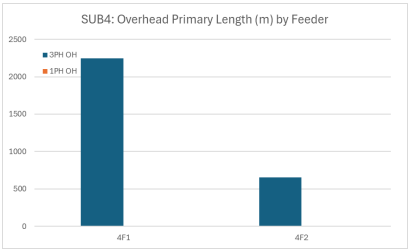


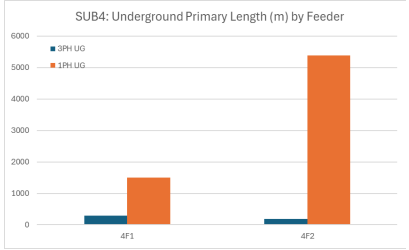


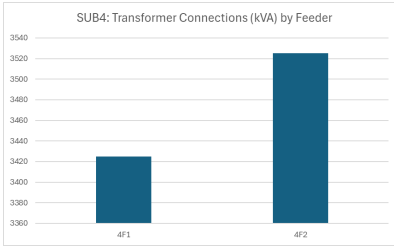


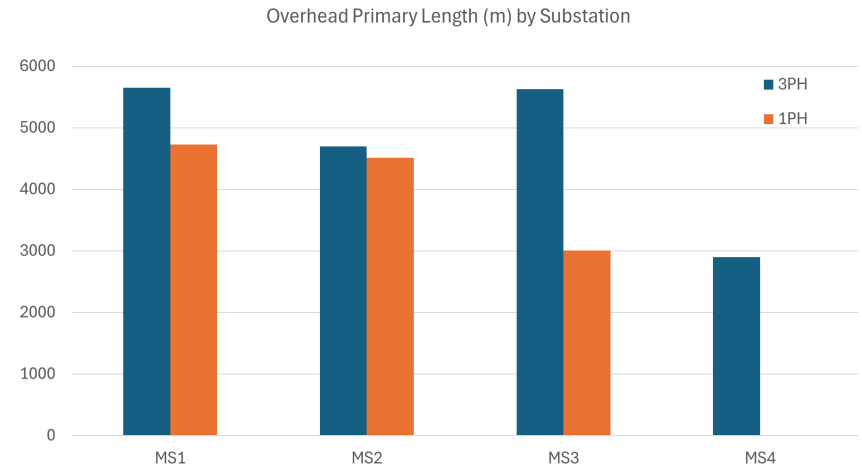


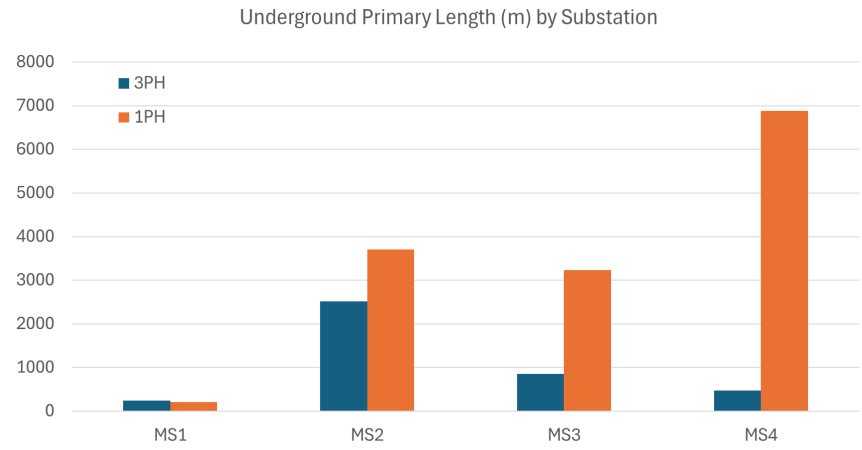


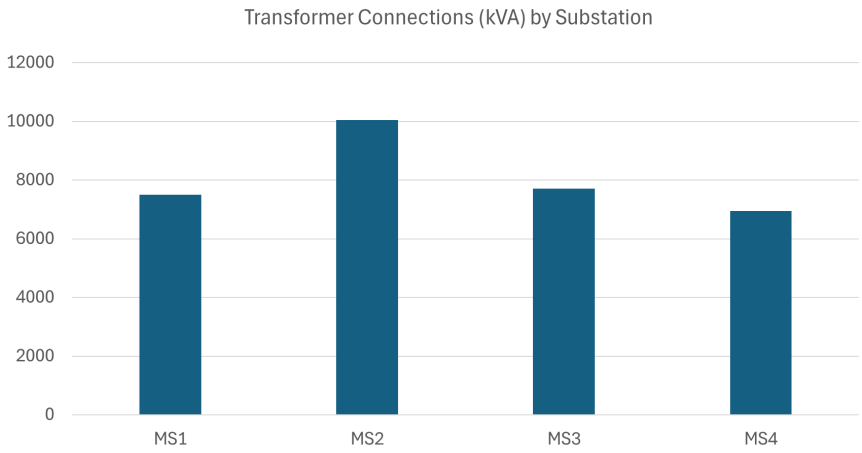







Overhead Primary Length (m) by Substation
6000
5000
4000
3000
2000
1000
0
3PH
1PH
MS1
MS2
MS3
MS4


Underground Primary Length (m) by Substation
8000
7000
6000
5000
4000
3000
2000
1000
0
3PH
1PH
MS1
MS2
MS3
MS4


Transformer Connections (kVA) by Substation
12000
10000
8000
6000
4000
2000
0
MS1
MS2
MS3
MS4

APPENDIX D – SUBSTATION CAPITAL PROJECT SUMMARIES (PLANNING LEVEL)

This appendix provides planning-level summaries of individual substation capital projects identified through the needs identification and prioritization processes described in Sections 6 through 8 of this DSP. The project summaries are intended to illustrate the **types** of investments, drivers, and relative timing considerations associated with addressing identified substation needs over the DSP planning horizon.

Each project summary reflects a conceptual scope of work, aligned with the applicable OEB investment category, ORPC DSP program, primary investment driver, and corresponding DSP need reference. Estimated capital costs are provided at a **high-level, order-of-magnitude** to support planning discussions and internal capital coordination, and are not intended to represent detailed engineering estimates or final approved budgets.

The projects included in this appendix do not constitute committed or execution-ready work. Advancement of any individual project remains subject to future engineering definition, coordination with upstream system owners, refinement of scope and cost, availability of capital, and subsequent ORPC governance and regulatory processes. Planning windows and priority classifications reflect **relative sequencing considerations** based on asset condition, safety, operational risk, and system criticality, and may be adjusted as system conditions, funding priorities, or regional coordination requirements evolve.

Accordingly, this appendix is provided to support transparency and traceability of the DSP's capital planning framework, while maintaining the appropriate distinction between planning intent and project execution.

Substation Project Summary

Project ID:	STN001
Substation:	PEM MS#1
Project Name:	SCADA & RELAY UPGRADE
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2028
Estimated Capital Cost:	$150,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)

Project Description:

Removal of existing legacy protective relays and SCADA equipment.

Installation of modern protective relays, station meter, SCADA server, communications infrastructure, and control wiring.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • Feeder Protection Relay (4EA) • Satellite Clock (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

Substation Project Summary

Project ID:		STN001
Substation:		PEM MS#1
Project Name:		SCADA & RELAY UPGRADE
	This project is classified as High Priority due to its role in addressing legacy protection and control infrastructure associated with elevated operational consequence, increasing obsolescence risk, and identified system needs related to reliability, safety, and system visibility. The project also provides enabling system-wide benefits that support restoration performance and future risk-informed planning.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The project addresses legacy protection and control infrastructure that lags current operational and safety expectations. Where deficiencies affect protection performance, system visibility, or safe restoration practices, the DSP prioritization framework assigns elevated urgency.
	System Consequence & Operational Impact	
		The affected assets support core substation functions whose degradation could materially affect outage response, restoration capability, or system reliability. The project therefore addresses risks with higher consequence relative to other identified needs.
	Asset Obsolescence & Reliability Risk	
		Existing protection and SCADA equipment exhibits advanced age, declining manufacturer support, and functional limitations. Continued reliance on legacy systems increases the likelihood of operational challenges, extended outage duration, or reduced situational awareness.
	Needs Planning	
		The project directly responds to planning-level needs related to reliability, operational flexibility, and system visibility identified in Section 6 of the DSP. These needs are considered higher urgency where condition concerns coincide with system consequence.
	Enabling & System Benefit	
		Modernization of protection, control, and communications infrastructure provides foundational improvements that enhance restoration performance, reduce operational complexity, and improve the quality of data used in future planning and asset management decisions.
	Planning Horizon Urgency	

Substation Project Summary

Project ID:		STN001
Substation:		PEM MS#1
Project Name:		SCADA & RELAY UPGRADE
		Based on the combined influence of safety exposure, consequence, and enabling value, the project is appropriately advanced within the nearer-term planning window relative to projects addressing lower consequence or more localized risks.
Alternatives Considered		
	1. Do Nothing Maintaining existing legacy protection and SCADA equipment was considered. This option would avoid near term capital expenditure but would not address increasing obsolescence, declining manufacturer support, or limitations in protection performance and system visibility. Continued reliance on aging equipment would increase long term reliability and operational risk. 2. Like for Like Replacement of Individual Components Targeted replacement of select relays or communication devices on a one for one basis was considered. While this approach could defer full modernization costs, it would result in a fragmented protection and control environment, continued dependence on legacy interfaces, and limited improvement in overall system functionality, maintainability, or standardization. 3. Operational Mitigation in Lieu of Capital Investment Enhanced monitoring and continued reliance on manual operational practices were considered. This approach would not address underlying equipment obsolescence or materially improve protection performance, system visibility, or restoration capability. It would also limit ORPC's ability to collect consistent asset and system performance data needed to support effective long term planning and risk informed capital decision making. 4. Deferred Implementation Deferring modernization to a later planning period was considered. While deferral may be appropriate where risk is low, continued aging of legacy equipment and the loss of technical support increases the likelihood of unplanned failures, emergency replacement, and reduced coordination flexibility with other system initiatives. 5. Selected Approach Comprehensive modernization of protection, control, and SCADA systems was selected as the preferred approach. This option provides improved reliability, standardized protection performance, enhanced system visibility, and supports more effective long term asset management and planning across the substation portfolio.	

Substation Project Summary

Project ID:	STN002
Substation:	PEM MS#2
Project Name:	SCADA & RELAY UPGRADE
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2028
Estimated Capital Cost:	$165,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)

Project Description:

Removal of existing legacy protective relays and SCADA equipment.

Installation of modern protective relays, station meter, SCADA server, communications infrastructure, and control wiring.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • Feeder Protection Relay (5EA) • Satellite Clock (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

Substation Project Summary

Project ID:		STN002
Substation:		PEM MS#2
Project Name:		SCADA & RELAY UPGRADE
	This project is classified as High Priority due to its role in addressing legacy protection and control infrastructure associated with elevated operational consequence, increasing obsolescence risk, and identified system needs related to reliability, safety, and system visibility. The project also provides enabling system-wide benefits that support restoration performance and future risk-informed planning.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The project addresses legacy protection and control infrastructure that lags current operational and safety expectations. Where deficiencies affect protection performance, system visibility, or safe restoration practices, the DSP prioritization framework assigns elevated urgency.
	System Consequence & Operational Impact	
		The affected assets support core substation functions whose degradation could materially affect outage response, restoration capability, or system reliability. The project therefore addresses risks with higher consequence relative to other identified needs.
	Asset Obsolescence & Reliability Risk	
		Existing protection and SCADA equipment exhibits advanced age, declining manufacturer support, and functional limitations. Continued reliance on legacy systems increases the likelihood of operational challenges, extended outage duration, or reduced situational awareness.
	Needs Planning	
		The project directly responds to planning-level needs related to reliability, operational flexibility, and system visibility identified in Section 6 of the DSP. These needs are considered higher urgency where condition concerns coincide with system consequence.
	Enabling & System Benefit	
		Modernization of protection, control, and communications infrastructure provides foundational improvements that enhance restoration performance, reduce operational complexity, and improve the quality of data used in future planning and asset management decisions.
	Planning Horizon Urgency	

Substation Project Summary

Project ID:		STN002
Substation:		PEM MS#2
Project Name:		SCADA & RELAY UPGRADE
		Based on the combined influence of safety exposure, consequence, and enabling value, the project is appropriately advanced within the nearer-term planning window relative to projects addressing lower consequence or more localized risks.
Alternatives Considered		
	1. Do Nothing Maintaining existing legacy protection and SCADA equipment was considered. This option would avoid near term capital expenditure but would not address increasing obsolescence, declining manufacturer support, or limitations in protection performance and system visibility. Continued reliance on aging equipment would increase long term reliability and operational risk. 2. Like for Like Replacement of Individual Components Targeted replacement of select relays or communication devices on a one for one basis was considered. While this approach could defer full modernization costs, it would result in a fragmented protection and control environment, continued dependence on legacy interfaces, and limited improvement in overall system functionality, maintainability, or standardization. 3. Operational Mitigation in Lieu of Capital Investment Enhanced monitoring and continued reliance on manual operational practices were considered. This approach would not address underlying equipment obsolescence or materially improve protection performance, system visibility, or restoration capability. It would also limit ORPC's ability to collect consistent asset and system performance data needed to support effective long term planning and risk informed capital decision making. 4. Deferred Implementation Deferring modernization to a later planning period was considered. While deferral may be appropriate where risk is low, continued aging of legacy equipment and the loss of technical support increases the likelihood of unplanned failures, emergency replacement, and reduced coordination flexibility with other system initiatives. 5. Selected Approach Comprehensive modernization of protection, control, and SCADA systems was selected as the preferred approach. This option provides improved reliability, standardized protection performance, enhanced system visibility, and supports more effective long term asset management and planning across the substation portfolio.	

Substation Project Summary

Project ID:	STN003
Substation:	PEM MS#3
Project Name:	SCADA & RELAY UPGRADE
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2026
Estimated Capital Cost:	$110,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)

Project Description:

Removal of existing legacy protective relays and SCADA equipment.

Installation of modern protective relays, station meter, SCADA server, communications infrastructure, and control wiring.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • Feeder Protection Relay (2EA) • Satellite Clock (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

Substation Project Summary

Project ID:		STN003
Substation:		PEM MS#3
Project Name:		SCADA & RELAY UPGRADE
	This project is classified as High Priority due to its role in addressing legacy protection and control infrastructure associated with elevated operational consequence, increasing obsolescence risk, and identified system needs related to reliability, safety, and system visibility. The project also provides enabling system-wide benefits that support restoration performance and future risk-informed planning.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The project addresses legacy protection and control infrastructure that lags current operational and safety expectations. Where deficiencies affect protection performance, system visibility, or safe restoration practices, the DSP prioritization framework assigns elevated urgency.
	System Consequence & Operational Impact	
		The affected assets support core substation functions whose degradation could materially affect outage response, restoration capability, or system reliability. The project therefore addresses risks with higher consequence relative to other identified needs.
	Asset Obsolescence & Reliability Risk	
		Existing protection and SCADA equipment exhibits advanced age, declining manufacturer support, and functional limitations. Continued reliance on legacy systems increases the likelihood of operational challenges, extended outage duration, or reduced situational awareness.
	Needs Planning	
		The project directly responds to planning-level needs related to reliability, operational flexibility, and system visibility identified in Section 6 of the DSP. These needs are considered higher urgency where condition concerns coincide with system consequence.
	Enabling & System Benefit	
		Modernization of protection, control, and communications infrastructure provides foundational improvements that enhance restoration performance, reduce operational complexity, and improve the quality of data used in future planning and asset management decisions.
	Planning Horizon Urgency	

Substation Project Summary

Project ID:		STN003
Substation:		PEM MS#3
Project Name:		SCADA & RELAY UPGRADE
		Based on the combined influence of safety exposure, consequence, and enabling value, the project is appropriately advanced within the nearer-term planning window relative to projects addressing lower consequence or more localized risks.
Alternatives Considered		
	1. Do Nothing Maintaining existing legacy protection and SCADA equipment was considered. This option would avoid near term capital expenditure but would not address increasing obsolescence, declining manufacturer support, or limitations in protection performance and system visibility. Continued reliance on aging equipment would increase long term reliability and operational risk. 2. Like for Like Replacement of Individual Components Targeted replacement of select relays or communication devices on a one for one basis was considered. While this approach could defer full modernization costs, it would result in a fragmented protection and control environment, continued dependence on legacy interfaces, and limited improvement in overall system functionality, maintainability, or standardization. 3. Operational Mitigation in Lieu of Capital Investment Enhanced monitoring and continued reliance on manual operational practices were considered. This approach would not address underlying equipment obsolescence or materially improve protection performance, system visibility, or restoration capability. It would also limit ORPC's ability to collect consistent asset and system performance data needed to support effective long term planning and risk informed capital decision making. 4. Deferred Implementation Deferring modernization to a later planning period was considered. While deferral may be appropriate where risk is low, continued aging of legacy equipment and the loss of technical support increases the likelihood of unplanned failures, emergency replacement, and reduced coordination flexibility with other system initiatives. 5. Selected Approach Comprehensive modernization of protection, control, and SCADA systems was selected as the preferred approach. This option provides improved reliability, standardized protection performance, enhanced system visibility, and supports more effective long term asset management and planning across the substation portfolio.	

Substation Project Summary

Project ID:	STN004
Substation:	PEM MS#5
Project Name:	SCADA & RELAY UPGRADE
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2028
Estimated Capital Cost:	$75,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)

Project Description:

Removal of existing legacy protective relays and SCADA equipment.

Installation of modern protective relays, station meter, SCADA server, communications infrastructure, and control wiring.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • Feeder Protection Relay (1EA) • Satellite Clock (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

Substation Project Summary

Project ID:		STN004
Substation:		PEM MS#5
Project Name:		SCADA & RELAY UPGRADE
	This project is classified as High Priority due to its role in addressing legacy protection and control infrastructure associated with elevated operational consequence, increasing obsolescence risk, and identified system needs related to reliability, safety, and system visibility. The project also provides enabling system-wide benefits that support restoration performance and future risk-informed planning.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The project addresses legacy protection and control infrastructure that lags current operational and safety expectations. Where deficiencies affect protection performance, system visibility, or safe restoration practices, the DSP prioritization framework assigns elevated urgency.
	System Consequence & Operational Impact	
		The affected assets support core substation functions whose degradation could materially affect outage response, restoration capability, or system reliability. The project therefore addresses risks with higher consequence relative to other identified needs.
	Asset Obsolescence & Reliability Risk	
		Existing protection and SCADA equipment exhibits advanced age, declining manufacturer support, and functional limitations. Continued reliance on legacy systems increases the likelihood of operational challenges, extended outage duration, or reduced situational awareness.
	Needs Planning	
		The project directly responds to planning-level needs related to reliability, operational flexibility, and system visibility identified in Section 6 of the DSP. These needs are considered higher urgency where condition concerns coincide with system consequence.
	Enabling & System Benefit	
		Modernization of protection, control, and communications infrastructure provides foundational improvements that enhance restoration performance, reduce operational complexity, and improve the quality of data used in future planning and asset management decisions.
	Planning Horizon Urgency	

Substation Project Summary

Project ID:		STN004
Substation:		PEM MS#5
Project Name:		SCADA & RELAY UPGRADE
		Based on the combined influence of safety exposure, consequence, and enabling value, the project is appropriately advanced within the nearer-term planning window relative to projects addressing lower consequence or more localized risks.
Alternatives Considered		
	1. Do Nothing Maintaining existing legacy protection and SCADA equipment was considered. This option would avoid near term capital expenditure but would not address increasing obsolescence, declining manufacturer support, or limitations in protection performance and system visibility. Continued reliance on aging equipment would increase long term reliability and operational risk. 2. Like for Like Replacement of Individual Components Targeted replacement of select relays or communication devices on a one for one basis was considered. While this approach could defer full modernization costs, it would result in a fragmented protection and control environment, continued dependence on legacy interfaces, and limited improvement in overall system functionality, maintainability, or standardization. 3. Operational Mitigation in Lieu of Capital Investment Enhanced monitoring and continued reliance on manual operational practices were considered. This approach would not address underlying equipment obsolescence or materially improve protection performance, system visibility, or restoration capability. It would also limit ORPC's ability to collect consistent asset and system performance data needed to support effective long term planning and risk informed capital decision making. 4. Deferred Implementation Deferring modernization to a later planning period was considered. While deferral may be appropriate where risk is low, continued aging of legacy equipment and the loss of technical support increases the likelihood of unplanned failures, emergency replacement, and reduced coordination flexibility with other system initiatives. 5. Selected Approach Comprehensive modernization of protection, control, and SCADA systems was selected as the preferred approach. This option provides improved reliability, standardized protection performance, enhanced system visibility, and supports more effective long term asset management and planning across the substation portfolio.	

Substation Project Summary

Project ID:	STN005
Substation:	PEM MS#6
Project Name:	STATION METERING
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2026
Estimated Capital Cost:	$20,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (Meter installation, less feeder relays)

Project Description:

Installation of substation load totalization meter.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA)
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Installations • Field programming • Commissioning

Project Justification Summary

	The project is classified as Moderate priority as it provides enabling improvements in system visibility and planning data quality, without addressing immediate safety risk, asset condition deficiencies, or consequence driven reliability concerns.

Detailed Justification Roadmap

	Safety & Compliance Risk Exposure	
		The project is not driven by a specific safety or compliance deficiency. Existing feeder level metering provides adequate operational visibility, and current

Project ID:	STN005
Substation:	PEM MS#6
Project Name:	STATION METERING

		arrangements do not present elevated safety risk. As a result, safety considerations do not elevate the project to High priority.
	System Consequence & Operational Impact	
		The absence of a dedicated station totalization meter does not materially increase outage consequence or restoration complexity. System operations can continue to rely on feeder level data. Accordingly, this project does not directly address consequence driven system risk.
	Asset Obsolescence & Reliability Risk	
		The project is not associated with deteriorated or obsolete primary equipment requiring renewal. Existing metering functionality remains serviceable, and the investment is therefore not condition driven.
	Needs Planning	
		The project responds primarily to planning level needs related to operational visibility, data quality, and longer term system performance assessment. These needs support improved understanding of station loading trends and capacity utilization but are not associated with immediate reliability or capacity constraints.
	Enabling & System Benefit	
		Installation of a dedicated station totalization meter provides incremental improvement in data confidence, operational awareness, and planning accuracy. This enabling value supports more effective long term asset management, load forecasting validation, and risk informed capital prioritization across the substation portfolio.
	Planning Horizon Urgency	
		The project can be implemented with minimal operational disruption and may be efficiently coordinated with other station upgrades. Its Moderate priority classification reflects the appropriateness of advancing the investment within the planning horizon without displacing higher urgency safety, reliability, or consequence driven projects.
Alternatives Considered		
	1. Do Nothing Maintaining the existing arrangement without a dedicated station totalization meter was considered. Under this approach, ORPC would continue to rely on feeder level metering for operational and planning purposes. This option would avoid near term	

Project ID:	STN005
Substation:	PEM MS#6
Project Name:	STATION METERING

capital expenditure but would not provide an independent station level measurement point to validate aggregate loading, support station level trending, or simplify future operational and planning analysis.

2. Virtual Totalization Using Existing Feeder Relay Data

Aggregation of existing feeder metering values within the RTAC to produce a calculated station total was considered. This approach would make use of available feeder level data and could provide an acceptable approximation of station loading at relatively low cost. However, it would remain dependent on the availability, configuration, and ongoing consistency of multiple feeder inputs and would not provide an independent metering point at the station level. As a result, it offers less robustness for validation, long term trending, and future operational or planning use.

3. Deferred Implementation

Deferring installation of a dedicated station totalization meter to a later planning period or incorporating it into a broader future station upgrade was considered. While this approach could defer capital cost, it would also defer the benefit of having a single validated station level measurement point to support system monitoring, capacity assessment, and future planning refinement.

4. Selected Approach

Installation of a dedicated station totalization meter was selected as the preferred approach. This option provides an independent and reliable station level measurement point, improves validation of feeder based loading information, and strengthens ORPC's ability to monitor station performance and support longer term planning and asset management.

Substation Project Summary

Project ID:	STN006
Substation:	PEM MS#7
Project Name:	SCADA & RELAY UPGRADE
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2026
Estimated Capital Cost:	$110,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope

Project Description:

Removal of existing legacy protective relays and SCADA equipment.

Installation of modern protective relays, station meter, SCADA server, communications infrastructure, and control wiring.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • Feeder Protection Relay (2EA) • Satellite Clock (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

	This project is classified as High Priority due to its role in addressing legacy protection and control infrastructure associated with elevated operational

Project ID:			STN006
Substation:			PEM MS#7
Project Name:			SCADA & RELAY UPGRADE
	consequence, increasing obsolescence risk, and identified system needs related to reliability, safety, and system visibility. The project also provides enabling system-wide benefits that support restoration performance and future risk-informed planning.		
Detailed Justification Roadmap			
	Safety & Compliance Risk Exposure		
		The project addresses legacy protection and control infrastructure that lags current operational and safety expectations. Where deficiencies affect protection performance, system visibility, or safe restoration practices, the DSP prioritization framework assigns elevated urgency.	
	System Consequence & Operational Impact		
		The affected assets support core substation functions whose degradation could materially affect outage response, restoration capability, or system reliability. The project therefore addresses risks with higher consequence relative to other identified needs.	
	Asset Obsolescence & Reliability Risk		
		Existing protection and SCADA equipment exhibits advanced age, declining manufacturer support, and functional limitations. Continued reliance on legacy systems increases the likelihood of operational challenges, extended outage duration, or reduced situational awareness.	
	Needs Planning		
		The project directly responds to planning-level needs related to reliability, operational flexibility, and system visibility identified in Section 6 of the DSP. These needs are considered higher urgency where condition concerns coincide with system consequence.	
	Enabling & System Benefit		
		Modernization of protection, control, and communications infrastructure provides foundational improvements that enhance restoration performance, reduce operational complexity, and improve the quality of data used in future planning and asset management decisions.	
	Planning Horizon Urgency		
		Based on the combined influence of safety exposure, consequence, and enabling value, the project is appropriately advanced within the nearer-term	

Project ID:	STN006
Substation:	PEM MS#7
Project Name:	SCADA & RELAY UPGRADE
	planning window relative to projects addressing lower consequence or more localized risks.
Alternatives Considered	
	1. Do Nothing Maintaining existing legacy protection and SCADA equipment was considered. This option would avoid near term capital expenditure but would not address increasing obsolescence, declining manufacturer support, or limitations in protection performance and system visibility. Continued reliance on aging equipment would increase long term reliability and operational risk. 2. Like for Like Replacement of Individual Components Targeted replacement of select relays or communication devices on a one for one basis was considered. While this approach could defer full modernization costs, it would result in a fragmented protection and control environment, continued dependence on legacy interfaces, and limited improvement in overall system functionality, maintainability, or standardization. 3. Operational Mitigation in Lieu of Capital Investment Enhanced monitoring and continued reliance on manual operational practices were considered. This approach would not address underlying equipment obsolescence or materially improve protection performance, system visibility, or restoration capability. It would also limit ORPC's ability to collect consistent asset and system performance data needed to support effective long term planning and risk informed capital decision making. 4. Deferred Implementation Deferring modernization to a later planning period was considered. While deferral may be appropriate where risk is low, continued aging of legacy equipment and the loss of technical support increases the likelihood of unplanned failures, emergency replacement, and reduced coordination flexibility with other system initiatives. 5. Selected Approach Comprehensive modernization of protection, control, and SCADA systems was selected as the preferred approach. This option provides improved reliability, standardized protection performance, enhanced system visibility, and supports more effective long term asset management and planning across the substation portfolio.

Substation Project Summary

Project ID:	STN007
Substation:	ALM MS#1
Project Name:	STATION METERING
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2027
Estimated Capital Cost:	$50,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities) - budget extended to include current transformers on main incoming supply.

Project Description:

Installation of substation load totalization meter. Installation of current transformers on incoming circuit.

Project Breakout:

	Materials:	• Substation Totalization Meter (1EA) • Current Transformer (3EA)
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Installations • Field programming • Commissioning

Project Justification Summary

	The project is classified as Moderate priority as it provides enabling improvements in system visibility and planning data quality, without addressing immediate safety risk, asset condition deficiencies, or consequence driven reliability concerns.

Detailed Justification Roadmap

	Safety & Compliance Risk Exposure

Substation Project Summary

Project ID:		STN007
Substation:		ALM MS#1
Project Name:		STATION METERING
		The project is not driven by a specific safety or compliance deficiency. Existing feeder level metering provides adequate operational visibility, and current arrangements do not present elevated safety risk. As a result, safety considerations do not elevate the project to High priority.
	System Consequence & Operational Impact	
		The absence of a dedicated station totalization meter does not materially increase outage consequence or restoration complexity. System operations can continue to rely on feeder level data. Accordingly, this project does not directly address consequence driven system risk.
	Asset Obsolescence & Reliability Risk	
		The project is not associated with deteriorated or obsolete primary equipment requiring renewal. Existing metering functionality remains serviceable, and the investment is therefore not condition driven.
	Needs Planning	
		The project responds primarily to planning level needs related to operational visibility, data quality, and longer term system performance assessment. These needs support improved understanding of station loading trends and capacity utilization but are not associated with immediate reliability or capacity constraints.
	Enabling & System Benefit	
		Installation of a dedicated station totalization meter provides incremental improvement in data confidence, operational awareness, and planning accuracy. This enabling value supports more effective long term asset management, load forecasting validation, and risk informed capital prioritization across the substation portfolio.
	Planning Horizon Urgency	
		The project can be implemented with minimal operational disruption and may be efficiently coordinated with other station upgrades. Its Moderate priority classification reflects the appropriateness of advancing the investment within the planning horizon without displacing higher urgency safety, reliability, or consequence driven projects.
Alternatives Considered		
	1. Do Nothing	

Project ID:	STN007
Substation:	ALM MS#1
Project Name:	STATION METERING

Maintaining the existing arrangement without a dedicated station totalization meter was considered. Under this approach, ORPC would continue to rely on feeder level metering for operational and planning purposes. This option would avoid near term capital expenditure but would not provide an independent station level measurement point to validate aggregate loading, support station level trending, or simplify future operational and planning analysis.

2. Virtual Totalization Using Existing Feeder Relay Data

Aggregation of existing feeder metering values within the RTAC to produce a calculated station total was considered. This approach would make use of available feeder level data and could provide an acceptable approximation of station loading at relatively low cost. However, it would remain dependent on the availability, configuration, and ongoing consistency of multiple feeder inputs and would not provide an independent metering point at the station level. As a result, it offers less robustness for validation, long term trending, and future operational or planning use.

3. Deferred Implementation

Deferring installation of a dedicated station totalization meter to a later planning period or incorporating it into a broader future station upgrade was considered. While this approach could defer capital cost, it would also defer the benefit of having a single validated station level measurement point to support system monitoring, capacity assessment, and future planning refinement.

4. Selected Approach

Installation of a dedicated station totalization meter was selected as the preferred approach. This option provides an independent and reliable station level measurement point, improves validation of feeder based loading information, and strengthens ORPC's ability to monitor station performance and support longer term planning and asset management.

Substation Project Summary

Project ID:	STN008
Substation:	ALM MS#2
Project Name:	SCADA UPGRADE/METERING
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2027
Estimated Capital Cost:	$50,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope

Project Description:

Installation of new station totalization meter, new local SCADA server and communications to SCADA master.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

	The project addresses planning-level needs related to improving operational visibility and establishing standardized monitoring capability at Almonte MS2. While modern protective relays are installed, the absence of station-level SCADA data aggregation, load totalization metering, and communications infrastructure limits

Project ID:		STN008
Substation:		ALM MS#2
Project Name:		SCADA UPGRADE/METERING
	ORPC's ability to effectively monitor loading, assess system performance, and support coordinated operational decision making. Implementation of station SCADA functionality enables consistent data collection, improves situational awareness, and supports risk-informed planning and asset management across the substation portfolio. The project represents a prudent enabling investment that enhances system operability and supports ongoing distribution system modernization objectives.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The absence of station-level SCADA monitoring and load totalization capability limits real-time operational awareness and reduces the effectiveness of remote oversight during abnormal system conditions. While no immediate regulatory non-compliance has been identified, implementation of standardized SCADA infrastructure supports improved operational safety through enhanced situational awareness, reduced reliance on manual field intervention, and improved event visibility. The project also supports alignment with evolving industry practices related to system monitoring, operational readiness, and prudent utility asset management.
	System Consequence & Operational Impact	
		The affected assets support core substation monitoring and operational awareness functions whose absence limits ORPC's ability to effectively respond to abnormal system conditions, manage restoration activities, and assess system performance. While contingency supply arrangements exist, reduced real-time visibility increases reliance on manual intervention and operational judgement during outage events. The project therefore addresses operational risks with comparatively higher system consequence relative to other identified monitoring and control needs, supporting improved reliability management and restoration effectiveness across the distribution system.
	Asset Obsolescence & Reliability Risk	
		While modern protective relays are in service at Almonte MS2, the absence of supporting SCADA data aggregation, load totalization metering, and communications infrastructure limits the effective utilization of installed protection and monitoring capabilities. Continued operation without

Project ID:	STN008
Substation:	ALM MS#2
Project Name:	SCADA UPGRADE/METERING

		standardized station monitoring introduces increasing operational dependency on manual processes and reduces the reliability of system performance data. Over time, lack of consistent data acquisition and integration capability may constrain ORPC's ability to proactively manage asset performance, assess loading trends, and coordinate system modernization initiatives. Implementation of station-level SCADA functionality mitigates these risks by enabling standardized monitoring, improving data reliability, and supporting more predictable long-term asset management outcomes.
	Needs Planning	
		The project directly responds to planning-level needs related to operational visibility, data standardization, and system monitoring capability identified in Section 6 of the DSP. These needs are considered higher priority where limitations in monitoring and operational awareness coincide with stations serving established distribution supply roles. Implementation of station-level SCADA functionality supports improved reliability management, restoration effectiveness, and development of consistent system performance data necessary to enable risk-informed capital planning across the substation portfolio.
	Enabling & System Benefit	
		Implementation of station-level SCADA data aggregation, load totalization metering, and communications infrastructure provides foundational improvements that enhance operational awareness, support more effective restoration decision making, and reduce reliance on manual monitoring practices. The project enables consistent collection of system performance data, improves coordination with broader substation modernization initiatives, and supports more effective long-term planning and asset management across the distribution system.
	Planning Horizon Urgency	
		Based on the combined influence of operational consequence, system visibility limitations, and enabling value, the project is appropriately advanced within the nearer-term planning window relative to initiatives addressing lower consequence or more localized monitoring needs. Implementation supports timely integration of existing modern protection assets and facilitates coordinated progression of broader substation modernization objectives.

Substation Project Summary

Project ID:	STN008
Substation:	ALM MS#2
Project Name:	SCADA UPGRADE/METERING

Alternatives Considered

1. Do Nothing

Maintaining operation without station level SCADA data aggregation or communications infrastructure was considered. This option would avoid near term capital expenditure but would not address current limitations in operational visibility, event recording, or system performance monitoring. Continued reliance on manual data retrieval and limited real time awareness would reduce ORPC's ability to proactively manage station loading, asset performance, and system restoration activities.

2. Minimal Communications Implementation

Provision of basic communications links directly to individual protective relays without installation of a local SCADA server or data concentrator was considered. While this approach could reduce initial capital cost, it would result in a non-standard and less scalable architecture, increased configuration complexity, and reduced flexibility for future system expansion. This option would also limit the ability to implement consistent station level data aggregation and performance monitoring.

3. Operational Mitigation in Lieu of Capital Investment

Continued reliance on local monitoring practices, manual data collection, and periodic field intervention was considered. This approach would not materially improve system visibility or enable effective real time operational awareness. It would also limit ORPC's ability to develop consistent loading histories and performance data necessary to support risk-informed planning and coordinated system modernization.

4. Deferred Implementation

Deferring installation of station SCADA infrastructure to a later planning period was considered. While immediate operational risk is manageable, continued absence of standardized monitoring capability limits ORPC's ability to support effective system planning, operational decision making, and coordination with broader modernization initiatives. Deferral may also increase future integration complexity and implementation cost.

5. Selected Approach

Implementation of a station level SCADA data aggregation platform, installation of load totalization metering, and establishment of robust communications infrastructure was selected as the preferred approach. This option enables standardized integration of modern protective relays, improves operational visibility,

Substation Project Summary

Project ID:	STN008
Substation:	ALM MS#2
Project Name:	SCADA UPGRADE/METERING
	and supports enhanced system monitoring, planning, and asset management across the substation portfolio.

Substation Project Summary

Project ID:	STN009
Substation:	ALM MS#3
Project Name:	SCADA UPGRADE/METERING
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2027-2028
Estimated Capital Cost:	$110,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope

Project Description:

Removal of existing legacy protective relays and SCADA equipment.

Installation of modern protective relays, station meter, SCADA server, communications infrastructure, and control wiring.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA) • Real Time Automation Controller (1EA) • Feeder Protection Relay (2EA) • Satellite Clock (1EA) • SCADA Modem (1EA)
	Engineering:	• Design - specifications & drawings • System modelling • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Existing equipment removals and disposals • Installations • Field programming • Commissioning

Project Justification Summary

	This project is classified as High Priority due to its role in addressing legacy protection and control infrastructure associated with elevated operational

Project ID:			STN009
Substation:			ALM MS#3
Project Name:			SCADA UPGRADE/METERING
	consequence, increasing obsolescence risk, and identified system needs related to reliability, safety, and system visibility. The project also provides enabling system-wide benefits that support restoration performance and future risk-informed planning.		
Detailed Justification Roadmap			
	Safety & Compliance Risk Exposure		
		The project addresses legacy protection and control infrastructure that lags current operational and safety expectations. Where deficiencies affect protection performance, system visibility, or safe restoration practices, the DSP prioritization framework assigns elevated urgency.	
	System Consequence & Operational Impact		
		The affected assets support core substation functions whose degradation could materially affect outage response, restoration capability, or system reliability. The project therefore addresses risks with higher consequence relative to other identified needs.	
	Asset Obsolescence & Reliability Risk		
		Existing protection and SCADA equipment exhibits advanced age, declining manufacturer support, and functional limitations. Continued reliance on legacy systems increases the likelihood of operational challenges, extended outage duration, or reduced situational awareness.	
	Needs Planning		
		The project directly responds to planning-level needs related to reliability, operational flexibility, and system visibility identified in Section 6 of the DSP. These needs are considered higher urgency where condition concerns coincide with system consequence.	
	Enabling & System Benefit		
		Modernization of protection, control, and communications infrastructure provides foundational improvements that enhance restoration performance, reduce operational complexity, and improve the quality of data used in future planning and asset management decisions.	
	Planning Horizon Urgency		
		Based on the combined influence of safety exposure, consequence, and enabling value, the project is appropriately advanced within the nearer-term	

Project ID:	STN009
Substation:	ALM MS#3
Project Name:	SCADA UPGRADE/METERING

planning window relative to projects addressing lower consequence or more localized risks.

Alternatives Considered

1. Do Nothing

Maintaining existing legacy protection and SCADA equipment was considered. This option would avoid near term capital expenditure but would not address increasing obsolescence, declining manufacturer support, or limitations in protection performance and system visibility. Continued reliance on aging equipment would increase long term reliability and operational risk.

2. Like for Like Replacement of Individual Components

Targeted replacement of select relays or communication devices on a one for one basis was considered. While this approach could defer full modernization costs, it would result in a fragmented protection and control environment, continued dependence on legacy interfaces, and limited improvement in overall system functionality, maintainability, or standardization.

3. Operational Mitigation in Lieu of Capital Investment

Enhanced monitoring and continued reliance on manual operational practices were considered. This approach would not address underlying equipment obsolescence or materially improve protection performance, system visibility, or restoration capability. It would also limit ORPC's ability to collect consistent asset and system performance data needed to support effective long term planning and risk informed capital decision making.

4. Deferred Implementation

Deferring modernization to a later planning period was considered. While deferral may be appropriate where risk is low, continued aging of legacy equipment and the loss of technical support increases the likelihood of unplanned failures, emergency replacement, and reduced coordination flexibility with other system initiatives.

5. Selected Approach

Comprehensive modernization of protection, control, and SCADA systems was selected as the preferred approach. This option provides improved reliability, standardized protection performance, enhanced system visibility, and supports more effective long term asset management and planning across the substation portfolio.

Substation Project Summary

Project ID:	STN010
Substation:	ALM MS#4
Project Name:	STATION METERING
ORPC DSP Program:	SYSTEM SERVICE
Primary Driver:	ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:	6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2027
Estimated Capital Cost:	$20,000
Estimate Basis:	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (Meter installation, less feeder relays)

Project Description:

Installation of substation load totalization meter.

Project Breakout:

	Materials:	• Station Totalization Meter (1EA)
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• Field data collection • Offsite fabrication • Switching for station isolation • Installations • Field programming • Commissioning

Project Justification Summary

	The project is classified as Moderate priority as it provides enabling improvements in system visibility and planning data quality, without addressing immediate safety risk, asset condition deficiencies, or consequence driven reliability concerns.

Detailed Justification Roadmap

	Safety & Compliance Risk Exposure	
		The project is not driven by a specific safety or compliance deficiency. Existing feeder level metering provides adequate operational visibility, and current

Project ID:	STN010
Substation:	ALM MS#4
Project Name:	STATION METERING

		arrangements do not present elevated safety risk. As a result, safety considerations do not elevate the project to High priority.
	System Consequence & Operational Impact	
		The absence of a dedicated station totalization meter does not materially increase outage consequence or restoration complexity. System operations can continue to rely on feeder level data. Accordingly, this project does not directly address consequence driven system risk.
	Asset Obsolescence & Reliability Risk	
		The project is not associated with deteriorated or obsolete primary equipment requiring renewal. Existing metering functionality remains serviceable, and the investment is therefore not condition driven.
	Needs Planning	
		The project responds primarily to planning level needs related to operational visibility, data quality, and longer term system performance assessment. These needs support improved understanding of station loading trends and capacity utilization but are not associated with immediate reliability or capacity constraints.
	Enabling & System Benefit	
		Installation of a dedicated station totalization meter provides incremental improvement in data confidence, operational awareness, and planning accuracy. This enabling value supports more effective long term asset management, load forecasting validation, and risk informed capital prioritization across the substation portfolio.
	Planning Horizon Urgency	
		The project can be implemented with minimal operational disruption and may be efficiently coordinated with other station upgrades. Its Moderate priority classification reflects the appropriateness of advancing the investment within the planning horizon without displacing higher urgency safety, reliability, or consequence driven projects.
Alternatives Considered		
	1. Do Nothing Maintaining the existing arrangement without a dedicated station totalization meter was considered. Under this approach, ORPC would continue to rely on feeder level metering for operational and planning purposes. This option would avoid near term	

Project ID:	STN010
Substation:	ALM MS#4
Project Name:	STATION METERING

capital expenditure but would not provide an independent station level measurement point to validate aggregate loading, support station level trending, or simplify future operational and planning analysis.

2. Virtual Totalization Using Existing Feeder Relay Data

Aggregation of existing feeder metering values within the RTAC to produce a calculated station total was considered. This approach would make use of available feeder level data and could provide an acceptable approximation of station loading at relatively low cost. However, it would remain dependent on the availability, configuration, and ongoing consistency of multiple feeder inputs and would not provide an independent metering point at the station level. As a result, it offers less robustness for validation, long term trending, and future operational or planning use.

3. Deferred Implementation

Deferring installation of a dedicated station totalization meter to a later planning period or incorporating it into a broader future station upgrade was considered. While this approach could defer capital cost, it would also defer the benefit of having a single validated station level measurement point to support system monitoring, capacity assessment, and future planning refinement.

4. Selected Approach

Installation of a dedicated station totalization meter was selected as the preferred approach. This option provides an independent and reliable station level measurement point, improves validation of feeder based loading information, and strengthens ORPC's ability to monitor station performance and support longer term planning and asset management.

Substation Project Summary

Project ID:	STN011
Substation:	PEM MS#1
Project Name:	44KV RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	LOW
Planning Window:	2031+
Estimated Capital Cost:	$400,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy oil circuit breakers. Installation of new pad mounted 44kV metal enclosed switchgear.

New switchgear pad, revised ground electrode system to accommodate switchgear.

Removal of legacy equipment.

Routing of and termination of new MV conductors.

Project Breakout:

	Materials:	• 46kV, 250kV BIL, Outdoor Style Metal-Enclosed Switchgear (2x Unfused Inc., 1x Tie, 1x Fuse Out.) (1EA) • Switchgear Foundation (1EA) • 46kV Primary Cabling • Copper ground conductors • 46kV Terminations • 46kV surge arresters
	Engineering:	• Design - specifications & drawings • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary system configuration to enable safe isolation of existing 44 kV equipment • Removal and disposal of existing dead tank breakers, air break switches, and associated structural assemblies • Civil works including new foundations, grounding modifications, trenching, and yard reconfiguration as required • Delivery handling, rigging, and installation of new metal enclosed air insulated switchgear

Project ID:		STN011
Substation:		PEM MS#1
Project Name:		44KV RENEWAL
		• Installation of primary conductors, bus connections, and line terminations • Installation and modification of protection, control, and auxiliary wiring interfaces • Functional testing, commissioning, energization support, and restoration of normal system configuration
Project Justification Summary		
	The project addresses aging 44 kV switching infrastructure with known condition issues; however, lower system consequence due to looped supply configuration supports sequencing modernization to a later planning period while managing risk through ongoing maintenance and operational mitigation.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		Observed equipment condition, including oil leakage and aging switching infrastructure, presents a potential future safety and environmental exposure. However, current risks can be managed through maintenance and operational controls in the near term, and no immediate compliance deficiency has been identified requiring urgent capital intervention.
	System Consequence & Operational Impact	
		MS1 operates as part of a looped supply configuration and does not represent a primary source of supply. As a result, the consequence of equipment failure is comparatively lower than at source substations, with greater opportunity for operational mitigation and load restoration through alternate supply paths.
	Asset Obsolescence & Reliability Risk	
		The existing 44 kV oil circuit breakers and associated switching equipment are of advanced vintage and exhibit declining reliability and maintainability. Continued aging and reduced availability of replacement components indicate that long term modernization will be required to sustain acceptable operational performance.
	Needs Planning	
		The project responds to planning level needs related to: - management of long term condition risk - modernization of legacy high voltage switching infrastructure

Project ID:		STN011
Substation:		PEM MS#1
Project Name:		44KV RENEWAL
		- improvement of operational reliability and maintainability These needs are recognized but are not associated with immediate system risk.
	Enabling & System Benefit	
		Replacement with standardized metal enclosed air insulated switchgear would support long term asset standardization, reduce maintenance burden, and improve operational safety. While beneficial, these enabling outcomes are not critical to near term system performance.
	Planning Horizon Urgency	
		Given the lower relative system consequence, the project can be reasonably deferred within the planning horizon and coordinated with broader system initiatives, outage planning opportunities, or lifecycle based asset programs.
Alternatives Considered		
	1. Do Nothing Maintaining the existing 44 kV dead tank oil circuit breakers and associated air break switching arrangement was considered. This option would avoid near term capital expenditure but would not address the observed operational deficiencies, oil leakage, or advanced equipment age. Continued reliance on this infrastructure would increase the likelihood of breaker failure and unplanned maintenance intervention; however, the looped configuration of MS1 reduces the overall system consequence relative to source supply stations. 2. Targeted Repair or Refurbishment of Existing Breakers Repair, refurbishment, or selective component replacement of the existing oil circuit breakers and control systems was considered. While this approach could extend service life in the short term, the breakers' vintage, deteriorated condition, and declining availability of replacement components limit the long term effectiveness of refurbishment. This option would also retain inherent design limitations and ongoing maintenance burden associated with legacy oil equipment. 3. Replacement with Like for Like Outdoor Equipment Replacement of the existing breakers and air break switches with modern outdoor 44 kV circuit breakers and comparable switching arrangements was considered. While this option would restore interrupting capability, it would retain the outdoor configuration and associated exposure to environmental degradation, operational complexity, and higher long term maintenance requirements. A like for like rebuild would also require substantial civil, structural, and wiring work and is expected to result in comparable or higher overall project cost relative to the proposed metal	

Project ID:	STN011
Substation:	PEM MS#1
Project Name:	44KV RENEWAL

enclosed air insulated switchgear solution, while offering limited improvement in operational flexibility or standardization.

4. Gas Insulated Switchgear Installation

Installation of compact gas insulated switchgear was considered as an alternative modernization approach. While GIS could provide reduced footprint and enhanced environmental isolation, it was determined to be less cost effective and more complex to implement for the scale, configuration, and system role of this station. The incremental benefits associated with GIS were not considered proportionate to investment objectives.

5. Deferred Implementation

Deferring replacement to a later planning period was considered. Given the looped supply configuration and relatively lower system consequence of MS1, deferral was determined to be a reasonable planning approach. Continued monitoring and maintenance can manage near term risk while allowing modernization to be aligned with broader system initiatives or asset lifecycle planning.

6. Selected Approach

Replacement of the existing dead tank oil circuit breakers, air break switches, and associated structures with metal enclosed air insulated switchgear was identified as the preferred long term modernization approach. This option provides improved reliability, reduced maintenance exposure, enhanced operational safety, and improved asset standardization. However, due to the lower system criticality of MS1 relative to source substations, implementation is appropriately sequenced to a later planning period within the DSP horizon.

Substation Project Summary

Project ID:	STN012
Substation:	PEM MS#1
Project Name:	5KV SWGR RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2029-2030
Estimated Capital Cost:	$500,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy 5kV metal enclosed switchgear. Installation of new gas insulated switchgear. Re-routing or pulling of new main and feeder conductors.

Project Breakout:

	Materials:	• 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear (1 Inc SW, 4 way out) (1 EA) • Switchgear Foundation (1 EA) • 15kV Primary Cabling • Copper Ground Conductors • 15kV Elbow Terminations • 15kV Cable Accessories • 15kV Surge Arresters
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary feeder reconfiguration to enable safe isolation of existing 5 kV indoor switchgear and associated primary circuits • Removal, dismantling, and disposal of existing indoor metal-clad switchgear, buswork, cable terminations, control panels, and auxiliary equipment • Building decommissioning works including removal of redundant raceways, equipment supports, ventilation components, and fire protection interfaces as required

Project ID:		STN012
Substation:		PEM MS#1
Project Name:		5KV SWGR RENEWAL
		• Civil works including construction of new outdoor switchgear foundation, grounding system extensions, trenching, duct bank installation, and site grading or drainage adjustments as required • Delivery handling, rigging, placement, and installation of new outdoor metal-enclosed gas-insulated switchgear lineup • Installation of new 15 kV primary cables, elbow terminations, surge arresters, and associated insulated cable accessories • Installation of grounding and bonding conductors including integration with the existing station ground grid • Installation and modification of protection, control, metering, SCADA, and auxiliary wiring interfaces including relay panel updates and communications integration • Installation of new conduits, cable tray, and raceway systems between switchgear, control building, and field equipment • Functional testing, protection and control verification, commissioning, energization support, and restoration of normal system configuration • Removal of temporary system configurations and completion of site restoration works as required
Project Justification Summary		
	Replacement of the legacy 5 kV switchgear at MS#1 addresses increasing safety exposure, equipment obsolescence, and declining operational reliability while improving long-term asset supportability and planning flexibility. The station serves a meaningful level of connected load and forms part of established contingency supply arrangements; however, the progression of condition-related risk remains manageable within the planning horizon. The project is therefore appropriately classified as moderate priority and is sequenced in alignment with broader risk-based asset management objectives.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The existing legacy 5 kV switchgear installation presents increasing safety exposure associated with aging mechanical operating mechanisms, legacy protection integration, and increased maintenance intervention requirements. While the equipment remains operational, variability in switching performance and the need for increased manual interaction introduce elevated

Project ID:	STN012
Substation:	PEM MS#1
Project Name:	5KV SWGR RENEWAL

		occupational risk relative to modern switchgear technologies. Replacement with modern gas-insulated switchgear improves operational safety through enhanced interlocking, reduced exposure to energized components, and improved arc-flash performance characteristics. No immediate regulatory non-compliance has been identified; however, replacement supports ongoing alignment with evolving industry safety practices and prudent asset stewardship.
	System Consequence & Operational Impact	
		MS1 serves a comparatively higher connected load relative to some of the other legacy 5 kV stations within the service territory. Loss of station functionality would therefore result in a broader customer impact than peer facilities of the same voltage class. All feeders supplied from MS1 have established contingency supply paths; however, some of these transfers require planned outages and manual switching actions. As a result, while sustained loss of supply risk is mitigated, restoration timelines would be extended relative to modern automated configurations. The existing switchgear condition does not currently present an imminent reliability risk, but continued operation increases the probability of in-service failure leading to unplanned outages, extended restoration durations, and reduced operational flexibility during abnormal system conditions. Accordingly, the station is assessed as presenting a moderate system consequence, reflecting: -higher relative load exposure compared to other legacy 5 kV facilities -availability of contingency supply with operational constraints -limited automation and switching flexibility under contingency conditions -increasing outage duration risk associated with aging primary equipment This consequence level supports renewal prioritization within the moderate risk classification framework rather than immediate replacement urgency.
	Asset Obsolescence & Reliability Risk	
		The existing switchgear is of vintage design with declining availability of standardized replacement components and reduced manufacturer support. Maintenance activities increasingly require custom solutions and specialized intervention, introducing uncertainty in lifecycle cost and restoration performance. Continued reliance on legacy technology increases long-term operational risk and reduces predictability of asset performance. Replacement

Project ID:		STN012
Substation:		PEM MS#1
Project Name:		5KV SWGR RENEWAL
		mitigates obsolescence risk and supports transition to modern, supportable equipment platforms.
	Needs Planning	
		The project responds to planning-level needs related to: – management of long-term condition and obsolescence risk associated with legacy 5 kV switchgear – improvement of operational reliability, switching flexibility, and restoration performance – modernization of aging primary equipment to support maintainability and future system readiness These needs are recognized within the planning horizon but are not associated with immediate system risk.
	Enabling & System Benefit	
		Installation of new switchgear provides improved operational flexibility and simplifies future maintenance and system configuration activities. The outdoor gas-insulated configuration reduces reliance on aging station structures and improves accessibility for future asset interventions. The project also facilitates modernization of associated conductor systems and supports incremental improvement in station operability.
	Planning Horizon Urgency	
		The need for renewal is driven by progressive asset aging and increasing obsolescence risk rather than an immediate reliability or safety deficiency. Continued operation of the existing switchgear is considered manageable in the near term; however, risk exposure is expected to increase over the medium term as component availability declines and maintenance requirements intensify. Accordingly, the project is appropriately positioned within the medium to long-term planning horizon, supporting proactive risk management while avoiding premature capital investment.
	Alternatives Considered	
	1. Do Nothing Continued operation of the existing 5 kV metal-enclosed switchgear in its current condition was considered. While this option would avoid near-term capital expenditure, it would not address the advanced age of the equipment, increasing variability in mechanical operating performance, or growing maintenance sensitivity	

Project ID:	STN012
Substation:	PEM MS#1
Project Name:	5KV SWGR RENEWAL

observed during routine switching activities. Continued reliance on this legacy infrastructure would progressively increase the risk of delayed restoration following fault events and unplanned maintenance intervention. This option does not align with prudent long-term asset lifecycle management.

2. Targeted Repair or Refurbishment of Existing Switchgear

Selective refurbishment, component replacement, or control system upgrades of the existing 5 kV switchgear were evaluated. While this approach could extend nominal serviceability in the short term, it would not resolve underlying limitations associated with legacy mechanical design, aging insulation systems, or declining availability of standardized replacement components. Increasing reliance on custom refurbishment and specialist maintenance introduces uncertainty in operational performance and lifecycle cost exposure. This option would also perpetuate operation at a legacy voltage class and would not provide additional capacity margin or planning flexibility.

3. Replacement with Like-for-Like 5 kV Metal-Enclosed Switchgear

Replacement of the existing equipment with new conventional 5 kV metal-enclosed air-insulated switchgear was considered. While this option would restore equipment condition and improve operational reliability relative to the existing installation, it would maintain the existing legacy voltage class and associated long-term capacity constraints. A like-for-like replacement would increase the likelihood of future step-change capital investment as system requirements evolve. Given comparable implementation complexity and lifecycle cost relative to the proposed solution, this option was not considered to provide optimal long-term value.

4. Outdoor Medium-Voltage Air-Insulated Switchgear Installation

Installation of outdoor-rated air-insulated medium-voltage switchgear was considered as an alternative configuration. While this approach would reduce dependence on existing building infrastructure, it would introduce increased exposure to environmental conditions, potentially higher long-term maintenance requirements, and reduced equipment compactness relative to gas-insulated solutions. This option was determined to provide limited net lifecycle benefit for the station configuration and modernization objectives.

5. Deferred Implementation

Deferral of switchgear replacement to a later planning period was evaluated. While continued operation of the existing equipment is feasible in the near term with enhanced maintenance oversight, progressive degradation in mechanical performance and declining component supportability would increase uncertainty in operational reliability over time. Deferral would therefore increase exposure to

Project ID:	STN012
Substation:	PEM MS#1
Project Name:	5KV SWGR RENEWAL

unplanned intervention and restoration risk, while delaying achievement of broader asset lifecycle renewal objectives.

6. Selected Approach

Removal of the existing legacy 5 kV metal-enclosed switchgear and installation of new 15 kV-class outdoor gas-insulated switchgear, including re-routing or replacement of associated main and feeder conductors, was identified as the preferred modernization approach. This option improves operational reliability, reduces maintenance exposure, and enhances safety performance while reducing long-term reliance on aging station structures. Selection of 15 kV-class equipment provides additional capacity margin and maintains planning flexibility for potential future distribution system configuration changes without requiring further step-change equipment replacement. Implementation timing is aligned with risk-based asset management prioritization within the DSP horizon.

Substation Project Summary

Project ID:	STN013
Substation:	PEM MS#2
Project Name:	5KV SWGR RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2031+
Estimated Capital Cost:	$500,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy 5kV metal enclosed switchgear. Installation of new gas insulated switchgear. Re-routing or pulling of new main and feeder conductors.

Project Breakout:

	Materials:	• 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear (1 Inc SW, 5 way out) (1 EA) • Switchgear Foundation (1 EA) • 15kV Primary Cabling • Copper Ground Conductors • 15kV Elbow Terminations • 15kV Cable Accessories • 15kV Surge Arresters
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary feeder reconfiguration to enable safe isolation of existing 5 kV indoor switchgear and associated primary circuits • Removal, dismantling, and disposal of existing indoor metal-clad switchgear, buswork, cable terminations, control panels, and auxiliary equipment • Building decommissioning works including removal of redundant raceways, equipment supports, ventilation components, and fire protection interfaces as required

Project ID:		STN013
Substation:		PEM MS#2
Project Name:		5KV SWGR RENEWAL
		• Civil works including construction of new outdoor switchgear foundation, grounding system extensions, trenching, duct bank installation, and site grading or drainage adjustments as required • Delivery handling, rigging, placement, and installation of new outdoor metal-enclosed gas-insulated switchgear lineup • Installation of new 15 kV primary cables, elbow terminations, surge arresters, and associated insulated cable accessories • Installation of grounding and bonding conductors including integration with the existing station ground grid • Installation and modification of protection, control, metering, SCADA, and auxiliary wiring interfaces including relay panel updates and communications integration • Installation of new conduits, cable tray, and raceway systems between switchgear, control building, and field equipment • Functional testing, protection and control verification, commissioning, energization support, and restoration of normal system configuration • Removal of temporary system configurations and completion of site restoration works as required
Project Justification Summary		
	Replacement of the legacy 5 kV switchgear at MS#2 addresses increasing safety exposure, equipment obsolescence, and declining operational reliability while improving long-term asset supportability and planning flexibility. The station serves a meaningful level of connected load and forms part of established contingency supply arrangements; however, the progression of condition-related risk remains manageable within the planning horizon. The project is therefore appropriately classified as moderate priority and is sequenced in alignment with broader risk-based asset management objectives.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The existing legacy 5 kV switchgear installation presents increasing safety exposure associated with aging mechanical operating mechanisms, legacy protection integration, and increased maintenance intervention requirements. While the equipment remains operational, variability in switching performance and the need for increased manual interaction introduce elevated

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Project Name:	5KV SWGR RENEWAL

		occupational risk relative to modern switchgear technologies. Replacement with modern gas-insulated switchgear improves operational safety through enhanced interlocking, reduced exposure to energized components, and improved arc-flash performance characteristics. No immediate regulatory non-compliance has been identified; however, replacement supports ongoing alignment with evolving industry safety practices and prudent asset stewardship.
	System Consequence & Operational Impact	
		MS2 serves a comparatively higher connected load relative to the other legacy 5 kV stations within the service territory. Loss of station functionality would therefore result in a broader customer impact than peer facilities of the same voltage class. All feeders supplied from MS2 have established contingency supply paths; however, some of these transfers require planned outages and manual switching actions. As a result, while sustained loss of supply risk is mitigated, restoration timelines would be extended relative to modern automated configurations. The existing switchgear condition does not currently present an imminent reliability risk, but continued operation increases the probability of in-service failure leading to unplanned outages, extended restoration durations, and reduced operational flexibility during abnormal system conditions. Accordingly, the station is assessed as presenting a moderate system consequence, reflecting: -higher relative load exposure compared to other legacy 5 kV facilities -availability of contingency supply with operational constraints -limited automation and switching flexibility under contingency conditions -increasing outage duration risk associated with aging primary equipment This consequence level supports renewal prioritization within the moderate risk classification framework rather than immediate replacement urgency.
	Asset Obsolescence & Reliability Risk	
		The existing switchgear is of vintage design with declining availability of standardized replacement components and reduced manufacturer support. Maintenance activities increasingly require custom solutions and specialized intervention, introducing uncertainty in lifecycle cost and restoration performance. Continued reliance on legacy technology increases long-term operational risk and reduces predictability of asset performance. Replacement

Project ID:		STN013
Substation:		PEM MS#2
Project Name:		5KV SWGR RENEWAL
		mitigates obsolescence risk and supports transition to modern, supportable equipment platforms.
	Needs Planning	
		The project responds to planning-level needs related to: – management of long-term condition and obsolescence risk associated with legacy 5 kV switchgear – improvement of operational reliability, switching flexibility, and restoration performance – modernization of aging primary equipment to support maintainability and future system readiness These needs are recognized within the planning horizon but are not associated with immediate system risk.
	Enabling & System Benefit	
		Installation of new switchgear provides improved operational flexibility and simplifies future maintenance and system configuration activities. The outdoor gas-insulated configuration reduces reliance on aging station structures and improves accessibility for future asset interventions. The project also facilitates modernization of associated conductor systems and supports incremental improvement in station operability.
	Planning Horizon Urgency	
		The need for renewal is driven by progressive asset aging and increasing obsolescence risk rather than an immediate reliability or safety deficiency. Continued operation of the existing switchgear is considered manageable in the near term; however, risk exposure is expected to increase over the medium term as component availability declines and maintenance requirements intensify. Accordingly, the project is appropriately positioned within the medium to long-term planning horizon, supporting proactive risk management while avoiding premature capital investment.
	Alternatives Considered	
	1. Do Nothing Continued operation of the existing 5 kV metal-enclosed switchgear in its current condition was considered. While this option would avoid near-term capital expenditure, it would not address the advanced age of the equipment, increasing variability in mechanical operating performance, or growing maintenance sensitivity	

Project ID:	STN013
Substation:	PEM MS#2
Project Name:	5KV SWGR RENEWAL

observed during routine switching activities. Continued reliance on this legacy infrastructure would progressively increase the risk of delayed restoration following fault events and unplanned maintenance intervention. This option does not align with prudent long-term asset lifecycle management.

2. Targeted Repair or Refurbishment of Existing Switchgear

Selective refurbishment, component replacement, or control system upgrades of the existing 5 kV switchgear were evaluated. While this approach could extend nominal serviceability in the short term, it would not resolve underlying limitations associated with legacy mechanical design, aging insulation systems, or declining availability of standardized replacement components. Increasing reliance on custom refurbishment and specialist maintenance introduces uncertainty in operational performance and lifecycle cost exposure. This option would also perpetuate operation at a legacy voltage class and would not provide additional capacity margin or planning flexibility.

3. Replacement with Like-for-Like 5 kV Metal-Enclosed Switchgear

Replacement of the existing equipment with new conventional 5 kV metal-enclosed air-insulated switchgear was considered. While this option would restore equipment condition and improve operational reliability relative to the existing installation, it would maintain the existing legacy voltage class and associated long-term capacity constraints. A like-for-like replacement would increase the likelihood of future step-change capital investment as system requirements evolve. Given comparable implementation complexity and lifecycle cost relative to the proposed solution, this option was not considered to provide optimal long-term value.

4. Outdoor Medium-Voltage Air-Insulated Switchgear Installation

Installation of outdoor-rated air-insulated medium-voltage switchgear was considered as an alternative configuration. While this approach would reduce dependence on existing building infrastructure, it would introduce increased exposure to environmental conditions, potentially higher long-term maintenance requirements, and reduced equipment compactness relative to gas-insulated solutions. This option was determined to provide limited net lifecycle benefit for the station configuration and modernization objectives.

5. Deferred Implementation

Deferral of switchgear replacement to a later planning period was evaluated. While continued operation of the existing equipment is feasible in the near term with enhanced maintenance oversight, progressive degradation in mechanical performance and declining component supportability would increase uncertainty in operational reliability over time. Deferral would therefore increase exposure to

Project ID:	STN013
Substation:	PEM MS#2
Project Name:	5KV SWGR RENEWAL

unplanned intervention and restoration risk, while delaying achievement of broader asset lifecycle renewal objectives.

6. Selected Approach

Removal of the existing legacy 5 kV metal-enclosed switchgear and installation of new 15 kV-class outdoor gas-insulated switchgear, including re-routing or replacement of associated main and feeder conductors, was identified as the preferred modernization approach. This option improves operational reliability, reduces maintenance exposure, and enhances safety performance while reducing long-term reliance on aging station structures. Selection of 15 kV-class equipment provides additional capacity margin and maintains planning flexibility for potential future distribution system configuration changes without requiring further step-change equipment replacement. Implementation timing is aligned with risk-based asset management prioritization within the DSP horizon.

Substation Project Summary

Project ID:	STN014
Substation:	PEM MS#3
Project Name:	5KV SWGR RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	LOW
Planning Window:	2031+
Estimated Capital Cost:	$500,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy 5kV metal enclosed switchgear. Removal of sheet metal ehouse. Installation of new gas insulated switchgear. Re-routing or pulling of new main and feeder conductors.

Project Breakout:

	Materials:	• 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear (1 Inc SW, 2 way out) (1 EA) • Switchgear Foundation (1 EA) • 15kV Primary Cabling • Copper Ground Conductors • 15kV Elbow Terminations • 15kV Cable Accessories • 15kV Surge Arresters
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary feeder reconfiguration to enable safe isolation of existing 5 kV indoor switchgear and associated primary circuits • Removal, dismantling, and disposal of existing indoor metal-clad switchgear, buswork, cable terminations, control panels, and auxiliary equipment • Building decommissioning works including removal of redundant raceways, equipment supports, ventilation components, and fire protection interfaces as required

Project ID:		STN014
Substation:		PEM MS#3
Project Name:		5KV SWGR RENEWAL
		• Civil works including construction of new outdoor switchgear foundation, grounding system extensions, trenching, duct bank installation, and site grading or drainage adjustments as required • Delivery handling, rigging, placement, and installation of new outdoor metal-enclosed gas-insulated switchgear lineup • Installation of new 15 kV primary cables, elbow terminations, surge arresters, and associated insulated cable accessories • Installation of grounding and bonding conductors including integration with the existing station ground grid • Installation and modification of protection, control, metering, SCADA, and auxiliary wiring interfaces including relay panel updates and communications integration • Installation of new conduits, cable tray, and raceway systems between switchgear, control building, and field equipment • Functional testing, protection and control verification, commissioning, energization support, and restoration of normal system configuration • Removal of temporary system configurations and completion of site restoration works as required
Project Justification Summary		
	Replacement of the legacy 5 kV switchgear at MS#3 addresses ongoing asset aging, equipment obsolescence, and the need to maintain long-term operational supportability of primary switching infrastructure. The station supplies a comparatively lower level of connected load within the legacy 5 kV group and benefits from established contingency supply arrangements that provide reasonable system resilience. While the condition trajectory supports eventual lifecycle renewal, the associated risk progression is gradual and remains manageable within the planning horizon. The project is therefore appropriately classified as low priority and is sequenced in alignment with broader risk-based asset management objectives.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The existing legacy 5 kV switchgear installation presents increasing safety exposure associated with aging mechanical operating mechanisms, legacy protection integration, and increased maintenance intervention requirements.

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Substation:	PEM MS#3
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		While the equipment remains operational, variability in switching performance and the need for increased manual interaction introduce elevated occupational risk relative to modern switchgear technologies. Replacement with modern gas-insulated switchgear improves operational safety through enhanced interlocking, reduced exposure to energized components, and improved arc-flash performance characteristics. No immediate regulatory non-compliance has been identified; however, replacement supports ongoing alignment with evolving industry safety practices and prudent asset stewardship.
	System Consequence & Operational Impact	
		MS3 serves a comparatively lower connected load relative to other legacy 5 kV stations within the service territory. Loss of station functionality would therefore result in a more limited customer impact compared to higher-loaded peer facilities of the same voltage class. All feeders supplied from MS3 have established contingency supply paths; however, some transfers require planned outages and manual switching actions. While sustained loss of supply risk is mitigated, restoration timelines would be extended relative to modern automated configurations. The existing switchgear condition does not currently present an imminent reliability concern; however, continued operation increases the likelihood of equipment-related outages and extended restoration durations over time. Accordingly, the station is assessed as presenting a low system consequence, reflecting: – lower relative load exposure within the legacy 5 kV station group – availability of contingency supply with manageable operational constraints – limited automation and switching flexibility under contingency conditions – gradual increase in outage duration risk associated with aging primary equipment This consequence level supports renewal prioritization consistent with a low risk classification within the planning framework.
	Asset Obsolescence & Reliability Risk	
		The existing switchgear is of vintage design with declining availability of standardized replacement components and reduced manufacturer support. Maintenance activities increasingly require custom solutions and specialized intervention, introducing uncertainty in lifecycle cost and restoration performance. Continued reliance on legacy technology increases long-term

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Substation:	PEM MS#3
Project Name:	5KV SWGR RENEWAL

		operational risk and reduces predictability of asset performance. Replacement mitigates obsolescence risk and supports transition to modern, supportable equipment platforms.
	Needs Planning	
		The project responds to planning-level needs related to: – management of long-term condition and obsolescence risk associated with legacy 5 kV switchgear – improvement of operational reliability, switching flexibility, and restoration performance – modernization of aging primary equipment to support maintainability and future system readiness These needs are recognized within the planning horizon but are not associated with immediate system risk.
	Enabling & System Benefit	
		Installation of new switchgear provides improved operational flexibility and simplifies future maintenance and system configuration activities. The outdoor gas-insulated configuration reduces reliance on aging station structures and improves accessibility for future asset interventions. The project also facilitates modernization of associated conductor systems and supports incremental improvement in station operability.
	Planning Horizon Urgency	
		The need for renewal is driven by progressive asset aging and increasing obsolescence risk rather than an immediate reliability or safety deficiency. Continued operation of the existing switchgear is considered manageable in the near term; however, risk exposure is expected to increase over the medium term as component availability declines and maintenance requirements intensify. Accordingly, the project is appropriately positioned within the medium to long-term planning horizon, supporting proactive risk management while avoiding premature capital investment.
	Alternatives Considered	
	1. Do Nothing Continued operation of the existing 5 kV metal-enclosed switchgear in its current condition was considered. While this option would avoid near-term capital expenditure, it would not address the advanced age of the equipment, increasing	

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Substation:	PEM MS#3
Project Name:	5KV SWGR RENEWAL

variability in mechanical operating performance, or growing maintenance sensitivity observed during routine switching activities. Continued reliance on this legacy infrastructure would progressively increase the risk of delayed restoration following fault events and unplanned maintenance intervention. This option does not align with prudent long-term asset lifecycle management.

2. Targeted Repair or Refurbishment of Existing Switchgear

Selective refurbishment, component replacement, or control system upgrades of the existing 5 kV switchgear were evaluated. While this approach could extend nominal serviceability in the short term, it would not resolve underlying limitations associated with legacy mechanical design, aging insulation systems, or declining availability of standardized replacement components. Increasing reliance on custom refurbishment and specialist maintenance introduces uncertainty in operational performance and lifecycle cost exposure. This option would also perpetuate operation at a legacy voltage class and would not provide additional capacity margin or planning flexibility.

3. Replacement with Like-for-Like 5 kV Metal-Enclosed Switchgear

Replacement of the existing equipment with new conventional 5 kV metal-enclosed air-insulated switchgear was considered. While this option would restore equipment condition and improve operational reliability relative to the existing installation, it would maintain the existing legacy voltage class and associated long-term capacity constraints. A like-for-like replacement would increase the likelihood of future step-change capital investment as system requirements evolve. Given comparable implementation complexity and lifecycle cost relative to the proposed solution, this option was not considered to provide optimal long-term value.

4. Outdoor Medium-Voltage Air-Insulated Switchgear Installation

Installation of outdoor-rated air-insulated medium-voltage switchgear was considered as an alternative configuration. While this approach would reduce dependence on existing building infrastructure, it would introduce increased exposure to environmental conditions, potentially higher long-term maintenance requirements, and reduced equipment compactness relative to gas-insulated solutions. This option was determined to provide limited net lifecycle benefit for the station configuration and modernization objectives.

5. Deferred Implementation

Deferral of switchgear replacement to a later planning period was evaluated. While continued operation of the existing equipment is feasible in the near term with enhanced maintenance oversight, progressive degradation in mechanical performance and declining component supportability would increase uncertainty in operational reliability over time. Deferral would therefore increase exposure to

Project ID:	STN014
Substation:	PEM MS#3
Project Name:	5KV SWGR RENEWAL

unplanned intervention and restoration risk, while delaying achievement of broader asset lifecycle renewal objectives.

6. Selected Approach

Removal of the existing legacy 5 kV metal-enclosed switchgear and installation of new 15 kV-class outdoor gas-insulated switchgear, including re-routing or replacement of associated main and feeder conductors, was identified as the preferred modernization approach. This option improves operational reliability, reduces maintenance exposure, and enhances safety performance while reducing long-term reliance on aging station structures. Selection of 15 kV-class equipment provides additional capacity margin and maintains planning flexibility for potential future distribution system configuration changes without requiring further step-change equipment replacement. Implementation timing is aligned with risk-based asset management prioritization within the DSP horizon.

Substation Project Summary

Project ID:	STN015
Substation:	PEM MS#4
Project Name:	44KV RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	HIGH
Planning Window:	2027-2028
Estimated Capital Cost:	$750,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy oil circuit breakers. Installation of new pad mounted 44kV metal enclosed switchgear.

New switchgear pad, revised ground electrode system to accommodate switchgear.

Removal of legacy equipment.

Routing of and termination of new MV conductors.

Project Breakout:

	Materials:	• 46kV, 250kV BIL, Outdoor Style Metal-Enclosed Switchgear (3x Fuse Inc., 2x Tie, 3x Fuse Out.) (1EA) • Switchgear Foundation (1EA) • 46kV Primary Cabling • Copper ground conductors • 46kV Terminations
	Engineering:	• Design - specifications & drawings • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary system configuration to enable safe isolation of existing 44 kV equipment • Removal and disposal of existing dead tank breakers, air break switches, and associated structural assemblies • Civil works including new foundations, grounding modifications, trenching, and yard reconfiguration as required • Delivery handling, rigging, and installation of new metal enclosed air insulated switchgear

Project ID:		STN015
Substation:		PEM MS#4
Project Name:		44KV RENEWAL
		• Installation of primary conductors, bus connections, and line terminations • Installation and modification of protection, control, and auxiliary wiring interfaces • Functional testing, commissioning, energization support, and restoration of normal system configuration
Project Justification Summary		
	This project addresses 44 kV oil circuit breakers (vintage 1960) that are beyond typical industry service life and have exhibited operational control deficiencies and active oil leakage at a primary supply interface. Continued reliance on this equipment introduces elevated risk of failure, reduced operational reliability, and increasing maintenance and safety exposure associated with aging high-voltage oil interrupting technology. Given the critical system function performed by these breakers and the limited practical mitigation available through maintenance alone, replacement represents a prudent risk management measure. Advancement within the near-term planning window is consistent with the DSP prioritization framework, reflecting the combined influence of asset condition, system consequence, and operational risk.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The existing 44 kV dead tank oil circuit breakers and associated switching structures exhibit leakage and operational reliability concerns. Aging oil-filled interrupting equipment presents elevated safety exposure related to failure modes, environmental containment, and maintenance activities. Replacement aligns with prudent utility practice for managing high-voltage oil-filled equipment nearing end of life.
	System Consequence & Operational Impact	
		The breakers perform a primary supply interface function. Failure or operational limitation would materially affect system reliability, outage response capability, and operational flexibility at the station. Replacement therefore aligns with the DSP objective of mitigating consequence-driven system risk at critical supply points.
	Asset Obsolescence & Reliability Risk	
		The breakers are vintage 1960 and represent equipment that is well beyond typical service life expectations. Observed leakage, control system

Project ID:	STN015
Substation:	PEM MS#4
Project Name:	44KV RENEWAL

		malfunction, and declining supportability indicate advanced deterioration and increasing risk of failure. Continued reliance on this equipment introduces growing operational uncertainty and maintenance burden.
	Needs Planning	
		The project responds directly to planning-level needs related to: - condition-driven asset renewal - supply reliability and restoration capability - operational risk associated with legacy high-voltage switching equipment
	Enabling & System Benefit	
		Replacement with modern metal enclosed air insulated switchgear improves operational safety, standardization, maintainability, and long-term reliability. The project also supports improved protection coordination, reduced environmental risk, and more consistent asset performance across the substation portfolio.
	Planning Horizon Urgency	
		Accordingly, the project is appropriately positioned within the long-term planning horizon, supporting lifecycle risk management while deferring capital investment until risk progression or system needs warrant advancement.
Alternatives Considered		
	1. Do Nothing Maintaining the existing 44 kV dead tank oil circuit breakers and associated air break switching arrangement was considered. This option would avoid near term capital expenditure but would not address the observed operational deficiencies, oil leakage, or advanced equipment age. Continued reliance on this infrastructure would increase the risk of breaker failure, extended outages, and emergency replacement under less controlled conditions. 2. Targeted Repair or Refurbishment of Existing Breakers Repair, refurbishment, or selective component replacement of the existing oil circuit breakers and control systems was considered. While this approach could extend service life in the short term, the breakers' vintage, deteriorated condition, and declining availability of replacement components limit the long term effectiveness of refurbishment. This option would not address inherent design limitations, aging insulation systems, or ongoing maintenance burden associated with legacy oil equipment.	

Project ID:	STN015
Substation:	PEM MS#4
Project Name:	44KV RENEWAL

3. Replacement of the existing breakers and air break switches with modern outdoor 44 kV circuit breakers and comparable switching arrangements was considered. While this option would restore interrupting capability, it would retain the existing outdoor configuration and associated exposure to environmental degradation, operational complexity, and higher long-term maintenance requirements. In addition, a like-for-like rebuild would require substantial civil, structural, and wiring work and is expected to result in comparable or higher overall project cost relative to the proposed metal-enclosed air-insulated switchgear solution. The approach would also provide limited improvement in safety, operational flexibility, or long-term standardization.

4. Gas-Insulated Switchgear (GIS) Installation

Installation of compact gas insulated switchgear was considered as an alternative modernization approach. While GIS could provide reduced footprint and enhanced environmental isolation, it was determined to be less cost effective and more complex to implement for the scale and configuration of this station. The benefits associated with GIS were not considered proportionate to the system requirements or investment objectives.

5. Deferred Implementation

Deferring replacement to a later planning period was considered. However, given the observed operational issues, oil leakage, and advanced equipment age, deferral would increase the likelihood of unplanned outages, safety exposure, and emergency replacement scenarios.

6. Selected Approach

Replacement of the existing dead tank oil circuit breakers, air break switches, and associated structures with metal enclosed air insulated switchgear was selected as the preferred approach. This option provides improved reliability, reduced maintenance requirements, enhanced operational safety, and better long term asset standardization while representing a cost effective modernization solution aligned with system needs.

Substation Project Summary

Project ID:	STN016
Substation:	PEM MS#4
Project Name:	5KV SWGR RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2029-2030
Estimated Capital Cost:	$500,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy 5kV metal enclosed switchgear. Removal of sheet metal ehouse. Installation of new gas insulated switchgear. Re-routing or pulling of new main and feeder conductors.

Project Breakout:

	Materials:	• 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear (1 Inc SW, 4 way out) (1 EA) • Switchgear Foundation (1 EA) • 15kV Primary Cabling • Copper Ground Conductors • 15kV Elbow Terminations • 15kV Cable Accessories • 15kV Surge Arresters
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary feeder reconfiguration to enable safe isolation of existing 5 kV indoor switchgear and associated primary circuits • Removal, dismantling, and disposal of existing indoor metal-clad switchgear, buswork, cable terminations, control panels, and auxiliary equipment • Building decommissioning works including removal of redundant raceways, equipment supports, ventilation components, and fire protection interfaces as required

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		• Civil works including construction of new outdoor switchgear foundation, grounding system extensions, trenching, duct bank installation, and site grading or drainage adjustments as required • Delivery handling, rigging, placement, and installation of new outdoor metal-enclosed gas-insulated switchgear lineup • Installation of new 15 kV primary cables, elbow terminations, surge arresters, and associated insulated cable accessories • Installation of grounding and bonding conductors including integration with the existing station ground grid • Installation and modification of protection, control, metering, SCADA, and auxiliary wiring interfaces including relay panel updates and communications integration • Installation of new conduits, cable tray, and raceway systems between switchgear, control building, and field equipment • Functional testing, protection and control verification, commissioning, energization support, and restoration of normal system configuration • Removal of temporary system configurations and completion of site restoration works as required
Project Justification Summary		
	Replacement of the legacy 5 kV switchgear at MS#4 addresses increasing safety exposure, equipment obsolescence, and declining operational reliability while improving long-term asset supportability and planning flexibility. The station serves a meaningful level of connected load and forms part of established contingency supply arrangements; however, the progression of condition-related risk remains manageable within the planning horizon. The project is therefore appropriately classified as moderate priority and is sequenced in alignment with broader risk-based asset management objectives.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The existing legacy 5 kV switchgear installation presents increasing safety exposure associated with aging mechanical operating mechanisms, legacy protection integration, and increased maintenance intervention requirements. While the equipment remains operational, variability in switching performance and the need for increased manual interaction introduce elevated

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		occupational risk relative to modern switchgear technologies. Replacement with modern gas-insulated switchgear improves operational safety through enhanced interlocking, reduced exposure to energized components, and improved arc-flash performance characteristics. No immediate regulatory non-compliance has been identified; however, replacement supports ongoing alignment with evolving industry safety practices and prudent asset stewardship.
	System Consequence & Operational Impact	
		MS4 serves a comparatively higher connected load relative to the other legacy 5 kV stations within the service territory. Loss of station functionality would therefore result in a broader customer impact than peer facilities of the same voltage class. All feeders supplied from MS4 have established contingency supply paths; however, some of these transfers require planned outages and manual switching actions. As a result, while sustained loss of supply risk is mitigated, restoration timelines would be extended relative to modern automated configurations. The existing switchgear condition does not currently present an imminent reliability risk, but continued operation increases the probability of in-service failure leading to unplanned outages, extended restoration durations, and reduced operational flexibility during abnormal system conditions. Accordingly, the station is assessed as presenting a moderate system consequence, reflecting: -higher relative load exposure compared to other legacy 5 kV facilities -availability of contingency supply with operational constraints -limited automation and switching flexibility under contingency conditions -increasing outage duration risk associated with aging primary equipment This consequence level supports renewal prioritization within the moderate risk classification framework rather than immediate replacement urgency.
	Asset Obsolescence & Reliability Risk	
		The existing switchgear is of vintage design with declining availability of standardized replacement components and reduced manufacturer support. Maintenance activities increasingly require custom solutions and specialized intervention, introducing uncertainty in lifecycle cost and restoration performance. Continued reliance on legacy technology increases long-term operational risk and reduces predictability of asset performance. Replacement

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		mitigates obsolescence risk and supports transition to modern, supportable equipment platforms.
	Needs Planning	
		The project responds to planning-level needs related to: – management of long-term condition and obsolescence risk associated with legacy 5 kV switchgear – improvement of operational reliability, switching flexibility, and restoration performance – modernization of aging primary equipment to support maintainability and future system readiness These needs are recognized within the planning horizon but are not associated with immediate system risk.
	Enabling & System Benefit	
		Installation of new switchgear provides improved operational flexibility and simplifies future maintenance and system configuration activities. The outdoor gas-insulated configuration reduces reliance on aging station structures and improves accessibility for future asset interventions. The project also facilitates modernization of associated conductor systems and supports incremental improvement in station operability.
	Planning Horizon Urgency	
		The need for renewal is driven by progressive asset aging and increasing obsolescence risk rather than an immediate reliability or safety deficiency. Continued operation of the existing switchgear is considered manageable in the near term; however, risk exposure is expected to increase over the medium term as component availability declines and maintenance requirements intensify. Accordingly, the project is appropriately positioned within the medium to long-term planning horizon, supporting proactive risk management while avoiding premature capital investment.
	Alternatives Considered	
	1. Do Nothing Continued operation of the existing 5 kV metal-enclosed switchgear in its current condition was considered. While this option would avoid near-term capital expenditure, it would not address the advanced age of the equipment, increasing variability in mechanical operating performance, or growing maintenance sensitivity	

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observed during routine switching activities. Continued reliance on this legacy infrastructure would progressively increase the risk of delayed restoration following fault events and unplanned maintenance intervention. This option does not align with prudent long-term asset lifecycle management.

2. Targeted Repair or Refurbishment of Existing Switchgear

Selective refurbishment, component replacement, or control system upgrades of the existing 5 kV switchgear were evaluated. While this approach could extend nominal serviceability in the short term, it would not resolve underlying limitations associated with legacy mechanical design, aging insulation systems, or declining availability of standardized replacement components. Increasing reliance on custom refurbishment and specialist maintenance introduces uncertainty in operational performance and lifecycle cost exposure. This option would also perpetuate operation at a legacy voltage class and would not provide additional capacity margin or planning flexibility.

3. Replacement with Like-for-Like 5 kV Metal-Enclosed Switchgear

Replacement of the existing equipment with new conventional 5 kV metal-enclosed air-insulated switchgear was considered. While this option would restore equipment condition and improve operational reliability relative to the existing installation, it would maintain the existing legacy voltage class and associated long-term capacity constraints. A like-for-like replacement would increase the likelihood of future step-change capital investment as system requirements evolve. Given comparable implementation complexity and lifecycle cost relative to the proposed solution, this option was not considered to provide optimal long-term value.

4. Outdoor Medium-Voltage Air-Insulated Switchgear Installation

Installation of outdoor-rated air-insulated medium-voltage switchgear was considered as an alternative configuration. While this approach would reduce dependence on existing building infrastructure, it would introduce increased exposure to environmental conditions, potentially higher long-term maintenance requirements, and reduced equipment compactness relative to gas-insulated solutions. This option was determined to provide limited net lifecycle benefit for the station configuration and modernization objectives.

5. Deferred Implementation

Deferral of switchgear replacement to a later planning period was evaluated. While continued operation of the existing equipment is feasible in the near term with enhanced maintenance oversight, progressive degradation in mechanical performance and declining component supportability would increase uncertainty in operational reliability over time. Deferral would therefore increase exposure to

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unplanned intervention and restoration risk, while delaying achievement of broader asset lifecycle renewal objectives.

6. Selected Approach

Removal of the existing legacy 5 kV metal-enclosed switchgear and installation of new 15 kV-class outdoor gas-insulated switchgear, including re-routing or replacement of associated main and feeder conductors, was identified as the preferred modernization approach. This option improves operational reliability, reduces maintenance exposure, and enhances safety performance while reducing long-term reliance on aging station structures. Selection of 15 kV-class equipment provides additional capacity margin and maintains planning flexibility for potential future distribution system configuration changes without requiring further step-change equipment replacement. Implementation timing is aligned with risk-based asset management prioritization within the DSP horizon.

Substation Project Summary

Project ID:	STN017
Substation:	PEM MS#7
Project Name:	44KV AIR BREAK SWITCH RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2029-2030
Estimated Capital Cost:	$100,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing legacy air break switches and motor operators. Installation of new 44kV switches, motor operators, and controls.

Project Breakout:

	Materials:	• 46kV, pole mounted air break switch (3 EA) • Air break switch motor operator (3 EA)
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• System Operations and Outage Coordination • Planning and execution of switching procedures, outage scheduling, system isolation, and temporary configuration required to safely remove and replace existing overhead switching equipment. • Site Preparation and Access • Establishment of safe work zones, access setup, traffic control (if required), and preparation of work areas around existing structures and switching locations. • Removal of Existing Equipment • De-energization confirmation, mechanical disconnection, removal of legacy overhead air break switches, motor operators, control wiring, and associated mounting hardware. Lowering, handling, and preparation of removed equipment for disposal. • Structural Modifications and Hardware Adjustments

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Substation:		PEM MS#7
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		• Minor modifications to existing poles or support structures, installation of new mounting assemblies, brackets, and hardware required to accommodate replacement switching equipment. • Installation of New Overhead Switches • Hoisting, alignment, and installation of new air break switch assemblies, including mechanical adjustment, contact alignment, and verification of proper operation. • Installation of Motor Operators and Control Interfaces • Mounting of new motor operators, installation of control cabling, conduit, junction boxes, and interface connections to existing control systems where applicable. • Primary Conductor Work • Disconnection and reconnection of primary conductors, installation of new jumpers, hardware replacement, and verification of conductor clearances and tension. • Grounding and Bonding Adjustments • Modification or installation of grounding conductors and bonding connections associated with new equipment installation. • Functional Testing and Commissioning Support • Operational testing of manual and motorized switching functions, verification of control signals, interlocks, and system integration prior to return to service. • System Restoration and Close-out • Return of the system to normal configuration, removal of temporary work protections, site clean-up, and completion of construction documentation.
Project Justification Summary		
	Replacement of the existing overhead air break switches and associated motor operators at MS7 addresses progressive asset aging, mechanical wear, and declining long-term supportability of legacy switching infrastructure. The switching locations perform an operational role within established feeder configuration and contingency arrangements, supporting system flexibility and restoration capability. While the existing equipment remains functional, condition trends support planned lifecycle renewal to maintain operational reliability and reduce maintenance burden. Alternative approaches, including refurbishment or conversion to manual operation, would not provide comparable long-term performance, while higher-cost	

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Project Name:	44KV AIR BREAK SWITCH RENEWAL

options such as metal-enclosed switchgear were determined to be disproportionate to the operational need.

The project is assigned a moderate priority, reflecting its contribution to improving overall operability and switching effectiveness within the 44 kV ring configuration. Renewal supports more efficient system reconfiguration under normal and contingency conditions while aligning with broader risk-based asset management objectives within the planning horizon.

Detailed Justification Roadmap

Safety & Compliance Risk Exposure

The existing overhead air break switches and associated motor operators present increasing safety exposure associated with aging mechanical operating mechanisms, weather-related degradation, and the need for field-based switching and maintenance intervention. While the equipment remains operational, variability in mechanical performance and reliance on manual interaction introduce elevated occupational risk relative to modern switching equipment.

Replacement with new overhead switching assemblies and motor operators improves operational safety through more reliable switching performance, reduced maintenance exposure at elevation, and improved control of switching operations under both normal and contingency conditions. No immediate regulatory non-compliance has been identified; however, renewal supports continued alignment with current utility safety practices and prudent lifecycle asset management.

System Consequence & Operational Impact

MS7 forms part of the 44 kV ring supplying distribution substations and load centres within the surrounding service area. While alternative supply paths exist through the ring configuration, continued reliance on legacy air break switching equipment introduces operational constraints during abnormal system conditions.

Loss of switching functionality at MS7 would not typically result in sustained customer outages due to available contingency configurations. However, restoration actions would require manual switching sequences, planned outages, and increased field intervention relative to modern automated switching installations. As a result, restoration timelines and operational flexibility would be reduced under contingency scenarios.

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		The existing air break switches remain operational; however, advancing equipment age and mechanical wear increase the likelihood of switching performance variability, unplanned outages during switching operations, and extended restoration durations. These factors affect system operability rather than immediate supply adequacy. Accordingly, MS7 is assessed as presenting a moderate system consequence, reflecting: -strategic role in supporting operability of the 44 kV ring configuration -availability of contingency supply with manual switching dependencies -reduced operational flexibility during abnormal system conditions -increasing outage duration risk associated with aging switching equipment This consequence level supports renewal prioritization within the moderate risk classification framework, aligned with operability improvement objectives rather than urgent supply capacity requirements.
	Asset Obsolescence & Reliability Risk	
		The existing air break switching equipment is of legacy design with declining availability of standardized replacement components and limited manufacturer support. Mechanical operating mechanisms, motor operator assemblies, and associated control interfaces are increasingly difficult to maintain using readily available parts, requiring custom fabrication or refurbishment approaches. As equipment age advances, maintenance activities become more intervention-intensive and less predictable, introducing uncertainty in lifecycle cost, switching reliability, and restoration performance. Continued reliance on this legacy switching technology increases long-term operational risk and reduces confidence in sustained asset operability within the 44 kV ring configuration. Renewal with modern switching equipment mitigates obsolescence exposure by restoring access to standardized components, improving supportability, and enhancing long-term maintainability consistent with prudent asset stewardship practices.
	Needs Planning	
		The project responds to planning-level needs related to: – mitigation of long-term condition and obsolescence risks associated with aging primary station equipment

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		– enhancement of operational reliability, system flexibility, and service restoration capability – modernization of legacy infrastructure to improve maintainability, asset performance, and readiness for future system requirements These needs are identified within the planning horizon and are not driven by immediate system reliability or safety risk.
	Enabling & System Benefit	
		The project enables improved operational flexibility and supports more reliable system configuration activities through renewal of existing motor-operated air break switching equipment with modern, dependable installations. Replacement of aging and increasingly unreliable operating mechanisms reduces operational inconsistency and maintenance intervention requirements. The upgraded configuration also facilitates incremental modernization of associated primary conductor terminations and control interfaces, supporting improved station operability and readiness for future system modifications.
	Planning Horizon Urgency	
		The need for renewal is driven by progressive deterioration in the reliability of aging motor-operated switching equipment and increasing lifecycle uncertainty rather than an immediate system reliability or safety deficiency. Continued operation of the existing installations is considered manageable in the near term; however, the likelihood of operational constraints and maintenance intervention is expected to increase over the medium term as equipment condition advances and component supportability declines. Accordingly, the project is appropriately positioned within the medium-term planning horizon, reflecting a moderate priority classification that supports proactive risk management and operability improvement while avoiding premature capital investment.
Alternatives Considered		
	1. Do Nothing / Continue Operation Continued operation of the existing overhead air break switches and associated motor operators was considered. While this option would defer near-term capital expenditure, it would not address increasing asset age, declining mechanical reliability, or reduced availability of replacement components. Continued reliance on legacy switching infrastructure would incrementally increase operational risk and maintenance burden over the planning horizon.	

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Project Name:	44KV AIR BREAK SWITCH RENEWAL

2. Targeted Repair or Refurbishment

Selective repair, refurbishment, or component replacement of the existing switches and motor operators was evaluated. While this approach could extend service life in the short term, the advanced age and mechanical wear of the equipment limit the effectiveness of refurbishment as a long-term solution. This option would not address inherent design limitations or improve long-term asset supportability.

3. Conversion to Manual Switching Configuration

Removal of motor operators and continued operation using manual air break switches was considered. This approach would reduce capital cost and simplify equipment configuration but would result in reduced operational flexibility, longer restoration times, and increased reliance on field resources during system events. This option was not preferred given the operational role of the switching locations.

4. Installation of Metal-Enclosed Switchgear

Replacement of the overhead switching arrangement with metal-enclosed switchgear was evaluated as a higher-performance alternative that would provide improved environmental protection, reduced maintenance exposure, and enhanced operational control. However, this option would require substantial capital investment, including civil works, foundations, enclosure installation, and system reconfiguration. Given the functional role of the switching locations and the absence of a corresponding system need, this approach was determined to be cost-prohibitive relative to the benefits achieved.

5. Replacement with New Overhead Air Break Switches (Selected Option)

Full replacement of the existing switches and motor operators with modern overhead equipment provides improved mechanical reliability, reduced maintenance requirements, and continued support for motorized switching operations. This approach represents the most cost-effective solution aligned with lifecycle asset management objectives and operational performance needs within the planning horizon.

Substation Project Summary

Project ID:	STN018
Substation:	PEM MS#8
Project Name:	TX FOUNDATION DESTABILIZATION MITIGATION
ORPC DSP Program:	RENEWAL
Primary Driver:	SAFETY AND COMPLIANCE IMPROVEMENT
DSP Need Reference:	6.3 - SAFETY AND COMPLIANCE NEEDS
Priority Classification:	MODERATE
Planning Window:	2027-2028
Estimated Capital Cost:	$100,000
Estimate Basis:	ENGINEERING JUDGEMENT

Project Description:

Stabilization of existing power transformer foundation. Installation of new 5kV secondary main conductors.

Project Breakout:

	Materials:	• Structural concrete (repair / partial reconstruction) • Reinforcing steel • Non-shrink grout / permanent shimming materials • Anchor bolts / anchoring hardware • Granular fill / subgrade stabilization materials • Drainage materials (minor)
	Engineering:	• Assessment of existing site and foundation condition • Development of a practical stabilization / repair approach • Preparation of planning-level civil / structural design documentation • Review of any impacts to adjacent station infrastructure (e.g., grounding, access, drainage) • Support during construction implementation • Post-work verification and documentation
	Labour:	• System switching and outage coordination to enable safe isolation of the transformer and surrounding work area • Temporary stabilization measures and preparation of the existing foundation area for remediation works • Excavation, removal of deteriorated concrete sections, and disposal of unsuitable materials • Subgrade preparation including compaction, localized stabilization, and installation of drainage provisions as required

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Substation:		PEM MS#8
Project Name:		TX FOUNDATION DESTABILIZATION MITIGATION
		• Formwork installation, reinforcing steel placement, and reconstruction or strengthening of the transformer support slab • Placement of structural concrete and curing activities associated with foundation repair or partial reconstruction • Installation of permanent shimming, bearing plates, and anchoring hardware to re-establish proper transformer support and alignment • Reinstatement or modification of grounding conductors affected by excavation or foundation works • Backfilling, grading, and restoration of surrounding station yard surfaces and drainage features • Post-construction verification, site cleanup, and restoration of normal station configuration
Project Justification Summary		
	The proposed project addresses a localized deterioration of the existing transformer support foundation at MS8 that has resulted in loss of level bearing and the need for interim field measures to maintain proper equipment alignment. While the condition does not presently represent an immediate reliability or safety deficiency, continued reliance on temporary stabilization introduces avoidable operational risk and increases the likelihood of more disruptive corrective work if deterioration progresses. The selected approach involves targeted stabilization and rehabilitation of the existing foundation, representing a proportionate response to the observed condition. This restores appropriate structural support for the transformer while limiting construction scope, outage requirements, and capital expenditure relative to more extensive civil reconstruction or broader station redevelopment alternatives. The issue is fundamentally site-specific and does not materially constrain system capability; however, prudent intervention supports continued safe and orderly station operation and reduces uncertainty associated with progressive civil degradation. Accordingly, the project is classified as moderate priority, with implementation appropriately positioned within the near- to mid-term planning horizon to address the condition proactively while maintaining flexibility for future station configuration decisions.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	

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Project Name:		TX FOUNDATION DESTABILIZATION MITIGATION
		The observed deterioration of the transformer support foundation introduces a localized safety exposure associated with loss of stable equipment bearing and the need for interim field measures such as shimming to maintain proper alignment. While the transformer remains operational and no immediate regulatory non-compliance has been identified, continued reliance on temporary stabilization is not consistent with prudent long-term station management practices. Progressive foundation movement may increase the potential for mechanical stress on connected conductors and ancillary equipment, as well as create less predictable working conditions during maintenance activities. Addressing the condition through targeted stabilization supports restoration of appropriate structural support and improves the overall safety profile of the installation. The proposed work therefore represents a proactive measure to maintain safe operating conditions and alignment with accepted utility asset stewardship practices, rather than a response to an immediate compliance deficiency.
	System Consequence & Operational Impact	
		The observed condition is localized to the transformer support foundation and does not presently constrain station capability or system configuration. The station remains operable and the issue does not introduce an immediate risk of supply interruption. However, continued deterioration of the foundation increases the likelihood of progressive mechanical misalignment or the need for more intrusive corrective work under emergent conditions. While system-level impact is therefore limited in the near term, prudent intervention reduces the risk of unplanned outages and supports continued reliable operation of this supply point. The consequence is accordingly characterized as moderate and primarily asset-specific, reflecting the importance of maintaining stable transformer support without indicating a broader system reliability driver.
	Asset Obsolescence & Reliability Risk	
		The identified issue is associated with deterioration of the transformer support foundation rather than with obsolescence of primary electrical equipment or control systems. As such, the project is not driven by declining availability of replacement components, manufacturer support limitations, or legacy technology considerations. The relevance of obsolescence in this case is therefore limited. The proposed work is focused on maintaining appropriate civil infrastructure conditions to

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Substation:	PEM MS#8
Project Name:	TX FOUNDATION DESTABILIZATION MITIGATION

		support continued operation of otherwise serviceable station assets, rather than addressing lifecycle constraints related to equipment modernization.
	Needs Planning	
		The project responds to planning-level needs related to: – restoration of stable structural support for the existing power transformer – mitigation of progressive civil deterioration that may otherwise lead to more disruptive corrective work – preservation of reliable station operation through proactive asset condition management – maintenance of safe and predictable working conditions for operational and maintenance activities The need is driven by localized infrastructure condition rather than by broader system capacity, performance, or modernization objectives.
	Enabling & System Benefit	
		Foundation stabilization maintains appropriate physical support for the existing transformer and reduces the need for interim corrective measures. The work supports continued normal operation of the station under the current configuration without introducing broader changes to system capability or asset strategy. This intervention allows the asset to remain in service as intended while longer-term station planning decisions are considered.
	Planning Horizon Urgency	
		The need for intervention is driven by observable deterioration of the transformer support foundation rather than by an immediate operational or reliability constraint. While the condition can be managed in the short term through interim measures, continued deferral would increase reliance on temporary stabilization and may lead to more disruptive corrective work if deterioration progresses. Accordingly, the project is appropriately positioned within the near- to mid-term planning horizon. This timing supports proactive management of a localized civil condition while avoiding premature escalation to more extensive station reconstruction or asset replacement decisions.
Alternatives Considered		

Substation Project Summary

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Substation:	PEM MS#8
Project Name:	TX FOUNDATION DESTABILIZATION MITIGATION

1. Continued operation with ongoing monitoring and temporary shimming

Under this approach, the existing foundation condition would be managed through periodic inspection and adjustment of temporary shimming as required. While this minimizes near-term capital expenditure, it increases reliance on interim measures and does not address the underlying cause of slab movement. Over time, this approach may lead to more intrusive corrective work under less controlled conditions and introduces uncertainty in long-term equipment support performance.

2. Targeted stabilization and rehabilitation of the existing transformer foundation (selected approach)

This alternative involves localized excavation, structural repair or reconstruction of the existing slab, and implementation of subgrade stabilization or drainage improvements as required. The approach directly addresses the observed deterioration while limiting the scope of intervention to the affected asset support structure. This represents a proportionate response that restores stable operating conditions without prematurely advancing broader station redevelopment decisions.

3. Full transformer foundation replacement with expanded civil works

A more extensive intervention could involve complete removal and reconstruction of the transformer foundation and surrounding yard area. While this would provide a long-term structural solution, it introduces higher cost, longer outages, and greater construction complexity relative to the observed condition. At this time, the level of deterioration does not justify a full replacement approach.

4. Advancement of broader station reconfiguration or redevelopment

A comprehensive station redevelopment program could address the foundation issue as part of a wider asset modernization initiative. However, the foundation condition is a localized civil matter and does not in itself warrant acceleration of broader station configuration changes. Proceeding with a full redevelopment at this stage would not represent a proportionate or risk-informed response.

Substation Project Summary

Project ID:	STN019
Substation:	ALM MS#3
Project Name:	5KV SWGR RENEWAL
ORPC DSP Program:	RENEWAL
Primary Driver:	ASSET CONDITION/EOL
DSP Need Reference:	6.2 - CONDITION & RELIABILITY NEEDS
Priority Classification:	MODERATE
Planning Window:	2027-2028
Estimated Capital Cost:	$350,000
Estimate Basis:	INDUSTRY BENCHMARK - MV Contractor Consultation

Project Description:

Removal of existing 5kV unit sub and metal enclosed switchgear. Installation of new pad mounted gas insulated switchgear.

Project Breakout:

	Materials:	• 15kV, Outdoor Style Metal-Enclosed Gas-Insulated Switchgear (1 Inc SW, 2 way out) (1 EA) • Switchgear Foundation (1 EA) • 15kV Primary Cabling • Copper Ground Conductors • 15kV Elbow Terminations • 15kV Cable Accessories • 15kV Surge Arresters
	Engineering:	• Design - specifications & drawings • Programming • Commissioning planning and oversight
	Labour:	• System switching, outage coordination, and temporary feeder reconfiguration to enable safe isolation of existing 5 kV indoor switchgear and associated primary circuits • Removal, dismantling, and disposal of existing indoor metal-clad switchgear, buswork, cable terminations, control panels, and auxiliary equipment • Building decommissioning works including removal of redundant raceways, equipment supports, ventilation components, and fire protection interfaces as required

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		• Civil works including construction of new outdoor switchgear foundation, grounding system extensions, trenching, duct bank installation, and site grading or drainage adjustments as required • Delivery handling, rigging, placement, and installation of new outdoor metal-enclosed gas-insulated switchgear lineup • Installation of new 15 kV primary cables, elbow terminations, surge arresters, and associated insulated cable accessories • Installation of grounding and bonding conductors including integration with the existing station ground grid • Installation and modification of protection, control, metering, SCADA, and auxiliary wiring interfaces including relay panel updates and communications integration • Installation of new conduits, cable tray, and raceway systems between switchgear, control building, and field equipment • Functional testing, protection and control verification, commissioning, energization support, and restoration of normal system configuration • Removal of temporary system configurations and completion of site restoration works as required
Project Justification Summary		
	Replacement of the legacy 5 kV switchgear at MS#3 addresses increasing safety exposure, equipment obsolescence, and declining operational reliability while improving long-term asset supportability and planning flexibility. The station serves a meaningful level of connected load and forms part of established contingency supply arrangements; however, the progression of condition-related risk remains manageable within the planning horizon. The project is therefore appropriately classified as moderate priority and is sequenced in alignment with broader risk-based asset management objectives.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	
		The existing legacy 5 kV switchgear installation presents increasing safety exposure associated with aging mechanical operating mechanisms, legacy protection integration, and increased maintenance intervention requirements. While the equipment remains operational, variability in switching performance and the need for increased manual interaction introduce elevated

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		occupational risk relative to modern switchgear technologies. Replacement with modern gas-insulated switchgear improves operational safety through enhanced interlocking, reduced exposure to energized components, and improved arc-flash performance characteristics. No immediate regulatory non-compliance has been identified; however, replacement supports ongoing alignment with evolving industry safety practices and prudent asset stewardship.
	System Consequence & Operational Impact	
		MS3 serves a level of connected load broadly consistent with other substations within the Almonte service area. Loss of station functionality would therefore result in customer impacts comparable to peer facilities rather than representing a uniquely high exposure point within the system. All feeders supplied from MS3 have established contingency supply paths that can be implemented without requiring customer outages under normal operating conditions. As a result, sustained loss of supply risk is effectively mitigated, although restoration performance would still be influenced by the limitations of existing switching arrangements and reduced automation relative to modern configurations. The existing switchgear condition does not currently present an imminent reliability concern; however, continued operation increases the probability of in-service failure leading to operational disruption, increased restoration complexity, and reduced flexibility during abnormal system conditions. Accordingly, the station is assessed as presenting a moderate system consequence, reflecting: – load exposure consistent with other substations in the Almonte area – availability of contingency supply without outage under typical conditions – limited automation and switching flexibility relative to modern installations – increasing operational risk associated with aging primary equipment This consequence level supports renewal prioritization within the moderate risk classification framework rather than indicating an immediate replacement requirement.
	Asset Obsolescence & Reliability Risk	
		The existing switchgear is of vintage design with declining availability of standardized replacement components and reduced manufacturer support. Maintenance activities increasingly require custom solutions and specialized intervention, introducing uncertainty in lifecycle cost and restoration

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		performance. Continued reliance on legacy technology increases long-term operational risk and reduces predictability of asset performance. Replacement mitigates obsolescence risk and supports transition to modern, supportable equipment platforms.
	Needs Planning	
		The project responds to planning-level needs related to: – management of long-term condition and obsolescence risk associated with legacy 5 kV switchgear – improvement of operational reliability, switching flexibility, and restoration performance – modernization of aging primary equipment to support maintainability and future system readiness These needs are recognized within the planning horizon but are not associated with immediate system risk.
	Enabling & System Benefit	
		Installation of new switchgear provides improved operational flexibility and simplifies future maintenance and system configuration activities. The outdoor gas-insulated configuration reduces reliance on aging station structures and improves accessibility for future asset interventions. The project also facilitates modernization of associated conductor systems and supports incremental improvement in station operability.
	Planning Horizon Urgency	
		The need for renewal is driven by progressive asset aging and increasing obsolescence risk rather than an immediate reliability or safety deficiency. Continued operation of the existing switchgear is considered manageable in the near term; however, risk exposure is expected to increase over the medium term as component availability declines and maintenance requirements intensify. Accordingly, the project is appropriately positioned within the medium to long-term planning horizon, supporting proactive risk management while avoiding premature capital investment.
	Alternatives Considered	
	1. Do Nothing Continued operation of the existing 5 kV metal-enclosed switchgear in its current condition was considered. While this option would avoid near-term capital	

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expenditure, it would not address the advanced age of the equipment, increasing variability in mechanical operating performance, or growing maintenance sensitivity observed during routine switching activities. Continued reliance on this legacy infrastructure would progressively increase the risk of delayed restoration following fault events and unplanned maintenance intervention. This option does not align with prudent long-term asset lifecycle management.

2. Targeted Repair or Refurbishment of Existing Switchgear

Selective refurbishment, component replacement, or control system upgrades of the existing 5 kV switchgear were evaluated. While this approach could extend nominal serviceability in the short term, it would not resolve underlying limitations associated with legacy mechanical design, aging insulation systems, or declining availability of standardized replacement components. Increasing reliance on custom refurbishment and specialist maintenance introduces uncertainty in operational performance and lifecycle cost exposure. This option would also perpetuate operation at a legacy voltage class and would not provide additional capacity margin or planning flexibility.

3. Replacement with Like-for-Like 5 kV Metal-Enclosed Switchgear

Replacement of the existing equipment with new conventional 5 kV metal-enclosed air-insulated switchgear was considered. While this option would restore equipment condition and improve operational reliability relative to the existing installation, it would maintain the existing legacy voltage class and associated long-term capacity constraints. A like-for-like replacement would increase the likelihood of future step-change capital investment as system requirements evolve. Given comparable implementation complexity and lifecycle cost relative to the proposed solution, this option was not considered to provide optimal long-term value.

4. Outdoor Medium-Voltage Air-Insulated Switchgear Installation

Installation of outdoor-rated air-insulated medium-voltage switchgear was considered as an alternative configuration. While this approach would reduce dependence on existing building infrastructure, it would introduce increased exposure to environmental conditions, potentially higher long-term maintenance requirements, and reduced equipment compactness relative to gas-insulated solutions. This option was determined to provide limited net lifecycle benefit for the station configuration and modernization objectives.

5. Deferred Implementation

Deferral of switchgear replacement to a later planning period was evaluated. While continued operation of the existing equipment is feasible in the near term with enhanced maintenance oversight, progressive degradation in mechanical performance and declining component supportability would increase uncertainty in

Project ID:	STN019
Substation:	ALM MS#3
Project Name:	5KV SWGR RENEWAL

operational reliability over time. Deferral would therefore increase exposure to unplanned intervention and restoration risk, while delaying achievement of broader asset lifecycle renewal objectives.

6. Selected Approach

Removal of the existing legacy 5 kV metal-enclosed switchgear and installation of new 15 kV-class outdoor gas-insulated switchgear, including re-routing or replacement of associated main and feeder conductors, was identified as the preferred modernization approach. This option improves operational reliability, reduces maintenance exposure, and enhances safety performance while reducing long-term reliance on aging station structures. Selection of 15 kV-class equipment provides additional capacity margin and maintains planning flexibility for potential future distribution system configuration changes without requiring further step-change equipment replacement. Implementation timing is aligned with risk-based asset management prioritization within the DSP horizon.

Substation Project Summary

Project ID:		STN020
Substation:		ALL
Project Name:		SCADA MASTER DATA CONCENTRATOR
ORPC DSP Program:		SYSTEM SERVICE
Primary Driver:		ENABLING/FOUNDATIONAL INVESTMENT
DSP Need Reference:		6.4 - OPERATIONAL FLEXIBILITY NEEDS
Priority Classification:		HIGH
Planning Window:		2026
Estimated Capital Cost:		$125,000
Estimate Basis:		INDUSTRY BENCHMARK - SCADA & P&C Consultant
Project Description: SCADA master upgrade & programming to actively and automatically log substation loading and performance metrics.		
Project Breakout:		
	Materials:	• Real Time Automation Controller (1EA) • Operator Workstation •
	Engineering:	• Topology design • Networking configuration & programming • RTAC programming and commissioning
	Labour:	• -
Project Justification Summary		
	The proposed SCADA master data concentrator upgrade addresses a critical need to improve visibility of substation loading and performance metrics, supporting both real-time operational awareness and evidence-based long-term system planning. The existing configuration provides limited automated data capture, constraining the utility's ability to monitor system behaviour, identify emerging constraints, and respond effectively to abnormal operating conditions. The selected approach involves upgrading the SCADA master platform and implementing enhanced programming to enable continuous, automated logging and reporting of key performance indicators. This targeted modernization improves data reliability and accessibility while avoiding the complexity and cost associated with full SCADA system replacement. Although the current system remains operational, the lack of comprehensive automated data capture introduces increasing operational and planning risk as	

Project ID:	STN020
Substation:	ALL
Project Name:	SCADA MASTER DATA CONCENTRATOR

system complexity and performance expectations evolve. Accordingly, the project is classified as high priority, reflecting its foundational role in supporting reliable system operation, informed capital planning, and modern utility asset management practices within the near-term planning horizon.

Detailed Justification Roadmap

Safety & Compliance Risk Exposure

The existing SCADA configuration provides limited automated capture and retention of substation loading and performance data, which constrains situational awareness during abnormal operating conditions and reduces the ability to perform timely post-event analysis. While the system remains operational and no immediate safety deficiency has been identified, enhanced automated data logging supports improved operational visibility and more informed system response.

Implementation of the SCADA master upgrade strengthens alignment with modern utility operational practices by improving monitoring capability, event reconstruction, and data availability for internal governance and external reporting requirements. The project therefore represents a proactive enhancement to operational safety oversight and regulatory compliance processes rather than a response to a specific safety deficiency.

System Consequence & Operational Impact

The current SCADA configuration limits the utility's ability to continuously monitor substation loading and performance trends, reducing visibility into evolving system conditions and constraining proactive operational response. While this does not presently restrict system capability, it increases reliance on manual data review and post-event analysis, which may delay identification of emerging constraints or abnormal operating conditions.

Enhanced automated data logging through the SCADA master upgrade improves real-time situational awareness, supports more efficient outage response and restoration planning, and strengthens the quality of information available for capital planning decisions. The consequence is therefore characterized as high, reflecting the foundational role of reliable system monitoring in supporting safe, efficient, and resilient network operation.

Asset Obsolescence & Reliability Risk

The current SCADA configuration reflects legacy system architecture that was not originally designed to support continuous automated capture and structured retention of substation loading and performance data. While the

Project ID:		STN020
Substation:		ALL
Project Name:		SCADA MASTER DATA CONCENTRATOR
		system remains operational and supported, its functional limitations constrain the utility's ability to meet evolving operational data and system monitoring expectations. Addition of a dedicated master data concentrator enhances the capability of the existing SCADA environment without requiring full platform replacement. This approach mitigates functional obsolescence associated with legacy data handling limitations while preserving value in the existing control infrastructure.
	Needs Planning	
		The project responds to planning-level needs related to: – improved visibility of substation loading and performance trends through continuous automated data capture – enhanced operational awareness to support timely response to abnormal system conditions – improved quality and availability of historical system performance data to inform asset planning and capital prioritization – alignment of monitoring capability with evolving utility operational data and reporting expectations The need is driven by functional limitations of the existing SCADA data handling configuration rather than by deficiencies in primary system control capability.
	Enabling & System Benefit	
		Implementation of a dedicated master data concentrator enables continuous automated logging and structured retention of substation loading and performance metrics. This improves the utility's ability to monitor system behaviour, support timely operational response, and develop more data-driven asset planning insights. The enhancement strengthens the effectiveness of the existing SCADA environment by extending monitoring and reporting capability without requiring broader system replacement. It also provides a scalable foundation for future integration of additional monitoring points or performance analytics as system needs evolve.
	Planning Horizon Urgency	
		The need for enhanced automated data logging capability is closely aligned with ongoing modernization of field SCADA devices across the substation fleet. As new intelligent electronic devices and communication infrastructure are

Project ID:	STN020
Substation:	ALL
Project Name:	SCADA MASTER DATA CONCENTRATOR

deployed, the utility has a timely opportunity to implement centralized data concentration and structured performance monitoring functionality.

Deferring implementation would reduce the effectiveness of these field upgrades and may result in fragmented data architecture, additional future integration costs, and continued reliance on limited historical system performance visibility. Accordingly, implementation of the master data concentrator is positioned within the near-term planning horizon and classified as high priority, reflecting the prudence of aligning system-level monitoring capability with concurrent field modernization initiatives.

Alternatives Considered

1. Continued operation with existing SCADA configuration and manual data collection

Under this approach, substation loading and performance metrics would continue to be monitored through existing SCADA indications supplemented by periodic manual data extraction and engineering review. While this minimizes near-term capital expenditure, it limits the utility's ability to proactively monitor system performance trends, support data-driven planning decisions, and respond efficiently to abnormal operating conditions.

2. Incremental enhancement of existing SCADA programming and reporting tools

This alternative involves targeted updates to existing SCADA configurations to improve visibility of selected parameters without replacement of the master data concentrator platform. While this approach reduces implementation cost and system disruption, it provides only partial functionality and may be constrained by the limitations of legacy hardware and software environments.

3. SCADA master data concentrator upgrade with enhanced automated data logging (selected approach)

Replacement or upgrade of the SCADA master data concentrator, combined with enhanced programming to enable automated logging and reporting of substation loading and performance metrics, provides a scalable and durable solution. This approach supports improved operational awareness, planning data quality, and long-term integration with evolving system monitoring requirements.

4. Comprehensive SCADA system replacement or enterprise-level data platform deployment

A full SCADA system modernization or implementation of a broader enterprise data management platform could provide enhanced system visibility and analytics capability. However, this approach would involve significantly higher cost, greater

Project ID:	STN020
Substation:	ALL
Project Name:	SCADA MASTER DATA CONCENTRATOR
	implementation complexity, and broader organizational change than required to address the identified need.

Substation Project Summary

Project ID:	STN021	
Substation:	ALM MS#2	
Project Name:	SUB-TRANSMISSION STRUCTURE FOUNDATION RESTORATION	
ORPC DSP Program:	RENEWAL	
Primary Driver:	SAFETY AND COMPLIANCE IMPROVEMENT	
DSP Need Reference:	6.3 - SAFETY AND COMPLIANCE NEEDS	
Priority Classification:	MODERATE	
Planning Window:	2027-2028	
Estimated Capital Cost:	$100,000	
Estimate Basis:	ENGINEERING JUDGEMENT	
Project Description: Rehabilitation of deteriorated structural foundations supporting substation structures.		
Project Breakout:		
	Materials:	• Structural concrete (foundation reconstruction) • Reinforcing steel • Anchor bolts / embedded anchoring hardware • Non-shrink grout / leveling compounds • Granular fill / subgrade stabilization materials • Formwork materials • Grounding conductor extensions / bonding hardware (minor) • Drainage materials (minor)
	Engineering:	• Assessment of existing foundation and structural condition • Development of foundation rehabilitation approach and construction sequencing • Preparation of planning-level civil / structural design documentation • Review of impacts to adjacent station infrastructure (e.g., grounding, access, drainage, clearances) • Construction support and field review • Post-construction verification and record documentation
	Labour:	• System switching and outage coordination to enable safe isolation of the transformer and surrounding work area • Temporary stabilization measures and preparation of the existing foundation area for remediation works

Project ID:		STN021
Substation:		ALM MS#2
Project Name:		SUB-TRANSMISSION STRUCTURE FOUNDATION RESTORATION
		• Excavation, removal of deteriorated concrete sections, and disposal of unsuitable materials • Subgrade preparation including compaction, localized stabilization, and installation of drainage provisions as required • Formwork installation, reinforcing steel placement, and reconstruction or strengthening of the transformer support slab • Placement of structural concrete and curing activities associated with foundation repair or partial reconstruction • Installation of permanent shimming, bearing plates, and anchoring hardware to re-establish proper transformer support and alignment • Reinstatement or modification of grounding conductors affected by excavation or foundation works • Backfilling, grading, and restoration of surrounding station yard surfaces and drainage features • Post-construction verification, site cleanup, and restoration of normal station configuration
Project Justification Summary		
	The proposed project addresses localized deterioration of structural foundations supporting station structures at Almonte MS2. While the observed condition does not currently represent an immediate reliability or safety deficiency, progressive degradation introduces increasing uncertainty regarding long-term structural stability and safe access for maintenance activities. The selected approach involves targeted rehabilitation and reconstruction of affected foundations, representing a proportionate response to the identified condition. This restores durable structural support while limiting construction scope, outage requirements, and capital expenditure relative to more extensive civil reconstruction or broader station redevelopment alternatives. The issue is site-specific and does not materially constrain current system capability; however, timely intervention supports continued safe and orderly station operation and reduces the likelihood of more disruptive corrective work if deterioration progresses. Accordingly, the project is classified as moderate priority, with implementation appropriately positioned within the near- to mid-term planning horizon.	
Detailed Justification Roadmap		
	Safety & Compliance Risk Exposure	

Substation Project Summary

Project ID:		STN021
Substation:		ALM MS#2
Project Name:		SUB-TRANSMISSION STRUCTURE FOUNDATION RESTORATION
		Observed deterioration of structural foundations supporting station structures at Almonte MS2 introduces a localized safety exposure associated with reduced confidence in long-term structural stability. While supported equipment remains operational and no immediate regulatory non-compliance has been identified, continued reliance on degraded foundations is not consistent with prudent asset stewardship practices. Progressive deterioration may increase the potential for structural movement and associated mechanical stress on supported equipment and connected conductors, as well as create less predictable conditions for maintenance and construction activities. Addressing the condition through targeted rehabilitation restores appropriate structural support and improves the overall safety profile of the installation. The proposed work therefore represents a proactive measure to maintain safe operating conditions and alignment with accepted utility asset management practices, rather than a response to an immediate compliance deficiency.
	System Consequence & Operational Impact	
		The observed condition is localized to the transformer support foundation and does not presently constrain station capability or system configuration. The station remains operable and the issue does not introduce an immediate risk of supply interruption. However, continued deterioration of the foundation increases the likelihood of progressive mechanical misalignment or the need for more intrusive corrective work under emergent conditions. While system-level impact is therefore limited in the near term, prudent intervention reduces the risk of unplanned outages and supports continued reliable operation of this supply point. The consequence is accordingly characterized as moderate and primarily asset-specific, reflecting the importance of maintaining stable transformer support without indicating a broader system reliability driver.
	Asset Obsolescence & Reliability Risk	
		The identified issue is associated with deterioration of the transformer support foundation rather than with obsolescence of primary electrical equipment or control systems. As such, the project is not driven by declining availability of replacement components, manufacturer support limitations, or legacy technology considerations.

Project ID:	STN021
Substation:	ALM MS#2
Project Name:	SUB-TRANSMISSION STRUCTURE FOUNDATION RESTORATION

		The relevance of obsolescence in this case is therefore limited. The proposed work is focused on maintaining appropriate civil infrastructure conditions to support continued operation of otherwise serviceable station assets, rather than addressing lifecycle constraints related to equipment modernization.
	Needs Planning	
		The project responds to planning-level needs related to: – restoration of stable structural support for the existing power transformer – mitigation of progressive civil deterioration that may otherwise lead to more disruptive corrective work – preservation of reliable station operation through proactive asset condition management – maintenance of safe and predictable working conditions for operational and maintenance activities The need is driven by localized infrastructure condition rather than by broader system capacity, performance, or modernization objectives.
	Enabling & System Benefit	
		Foundation stabilization maintains appropriate physical support for the existing transformer and reduces the need for interim corrective measures. The work supports continued normal operation of the station under the current configuration without introducing broader changes to system capability or asset strategy. This intervention allows the asset to remain in service as intended while longer-term station planning decisions are considered.
	Planning Horizon Urgency	
		The need for intervention is driven by observable deterioration of the transformer support foundation rather than by an immediate operational or reliability constraint. While the condition can be managed in the short term through interim measures, continued deferral would increase reliance on temporary stabilization and may lead to more disruptive corrective work if deterioration progresses. Accordingly, the project is appropriately positioned within the near- to mid-term planning horizon. This timing supports proactive management of a localized civil condition while avoiding premature escalation to more extensive station reconstruction or asset replacement decisions.

Substation Project Summary

Project ID:	STN021
Substation:	ALM MS#2
Project Name:	SUB-TRANSMISSION STRUCTURE FOUNDATION RESTORATION

Alternatives Considered

1. Do Nothing

Maintaining existing deteriorated structural foundations was considered. This option would avoid near-term capital expenditure but would not address progressive degradation of structural support elements. Continued deterioration may eventually affect equipment stability, safe maintenance access, and long-term operability of station infrastructure.

2. Targeted Localized Repairs

Undertaking minor patching or localized stabilization of the most visibly affected foundation areas was considered. While this approach could defer full remediation costs, it would not address underlying deterioration mechanisms or provide a durable long-term solution. This option may result in repeated intervention requirements and increased lifecycle cost.

3. Operational Mitigation in Lieu of Capital Investment

Continued monitoring of foundation condition combined with operational restrictions or temporary stabilization measures was considered. This approach would not materially reduce long-term structural risk and would increase reliance on ongoing inspection and reactive maintenance activities.

4. Deferred Implementation

Deferring foundation rehabilitation to a later planning period was considered. While immediate structural risk may be manageable, continued exposure to environmental and loading effects increases the likelihood of accelerated deterioration, unplanned corrective work, and potential impacts to station operability.

5. Selected Approach

Comprehensive rehabilitation and reconstruction of deteriorated structural foundations was selected as the preferred approach. This option provides a durable long-term solution that restores structural integrity, supports safe operation and maintenance activities, and aligns with prudent asset stewardship practices for critical substation infrastructure.

APPENDIX D1 – CAPITAL PROJECT REGISTER (SUMMARY TABLE)

This section presents the Substation Capital Project Register, which consolidates all planning-level capital projects identified through the needs identification and prioritization processes described in Sections 6 through 8 of this Distribution System Plan. The register provides a structured summary of proposed projects by substation, including the applicable OEB investment category, ORPC DSP program alignment, primary investment driver, DSP need reference, affected asset group, relative priority classification, indicative timing, and high-level cost basis.

The project register is intended to support comparative evaluation, phasing discussion, and internal capital coordination over the DSP planning horizon. Projects are presented at a planning level only and reflect conceptual scopes and order-of-magnitude cost estimates, typically developed using historical ORPC experience, industry benchmarks, or engineering judgment, with an assumed accuracy of approximately ±50 percent.

Indicative in-service years and planning windows represent anticipated sequencing ranges rather than fixed execution commitments and may shift as projects are refined, dependencies are resolved, or coordination requirements with upstream system owners evolve. Priority classifications reflect relative urgency and system impact based on asset condition, safety considerations, operational risk, and substation criticality, and are not intended to represent final approval or funding decisions.

The Substation Capital Project Register does not constitute an approved capital program. Advancement of any project listed herein remains subject to future engineering definition, refinement of scope and cost, availability of capital, coordination with external stakeholders, and subsequent ORPC governance and regulatory review processes.

SUBSTATION CAPITAL PROJECT REGISTER

PROJECT ID	SUBSTATION	PROJECT NAME	ORPC DSP PROGRAM	PRIMARY DRIVER	DSP NEED REFERENCE	ASSET GROUP	PRIORITY CLASSIFICATION	INDICATIVE IN-SERVICE YEAR	PLANNING WINDOW	ESTIMATED CAPITAL COST (+/-50%)	COST BASIS
STN001	PEM MS#1	SCADA & RELAY UPGRADE	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2028	2028	$ 150,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)
STN002	PEM MS#2	SCADA & RELAY UPGRADE	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2028	2028	$ 165,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)
STN003	PEM MS#3	SCADA & RELAY UPGRADE	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2026 (Transition Year)	2026 (Transition Year)	$ 110,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)
STN004	PEM MS#5	SCADA & RELAY UPGRADE	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2028	2028	$ 75,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities)
STN005	PEM MS#6	STATION METERING	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	MODERATE	2026 (Transition Year)	2026 (Transition Year)	$ 20,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (Meter installation, less feeder relays)
STN006	PEM MS#7	SCADA & RELAY UPGRADE	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2026 (Transition Year)	2026 (Transition Year)	$ 110,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope
STN007	ALM MS#1	STATION METERING	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	MODERATE	2027	2027	$ 50,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (differing quantities) - budget extended to include current transformers on main incoming supply.
STN008	ALM MS#2	SCADA UPGRADE/METERING	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2027	2027	$ 50,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope
STN009	ALM MS#3	SCADA UPGRADE/METERING	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2029-2030	2027-2028	$ 110,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope
STN010	ALM MS#4	STATION METERING	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	MODERATE	2027	2027	$ 20,000.00	HISTORICAL - Estimate is based on costs incurred during 2024 upgrade of MS8 - Equivalent scope (Meter installation, less feeder relays)
STN011	PEM MS#1	44KV RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	44KV PRIMARY EQUIPMENT	LOW	2031+	2031+	$ 400,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN012	PEM MS#1	5KV SWGR RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	MV METALCLAD SWITCHGEAR	MODERATE	2031+	2029-2030	$ 500,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN013	PEM MS#2	5KV SWGR RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	MV METALCLAD SWITCHGEAR	MODERATE	2031+	2031+	$ 500,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN014	PEM MS#3	5KV SWGR RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	MV METALCLAD SWITCHGEAR	LOW	2031+	2031+	$ 500,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN015	PEM MS#4	44KV RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	44KV PRIMARY EQUIPMENT	HIGH	2029-2030	2027-2028	$ 750,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN016	PEM MS#4	5KV SWGR RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	MV METALCLAD SWITCHGEAR	MODERATE	2031+	2029-2030	$ 500,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN017	PEM MS#7	44KV AIR BREAK SWITCH RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	44KV PRIMARY EQUIPMENT	MODERATE	2031+	2029-2030	$ 100,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN018	PEM MS#8	TX FOUNDATION DESTABILIZATION MITIGATION	RENEWAL	SAFETY AND COMPLIANCE IMPROVEMENT	6.3 - SAFETY AND COMPLIANCE NEEDS	SUBSTATION CIVIL	MODERATE	2029-2030	2027-2028	$ 100,000.00	ENGINEERING JUDGEMENT
STN019	ALM MS#3	5KV SWGR RENEWAL	RENEWAL	ASSET CONDITION/EOL	6.2 - CONDITION & RELIABILITY NEEDS	MV METALCLAD SWITCHGEAR	MODERATE	2029-2030	2027-2028	$ 350,000.00	INDUSTRY BENCHMARK - MV Contractor Consultation
STN020	ALL	SCADA MASTER DATA CONCENTRATOR	SYSTEM SERVICE	ENABLING/FOUNDATIONAL INVESTMENT	6.4 - OPERATIONAL FLEXIBILITY NEEDS	SCADA & COMMS	HIGH	2026 (Transition Year)	2026 (Transition Year)	$ 125,000.00	INDUSTRY BENCHMARK - SCADA & P&C Consultant
STN021	ALM MS#2	SUB-TRANSMISSION STRUCTURE FOUNDATION RESTORATION	RENEWAL	SAFETY AND COMPLIANCE IMPROVEMENT	6.3 - SAFETY AND COMPLIANCE NEEDS	SUBSTATION CIVIL	MODERATE	2029-2030	2027-2028	$ 100,000.00	ENGINEERING JUDGEMENT

APPENDIX D2 – CAPITAL PROJECT EXECUTION CONSIDERATIONS

The project summaries presented in Appendix D identify the capital projects recommended through the DSP planning process. In addition to project need, timing, and investment requirements, each project includes practical execution considerations that may influence implementation planning, outage coordination, construction staging, procurement activities, operational flexibility, stakeholder coordination, or overall project scheduling.

The execution considerations presented in this appendix are intended to provide visibility into the primary technical and operational factors associated with implementation of each project. These considerations support planning, prioritization, budgeting, and future project development activities and should be considered alongside the project summaries presented in Appendix D.

The execution considerations are organized at a planning level and focus on the principal factors expected to influence project execution.

APPENDIX D2 – CAPITAL PROJECT EXECUTION CONSIDERATIONS

Project Group	Associated Projects	Key Execution Considerations	Execution Uncertainty	Uncertainty Mitigation Strategy
SCADA & Relay Upgrade	STN001 STN002 STN003 STN004 STN006 STN008 STN009 STN020	Protection cutovers and commissioning activities must be coordinated to maintain system protection and operational visibility during implementation. Communications integration, SCADA database updates, device programming, and system testing require coordination across multiple stations and operational technology platforms. Successful implementation is dependent on standardized design approaches and sequencing of field and central system upgrades.	Medium	Detailed engineering, standardized protection and SCADA architectures, staged commissioning plans, pre-construction acceptance testing, and coordinated outage planning.
Station Metering	STN005 STN007 STN010	Metering installations require integration with existing station infrastructure, commissioning of metering and communications systems, and planned outages where instrument transformer modifications are required. Execution complexity is generally limited and can often be coordinated with other planned station activities.	Low	Detailed engineering, coordination with planned station outages, and integration with broader SCADA and operational technology initiatives.
44 kV Renewal	STN011 STN015 STN017	Projects involve work on critical sub-transmission infrastructure and require extensive outage coordination, switching plans, and temporary operating arrangements to maintain system reliability during construction. Long-lead equipment procurement, coordination with upstream supply configurations, and construction adjacent to energized equipment may influence implementation timing and complexity.	High	Detailed engineering, constructability reviews, advance equipment procurement, development of detailed switching and outage plans, and early operational coordination with affected stakeholders.
5 kV Switchgear Renewal Projects	STN012 STN013 STN014 STN016 STN019	Projects involve major station reconstruction activities including switchgear replacement, primary cable modifications, equipment removals, civil works, and commissioning of protection and control systems. Extended outages, equipment procurement lead times, site-specific constructability constraints, and coordination of multiple construction disciplines may affect implementation complexity.	High	Detailed engineering, staged construction planning, advance procurement of major equipment, constructability reviews, detailed outage planning, and phased commissioning strategies.
Civil and Structural Infrastructure Rehabilitation	STN018 STN021	Work is concentrated around existing energized station infrastructure and may be influenced by unknown subsurface conditions, extent of deterioration, access constraints, and weather-dependent construction activities. Site conditions identified during excavation may affect final scope and construction methodology.	Medium	Detailed engineering, condition verification, geotechnical or structural investigations as appropriate, construction staging plans, and coordination of outages required to safely access affected infrastructure.

APPENDIX D3: - CAPITAL PROGRAM SCOPE SUMMARY

Asset/Scope Category	Program Scope Metric	Associated Project
Substations with Capital Projects	12 Substations	-
Total Capital Projects Identified	21 Projects	-
Protection & Control Modernization Projects	7 Substations	STN001, STN002, STN003, STN004, STN006, STN008, STN009
SCADA Modernization Projects	7 Substations	STN001, STN002, STN003, STN004, STN006, STN008, STN009, STN020
Station Metering Upgrade Projects	3 Substations	STN005, STN007, STN010
SCADA Master Infrastructure Upgrades	1 System Wide Project	STN020
5kV Switchgear Renewal Projects	5 Substations	STN012, STN013, STN014, STN016, STN019
44kV Infrastructure Renewal Projects	3 Substations	STN011, STN015, STN017
Transformer Foundation Rehabilitation Projects	1 Substation	STN018
Structural Foundation Rehabilitation Projects	1 Substation	STN021

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

PURPOSE & INTENDED USE

This appendix presents a representative preventive and predictive maintenance framework applicable to ORPC's distribution substations and associated major electrical assets. The framework is intended to support long-term asset stewardship, reliability management, and condition-informed operational planning within the context of ORPC's broader asset management practices.

The activities and intervals presented are planning-level in nature and are informed by generally accepted industry practice, including guidance contained within ANSI/NETA Maintenance Testing Specifications (MTS), manufacturer recommendations, utility operating experience, and standard power system maintenance practices. Consistent with industry guidance, the appropriate maintenance approach for any individual asset should ultimately be determined based on asset condition, operational criticality, historical performance, environmental exposure, equipment vintage, and system reliability requirements.

The purpose of this appendix is not to prescribe a rigid maintenance program or detailed testing specification. Rather, it establishes a structured reference framework illustrating the types of inspection, testing, monitoring, and servicing activities typically associated with prudent utility asset management programs.

The framework also reflects the increasing importance of condition-based and data-driven maintenance practices. Modernization of protection, control, SCADA, metering, and monitoring infrastructure improves ORPC's ability to collect operational and diagnostic information necessary to support targeted maintenance intervention, equipment trending, breaker wear analysis, load monitoring, event analysis, and more informed lifecycle decision-making.

Actual maintenance implementation, testing procedures, acceptance criteria, outage coordination, and equipment-specific work practices should continue to be governed by ORPC operational procedures, applicable safety requirements, manufacturer guidance, and detailed maintenance program development activities outside the scope of this DS1P.

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

POWER TRANSFORMER			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual and mechanical inspection, including inspection of bushings, gauges, grounding, surge arresters, cooling systems, control cabinets, and overall transformer condition	Bi-Annual	Preventative	Identify visible deterioration, leakage, corrosion, contamination, abnormal operating conditions, or mechanical deficiencies
Infrared thermographic inspection	Annual	Predictive	Identify abnormal thermal conditions, loose connections, cooling deficiencies, or localized overheating
Transformer oil sampling and laboratory analysis, including dissolved gas analysis (DGA), moisture content, dielectric strength, acidity, and interfacial tension testing	Annual	Predictive	Assess insulating system condition, identify internal fault development, monitor oil degradation, and support condition trending
Power factor / dissipation factor testing of transformer insulation and bushings	3 Years	Predictive	Evaluate insulation system integrity and identify deterioration or contamination
Insulation resistance testing	3 Years	Predictive	Assess insulation condition and identify moisture ingress or degradation
Transformer turns ratio (TTR) testing	3 Years	Predictive	Verify winding integrity and detect winding deformation or tap changer issues
Winding resistance testing	3 Years	Predictive	Identify abnormal winding resistance, loose connections, or tap changer contact deterioration
Excitation current / core integrity testing	3 Years	Predictive	Detect core degradation, winding movement, or magnetic circuit abnormalities

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

POWER TRANSFORMER			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Review of transformer loading, temperature, and operational trends	Annual	Predictive	Support lifecycle planning, overload assessment, and condition based maintenance decisions
Oil processing, leak repair, corrosion remediation, or corrective maintenance	Condition Based	Corrective	Restore equipment condition, mitigate deterioration, and extend service life

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

MEDIUM VOLTAGE SWITCHGEAR			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual and mechanical inspection, including inspection of breakers, buswork, insulating barriers, shutters, interlocks, grounding, control wiring, space heaters, ventilation, and overall equipment condition	Bi-Annual	Preventative	Identify visible deterioration, leakage, corrosion, contamination, abnormal operating conditions, or mechanical deficiencies
Infrared thermographic inspection	Annual	Predictive	Identify overheating connections, abnormal thermal conditions, or developing component failures
Cleaning of switchgear compartments and insulation surfaces	Annual	Preventative	Reduce contamination, moisture accumulation, and insulation tracking risk
Mechanical exercise and operational inspection of circuit breakers and switching devices	Annual	Preventative	Verify proper operation of breaker mechanisms, interlocks, and switching functions
Insulation resistance testing	3 Years	Predictive	Assess insulation integrity and identify moisture ingress or insulation degradation
Contact resistance testing	3 Years	Predictive	Identify deteriorated, loose, or high resistance current carrying connections
Circuit breaker timing and operational testing	3 Years	Preventative	Verify breaker operating performance, opening/closing times, and mechanism condition
Secondary injection testing of protective systems	3 Years	Preventative	Verify protection system operation, trip functionality, and coordination integrity
Functional testing and calibration of protective relays	3 Years	Preventative	Confirm proper relay operation, settings integrity, and protective performance

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

MEDIUM VOLTAGE SWITCHGEAR			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Inspection and maintenance of breaker auxiliary contacts, control circuits, and trip/close coils	3 Years	Preventative	Verify proper control system operation and identify component wear or degradation
Inspection and maintenance of grounding and bonding connections	3 Years	Preventative	Maintain grounding continuity and personnel safety
Review of breaker operation counts, fault interruption history, and maintenance records	Annual	Predictive	Support condition based maintenance planning and breaker wear assessment
Corrective maintenance, component replacement, lubrication, corrosion remediation, or refurbishment	Condition Based	Corrective	Restore equipment condition, reliability, and operational performance

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

44KV OIL CIRCUIT BREAKERS			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual and mechanical inspection, including inspection of breakers, buswork, insulating barriers, shutters, interlocks, grounding, control wiring, space heaters, ventilation, and overall equipment condition	Bi-Annual	Preventative	Identify visible deterioration, leakage, corrosion, contamination, abnormal operating conditions, or mechanical deficiencies
Infrared thermographic inspection	Annual	Predictive	Identify overheating connections, abnormal thermal conditions, or developing component failures
Cleaning of bushings, insulators, and accessible insulating surfaces	Annual	Preventative	Reduce contamination, tracking risk, and surface leakage current exposure
Mechanical exercise and operational inspection of breaker mechanisms and interlocks	Annual	Preventative	Verify proper breaker operation, mechanism integrity, and interlock functionality
Insulating oil sampling and laboratory analysis, including dielectric strength, moisture content, dissolved gas analysis (DGA), and acidity testing	Annual	Predictive	Assess insulating oil condition, identify internal deterioration, and support condition trending
Contact resistance testing	3 Years	Predictive	Identify deteriorated, loose, or high resistance current carrying connections
Circuit breaker timing and operational testing	3 Years	Preventative	Verify breaker operating performance, opening/closing times, and mechanism condition
Insulation resistance testing	3 Years	Predictive	Assess insulation integrity and identify moisture ingress or insulation degradation
Power factor / dissipation factor testing of breaker insulation and bushings	3 Years	Predictive	Evaluate insulation system integrity and identify deterioration or contamination

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

44KV OIL CIRCUIT BREAKERS			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Secondary injection testing of protective systems	3 Years	Preventative	Verify protection system operation, trip functionality, and coordination integrity
Functional testing and calibration of protective relays	3 Years	Preventative	Confirm proper relay operation, settings integrity, and protective performance
Inspection and maintenance of auxiliary contacts, trip/close coils, and control circuits	3 Years	Preventative	Verify proper operation of breaker control and protection interfaces
Inspection and maintenance of grounding and bonding connections	Annual	Preventative	Maintain grounding continuity and personnel safety
Review of breaker operation counts, fault interruption history, and maintenance records	Annual	Predictive	Support condition based maintenance planning and breaker wear assessment
Oil processing, leak repair, contact maintenance, mechanism refurbishment, corrosion remediation, or component replacement	Condition Based	Corrective	Restore equipment condition, reliability, and operational performance

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

AIR INSULATED LOAD BREAK SWITCHES			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual and mechanical inspection, including inspection of switch blades, insulators, conductors, pole/structure condition, grounding, operating linkages, motor operators, and overall equipment condition	Annual	Preventative	Identify deterioration, corrosion, contamination, loose hardware, mechanical wear, or structural deficiencies
Infrared thermographic inspection	Annual	Predictive	Identify overheating connections, abnormal thermal conditions, or deteriorated contacts
Cleaning of insulators and accessible insulating surfaces	Condition Based	Preventative	Reduce contamination, tracking risk, and surface leakage current exposure
Mechanical exercise and operational inspection of switch mechanisms and interlocks	3 Years	Preventative	Verify proper switching operation, mechanism integrity, and operability under normal conditions
Inspection and lubrication of bearings, linkages, gears, and operating mechanisms	3 Years	Preventative	Reduce mechanical wear and maintain reliable switch operation
Inspection and testing of motor operators, control circuits, and auxiliary devices (where applicable)	3 Years	Preventative	Verify proper operation of remotely operated switching equipment and associated controls
Contact resistance testing (where practical)	3 Years	Predictive	Identify deteriorated or high-resistance current-carrying connections
Insulation resistance testing of control and auxiliary circuits (where applicable)	3 Years	Predictive	Assess integrity of auxiliary insulation systems and identify degradation or moisture ingress
Inspection and maintenance of grounding and bonding connections	Annual	Preventative	Maintain grounding continuity and personnel safety
Inspection of pole or support structure integrity, foundations, and hardware	Annual	Preventative	Identify structural deterioration, settlement, corrosion, or mechanical instability

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

AIR INSULATED LOAD BREAK SWITCHES			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Functional verification of SCADA indication, status monitoring, and remote operation (where applicable)	Annual	Preventative	Verify operational visibility and remote switching capability
Review of switching operation history and maintenance records	Annual	Predictive	Support condition-based maintenance planning and identification of recurring operational issues
Corrective maintenance, contact replacement, linkage repair, structural remediation, corrosion treatment, or component replacement	Condition Based	Corrective	Restore equipment condition, reliability, and operational performance

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

PROTECTION & CONTROL SYSTEMS			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual inspection of protection panels, relays, RTUs, wiring, terminal blocks, annunciators, communications equipment, batteries, chargers, and auxiliary systems	Annual	Preventative	Identify deterioration, contamination, loose connections, corrosion, environmental issues, or abnormal equipment condition
Functional testing and calibration of protective relays	3 Years	Preventative	Verify protection operation, settings integrity, coordination performance, and trip functionality
Secondary injection testing may be omitted where equivalent relay functional verification has already been completed as part of integrated protection testing programs	Min – 3 Years	Preventative	Avoid duplication of testing activities while maintaining verification of protection system performance
SCADA communications verification and operational testing	Annual	Preventative	Verify operational visibility, alarm functionality, remote monitoring, and remote control capability
Verification of telemetry, indication points, alarms, status points, and analog values	Annual	Preventative	Confirm integrity and accuracy of operational monitoring systems
Verification of sequence-of-events recording, event reporting, oscillography, and time synchronization systems	Annual	Preventative	Maintain integrity of operational diagnostics, disturbance analysis, and event investigation capability
Firmware, software, and configuration management review	As Required	Preventative	Maintain cybersecurity, configuration integrity, compatibility, and lifecycle supportability

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

GROUNDING SYSTEMS			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Inspection and verification of equipment bonding and station grounding continuity	Annual	Preventative	Maintain personnel safety and ensure effective fault current return paths
Infrared thermographic inspection of grounding and bonding connections (where accessible)	Annual	Predictive	Identify overheating or deteriorated grounding connections
Ground resistance testing of station grounding systems	3 Years	Predictive	Verify grounding system integrity and effective dissipation of fault current
Step and touch potential assessment	3 Years	Predictive	Assess personnel safety and grounding system performance under fault conditions
Inspection of fence grounding, gates, barb wire bonding, and perimeter grounding systems	Annual	Preventative	Maintain public and worker safety and reduce hazardous touch potential exposure
Inspection of grounding associated with surge arresters, instrument transformers, structures, and metallic equipment	Annual	Preventative	Verify continuity of protective grounding systems and surge current dissipation paths
Inspection of grounding system condition following fault events, excavation activities, or major civil work	Event Based	Preventative	Identify grounding damage or degradation resulting from system disturbances or construction activities
Review of grounding test records, deficiencies, and historical maintenance trends	Annual	Predictive	Support condition based maintenance planning and identification of recurring grounding issues
Corrective maintenance, bond repair, conductor replacement, connector replacement, corrosion remediation, or grounding system upgrades	Condition Based	Corrective	Restore grounding system integrity, personnel safety, and fault current performance

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

CIVIL/STRUCTURAL INFRASTRUCTURE			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual inspection of station foundations, transformer pads, structures, retaining walls, stairs, walkways, fencing, gates, and general civil infrastructure	Annual	Preventative	Identify deterioration, settlement, cracking, corrosion, erosion, or structural deficiencies
Inspection of transformer foundations and support structures for settlement, movement, alignment issues, or conductor stress	Annual	Predictive	Identify progressive structural deterioration and mitigate long term mechanical integrity risks
Inspection of structural steel, galvanized structures, supports, brackets, and hardware	Annual	Preventative	Identify corrosion, coating deterioration, loose hardware, or structural degradation
Vegetation management, inspection of vegetation encroachment, maintenance of crushed rock levels	Annual or seasonally as required	Preventative	Maintain equipment clearances, access, visibility, and grounding system effectiveness
Inspection of security infrastructure, including fencing, gates, locks, signage, and barriers	Annual	Preventative	Maintain public safety, site security, and regulatory compliance
Inspection of building envelopes, roofs, doors, ventilation systems, and HVAC systems (where applicable)	Annual	Preventative	Maintain environmental protection of electrical equipment and station facilities
Inspection of indoor moisture, condensation, dust accumulation, and environmental conditions	Annual	Predictive	Identify environmental factors contributing to accelerated equipment deterioration
Civil or geotechnical assessment of significant settlement, erosion, or foundation movement concerns	Condition Based	Predictive	Evaluate structural risk and support corrective planning or remediation activities
Review of civil inspection records, deficiencies, and recurring maintenance issues	Annual	Predictive	Support condition based maintenance planning and identification of recurring infrastructure concerns

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

CIVIL/STRUCTURAL INFRASTRUCTURE			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Corrective maintenance, structural repair, repainting, drainage remediation, vegetation removal, foundation stabilization, or infrastructure replacement	Condition Based	Corrective	Restore structural integrity, operational safety, environmental protection, and long term site reliability

APPENDIX E – PREVENTATIVE AND PREDICTIVE MAINTENANCE FRAMEWORK

STATION SERVICE & DC SYSTEMS			
Maintenance Activity	**Typical Frequency**	**Maintenance Category**	**Purpose**
Visual inspection of station service equipment, panels, transformers, batteries, chargers, rectifiers, inverters, wiring, and associated auxiliary systems	Annual	Preventative	Identify deterioration, contamination, corrosion, loose connections, overheating, or abnormal operating conditions
Infrared thermographic inspection of station service and DC system connections	Annual	Predictive	Identify overheating connections, abnormal thermal conditions, or deteriorated components
Battery system inspection, including terminals, electrolyte levels, ventilation, racks, and physical condition	Annual	Preventative	Identify deterioration, corrosion, contamination, or abnormal battery conditions
Battery impedance testing, conductance testing, or load testing	Annual	Predictive	Assess battery health, capacity degradation, and DC system reliability
Verification of battery charger and rectifier operation	Annual	Preventative	Confirm reliable DC supply operation and battery charging performance
DC system voltage monitoring and alarm verification	Annual	Preventative	Verify integrity of station DC supply and alarm functionality
Verification of automatic transfer functionality and backup supply operation (where applicable)	Annual	Preventative	Maintain continuity of station auxiliary power systems during supply interruptions
Review of battery performance history, alarms, event logs, and maintenance records	Annual	Predictive	Support condition based maintenance planning and identification of recurring issues
Corrective maintenance, battery replacement, charger replacement, wiring remediation, panel repair, or auxiliary system refurbishment	Condition Based	Corrective	Restore reliability and operational performance of station service and DC systems

APPENDIX D – GREATER OTTAWA REGION RIP REPORT



REGIONAL INFRASTRUCTURE PLAN REPORT

GREATER OTTAWA

Regional Infrastructure Plan Report

Greater Ottawa

February 09, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Greater Ottawa Technical Working Group

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Disclaimer

This Regional Infrastructure Plan (RIP) Report for the Greater Ottawa region was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

The preferred solution(s) that have been recommended in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP TWG at the time.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Regional Infrastructure Plan Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Regional Infrastructure Plan Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION **Greater Ottawa** (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: August 18, 2025 **END DATE:** February 09, 2026

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Greater Ottawa region, preceded by, the publication of Needs Assessment (NA) report in December 2022 by Hydro One which was triggered early due to high growth in the region followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in March 2023 and in July 2025 respectively, by the Independent Electricity System Operator (IESO).

Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs and publishes a RIP report. The RIP report includes a discussion of all options and plans identified in earlier phases and recommends a preferred wires plan to address the near, medium, and long - term needs over a twenty-year study period.

The objectives and scope of the RIP are:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs (2025-2034) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identify any new need(s) over the 2025-2034 that may have emerged since previous planning phases. Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.
- Consideration of long-term needs identified in the Ottawa area sub-region IRRP, Bulk system studies or as identified by the TWG.

Since the IRRP study addressed needs only for the Ottawa Area Sub-region, the RIP as per TWG discussions developed a new load forecast for stations outside the IRRP scope and revised forecasts for certain stations. For the remaining stations, the IRRP load forecast was adopted for the RIP study, as no material changes were identified. During the IRRP stakeholder engagement process, IESO received municipal input on future load growth for consideration in the IRRP load forecast.

The list of major infrastructure investments recommended by the TWG in the region is given below. The needs include those previously identified in the NA and IRRP, as well as any new needs identified during the RIP phase, if any.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M)
Asset Renewal Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	Hydro One	2031	$60M
Nepean TS	Replacement of T3/T4 transformers based on asset condition	Hydro One	2034	$30M
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	Hydro One	2030	$5M
Station Capacity Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Carling TS	Replacement of limiting LV cables.	Hydro One	2030	$10M
Lisgar TS	Replacement of T2 transformer and LV cables/breakers - Greenfield	Hydro One	2034	$50M
	Replacement of T2 transformer and LV cables/breakers – In Situ	Hydro One	2031	$30M
King Edward TS	Replacement of LV cables and breakers.	Hydro One	2033	$20M

Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating and upgrade station transformation capacity.	Hydro One/ Hydro Ottawa	2029	$85M*
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	Hydro Ottawa	2029	$5M
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	Hydro One/ Hydro Ottawa	2031	$110M*
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	Hydro One/ Hydro Ottawa	2028	$100M*
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and new transmission line from South March TS	Hydro One/ Hydro Ottawa	2028	$100M*
Marionville DS	Install a second transformer to increase station rating.	Hydro One Dx	2029	$12M*
Greely DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland East DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2027	$3M*

Transmission Line Capacity Needs				
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	Hydro One	2030	$30M
L2M	Uprate line section between Merivale TS x Limebank JCT	Hydro One	2032	$30M
System Reliability, Operation and Load restoration Needs				
Kanata Area	Kanata Area Transmission Reinforcement	Hydro One	2033	$250M
Nepean TS – Load Security Criteria	Second 230 kV Supply to station	Hydro One	2032	$70M
M1R+L2M	Split Breaker position for M1R and L2M at Merivale TS	Hydro One	2032	$45M
East Ottawa Area	Supply to East Ottawa	Hydro One	2029-2030	$165M*

* These investment costs include associated distribution system costs.

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are high-level planning estimates and actual costs may vary.

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of the Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs) and publishes a RIP report. The third cycle of the Regional Planning process for the Greater Ottawa region was initiated early due to high growth in the region with the publication of Needs Assessment (NA) and the report was published in December 2022 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) only for the Ottawa Sub-Region Area which were published in March 2023 and July 2025 respectively, by the Independent Electricity System Operator (IESO).

This RIP report is for the "Greater Ottawa Region" and includes the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of County Road 43 (Highway 43) and includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by the Greater Ottawa TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies (LDC), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1-1.

Table 1-1: Greater Ottawa region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission)
2	Independent Electricity System Operator (IESO)
3	Hydro One Networks Inc. (Distribution)
4	Hydro Ottawa Limited
5	Hydro Hawkesbury
6	Renfrew Hydro Inc.
7	Hydro 2000 Inc.
8	Ottawa River Power Corp.

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Greater Ottawa region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs of the Greater Ottawa region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, Electricity Demand Side Management ("eDSM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2025-2034 identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2025-2034 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Ottawa area sub-region IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and require longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and.
b) require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, the recommended options are implemented, and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and.
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Electricity Demand Side Management ("eDSM"), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

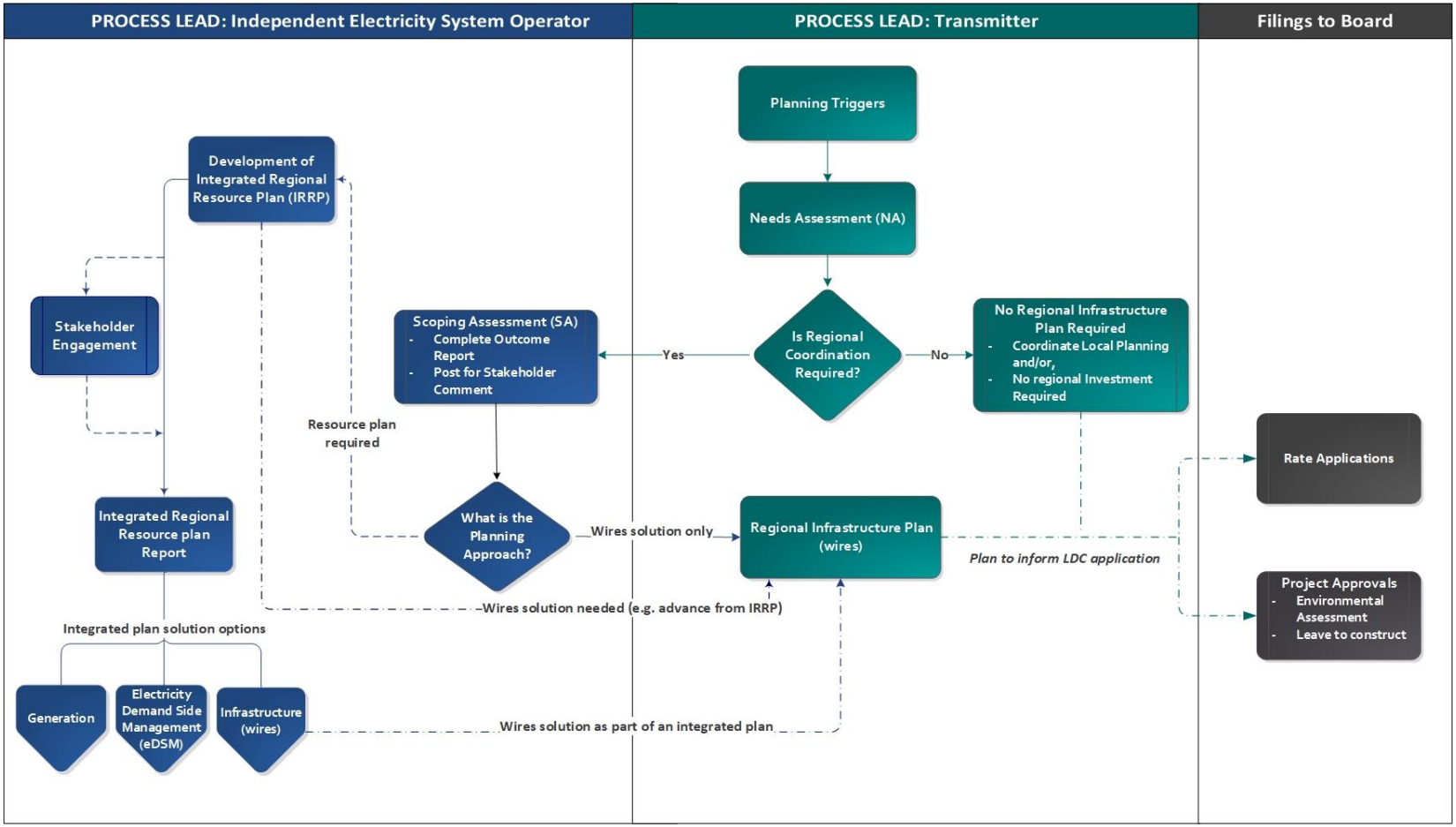
The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' eDSM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

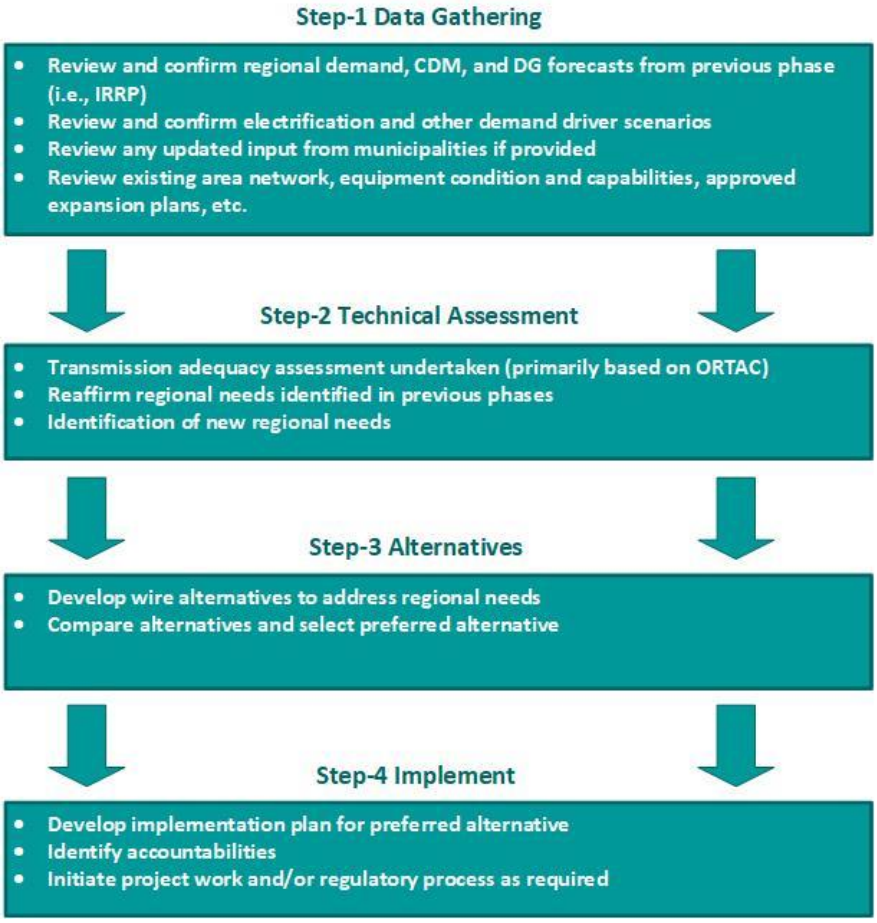
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure 3-1.

Figure 3-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure 3-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or eDSM programs. As agreed by TWG members, the load forecast from the Ottawa Area sub-region IRRP was used for this RIP with modifications to some stations and developed a load forecast for the outer Ottawa stations which were not covered in the IRRP.

- Review and confirm electrification and other growth scenarios which affect the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

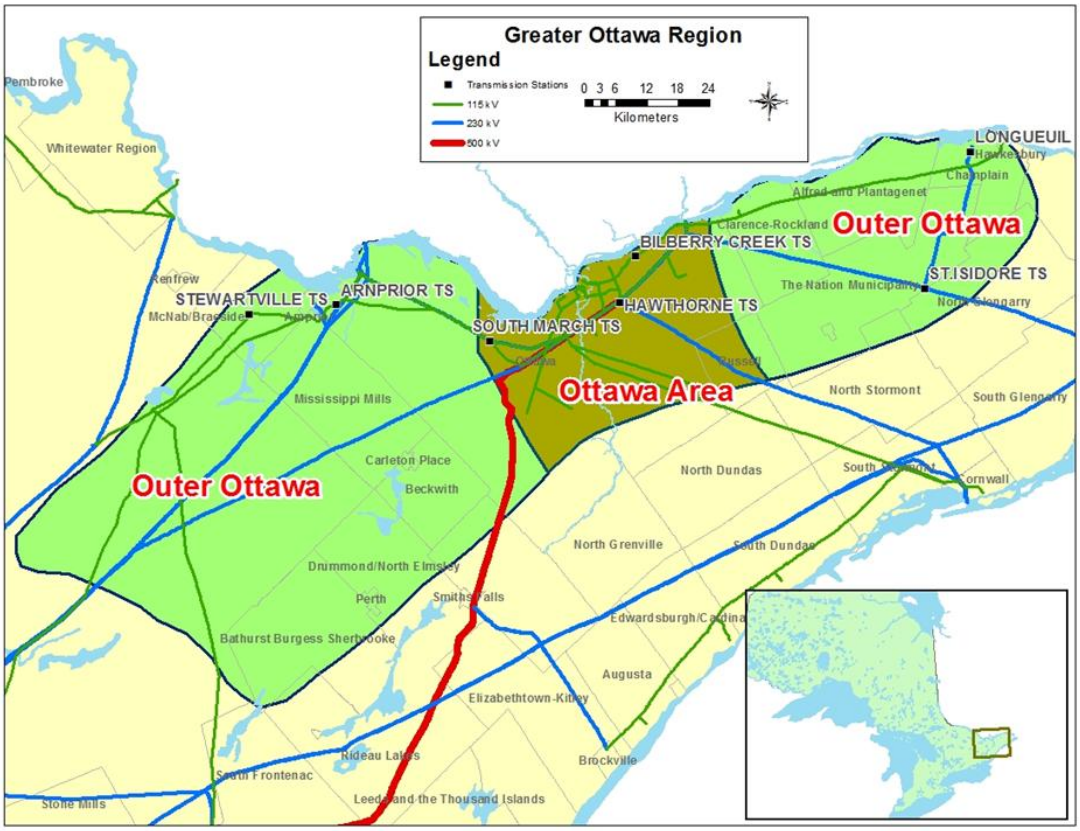
3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identify accountabilities and initiate project work or obtain permissions from the Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of County Road 43 (Highway 43). At the center of this region is the City of Ottawa. Electrical supply to the Region is provided from fifty-two (52) 230 kV and 115 kV step-down transformer stations. The boundaries of the Region are shown in Figure 4-1 below. The outer regions are referred to as the East and West Outer Ottawa sub-regions. The central region comprising of City of Ottawa is referred to as the Ottawa sub-region

Figure 4-1: Map of Greater Ottawa Regional Planning Area

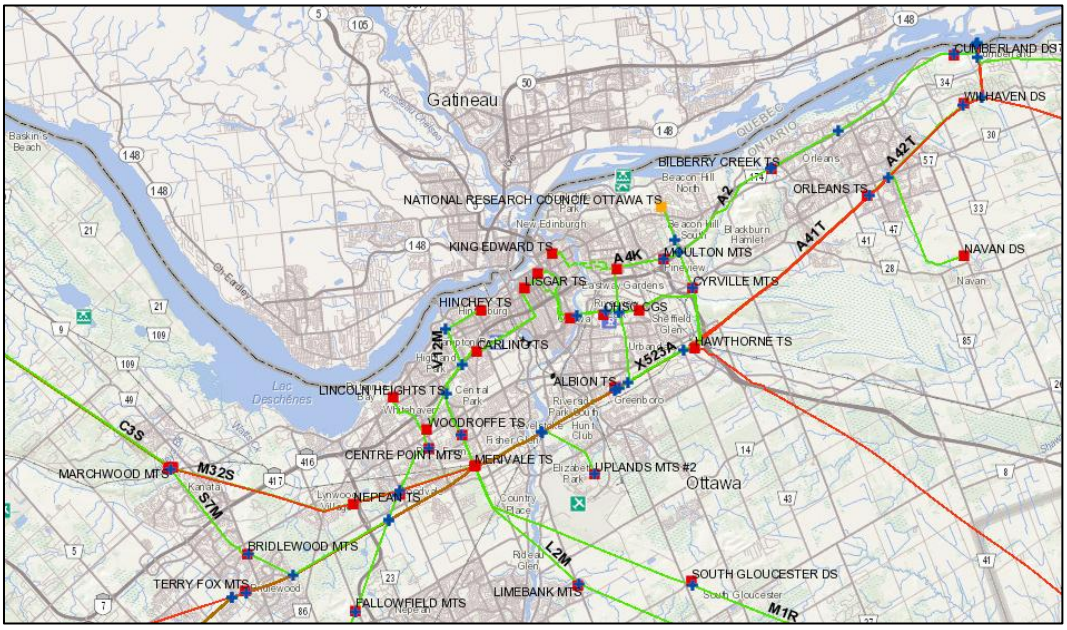


Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS autotransformers and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into two sub-regions as shown in Figure 4-1 and described below:

The Ottawa Area Sub-region comprises primarily the City of Ottawa. It is supplied by two (2) 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS), eight (8) 230 kV and thirty-three (33) 115 kV transformer stations stepping down to lower voltages. Local generation in the area consists of the 74 MW

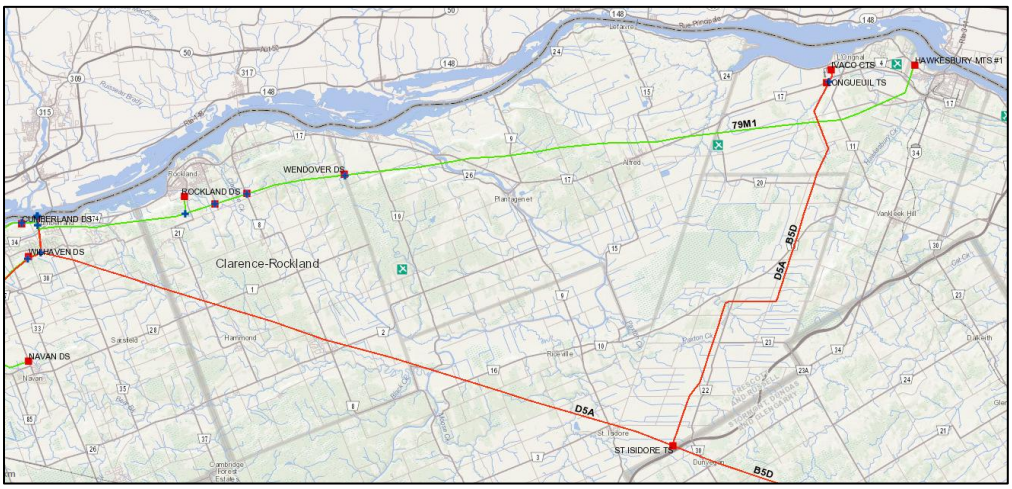
Non-Utility Generator ("NUG") CGS-2 located near the downtown area and connected to the 115 kV network. The Ottawa Area Sub-region is shown in Figure 4-2 below. Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to end users, including industrial, commercial and residential customers.

Figure 4-2: City of Ottawa Sub-Region Map



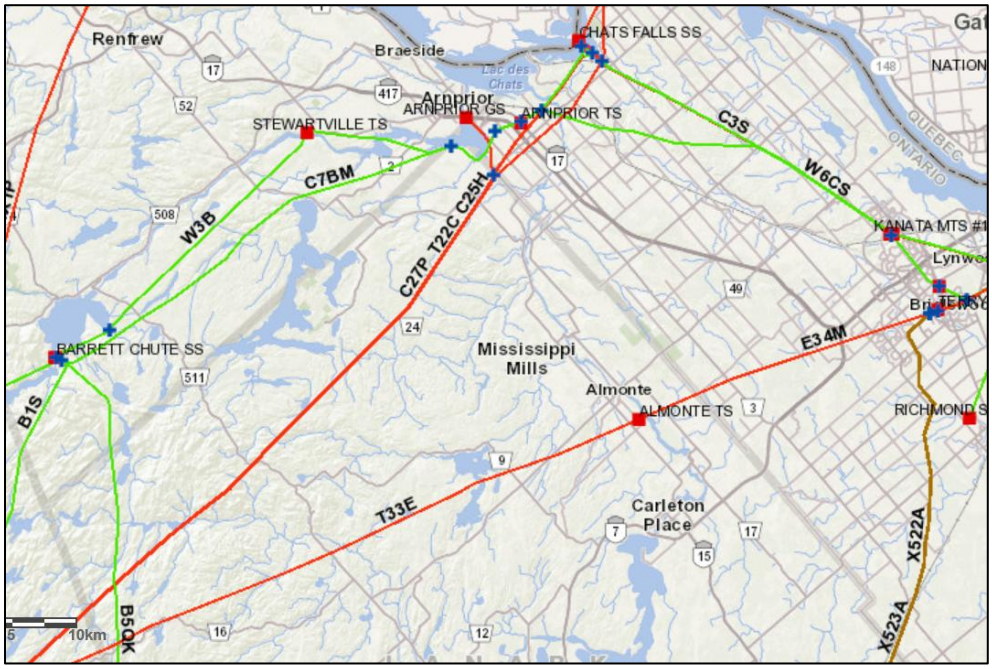
The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area as shown in Figure 4-3 below is served by three (3) 230 and five (5) 115 kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to their end use customers. Hydro 2000 is an embedded LDC that supplies its customers from Longueuil TS via Hydro One Distribution's 44kV feeders. It also includes a large industrial customer, in L'Orignal, Ontario.

Figure 4-3: Outer Ottawa Sub-Region Map (Eastern Part)



The western area of the Outer Ottawa Sub-Region, shown in Figure 4-4 is served by one (1) 230 kV and two (2) 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies its end use customers from these stations. Ottawa River Power Corp. is an embedded LDC that supplies its customers from Almonte TS via Hydro One Distribution's 44kV feeders. Renfrew Hydro is an embedded LDC that supplies its customers from Stewartville TS via Hydro One Distribution's 44kV feeders. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS and Stewartville GS with a peak generation capacity of about 450 MW.

Figure 4-4: Outer Ottawa Sub-Region Map (Western Part)



Electricity demand in the region is projected to grow steadily over the forecast horizon, primarily driven by municipal expansion, increased commercial development, and the accelerating impacts of electrification and decarbonization initiatives. A key factor influencing long-term demand and supply requirements is the planned phase-out of natural gas heating, which is expected to significantly increase electricity consumption in the sub-region, particularly in the latter years of the forecast period. The circuits and stations of the area are summarized in Table 4-1 below:

Table 4-1: Transmission Station and Circuits in the Greater Ottawa region

115kV circuits	230kV circuits	Hydro One Transformer Stations		Generation Stations
A2	B5D	Albion TS	Marchwood MTS	CGS-1
A3RM	C3S	Almonte TS	Marionville DS	CGS-2
A4K	D5A	Arnprior TS	Merivale MTS	Chat Falls GS
A5RK	E34M	Bridlewood MTS	Moulton MTS	Stewartville GS
A6R	L24A	Bilberry Creek TS**	CTS -2	Barret Chute GS
A8M	M30A	Cambrian MTS	NRC TS	
C7BM	M31A	Carling TS	Navan DS	
F10MV	M32S	Centrepoint MTS	Nepean Epworth MTS	
H9A		Clarence DS	Nepean TS	
L2M		Cumberland DS	Orleans TS	
M1R		Cyrville MTS	Overbrook TS	
M4G		Ellwood MTS	Richmond South MTS	
M5G		Fallowfield MTS	Riverdale TS	
S7M		Greely DS	Russell DS	
V12M		Hawthorne TS*	Russell TS	
W6CS		Hawkesbury MTS #1	Rockland DS	
79M1		Merivale TS*	Rockland East DS	
		Hinchey TS	Slater TS	
		CTS-1	South Gloucester DS	

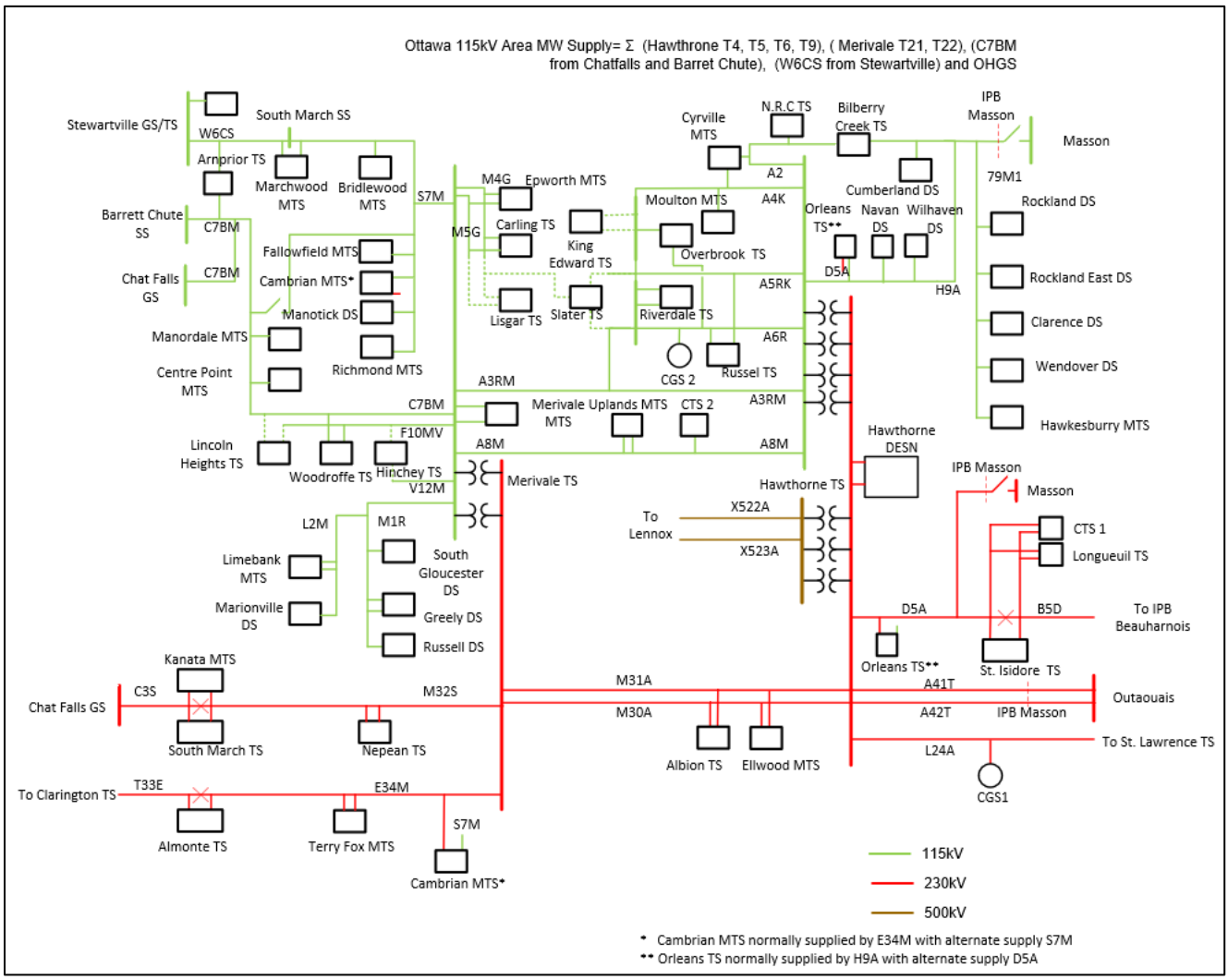
		Kanata MTS King Edward TS Limebank MTS Lincoln Heights TS Lisgar TS Longueuil TS Manotick DS	South March TS St. Isidore TS Stewartville TS Terry Fox MTS Uplands MTS Wendover DS Wilhaven DS Woodroffe TS	

*Stations with Autotransformers installed

** Planned to decommission

The single line diagram of the existing Transmission Network of Greater Ottawa region is shown in Figure 4-5 below.

Figure 4-5: Greater Ottawa Transmission Single Line Diagram



5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that were completed in the past ten years or are currently underway is provided and is briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the **Greater Ottawa region** to improve the supply capability and reliability.

Hydro One Transmission, Hydo Ottawa Ltd and Hydro Hawkesbury are the Transmission Asset Owner (TAO) in the region and have undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Build New Orleans TS (2015) – built a new step-down transformer station in East Ottawa supplied from 230 kV circuit D5A and 115 kV circuit H9A. This station provides additional load meeting capability to meet Hydro One Distribution and Hydro Ottawa requirements. It provides improved reliability for Hydro One Distribution customers in the Orleans-Cumberland area.
2. Hinchey TS (2015) – Connected idle winding of transformers T1/T2 to new Hydro Ottawa metalclad switchgear to provide additional load meeting capability at the station.
3. Add 230 kV inline breaker on 230 kV circuit M29C at Almonte TS (2015) – added breaker to improve reliability of supply for Almonte TS and Terry Fox MTS and split line M29C into E34M and E29C (now T33E)
4. Overbrook TS (2017): Replaced 45/60/75 MVA, 115/13.8 kV step down transformers with new 60/80/100 MVA, 115/13.8 kV based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
5. Hawthorne TS (2019): Replaced 50/67/83 MVA, 230/44 kV step down transformers with new 75/100/125 MVA, 230/44 kV units based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
6. Change supply to Overbrook TS (2019) – Reduced the loading on A4K by modifying the supply to Overbrook TS by connecting transformer T1 to A6R instead of A4K. This was accomplished by rebuilding the line section of A5RK from Riverdale JCT to Overbrook TS as a double circuit 115 kV line and tapping A6R at Riverdale JCT.
7. Connection of CGS 1 wind farm (2020) – connection of 100 MW wind farm to 230 kV circuit L24A.

8. Hawthorne TS T5 and T6 autotransformer replacement (2021): Replace 225 MVA, 230/115 kV autotransformers T5 and T6 with new 250 MVA, 230/115 kV autotransformers to provide additional 230/115 kV transformation capacity.
9. King Edward TS transformer T3 replacement (2021): Replacement of 45/60/75 MVA, 115/13.8 kV step down transformer T3 with upgraded 60/80/100 MVA, 115/13.8 kV to match the existing rating of T4 and to provide additional load meeting capability at the station.
10. Connection of Cambrian MTS (2022): connect a new Hydro Ottawa owned transformer station in the South Nepean area. The station is supplied from 230kV circuit E34M with alternate supply from 115kV circuit S7M. S7M was rebuilt as a double circuit line from the main line (S7M STR673JCT to Cambrian JCT (~10.9km) with a 1.3km extension to Cambrian MTS.
11. Overbrook TS LV cable review (2022): the transformer cable capacity limitation review was analyzed. The transformer LTR was increased based on the result of the study.
12. Arnprior TS T1/T2 replacement (2023): The two 25/33/42 MVA 115.5kV/44kV transformers were replaced like-for-like with new standard 25/33/42 MVA 110kV/44kV transformers.
13. M30A/M31A upgrade (2023): Increase the power interface limit between Hawthorne TS and Merivale TS by replacing the existing conductor 1843.2kcmil with new twin bundled 1443.7 kcmil conductor (2 conductors per phase).
14. Slater TS T2/T3 replacement (2024): Replaced 38/63 MVA, 110/12 kV step down transformers T2 and T3 with new 60/80/100 MVA, 110/14.2 kV units based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station.
15. Lincoln Heights TS T1/T2 (2024): Like-for-like replacement of the two 45/60/75 MVA 110kV/14.2kV transformers.
16. Longueuil TS T1/T2 replacement (2025): Replacement of 50/75/93 MVA 235kV/44kV transformers T1/T2 with standard 50/67/83 MVA 215.5kV/44kV units.
17. Lisgar TS T1 replacement (2025): Replacement of 45/60/75 MVA 110/14.2-14.2 kV transformer T1 with standard 60/80/100 MVA 110/14.2-14.2kV unit.

II. Following Major projects are underway:

1. Piperville MTS – Connection of Hydro Ottawa's new transformer station to 230 kV L24A circuit with in-service date in Q2 2026.
2. Russell TS – T1/T2 transformers (45/60/75 MVA) will be replaced with 60/80/100 MVA transformers. The planned in-service date is 2027.
3. Connection of Hydro Rd. MTS – Connection of new Hydro Ottawa station to 230kV circuits M30A/M31A near Hawthorne TS. Building ~500m line tap to the new station. The planned in-service date for connection of this new station is October 2027.
4. Connection of Mer Bleue MTS - Connection of new Hydro Ottawa station to 230kV circuits D5A about 10km east of Hawthorne TS. The planned in-service date for connection of this

new station is July 2027. This project is also planned to connect to circuit A25 with expected in-service in June 2029. Please refer to section 8.4.5 for further information.

5. Connection of South March BESS – Connection of new 250MW Battery Energy Storage System to 230kV circuit C3S about 11.5km from South March TS. The planned in-service date for connection is Q2 2027.
6. Connection of Trail Road BESS - Connection of new 159MW Battery Energy Storage System to 230kV circuit E34M about 275m from Cambrian JCT. The planned in-service date for connection is 2027.
7. Hawkesbury MTS: Project for transformer upgrade with a new 15MVA transformer unit is underway and is being led by Hydro Hawkesbury. The planned in-service date is 2027-2028.
8. Merivale TS T22/T23 – The planned in-service date for replacement of autotransformer T22 and addition of new autotransformer T23 and for replacement of six (6) 230 kV circuit breakers and four (4) 115 kV circuit breakers is 2029.
9. Bilberry Creek TS – The station is expected to be retired around 2030. Its load will be transferred to Mer Bleue MTS and Orleans TS. Please refer to section 8.4.5 for further information.
10. Orleans TS – The station will be upgraded from dual supply of 230/27.6 kV 115/27.6 kV to 230/27.6 kV DESN. The planned in-service date is June 2029. Please refer to section 8.4.5 for further information.

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

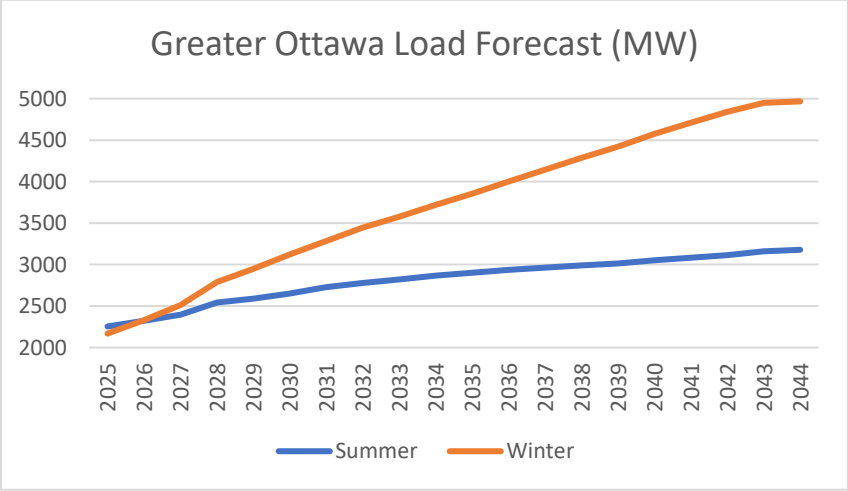
The TWG developed a load forecast for stations in the Outer Ottawa area as these were outside the IRRP scope. The LDCs also reviewed the IRRP forecast and provided revisions for some of the stations. For the remaining stations, the IRRP load forecast was adopted for the RIP study, as no changes were required by the LDCs. TWG participants, including representatives from LDCs, IESO and Hydro One provided information and input for the IRRP and RIP Load forecasts. During the IRRP stakeholder engagement process, IESO received municipal input on future load growth for consideration in the IRRP load forecast.

During the study period, the load in the Greater Ottawa region is expected to grow at an average annual rate of approximately 2% in summer and 4% in winter from 2025 to 2044. The region is currently summer-peaking, however based on the forecast it is expected that the region will transition to winter-peaking in the near future. This shift is largely driven by electrification such as the ongoing transition of heating systems from natural gas to electric or hybrid solutions, which will significantly increase electricity demand during winter months.

Figure 6-1 shows the Greater Ottawa region extreme summer/winter weather net load MW forecast from 2025 to 2044. The load forecasts from the Ottawa sub-region were updated from the IRRP forecast as agreed by the TWG.

The forecast for the individual stations in the region is available in Appendix A and is used to determine any need in the region.

Figure 6-1: Greater Ottawa region summer/winter Net Peak Load Forecast



6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2025-2044.
- LDCs have reviewed the forecast and provided updates where necessary and reconfirmed load forecasts up to 2044 in the area.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is currently summer peaking but expected to become winter peaking within the study period, so this assessment considers both summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the station peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Greater Ottawa region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed as per their respective in-service dates.

In the current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Greater Ottawa region Third cycle Needs Assessment Report, Completed in December 2022 by Hydro One
- Greater Ottawa region Third cycle Scoping Assessment Report, Completed in March 2023 by the IESO
- Greater Ottawa region Third cycle Integrated Regional Resource Plan Report, Completed in July 2025 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in the previous regional planning cycle, Hydro One and TWG have also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Greater Ottawa region. The complete list of major HV transmission equipment requiring replacement in the Greater Ottawa region is provided in Table 7-1 in this sub-section. Hydro One along with Hydro Ottawa Ltd and Hydro Hawkesbury are the only Transmission Asset Owner (TAO) in the Region

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two

- 230 and 115kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 7-1: Major HV Transmission Asset assessed for Replacement in the region planned in next 10 years

Station/Circuit	Need Description	Planned ISD
South March TS	T1/T2 Transformers replacement	2031
Albion TS	T1/T2 Transformers replacement	2031
Nepean TS	T3/T4 Transformers replacement	2034
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	2030

Note: The planned in-service year for the above projects is tentative and is subject to change.

7.2. Station Capacity Needs

Over the study period **2025 -2044** RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the **Greater Ottawa region**. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 7-2 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer and winter) Limited Time ratings.

Table 7-2: Greater Ottawa region Station Capacity Needs in the study period

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2024 Loading (MW) (Summer/Winter)	Need Date (Summer/Winter)	High Forecast Need Date (Summer/Winter)
1	Albion TS	86.5/101.7	57.4/47.0	-/2034	2043/2030
2	Arnprior TS	54.9/59.4	36.9/37.5	2044/-	2043/-
3	Bridlewood MTS	23.5/23.5	29.6/19.7	2035/2030	2029/2027
4	Cambrian MTS	114/123.5	58.7/33.6	-/2041	-/2033
5	Carling TS	95/124.3	67.7/64.9	2028/2028	2028/2028
6	Centrepoint MTS	13.3/13.3	14.6/11.9	2032/2027	2027/2025

7	Cumberland DS	6.8/8.6	5.5/5.0	2037/-	2036/-
8	Cyrville MTS	47.5/47.5	33.6/24.4	2028/2030	2028/2028
9	Ellwood MTS	47.0/47.0	44.8/46.5	2027/2027	2027/2025
10	Fallowfield MTS	27.2/27.2	35.6/14.4	2026/2030	2026/2028
11	Greely DS	20.7/25.2	19.5/16.3	2025/2025	2025/2025
12	Hawkesbury MTS	18/18	13.3/14.9	-/2037	-/2036
13	Hawthorne TS	144.8/	106.1/97.1	2038/2031	2038/2028
14	Hinchey TS	85.6/95.0	45.4/40.8	-/2031	-/2029
15	Kanata MTS	51.5/51.5	53.2/55.8	2025/2025	2025/2025
16	King Edward TS	86.9/90.3	80.0/77.7	2033/2026	2030/2025
17	Limebank MTS	75.0/75.0	48.1/38.2	2031/2028	2031/2026
18	Lincoln Heights TS	99.4/113.1	40.3/40.9	-/2039	-/2035
19	Lisgar TS	83.4/105.1	42.7/58.9	2028/2028	2028/2027
20	Manordale MTS	9.6/9.6	11.0/8.4	2026/2026	2025/2025
21	Manotick DS	7.7/10.4	9.5/8.1	2025/2025	2025/2025
22	Marchwood MTS	32.3/32.3	46.3/42.5	2025/2025	2025/2025
23	Marionville DS	13.5/13.5	14.4/12.1	2025/2025	2025/2025
24	Moulton MTS	32/32.0	21.6/16.6	2028/2028	2028/2028
25	Nepean Epworth MTS	12.9/12.9	11.4/11.4	2035/2028	2029/2026
26	Nepean TS	144.1/160.7	113.2/108.6	-/2030	-/2027
28	Richmond South MTS	49.0/49.0	19.4/6.9	2034/2028	2034/2028
29	Riverdale TS	110.8/117.0	92.4/71.5	2030/2028	2029/2026
30	Rockland DS	7.8/10.5	7.8/4.1	2025/2031	2025/2030
31	Rockland East DS	15.5/20.9	14.3/12.4	2026/2040	2026/2040
32	South March TS	99.2/113.7	95.9/72.2	2026/2028	2026/2027
33	Terry Fox MTS	91.7/105.8	53.9/41.7	-/2038	-/2032
34	Woodroffe TS	97.4/102.4	33.4/28.9	-/2039	-/2034

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period **2025-2044** RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the **Greater Ottawa region**. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 7-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 7-3: Greater Ottawa region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Maximum capacity	Current loading	Need Date
1	M4G/M5G	Merivale TS x Carling TS	1279 A	503 A	2030
2	L2M	Merivale TS X Limebank JCT	467 A	339 A	2028
3	S7M	Merivale TS x STR654JCT (Fallowfield tap)	1381 A	488 A	2032
4	C7BM	Merivale TS x NQL1 JCT	777 A	455 A	2034 (winter)
5	F10MV	City View JCT x Woodroffe TS	777 A	402 A	2034 (winter)
6	A4K	Hawthorne TS x Cyrville JCT x Overbrook TS	1214 A	550 A	2032/33 (winter)
7	A4K	Overbrook TS x King Edward TS	800 A	204 A	2032/33 (winter)
8	A3RM	Ellwood JCT x Riverdale JCT	1016 A	235 A	2034
9	A5RK	Hawthorne TS x Russel TS	1595 A	538 A	2034
10	A6R	Hawthorne TS x Russel TS	1703 A	489 A	2034

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operation and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The following load security needs were reviewed as a part of RIP:

M32S

Nepean TS is supplied solely by the 230 kV M32S circuit, and a contingency on M32S would result in the complete loss of load at Nepean TS due to its configuration. Under current load security criteria, no more than 150 MW should be lost for a single element contingency. While this limit is not exceeded in the summer forecast, it is projected to be reached in the winter forecast by 2029. A working group recommendation is discussed in section 8.4.

M1R+L2M

Circuits M1R and L2M share a breaker position at Merivale TS, so the loss of either circuit results in both being tripped. This configuration affects stations including Limebank MTS, Marionville DS, South Gloucester DS, Greely DS, and Russell DS. For this group, the 150 MW load security threshold is expected to be reached in the summer forecast by 2040 and in the winter forecast by 2031. A working group recommendation is discussed in section 8.4.

Load Restoration for C3S/M32S

M32S is a 230kV circuit connecting Merivale TS to South March TS, and 230kV circuit C3S connecting Chats Falls SS to South March TS. The two circuits are connected through an in-line breaker A1A2 at South March TS. Stations South March TS and Kanata MTS are supplied by both C3S and M32S. Nepean TS is only fed from circuit M32S. Load restoration was assessed for A1A2 breaker fail. The breaker fail condition can lead to no supply to all three stations. The loss of the two circuits results in approximately 330MW of load loss during summer. As per ORTAC, 80MW have to be restored in 30 minutes, 150MW restored in 4 hours and the entire load in 8 hours. Nepean TS can be restored by opening circuit switcher M32S-1 within 30 minutes. The breaker A1A2 disconnect switches at South March TS can be opened within 30 minutes to restore load stations from either C3S or M32S. All load can be restored within 4 hours. In addition, as discussed in section 8.4 a new switching station is planned at South March TS, which will eliminate this problem.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

Load Restoration for S7M

Circuit S7M and W6CS are tie via an in-line breaker L6L7 at South March SS. A L6L7 breaker failure results in no supply to Fallowfield MTS, Richmond MTS, Manotick DS, Bridlewood MTS, and Marchwood MTS. The amount of load loss is about 199 MW by the end of the study period in summer. As per ORTAC, all load above 150MW must be restored in 4 hours and all load restored in 8 hours. All load can be restored by opening breaker L6L7 disconnect switches at South March SS within 4 hours. The Study Team recommends that no further action is required at this time.

During winter time under contingency of S7M 150 MW can be interrupted by configuration by 2036. TWG recommends monitoring the winter load and addressing the need in the next regional planning cycle.

Load Restoration for D5A/B5D

Circuits D5A and B5D supply Longueuil TS, St Isidore TS, and Ivaco CTS. The worst contingency for the area can result in approximately 212MW of load loss. Hydro One prepared a Local Planning report which considered the loss of up to 174MW of load for the same contingency. Hydro One has reviewed the report and determined that the conclusions of the report are still applicable to the new load forecast. The report shows that all load can be restored in at least 4 hours, meeting ORTAC restoration criteria. The Study Team recommends that no further action is required at this time.

Load Restoration for M4G/M5G

Load restoration was assessed for the 115 kV double-circuit M4G/M5G supply serving Nepean–Epworth MTS, Carling TS, and Lisgar TS in downtown Ottawa. Although Slater TS is also supplied from M4G, it was excluded from this assessment because it has alternate supply from two other circuits and therefore does not drive the same restoration need. Based on the load forecast, the combined demand on M4G/M5G is expected to exceed 250 MW in the mid-term; under ORTAC, loads greater than 250 MW must be restored within 30 minutes following a contingency. To ensure compliance with this requirement as loading increases, Hydro Ottawa and Hydro One will review restoration options, which may include LV load transfers and/or additional switching and operational restoration actions. The TWG recommends that this review be reviewed as part of the M4G/M5G upgrade and/or the Bronson connection project scopes, where practical restoration enhancements can be implemented and validated against the 30-minute restoration criterion.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Greater Ottawa region. These needs include those previously identified in the NA and IRRP for the Greater Ottawa region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 8-1 below:

Table 8-1: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	2031	8.1.1
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	2031	8.1.2
Nepean TS	Replacement of T3/T4 transformers based on asset condition	2034	8.1.3
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	2030	8.1.4
Station Capacity Needs			
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and a new transmission line from Merivale TS.	2028	8.2.1
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	2031	8.2.2
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	2028	8.2.3

South March TS	Replacement of T1/T2 transformers and associated equipment's with upgraded units based on capacity needs.	2026	8.2.4
Albion TS	Replacement of T1/T2 transformers and associated equipment's with upgraded units based on capacity needs.	2031	8.2.5
Carling TS	Station capacity will be exceeded due to limiting components at LV side. Replacing limiting LV cables will add capacity to station.	2028	8.2.6
Lisgar TS	Station capacity will be exceeded due to limiting LV cables and 75 MVA transformer unit (T2).	2028	8.2.7
King Edward TS	Station capacity will be exceeded due to limiting components at LV side. Replacing LV components will add capacity to station.	2026	8.2.8
Nepean TS	Station capacity will be exceeded during winter season.	2030	8.2.9
Riverdale TS	Station capacity will be exceeded due to limiting LV components and 75 MVA transformer units.	2028	8.2.10
Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating.	2028	8.2.11
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	2028	8.2.12
Marionville DS	Install a second transformer to increase station rating.	2025	8.2.13
Greely DS	Install SCADA transformer fan monitoring	2025	8.2.14
Manotick DS	Load transfer from T1 to T2 at Manotick DS	2025	8.2.15
Hinchey TS	Load to be monitored and necessary actions to be taken as load picks up.	2031	8.2.16
Rockland DS	Install SCADA transformer fan monitoring	2025	8.2.17
Rockland East DS	Install SCADA transformer fan monitoring	2026	8.2.18
Manordale MTS	Load transfers to existing stations	2026	8.2.19

Nepean Epworth MTS	Load transfers to existing stations	2028	8.2.19
Kanata MTS	Load transfers to existing stations	2025	8.2.19
Ellwood MTS	Load transfers to existing stations	2027	8.2.19
Limebank MTS	Load transfers to existing stations	2028	8.2.19
Bridlewood MTS	Load transfers to existing stations	2030	8.2.19
Marchwood MTS	Load transfers to existing stations	2025	8.2.19
Centrepoint MTS	Load transfers to existing stations	2027	8.2.19
Fallowfield MTS	Load transfers to existing stations	2026	8.2.19
Transmission Line Capacity Needs			
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	2030	8.3.1
L2M	Uprate line section between Merivale TS x Limebank JCT	2028	8.3.2
A4K	Continue to monitor the winter load.	2032/33	8.3.3
System Reliability, Operation and Load restoration Needs			
Load Security issue due to contingency of M32S	Provide a second supply to Nepean TS via a new transmission circuit from Merivale TS.	2029	8.4.1
Kanata Area	New Switching Station to improve reliability and flexibility in Kanata Area		8.4.2
Load Security issue due to contingency of M1R+L2M	Install a new breaker at Merivale TS and separate L2M and M1R breaker positions.	2031	8.4.3
Loading and voltage issues on S7M	Continue monitoring load growth and system performance	2032	8.4.4
East Ottawa Area	Supply in East Ottawa Area	2029-2030	8.4.5

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo.
- Replacing equipment with similar equipment with *lower* ratings and built to current standards.
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards.

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

8.1.1 South March TS T1/T2

The existing transformers 50/83 MVA 230/44 kV T1 and T2 at South March TS were originally commissioned in 1971 and based on asset condition assessment, they are identified for replacement in 2031.

A like-for-like replacement of these units would not be adequate in meeting the load during the study period. However, as discussed in Section 8.2, there are station capacity needs in the near term which require upsizing the transformers.

As outlined in the Ottawa area sub-region IRRP and endorsed by the TWG, the recommended solution is to replace the existing transformers with new 75/125 MVA units. This upgrade will ensure adequate capacity and reliability for the growing load in the South March area. Hydro One is working to accelerate the replacement schedule to 2029–2030 to address reliability risks and align with regional planning objectives.

8.1.2 Albion TS T1/T2

Albion TS has two power transformers rated at 45/60/75 MVA, 230 kV / 14 kV / 14 kV, built in 1970. Based on asset condition assessment, these transformers are identified for replacement in 2031.

The 13.8 kV metalclad switchgear installed since 1971 contains six air circuit breakers and two SF6 capacitor bank breakers. The station also has four 13.8 kV conventional SF6 breakers. All circuit breakers require replacement in the near to medium term planning horizon.

The existing transformers at Albion TS will be replaced with new standard 60/80/100 MVA units. These are closest standard size units to the existing transformers. All existing Hydro One owned circuit breakers will be replaced with breakers of similar rating. This alternative would address the asset renewal needs and would maintain reliable supply to customers.

However, as discussed in Section 8.2, additional station capacity will be required in the mid-term, necessitating upgrades at Albion TS.

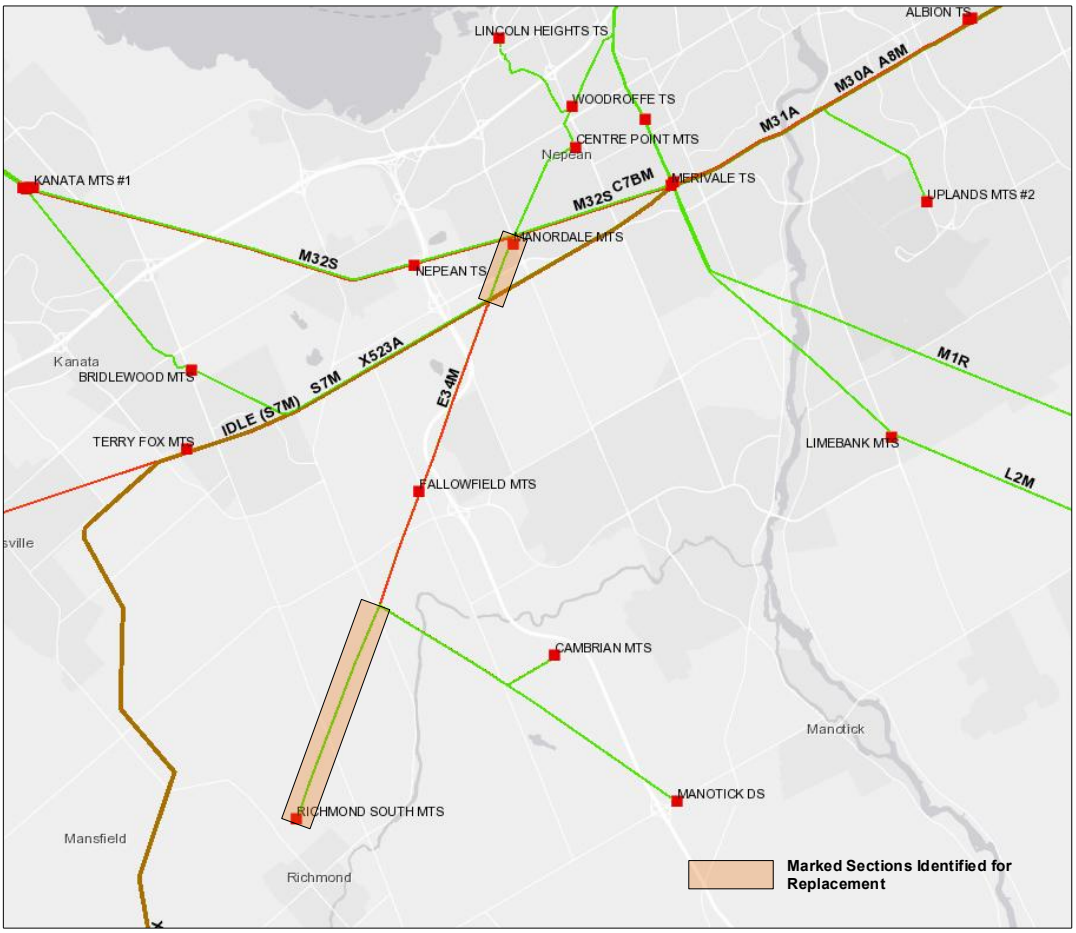
8.1.3 Nepean TS T3/T4

Nepean TS has two power transformers rated at 75/125 MVA, 230 kV / 14 kV / 14 kV, built in 1970's. Based on asset condition assessment, these transformers are identified for replacement in with like-for-like units as this is the highest rating available, with a planned in-service date of 2034.

8.1.4 S7M Line Refurbishment

Two sections of circuit S7M between Manotick JCT × Richmond MTS (5 km) and S7M STR 673N JCT × Manordale JCT (1.4 km) are identified for replacement as shown in Figure 8-1. These sections are 115 kV predominantly wood pole transmission line that was originally placed in service in 1928. Asset renewal is required on these line sections.

Figure 8- 1: S7M section requiring sustainment highlighted



Two possible options are considered for this line section rebuild:

Alternative 1 - Rebuild H frame wood structures: This alternative would be a like for like rebuild of the existing 5km of 115kV transmission line. This would be adequate to supply the forecasted load at Richmond South MTS. The planned in-service date for this refurbishment is 2030.

Alternative 2 - Upgrade to 230 kV ready operation by rebuilding the 115kV single circuit line as a double circuit 230kV line. This would be similar to upgrade done to S7M for the Cambrian MTS Connection as described in Section 5. This alternative considers possible area conversion to 230kV by making the rebuild ready for the upgrade. This would be in accordance with the long-term plan for the area as described in IRRP.

Recommendation:

The recommended near-term plan is to refurbish these line sections to maintain reliability. However, this line section may also be considered for a configuration change refer to Section 8.4.3. Further discussion will occur as part of bulk system planning.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period **2025-2044** for the 230kV and 115kV Transformer stations in the **Greater Ottawa region** using both the summer and winter peak load forecasts that were provided by the study team. This section describes the following capacity needs that have been identified during the study period

To address the station capacity needs, the recommendation of this planning cycle is a combination of new transformer stations and upgrades at existing stations. The new stations are described first, followed by the upgrades considered at the existing stations. The RIP focuses on wire alternatives, however where possible non-wire alternatives are also considered as per the IRRP.

As can be seen in Section 6 Figure 6-1, the area winter load is expected to increase significantly over the study period. The greater Ottawa region has historically been a summer peaking region; however, the region is forecasted to become winter peaking in the near term due to the impact of measures such as electrification and decarbonization. The winter load forecast shows many stations reaching their capacity in the near midterm. Plans have been identified to address these needs and are discussed in this section.

The working group will monitor closely the winter load to track its growth and determine if the forecasted trends materialize in the short term. Many stations are forecasted to go over their transformation capacity and in the long term are expected to far exceed the station LTR. Significant investments will be required at the bulk and regional level to meet this load. Thus, the TWG will monitor the demand in the coming winters and may decide to trigger the next regional planning cycle earlier to address these emerging needs.

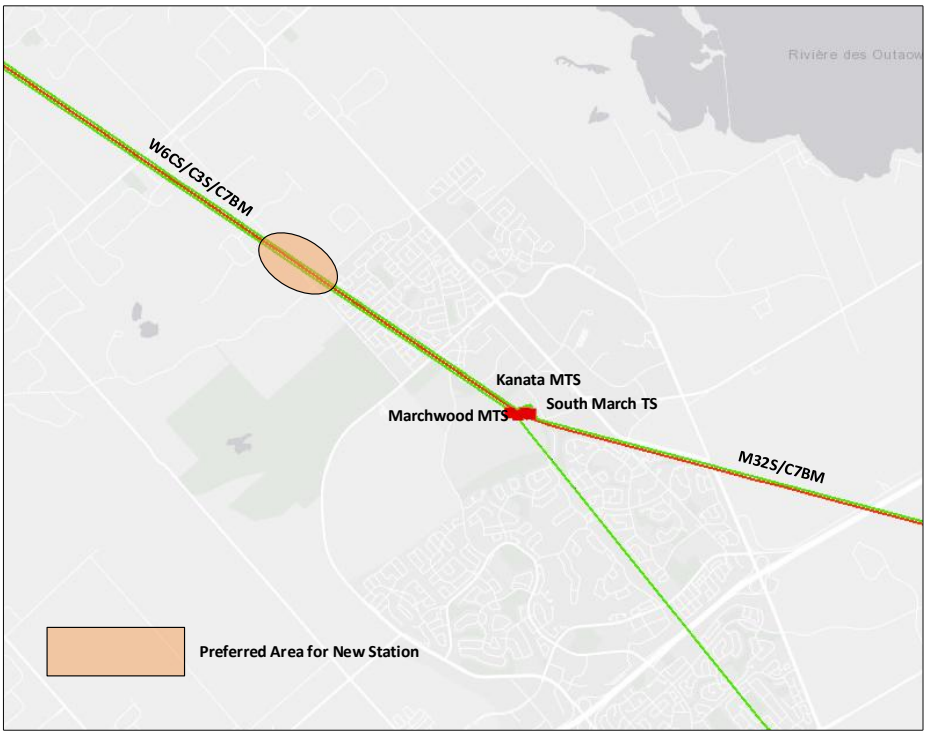
Also, please note there are several downtown stations that are recommended for upgrades in similar timeframes. The ISD highlighted in this section is based on preliminary information. Hydro Ottawa and

Hydro One will work together to review the work required and timing for each upgrade to better coordinate the plans. The dates are subject to change based on the review and determination of the preferred path to achieve all the upgrades listed.

8.2.1 Kanata North – Stittsville Area

Significant growth and capacity needs have been identified in Kanata North and Stittsville area. The area is supplied mainly through three transformer stations: Marchwood MTS, Kanata MTS, and South March TS. Based on the load forecast, all 3 stations will reach their LTR in the short term. Hydro One is proceeding with capacity upgrade at South March TS as described in section 8.2.4. However, additional transformation capacity is required and TWG, as part of the IRRP, has recommended building a new station to address this need. Hydro Ottawa has identified preferred location for the station as shown in Figure 8-2 below.

Figure 8-2: Preferred Location of New Station in Kanata North – Stittsville Area



The following alternatives were considered to meet the growth of the area.

Alternative 1: New station supplied from existing single circuit 230kV line.

Build a new station and connect to 230kV circuit C3S as shown in Figure 8-3. The station would have sufficient capacity to address the growth of the area over the study period. However, a single circuit supply would not provide the same level of reliability as the stations in the area currently have. Also, depending on the dispatch of resources and system configuration of the area, the existing system capacity to meet the demand is limited.

Alternative 2: New station supplied from two 230kV circuits.

Build the station as described in Alternative 1 and bring an additional 230kV supply. Please refer to Figure 8-4 below. The new circuit would be extended from M32S at South March TS and would help meet load growth over a wider range of system conditions. The new circuit would make use of the existing right of way by rebuilding one of the 3 circuits as a double circuit line.

Preliminary review of possible transfers to the new station has been considered and a revised forecast for the stations in the area is shown in Table 8-2.

Table 8-2. Updated summer forecast (MW) with transfers to Kanata North Considered.

	LTR (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035
Marchwood MTS	32.2	52.9	33.1	34.3	35.3	36.4	37.4	38.7	39.4	39.2
Kanata MTS	51.5	53.8	36.8	36.4	36.2	36.0	35.7	35.6	35.6	35.4
Kanata North MTS	108[1]	0	38	38.4	38.7	39.1	39.4	39.8	40	40.4

[1]Capacity for the new station will be confirmed as the project progresses.

Figure 8-3: Connection of New Kanata North MTS to C3S (initial connection)

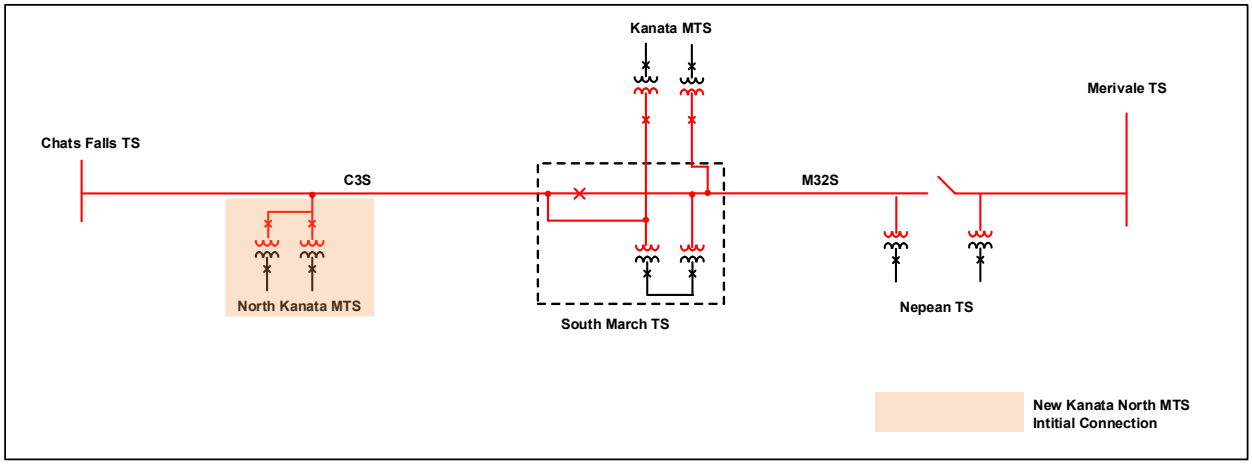
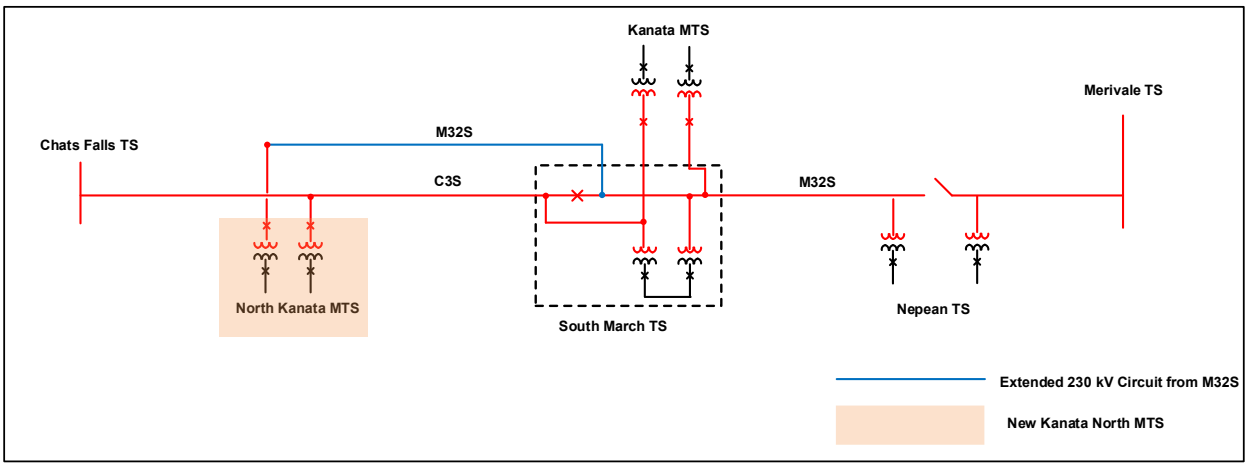


Figure 8-4: Connection of New Kanata North MTS to C3S and New Circuit (recommended alternative)

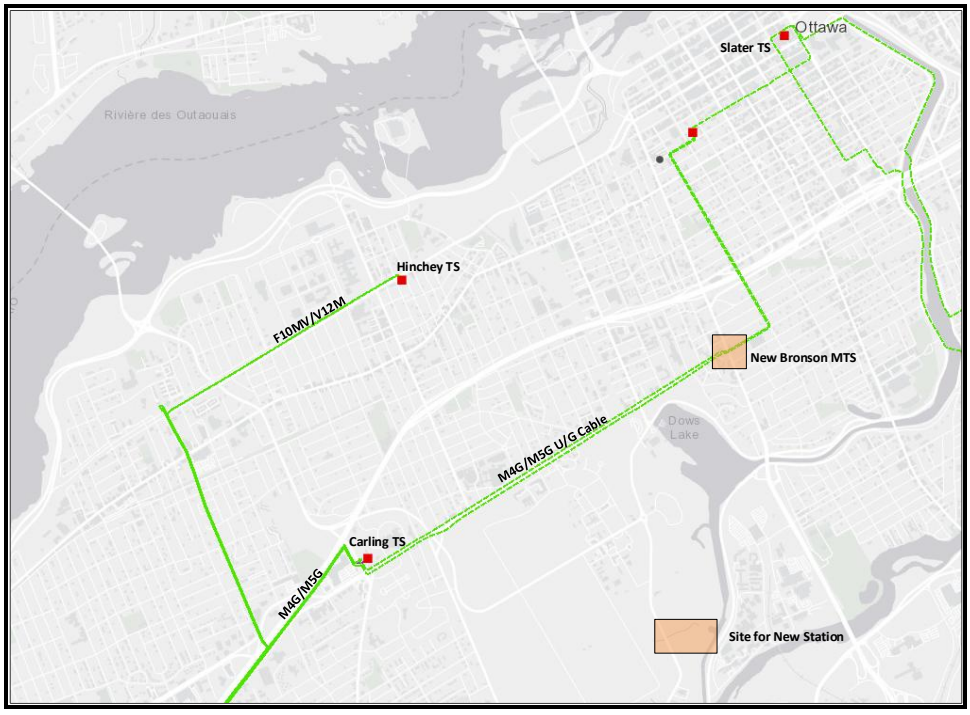


The TWG recommends Hydro Ottawa and Hydro One proceed with Alternative 2. This option will provide the necessary transformation capacity for the area and will provide higher level of reliability by having two circuits supplying the station. Based on the immediate need for transformation capacity, Hydro Ottawa is planning to build the station by 2028. In order to meet this in-service date, the station will be connected initially to existing 230kV circuit C3S only as described in Alternative 1. The second circuit is expected to be completed by 2031.

8.2.2 Bronson MTS

Several stations supplied from the 115kV network in the downtown core have been identified as reaching their capacity in the short term. Upgrading some of these stations is feasible to increase their transformation capacity. However, given the magnitude of the growth expected, additional transformation capacity in the form of a new station is required. Hydro Ottawa has identified a site for a new station: the alternative considered is to convert an existing Hydro Ottawa owned distribution station into a 115 kV DESN. The site of this station is adjacent to an underground cable section of M4G/M5G between Carling TS and Lisgar TS as shown in Figure 8-5.

Figure 8-5: Ottawa Downtown Area Map with new Bronson MTS



This conversion to a 115 kV DESN would increase the transformation capacity of the station. It would also enable load transfers from nearby stations and allow for new developments in Ottawa's Core East area, which is experiencing significant growth driven by urban densification, electrification of heating and transportation, and federal decarbonization initiatives. To note, this option would necessitate uprating circuits M4G and M5G to address thermal limitations, as discussed in Section 8.3 of this report.

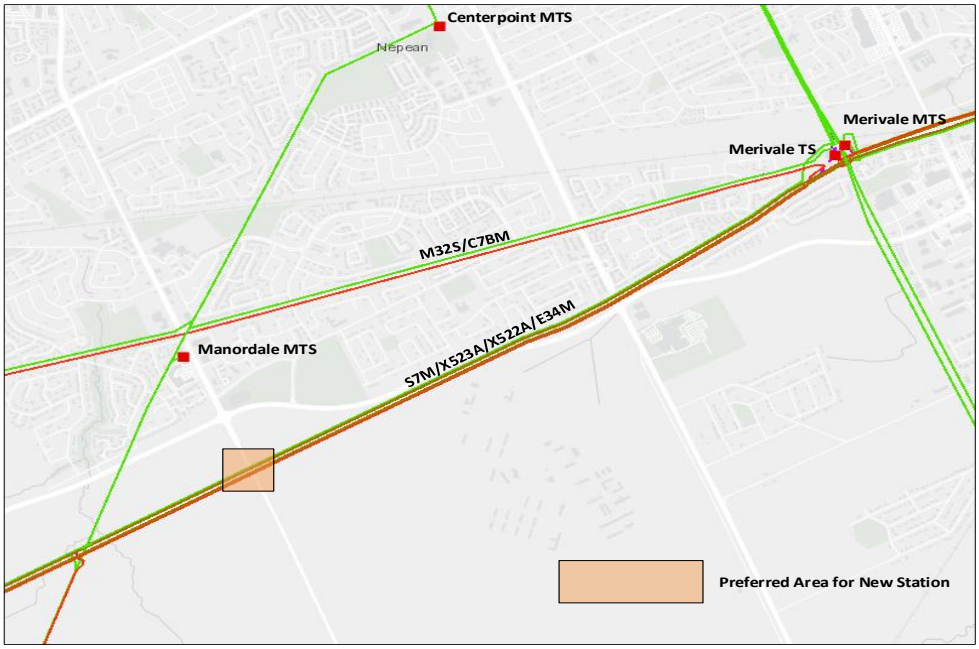
This plan was initially proposed as part of the IRRP. TWG has reviewed the need and proposed solution and reaffirmed the plan as the preferred alternative.

Hydro Ottawa and Hydro One are proceeding into studies to determine how the station will be connected to the existing 115kV underground cables. The proposed in-service date for the station is 2031.

8.2.3 Greenbank MTS

Another area expected to experience high growth is in the west of the city. The existing stations have limited capacity and TWG is recommending a new station to be built to address this need. Hydro Ottawa has identified preferred location for the station as shown in Figure 8-6 below.

Figure 8-6: Preferred Location of New Station in West Ottawa

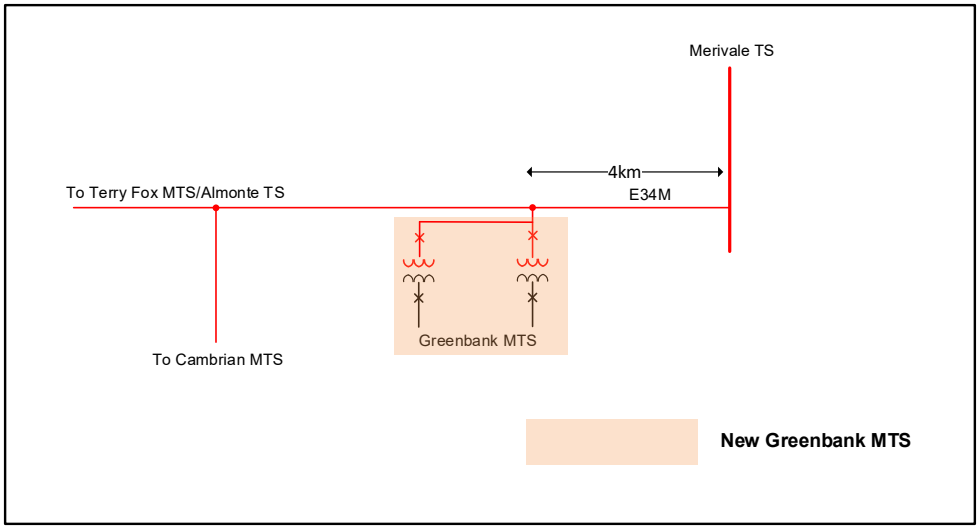


The following alternatives were considered to meet the growth of the area.

Alternative 1: New station supplied from existing single circuit 230kV line.

Build a new station and connect to 230kV circuit E34M as shown in Figure 8-7. The station would have sufficient capacity to address the growth of the area over the study period. However, connection to E34M alone would limit the growth that can be supplied from the station. In addition, the circuit needs to be connected at Merivale TS for the voltage to be acceptable.

Figure 8-7: Connection of New Greenbank MTS to E34M



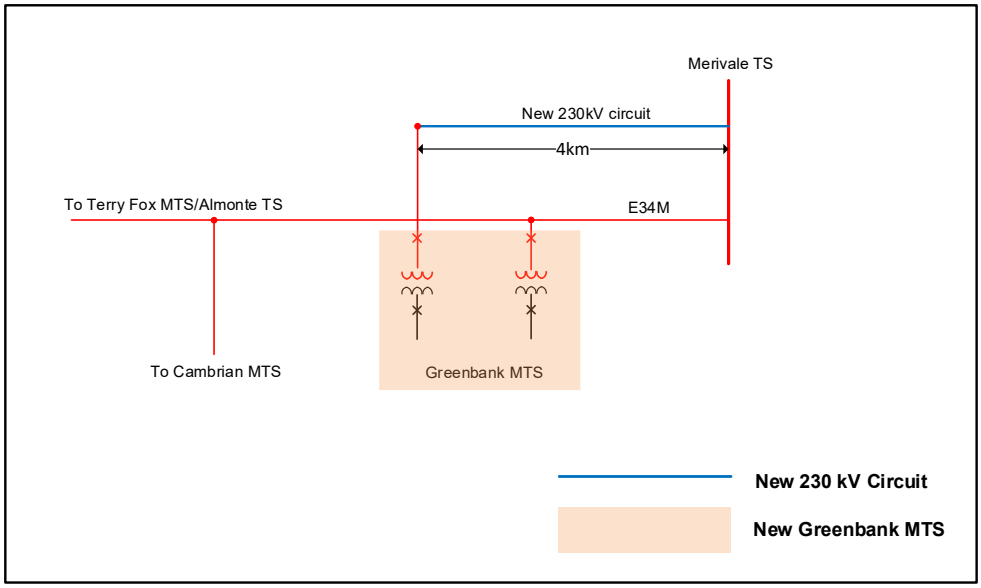
Alternative 2: New station supplied from two 230kV circuits.

Build the station as described in Alternative 1 and bring an additional 230kV supply. Please refer to Figure 8-8 below. The new circuit would be extended from Merivale along the E34M corridor. The new circuit would alleviate the concerns identified for Alternative 1 and would help meet load growth over a wider range of system conditions.

Alternative 2 was initially proposed as part of the IRRP. TWG has reviewed the need and proposed solution and reaffirms the plan as the preferred alternative.

Hydro Ottawa and Hydro One are proceeding with a project to connect the new station to the 230kV system. Hydro Ottawa's new station is planned for in-service in 2028. The new circuit must be coordinated with the Merivale TS upgrade described in Section 6 and is currently expected for in-service in 2031. Both transformers at the new station will be supplied by circuit E34M as per Alternative 1 until the new circuit is available. Operating measures may be required to help supply the load should there be issues with E34M until the second circuit is available.

Figure 8-8: Connection of New Greenbank MTS to E34M and new circuit



8.2.4 South March TS – T1/T2

South March TS, located in the Kanata–Stittsville area currently served by 230 kV circuits M32S and C3S. The station is equipped with two aging 50/83MVA 230kV/44kV transformers (T1/T2) which, based on their condition, were identified for replacement in 2030–2032 as outlined in Section 8.1.1.

Based on the updated load forecast, South March TS is projected to exceed its summer LTR by approximately 3 MW in 2026 and its winter LTR by about 6 MW in 2028, with the high-growth scenario the need date is 2026 for summer and 2027 for winter. TWG has recommended upgrading the existing

transformers to new 75/125 MVA units. The tentative planned ISD for this upgrade project is scheduled in 2031- 2032. Hydro One is working to expedite the replacement work to 2029-2030 to meet the rising load growth.

In the interim, coordination with LDCs will be required to explore load transfer opportunities to adjacent stations or other operating measures to manage short-term capacity constraints until the transformer replacement is completed should there be any issues at the station.

8.2.5 Albion TS T1/T2

Albion TS is a 230 kV / 14-14 kV DESN station supplied from circuits M30A and M31A. The station's two 75 MVA, 230 kV / 14-14 kV transformers were identified for replacement based on condition assessments. Planned in-service date for this work is 2031(refer to Section 8.1.2).

Based on the load forecast, Albion TS is projected to exceed its winter LTR by approximately 3 MW in 2034, while the summer LTR remains within limits over the study period. Under the high-growth scenario, the need date is 2030 for winter and 2043 for summer.

To address the loading issue, TWG has recommended upgrading the two transformers to standard 100 MVA units, along with the metalclad switchgear upgrade. The tentative in-service date for this upgrade is 2031. A feasibility study will be conducted to determine the preferred option to upgrade the metalclad as the existing installation has space limitations which may restrict the possible upgrade.

8.2.6 Carling TS – T1/T2

Carling TS is a transformer station that steps down voltage from 115 kV to 13.2 kV that is supplied from circuits M4G and M5G. Each transformer is rated at 115/14.2/14.2 kV, 60/80/100 MVA.

Based on the forecasts, Carling TS will exceed its summer LTR by approximately 11 MW and its winter LTR by about 1 MW by 2028. The current capacity limitation is primarily due to the existing series-connected low-voltage (LV) cables which limit the station capacity.

To address this constraint, TWG recommends upgrading the LV cables associated with both transformers as the preferred solution, as it will increase station capacity and eliminate low-voltage limitations. This upgrade project is tentatively planned for an in-service date in summer 2030.

8.2.7 Lisgar TS T1/T2

Lisgar TS is an indoor facility that steps down voltage from 115 kV to 13.2 kV that is supplied from circuits M4G and M5G. Replacement of 75 MVA transformer T1 with a 100 MVA unit was recently completed in December 2025. Following this replacement, the forecasts indicate that the station will exceed its summer LTR by approximately 13 MW and its winter LTR by about 8 MW by 2028. Under the high-growth scenario, the winter need date is advanced to 2027.

The current capacity limitation is primarily due to the existing LV cables and metalclad breakers, which limit the station capacity. To address this constraint and meet future demand, TWG recommends replacing 75MVA transformer T2 with a 100 MVA unit that will match T1 and upgrading the LV cables and metalclad breakers. Based on preliminary review by Hydro One, two options are identified for the station upgrade.

Alternative 1: In-Situ replacement of transformer T2

Under this option, transformer T2 will be replaced at its existing location within Lisgar TS. During the replacement process, the entire station load will temporarily be supplied by transformer T1, which will require careful operational planning to avoid overloading. To facilitate this, Hydro Ottawa will need to implement targeted load transfers to adjacent stations to reduce stress on T1 during the outage. This approach minimizes the need for major civil works and leverages existing infrastructure. The target in-service date for this In-Situ replacement is 2031.

Alternative 2: Greenfield Replacement of transformer T2

If operational constraints or stranded load conditions make it impractical to transfer Lisgar TS load to other stations during the replacement, a greenfield approach will be considered. This involves installing the new transformer at a new location within the station property, which will require extension of the existing building and additional civil works. The target in-service date for this approach is 2034.

A conceptual layout for this greenfield approach is shown in Figure 8-9.

Figure 8-9: Lisgar TS extension under alternative 2



Recommendation:

A feasibility study will be conducted to evaluate both alternatives in detail, considering technical, and operational implications. Hydro Ottawa and Hydro One will review the options following the feasibility

study and decide on the preferred alternative. In the interim, coordination with LDCs will be required to explore load transfer opportunities to adjacent stations to manage short-term capacity constraints until the transformer and component replacements are completed should there be any issues at the station.

8.2.8 King Edward TS

King Edward TS, located in the downtown core of Ottawa, supplies Hydro Ottawa customers. The station is fed by two underground 115 kV cables from A4K and A5RK. The station capacity is limited due to the existing metalclad breakers and LV cables. The forecasts indicate that King Edward TS will exceed its winter LTR by approximately 9 MW as early as 2026 and its summer LTR by about 1 MW in 2033. Under the high-growth scenario, the need dates advance significantly to 2025 for winter and 2030 for summer.

The proposed solution involves upgrading the metalclad breakers and LV cables to increase station capacity and support future downtown demand. This upgrade project is tentatively planned for an in-service date of 2033. In the interim, coordination with LDCs will be required to explore load transfer options to manage short-term capacity limitations until the upgrades are completed should there be any issues at the station.

8.2.9 Nepean TS T3/T4

Nepean TS is supplied from 230 kV circuit M32S and steps down voltage to 44 kV for local Hydro Ottawa customers. Regional load forecasts indicate that Nepean TS is expected to exceed its winter LTR by approximately 9 MW in 2030, while summer LTR is projected to remain within limits throughout the study period. Since this need is primarily in the winter timeframe, the TWG recommends monitoring winter load growth and revisiting this capacity need in the next regional planning cycle which can be triggered in advance if load growth is significant.

8.2.10 Riverdale TS T2/T3

Riverdale TS T2/T3 is a 45/75 MVA 115 kV/13.2 kV facility located in downtown Ottawa, supplied by three 115 kV circuits: A5K, A3RM, and A6R. The forecasts indicate that Riverdale TS will exceed its summer LTR by approximately 2 MW in 2030 and its winter LTR by about 9 MW in 2028. Under the high-growth scenario, the summer need date advances to 2029 and the winter need date to 2026.

The station’s transformation capacity is limited due to LV cables. Replacing the LV cables will provide additional capacity, enabling Riverdale TS to support projected load growth and relieve constraints in the Core East area. However, Hydro Ottawa has confirmed that some load transfers to nearby stations are available, which can help manage growth in the foreseeable future. Therefore, TWG recommends monitoring load growth at Riverdale TS and proceed with distribution load transfers as necessary until further upgrades are deemed required.

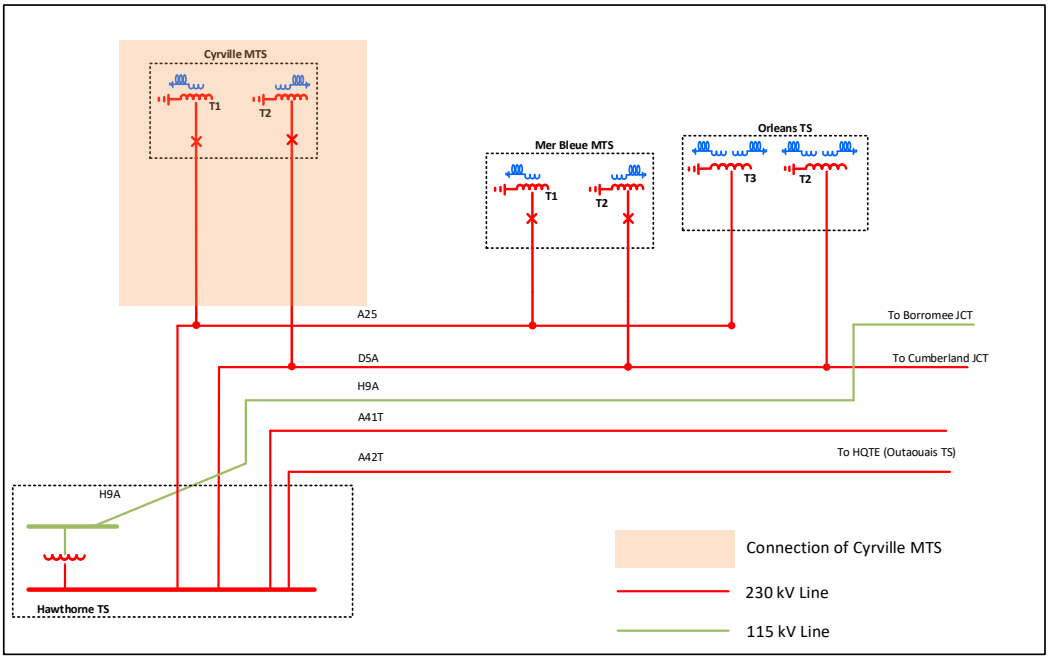
8.2.11 Cyrville MTS

Cyrville MTS is currently supplied by 115 kV circuits A4K and A2. The forecasts indicate that Cyrville MTS will exceed its summer LTR by approximately 1 MW in 2028 and its winter LTR by about 1 MW in 2030. Under the high-growth scenario, the winter need date advances to 2028.

The current plan as recommended in IRRP is to convert Cyrville MTS from a 115 kV station to a 230 kV station with two 100 MVA transformers by connecting to existing circuit D5A and a new 230 kV circuit A25

from Hawthorne TS, with a tentative in-service date of 2029. The planned conversion of Cyrville MTS will not only address near-term capacity needs but also position the station to accommodate future electrification and resilience requirements for Ottawa's east end. Please refer to Figure 8-10 for the planned connection. Hydro One is working on feasibility study to determine the preferred corridor for the connection of the station to the 230kV in collaboration with Hydro Ottawa.

Figure 8-10: New Cyrville MTS connected to D5A and new A25 circuit



8.2.12 Moulton MTS

Moulton MTS has a LTR of 32 MW in both summer and winter seasons. The forecasts indicate that the station will exceed its summer LTR by approximately 5 MW and its winter LTR by about 6 MW by 2028. To address this need, TWG has recommended to repurpose two 50 MVA, 115 kV transformers from Cyrville MTS following its planned conversion to 230 kV. Relocating these transformers to Moulton MTS will provide additional transformation capacity to meet projected demand growth. This approach leverages existing assets efficiently while supporting reliability in the growing east-end area.

8.2.13 Marionville DS

Marionville DS is forecasted to exceed its summer and winter Planned Loading Limit (PLL) as early as 2025.To address this need, the recommended action is to install a second transformer rated at 20 MVA and construct approximately 4.2 km of new distribution feeder to integrate the additional capacity. The tentative in-service date for this upgrade is December 2029. In the interim, Hydro One Distribution will manage load growth through transfers to nearby stations to maintain reliability until the new transformer and feeder build are completed.

8.2.14 Greely DS

Greely DS is projected to reach its summer and winter PLL in 2025. To address this the recommended action is to install SCADA fan monitoring for transformers T1 and T2 (115 kV to 28 kV). This upgrade will enable fan monitoring and allow higher ratings for both transformers, increasing their capacity from 23 MVA to 38 MVA in summer time and 28 MVA to 43 MVA in winter. The planned in-service date for SCADA fan monitoring is scheduled for 2026.

8.2.15 Manotick DS

Manotick DS has a summer PLL of 8.6 MVA and a winter PLL of 11.6 MVA. This PLL considers the loss of one transformer. Load forecasts indicate that the station will exceed these limits in both summer and winter starting in 2025.

Hydro One Distribution has operating measures to deal with station load in the near and medium term should one of the transformers fail such as use of Mobile Unit Substation (MUS)

Other measures such as Scada fan monitoring can be considered and will be reviewed as a part of next regional planning cycle.

8.2.16 Hinchey TS

Load forecasts indicate that Hinchey TS is expected to exceed its winter LTR by approximately 2 MW in 2031, while summer LTR is projected to remain within limits throughout the study period. Since this need is primarily in the winter timeframe. TWG is recommending monitoring winter load growth and revisiting this capacity need in the next regional planning cycle which can be triggered in advance if load growth is significant.

8.2.17 Rockland DS

Rockland DS is forecasted to reach its summer PLL in 2025, TWG recommends the implementation of SCADA monitoring of transformer fan. This will increase the summer PLL to 14.4 MVA and alleviate the overload at station. The planned in-service date for the fan monitoring installation is 2026.

In the interim, LDCs will implement operational measures, to manage loading and maintain system reliability until the permanent solution is in place.

8.2.18 Rockland East DS

Rockland East DS is forecasted to reach its summer PLL in 2026. TWG recommends the implementation of SCADA monitoring for transformer fans. The planned ISD for the fan monitoring installation is 2027.

In the interim, LDCs will implement operational measures to manage loading and maintain system reliability until the permanent solution is in place.

8.2.19 Additional Transformation Capacity needs

Several stations in the Greater Ottawa area are forecasted to exceed their LTR within the study period. The following summarizes the anticipated capacity needs:

- Nepean Epworth MTS – Expected to exceed its LTR in 2028 (winter) and 2035 (summer).
- Kanata MTS – Projected to exceed its summer and winter LTR in 2025.

- Ellwood MTS – Forecasted to exceed its summer and winter LTR in 2027.
- Limebank MTS – Expected to exceed its LTR in 2028 (winter) and 2031 (summer).
- Bridlewood MTS – Projected to exceed its LTR in 2030 (winter) and 2035 (summer).
- Marchwood MTS – Anticipated to exceed its summer and winter LTR in 2025.
- Centrepoint MTS – Expected to exceed its LTR in 2027 (winter) and 2032 (summer).
- Manordale MTS – Forecasted to exceed its LTR in 2026 (winter and summer).
- Fallowfield MTS – Projected to exceed its LTR in 2030 (winter) and 2026 (summer).

Hydro Ottawa has confirmed that loading at these stations can be managed through operational load transfers to nearby stations in the near term. Additionally, the commissioning of new stations—Kanata North MTS, Mer Bleue MTS, Greenbank MTS, Bronson MTS and Piperville MTS—will allow permanent load shifts, providing long-term relief to these stations and addressing regional capacity needs.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period **2025-2044** for the 230kV and 115kV Transmission line circuits in the **Greater Ottawa region** by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater to this need. Based on the results, the following line capacity needs have been identified during the study period:

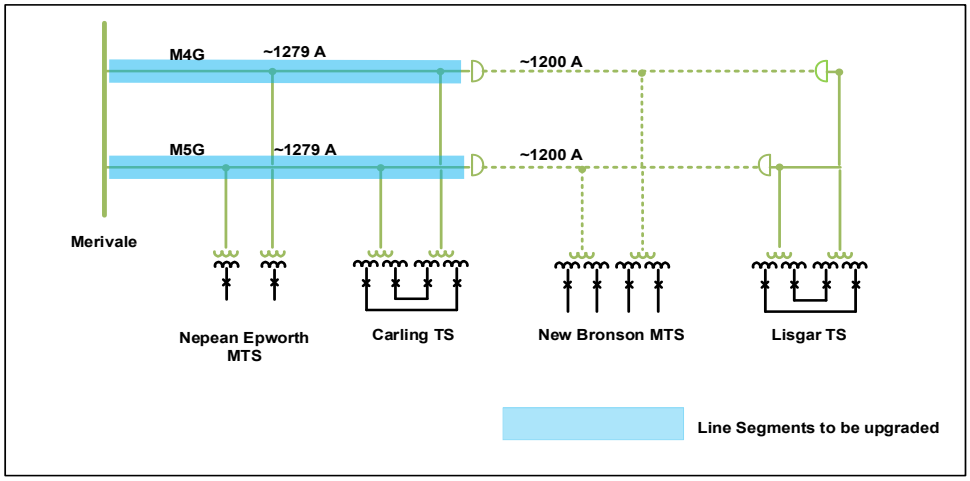
8.3.1 M4G/M5G – 115 kV – Section Uprate

The M4G and M5G circuits, which supply Nepean Epworth MTS, Carling TS and Lisgar TS, are forecasted to experience thermal constraints under contingency conditions as downtown Ottawa load continues to grow. When one circuit is out of service, the remaining circuit would be required to fully supply all stations, resulting in thermal overload conditions. Based on the regional load forecast, this limit is expected to be reached in the summer of 2030 and in the winter of 2032.

To address this issue, the recommended action is to upgrade sections of M4G and M5G between Merivale TS and Carling TS to remove thermal constraints and support higher downtown load.

Based on studies, this load pocket can supply about 360 MW before voltage issues arise. Hydro One will consider different conductor options to meet this load. The feasibility of using ACSS (Aluminum Conductor Steel Supported) conductor options will be explored to provide sufficient capacity while maintaining reliability.

Figure 8-11: Uprate Section from Merivale TS to Carling TS

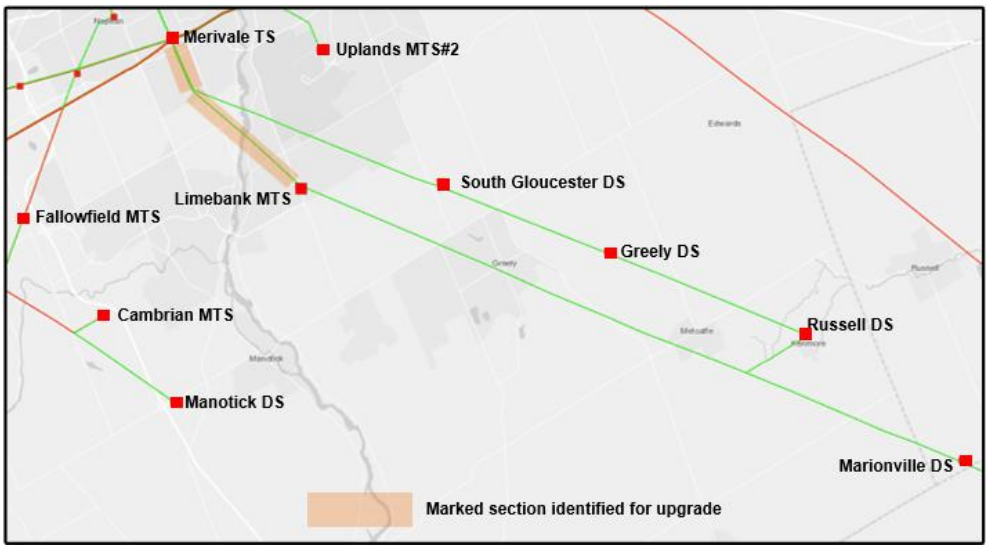


Regional planning emphasizes that downtown Ottawa is a critical load pocket with limited space for new infrastructure, making reinforcement of existing transmission corridors essential. Since Bronson MTS is also planned as a new station to relieve downtown capacity constraints, uprating the M4G/M5G corridor is a key enabler for this project and for supporting long-term growth in the Core East area.

8.3.2 L2M – 115 kV – Uprating Merivale TS x Limebank MTS

Thermal constraints have been identified on the L2M transmission line section between Merivale TS and Limebank MTS, which supplies Limebank MTS and Marionville DS as shown in Figure 8-12. These constraints are primarily driven by the increasing load forecast at Limebank MTS, as identified in the regional planning load forecast. The section of L2M has a summer rating of 93 MVA (477 A) and based on the study results, the 7.8km line section between Merivale TS and Limebank MTS is expected to reach its thermal capacity limit in the near term by 2028.

Figure 8-12: Uprate Section from Merivale TS to Limebank MTS



Alternative 1 - Remove sag limitation

The rating of circuit L2M between Merivale TS and Limebank MTS is currently limited due to clearance concerns. This option looks to increase the thermal capacity of L2M by addressing the conductor's sag issue. Hydro One has previously reviewed the work necessary to remove the limitation and has determined that approximately 3.2km of the line section would have to be rebuilt in addition to modification to some existing towers and insulators where no rebuilding is required. This work would remove the clearance limitation and would allow the circuit capacity to be increased to approximately 106MW in summer and 131 MW in winter. This allows us to meet the demand up to the mid-term.

Alternative 2: Rebuild the circuit

This alternative would look at rebuilding the 7.8km circuit L2M between Merivale TS and Limebank MTS to increase the circuit's thermal rating. Two options were considered.

> **Alt 2a:** This option would rebuild the existing 7.8km as a single circuit 115kV line. It would address the thermal rating constraint currently on the circuit and would be adequate to supply the forecasted load of Marionville DS and Limebank MTS. However, with this option, Limebank MTS and Marionville DS would remain on a single circuit supply.
>
> **Alt 2b:** This option would rebuild the existing 7.8km as a double circuit 115kV line. Similar to Alternative 2a, this option would address the thermal rating issue. This option would also help improve the reliability of supply to Limebank MTS by providing a second supply to the station.

Recommendation

TWG recommends uprating L2M to support the south-end growth and align with recommendations for proactive reinforcement of critical transmission corridors. A feasibility study will be done after which Hydro One and LDCs will review the different options. The selected alternative will follow the recommendation to uprate the section of L2M from Merivale TS to Limebank MTS, with a tentative in-service date of 2032.

8.3.3 A4K – 115 kV

Hawthorne TS x Overbrook TS section

Under the winter peak forecast for 2032, thermal overload has been identified on a critical section of the A4K corridor, specifically between Hawthorne TS x Overbrook TS, under the contingency of either circuit A5RK or A6R. When either of the circuits are out of service, the resulting increased loading on A4K is beyond its thermal capability.

Overbrook TS x King Edward TS section

This section is an underground cable section, and it exceeds its capacity due to King Edward TS being overloaded beyond the capacity described in section 8.2. If the station load is to increase as per the winter forecast, the upgrades to the station (beyond what is described in section 8.2) would have to be done in coordination with upgrades to cables.

TWG has reviewed the overload scenarios, and the recommended approach is to monitor load growth of the stations on A4K over the coming years. As demand continues to increase, TWG will reassess the situation and develop an appropriate action plan, which may include options such as reconductoring, circuit upgrades, or alternative reinforcement strategies to ensure compliance with thermal limits and maintain system reliability.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net load forecast and the loss of one element over the study period 2025-2044 to cater for this need**.** Based on the results, the following system reliability, operating and restoring issues have been identified for this Region.

8.4.1 Load Security issue due to contingency of M32S

Nepean TS currently relies on a single 230 kV transmission supply circuit (M32S) from Merivale TS to South March TS. Under an M32S contingency, the entire load at Nepean TS would be lost due to configuration. According to ORTAC criteria, load security requires that no more than 150 MW of load can be lost for a single element contingency. While this limit is not exceeded in the summer forecast, it is projected to be reached in the winter forecast by 2029, when Nepean TS's peak demand is expected to surpass 150 MW. This creates a load security concern, as an outage of M32S would result in a full load loss, violating ORTAC requirements.

To address this issue, the recommended plan includes providing Nepean TS with a second transmission supply circuit originating from Merivale TS. This will ensure compliance with ORTAC and enhance the station reliability. The timing of this plan will be determined based on ongoing load monitoring and coordination with the Merivale TS upgrade project.

8.4.2 New Switching Station to improve reliability and flexibility in Kanata Area

As discussed in Section 8.2, one of the recommended plans includes the development of a new 230 kV Kanata North MTS, which will initially connect to the existing 230 kV circuit C3S. To enhance reliability, a second supply will be brought from M32S. This second supply will be enabled by rebuilding one of the existing transmission lines in the C7BM/C3S/W6CS corridor to double circuit 230kV line, thus connecting M32S to the new Kanata North MTS.

With the addition of Kanata North MTS and potential load transfers from Marchwood MTS and Kanata MTS, the summer and winter load forecasts were preliminary revised for the stations in the Kanata area as shown in Tables 8-3 below.

Table 8-3: Updated summer and winter load forecast (in MW) with preliminary transfers to Kanata North Considered

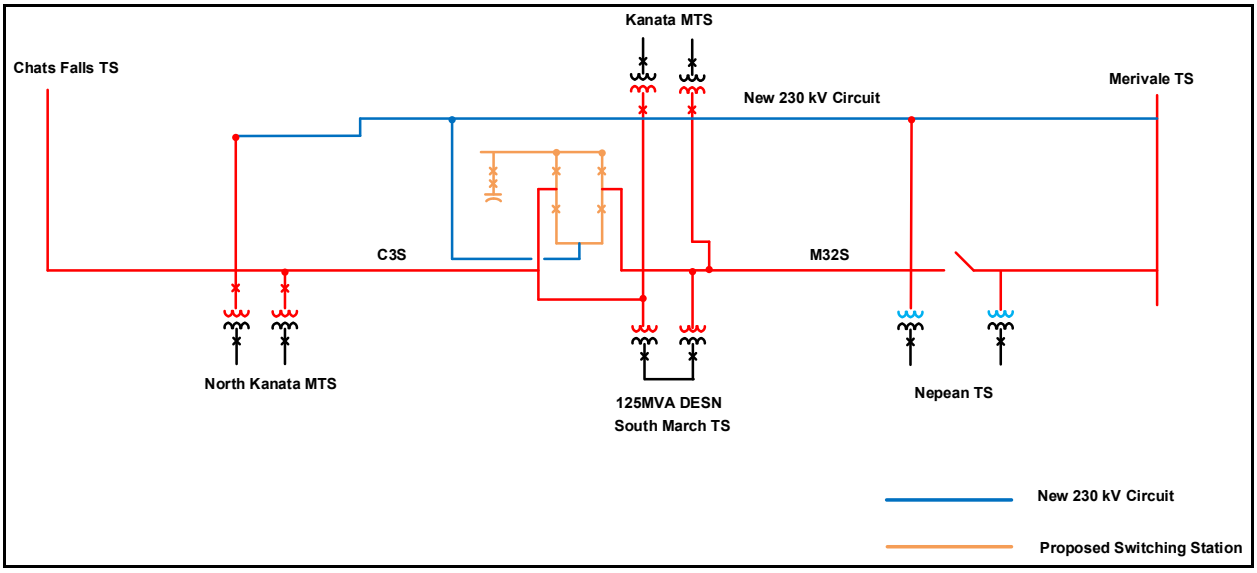
SUMMER											
Station	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
KANATA MTS	37	36	36	36	36	36	36	35	36	36	36
NEPEAN TS	127	128	128	128	128	128	128	129	129	130	131
SOUTH MARCH TS	112	112	114	122	121	122	126	127	128	129	130
Kanata North MTS	38	38	39	39	39	40	40	40	41	41	41
Load in 230 kV area	314	314	317	325	324	325	330	331	333	336	338
WINTER											
	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
KANATA MTS Revised	49	50	52	54	57	59	61	63	65	67	69
NEPEAN TS	148	159	169	176	184	191	198	205	214	223	231
SOUTH MARCH TS	119	124	132	143	147	151	158	162	168	173	179
Kanata North MTS	38	38	39	39	39	40	40	40	41	41	41
Load in 230 kV area	354	371	392	412	427	440	457	471	488	504	520

Analysis of contingencies on the 230 kV system indicates that stations supplied by these circuits can reliably support up to 340 MW of load while maintaining system performance. This threshold is expected to be reached under the summer forecast by 2038 and under the winter forecast as early as 2028.

To address this emerging constraint, the current strategy is to monitor winter load growth closely while advancing plans for a new switching station in the Kanata area. This switching station will facilitate flexible interconnections among Chats Falls TS, Merivale TS, South March TS, Nepean TS, and the new Kanata North MTS, thereby providing support for additional capacity, operational flexibility, and improved resiliency for the regional network. The conceptual layout of this switching station and its integration into the transmission system is illustrated in Figure 8-13.

The line that is planned from Merivale to Nepean as described in section 8.4.1 can be extended to the new switching station.

Figure 8-13: Proposed new 230 kV Line along with Switching Station



8.4.3 Load Security issue due to contingency of M1R+L2M

Merivale TS currently supplies two 115 kV circuits, M1R and L2M, which share a common breaker position. This configuration creates a common-mode outage risk: the loss of either circuit results in both circuits being tripped. Under ORTAC criteria, load security requires that no more than 150 MW of load can be lost for a single element contingency. While this limit is not exceeded in the summer forecast until 2040, it is projected to be reached in the winter forecast by 2031. This creates a load security concern, as an outage of either circuit would result in a full loss of supply to connected stations, violating ORTAC requirements.

To address these issues and improve reliability, the plan includes installing a new breaker at Merivale TS to separate circuits M1R and L2M into two independent 115 kV paths. This will eliminate the common-mode outage risk and ensure compliance with ORTAC load security criteria. The timing of this plan is driven by the emerging winter load security need, with a targeted in-service date of 2032. This solution also supports long-term thermal performance and operational flexibility. Figure 8-14 shows the 115 kV yard at Merivale TS following completion of Merivale TS upgrade project and Figure 8-15 shows the split M1R/L2M configuration that will be providing a separate breaker position for each line.

Figure 8-14: 115 kV Merivale TS after Merivale TS upgrade project

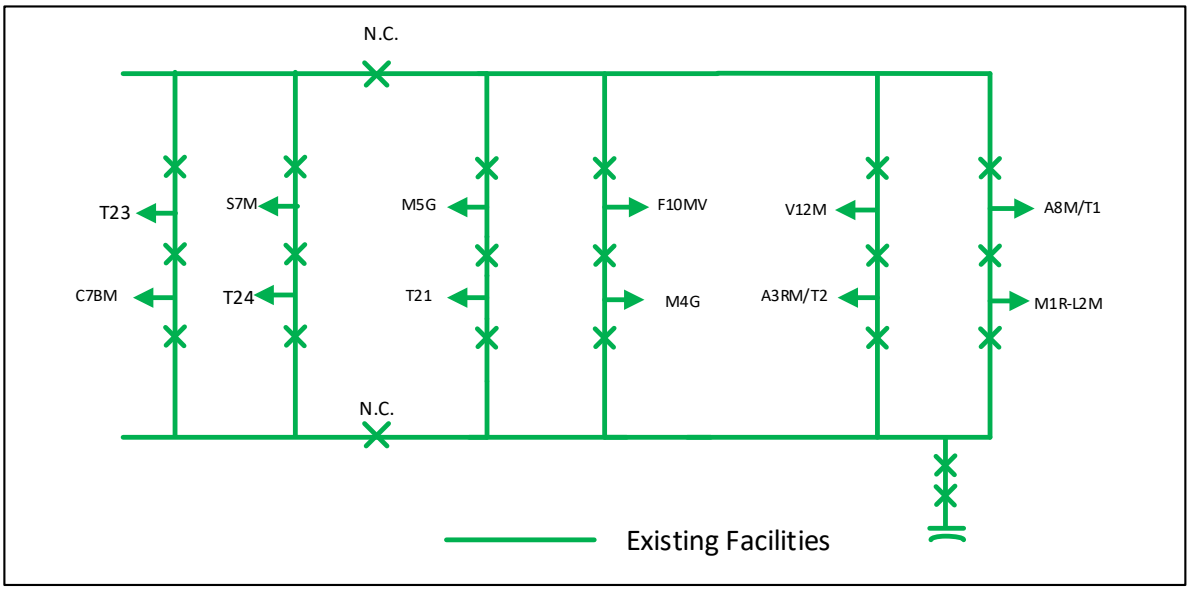
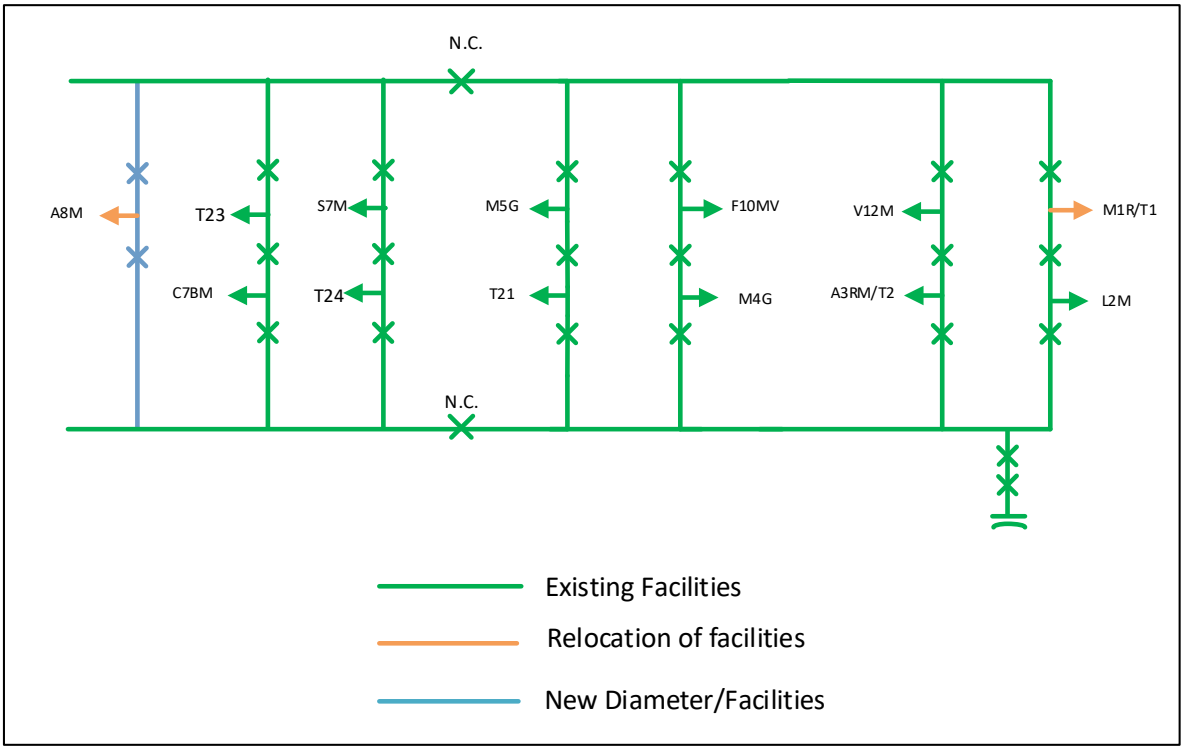


Figure 8-15 Different breaker positions of M1R and L2M



8.4.4 Loading and Voltage issues on S7M

Under the medium-term planning horizon, there is a limitation on the amount of load that can be transferred from Cambrian MTS to S7M under the contingency of E34M. This constraint arises due to both loading and voltage performance issues observed on S7M when additional load from Cambrian MTS is transferred to it during contingency conditions.

To address these challenges, several options are being considered. One potential solution is the planned conversion of S7M to 230 kV, which would significantly improve its capacity and voltage performance under contingency scenarios. Another option is to explore reactive power (VAR) support as load continues to grow, which could help maintain acceptable voltage levels and system stability. At this stage, the recommendation is to continue monitoring load growth and system performance, and to review the needs as part of the next cycle of regional planning. Ongoing bulk study may make recommendations that could impact the area, such as 230kV conversion.

8.4.5 Supply to East Ottawa

In the previous regional planning cycle, the recommended plan for the East Ottawa area included refurbishment of Bilberry Creek TS and the addition of two new feeder breakers. While the Greater Ottawa regional planning process was inactive, new information related to load growth and system conditions prompted a re-evaluation of the supply plan. In 2023, the TWG reviewed updated growth expectations for the area, the sustainment need at Bilberry Creek TS, and the capability of the 115 kV system to support future growth. Based on this review, TWG agreed to revise the recommendations for the area.

TWG's revised plan and new recommendation includes three components.

Retirement of Bilberry Creek TS

The TWG recommends retiring Bilberry Creek TS due to aging infrastructure and associated sustainment requirements. The revised approach shifts supply for the area away from continued reinvestment at Bilberry Creek TS resulting in removing load from 115 kV system and instead transitioning the connected load to the 230 kV system to support longer-term capacity and system reliability.

Upgrade at Orleans TS

As part of this approach, Orleans TS will be upgraded from dual supply 230/27.6 kV and 115/27.6 kV to 230/27.6 kV DESN. This upgrade includes a new 230 kV circuit A25 between Hawthorne TS and Orleans TS (~11km). The planned in-service date for the Orleans TS upgrade and the A25 circuit is June 2029.

Connection of new Mer Bleue MTS

The revised plan also includes the connection of a new Hydro Ottawa station, Mer Bleue MTS, to the 230 kV system. Mer Bleue MTS will be connected to 230 kV circuits D5A approximately 10 km east of Hawthorne TS, with a planned in-service date of July 2027. The project is also planned to connect to circuit A25 with an expected in-service date of June 2029.

This new recommendation provides the following benefits:

i. Addresses the Limited growth available on the 115kV system. The Ottawa 115kV system is mainly supplied via 250MVA autotransformers at Hawthorne TS and Merivale TS. East Ottawa 115kV system is connected to Hawthorne TS and most of its supply is from the station's autotransformers. These autotransformers are heavily loaded and limit the growth that can supplied from 115kV. Installing additional autotransformers at the station will be very challenging due to space constraints and short circuit level considerations. As such removing load from the 115kV system and transferring it to the 230kV wherever possible, helps preserve the current capacity on the 115kV to address the growth at existing stations that cannot be converted to 230kV at reasonable cost. This Project helps by reducing the 115kV loading and transferring the load to 230kV.

ii. The Project avoids significant refurbishment work at the station as the load can be transferred onto the 230kV system and Bilberry Creek TS can be retired instead of refurbished. In addition, there is also limited growth available at Bilberry Creek even if the station is refurbished.

iii. Orlean TS will no longer be subject to momentary interruptions due to its configuration.

iv. The new 230kV circuit will allow more growth and improve supply reliability in the Orleans area. Currently connection on the 230 kV in the Orleans area will have to be limited to 100 MW. With the new circuit the area can support over 300 MW.

The RIP concludes that retiring Bilberry Creek TS, upgrading Orleans TS, and completing the associated 230 kV circuit and station connections is the most cost-effective option to address the long-term needs in East Ottawa. This combined set of projects is being pursued as an alternative to the sustainment and upgrade work at Bilberry Creek TS that was recommended in the previous regional planning cycle.

From a reliability perspective, the revised plan reduces dependence on aging station equipment, increases supply robustness by serving the area from the higher-capacity 230 kV network, and improves operational flexibility during planned outages or contingencies by enabling better load restoration options across the East Ottawa supply area.

Figure 8-16 Existing Orleans Area

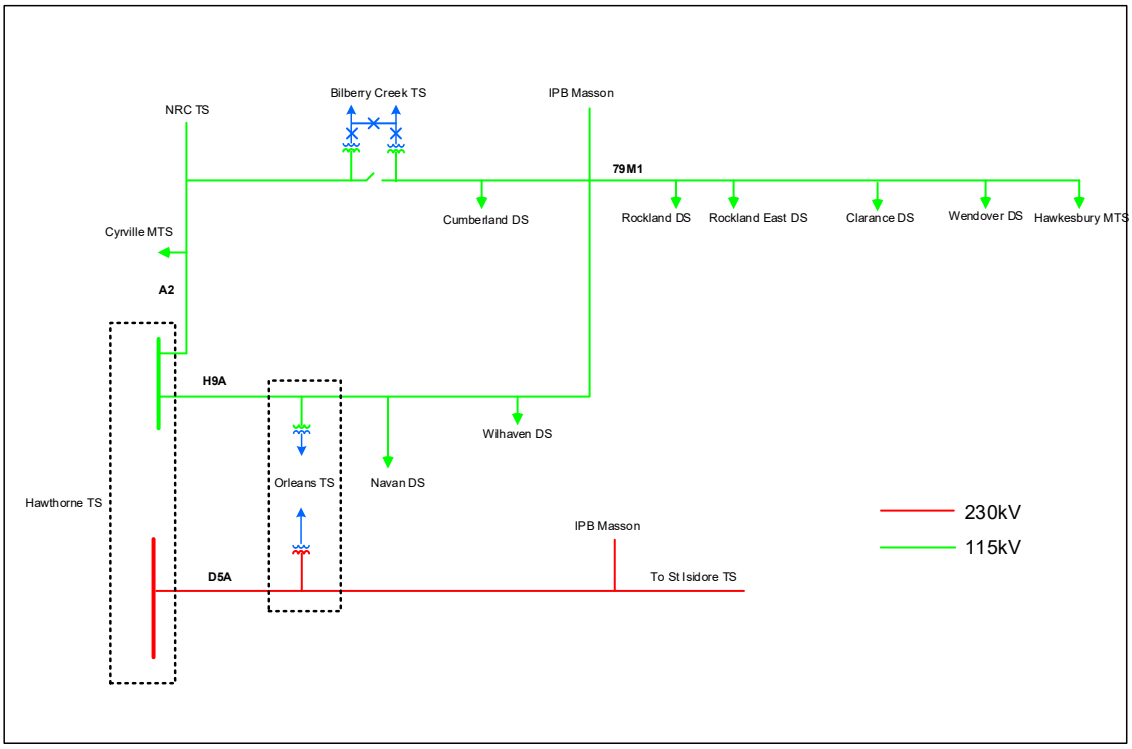
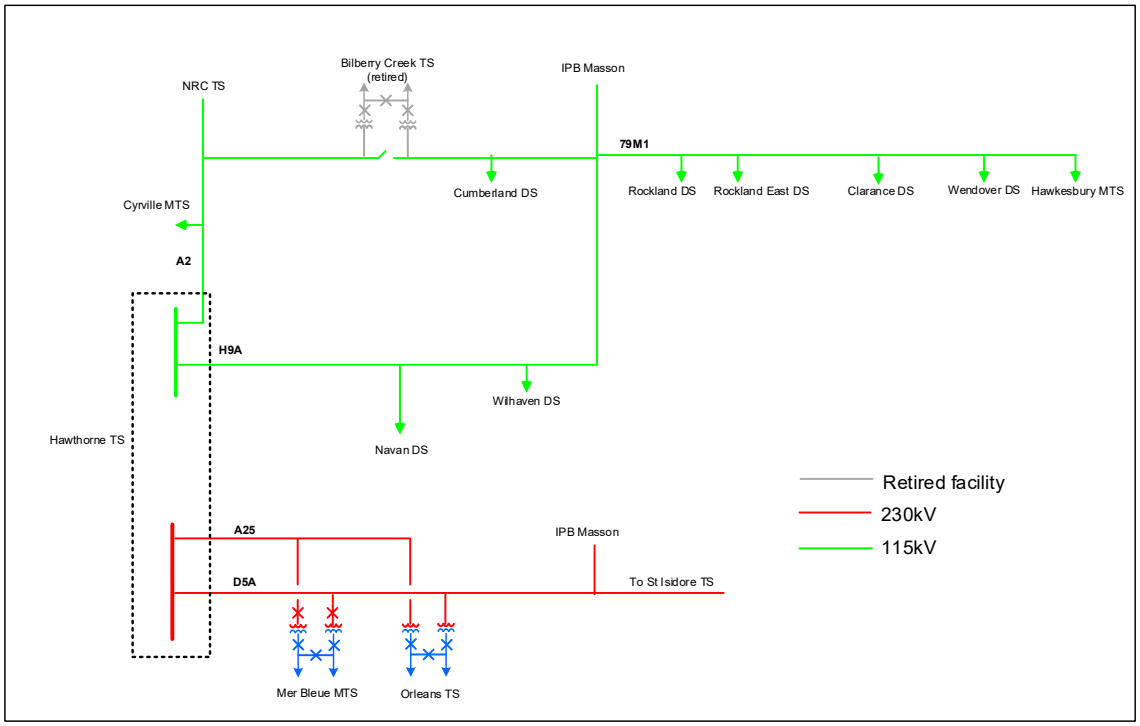


Figure 8-17 Orleans Area after Upgrade



9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for the Greater Ottawa region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2025-2044 are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M)
Asset Renewal Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	Hydro One	2031	$60M
Nepean TS	Replacement of T3/T4 transformers based on asset condition	Hydro One	2034	$30M
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	Hydro One	2030	$5M
Station Capacity Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Carling TS	Replacement of limiting LV cables.	Hydro One	2030	$10M

Lisgar TS	Replacement of T2 transformer and LV cables/breakers - Greenfield	Hydro One	2034	$50M
	Replacement of T2 transformer and LV cables/breakers – In Situ	Hydro One	2031	$30M
King Edward TS	Replacement of LV cables and breakers.	Hydro One	2033	$20M
Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating and upgrade station transformation capacity.	Hydro One/ Hydro Ottawa	2029	$85M*
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	Hydro Ottawa	2029	$5M
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	Hydro One/ Hydro Ottawa	2031	$110M*
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	Hydro One/ Hydro Ottawa	2028	$100M*
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and new transmission line from South March TS	Hydro One/ Hydro Ottawa	2028	$100M*
Marionville DS	Install a second transformer to increase station rating.	Hydro One Dx	2029	$12M*
Greely DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*

Rockland DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland East DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2027	$3M*
Transmission Line Capacity Needs				
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	Hydro One	2030	$30M
L2M	Uprate line section between Merivale TS x Limebank JCT	Hydro One	2032	$30M
System Reliability, Operation and Load restoration Needs				
Kanata Area	Kanata Area Transmission Reinforcement	Hydro One	2033	$250M
Nepean TS – Load Security Criteria	Second 230 kV Supply to station	Hydro One	2032	$70M
M1R+L2M	Split Breaker position for M1R and L2M at Merivale TS	Hydro One	2032	$45M
East Ottawa Area	Supply to East Ottawa	Hydro One	2029-2030	$165M*

* These investment costs include associated distribution system costs.

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are high-level planning estimates and actual costs may vary.

10. REFERENCES

[1] Hydro One, RIP Report – Greater Ottawa (Second cycle), published on December 18, 2020

[2] Hydro One, NA Report – Greater Ottawa (Third cycle), published on December 20, 2022

[3] Independent Electricity System Operator, SA Report – Greater Ottawa (Third cycle), published on March 21, 2023

[4] Independent Electricity System Operator, IRRP Report – Ottawa Area Sub-region (Third cycle), published on July 31, 2025

[5] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[6] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[7] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[8] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Greater Ottawa region – Summer - Reference Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	86.5	58.6	59.2	59.7	60.3	60.7	61.2	61.9	62.6	63.5	64.5	65.2	65.5	65.9	66.4	66.8	67.2	67.8	68.4	69.0	69.0
ALMONTE TS	96.7	55.4	56.1	56.7	57.4	58.0	62.4	63.8	64.9	68.4	71.8	72.8	74.1	75.4	76.8	78.1	79.6	81.0	82.5	83.9	85.5
ARNPRIOR TS	54.9	39.5	39.8	39.9	40.7	41.3	44.2	47.3	48.6	48.9	49.3	49.8	50.4	51.0	51.6	52.2	53.0	53.7	54.3	54.9	55.6
BILBERRY CREEK TS	85.3	64.0	64.2	64.4	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	21.7	22.0	22.2	22.4	22.6	22.8	22.9	23.1	23.2	23.4	23.6	23.5	23.7	23.7	23.7	23.7	23.9	24.2	24.4	24.4
CAMBRIAN MTS	114.0	58.9	62.7	68.3	71.9	74.7	77.1	80.6	84.2	87.8	91.4	95.1	99.1	101.8	102.3	102.5	103.0	103.7	104.4	105.1	105.8
CARLING TS	95.0	89.2	90.6	91.6	105.9	106.6	113.8	126.4	139.2	139.6	140.0	141.2	140.9	140.9	141.1	141.3	141.4	142.6	143.7	144.9	144.9
CENTREPOINT MTS	13.3	12.8	12.9	13.0	13.0	13.1	13.1	13.2	13.4	13.5	13.7	13.8	13.9	14.0	14.1	14.2	14.3	14.6	14.8	15.1	15.1
CLARENCE DS	7.8	2.6	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.5
CUMBERLAND DS	6.8	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.2	7.3	7.4	7.5	7.7	7.8
CYRVILLE MTS	47.5	31.9	34.1	35.0	48.4	49.1	49.0	49.1	49.0	49.2	49.2	49.4	49.8	50.2	50.6	50.5	50.5	50.8	51.2	51.5	51.9
ELLWOOD MTS	47.0	41.7	45.0	47.3	48.4	49.4	49.4	49.3	49.2	49.3	49.2	49.3	49.6	49.9	50.2	50.4	50.7	51.1	51.4	51.8	52.2
FALLOWFIELD MTS	27.2	24.1	27.3	30.5	33.1	33.3	33.3	33.3	33.4	33.3	33.2	33.3	33.5	33.7	33.8	33.8	34.0	34.2	34.5	34.7	35.0
GREELY DS	20.7	22.4	22.6	22.9	23.2	23.4	23.9	24.2	24.5	24.9	25.2	25.9	26.6	27.6	28.4	29.3	30.1	30.6	30.9	30.9	30.9
HAWKESBURY MTS #1	18.0	12.1	12.3	12.4	12.6	12.7	12.9	13.0	13.1	13.2	13.4	13.6	13.9	14.1	14.4	14.7	15.0	15.3	15.6	15.9	16.2
HAWTHORNE TS	144.8	136.6	137.1	137.3	138.0	138.4	139.1	139.6	140.2	141.0	141.7	143.1	143.8	144.7	145.7	146.5	147.4	148.1	148.7	148.6	148.7
HINCHEY TS	85.6	21.6	22.2	28.6	36.5	40.9	44.8	47.7	49.6	50.9	51.7	52.3	52.3	52.3	52.3	52.2	52.2	52.7	53.2	70.3	70.8
HYDRO RD MTS	114.0	-	-	13.0	18.5	23.9	29.3	32.9	36.5	40.0	43.6	47.2	47.7	48.2	48.6	49.1	49.6	49.8	50.0	50.2	50.2
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	54.1	54.1	53.8	53.8	53.6	53.5	53.5	53.3	53.4	53.5	53.5	53.9	54.3	54.7	55.0	55.3	55.7	56.1	56.4	56.8
KING EDWARD TS	86.9	77.6	78.8	79.8	80.8	81.6	82.6	85.0	86.4	87.7	89.0	90.1	91.4	92.7	94.0	95.4	96.8	98.9	101.1	103.2	103.2
LIMEBANK MTS	75.0	50.9	57.2	63.1	68.6	71.5	73.7	75.8	77.8	79.5	80.7	82.0	83.6	85.2	86.9	88.5	90.1	90.8	91.4	91.9	92.6
LINCOLN HEIGHTS TS	99.4	46.4	46.7	46.9	47.0	47.1	47.3	47.8	48.3	48.9	49.5	50.0	50.1	50.3	50.5	50.7	50.9	51.5	52.1	52.7	52.7
LISGAR TS	83.4	78.5	80.2	81.5	96.6	97.7	98.9	109.8	109.8	109.8	109.9	110.7	109.9	109.2	108.6	108.0	107.4	107.7	108.0	108.3	108.3
LONGUEUIL TS	123.5	45.6	48.1	50.4	51.8	52.1	52.6	53.0	53.5	61.3	64.5	65.2	68.6	69.7	70.8	71.9	73.0	73.9	74.9	75.8	76.8

MANORDALE MTS	9.6	9.5	9.7	9.8	10.0	10.1	10.3	10.4	10.4	10.5	10.6	10.7	10.7	10.8	10.8	11.0	11.1	11.2	11.4	11.6	11.6
MANOTICK DS	7.7	10.5	10.7	10.8	11.0	11.1	11.3	11.4	11.6	11.8	12.0	12.3	12.5	12.8	13.1	13.3	13.6	13.9	14.2	14.6	14.9
MARCHWOOD MTS	32.3	51.3	52.2	52.9	54.1	55.5	56.7	58.0	59.2	60.7	61.5	61.5	61.8	62.2	62.5	62.9	63.2	63.6	64.0	64.4	64.8
MARIONVILLE DS	13.5	15.5	15.6	15.7	15.9	16.0	16.3	16.4	16.6	16.8	17.0	17.3	17.8	18.2	18.7	19.2	19.7	20.0	20.2	20.1	20.1
Mer Bleue MTS	114.0	-	-	-	65.3	66.0	66.7	67.4	68.2	69.0	69.9	70.7	71.3	72.0	72.8	73.5	74.2	75.2	76.3	77.3	77.3
MERIVALE MTS	32.9	18.3	18.2	18.0	17.8	17.6	17.4	17.5	17.6	17.7	17.8	17.9	17.9	17.8	17.8	17.8	17.8	18.0	18.2	18.4	18.4
MOULTON MTS	32.0	23.7	23.5	23.2	36.7	36.2	35.9	35.9	36.0	36.1	36.2	36.3	36.2	36.1	36.1	36.1	36.0	36.2	36.3	36.5	36.5
CTS-2	14.0	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
NRC TS	77.4	5.1	5.1	5.0	17.1	16.8	16.5	16.4	16.4	16.3	16.2	16.0	15.8	15.8	15.8	15.8	15.8	15.7	15.7	15.7	15.7
NAVAN DS	13.5	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.1
NEPEAN EPWORTH MTS	12.9	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.7	12.8	12.9	13.0	13.0	13.0	13.1	13.1	13.1	13.3	13.5	13.6	13.6
NEPEAN TS	144.1	126.1	126.7	126.9	127.3	127.5	127.9	128.0	127.8	128.0	128.1	128.5	129.3	130.2	131.1	131.9	132.8	133.7	134.6	135.4	136.3
ORLEANS TS	118.2	118.5	123.0	120.3	123.8	126.6	143.9	146.9	149.8	151.6	153.5	155.7	158.3	160.2	162.1	163.9	165.8	167.7	169.5	171.3	173.2
OVERBROOK TS	116.8	86.1	88.3	90.2	92.2	94.0	95.9	96.8	97.9	98.9	100.0	101.1	101.7	102.4	103.2	104.0	104.8	106.5	108.2	109.8	110.8
PIPERVILLE MTS	108.0	-	2.3	4.6	6.8	9.0	11.2	11.4	11.7	11.9	12.2	12.4	12.7	13.1	13.4	13.8	14.1	14.4	14.6	14.8	14.8
RICHMOND SOUTH MTS	49.0	20.7	24.2	27.0	29.8	32.0	34.3	38.3	42.1	45.6	49.2	52.3	55.6	56.3	57.1	57.8	58.5	58.9	59.3	59.6	60.0
RIVERDALE TS	110.8	96.8	100.1	103.2	106.3	109.1	112.1	112.8	113.6	114.5	115.3	116.0	116.5	117.2	117.9	118.7	119.5	121.4	123.3	125.1	125.1
ROCKLAND DS	7.8	8.3	8.6	8.8	9.0	10.3	11.5	12.6	13.7	14.8	17.4	18.8	20.4	21.9	23.5	25.0	26.5	28.1	29.6	31.1	32.7
ROCKLAND EAST DS	15.5	15.3	15.9	16.4	16.9	17.4	18.0	18.5	19.0	19.6	20.1	20.7	21.3	22.0	22.7	23.3	24.0	24.7	25.1	25.4	25.8
RUSSELL DS	6.8	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.1	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.9	5.9
RUSSELL TS	72.7	72.0	76.6	78.8	78.9	79.0	79.1	79.4	79.9	80.3	81.0	81.4	81.5	81.6	81.8	81.9	92.2	92.4	92.8	93.1	93.1
SLATER TS	158.7	96.1	96.9	98.2	102.3	107.0	111.8	115.9	117.7	119.1	119.3	119.5	120.2	120.8	121.5	122.1	122.7	123.6	124.4	125.2	126.1
SOUTH GLOUCESTER DS	6.8	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.6	6.7	6.7	6.7
SOUTH MARCH TS	99.2	98.1	102.8	108.6	111.8	111.7	114.2	122.1	121.4	121.6	126.2	126.6	127.6	128.6	129.7	130.7	131.7	133.0	134.0	135.1	136.4
ST. ISIDORE TS	117.8	44.9	47.4	48.6	49.9	51.2	52.5	56.4	60.5	61.6	63.7	64.4	65.1	66.0	66.8	67.6	68.5	69.4	70.3	71.1	72.0
STEWARTVILLE TS	49.5	28.5	28.8	29.0	29.3	29.5	29.8	30.1	30.4	30.8	31.2	31.6	34.7	35.6	36.1	36.6	37.1	37.7	38.2	38.7	39.2
TERRY FOX MTS	91.7	63.3	64.2	64.9	65.7	66.4	67.2	67.0	66.9	66.9	66.9	67.0	66.7	66.5	66.3	66.0	65.9	66.3	66.8	67.3	67.8
UPLANDS MTS	57.6	29.4	33.3	40.7	43.2	44.8	45.6	46.3	47.0	47.7	48.4	49.2	50.2	50.9	51.7	52.4	53.1	53.4	53.8	54.1	54.5
WENDOVER DS	30.4	15.8	16.1	16.3	16.5	16.7	16.9	17.1	17.4	17.8	18.1	18.4	18.8	19.2	19.7	20.1	23.6	24.0	24.5	24.9	25.3
WILHAVEN DS	34.2	7.8	7.9	7.9	8.0	8.0	8.0	8.1	8.1	8.2	8.4	8.7	8.9	9.1	9.2	9.3	9.4	9.5	9.7	9.8	9.9
WOODROFFE TS	97.4	48.3	49.4	50.5	51.5	52.4	53.4	53.8	54.2	54.7	55.2	55.6	56.1	56.6	57.2	57.8	58.4	59.3	60.2	61.1	61.1

Table A.2: Greater Ottawa region –Winter - Reference Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	101.7	59.8	65.7	71.5	77.3	82.8	88.4	92.3	96.2	100.2	104.2	108.1	112.9	117.8	122.5	127.0	131.7	136.2	140.6	145.0	145.0
ALMONTE TS	125.1	52.2	53.1	54.0	54.9	55.6	60.1	61.6	62.7	63.7	64.6	65.8	67.1	68.4	69.8	71.3	72.8	74.3	75.7	77.3	78.8
ARNPRIOR TS	59.4	39.4	39.8	40.2	41.1	41.9	42.2	42.7	44.1	44.5	45.0	45.6	46.2	46.9	47.6	48.3	49.0	49.8	50.4	51.2	51.9
BILBERRY CREEK TS	95.5	54.1	46.0	38.0	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	17.1	18.7	20.3	21.9	23.4	25.0	26.1	27.3	28.5	29.7	30.9	32.2	33.6	34.9	36.2	37.6	38.9	40.3	41.7	41.7
CAMBRIAN MTS	123.5	43.7	48.4	52.9	67.3	71.5	75.6	79.0	98.8	102.2	105.7	109.2	112.1	115.0	117.8	120.6	123.5	127.7	131.9	136.2	136.2
CARLING TS	124.3	84.7	94.0	103.1	125.3	133.9	148.9	167.9	187.0	193.7	200.3	207.6	214.2	220.9	227.2	233.1	239.6	246.3	253.0	259.6	259.6
CENTREPOINT MTS	13.3	12.0	13.2	14.4	15.6	16.7	17.8	18.9	20.0	21.0	22.1	23.2	24.4	25.5	26.7	27.8	29.0	30.1	31.2	32.4	32.4
CLARENCE DS	10.5	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1
CUMBERLAND DS	8.6	5.2	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.6	6.7	6.8	6.9
CYRVILLE MTS	47.5	31.6	35.1	38.5	41.9	45.2	48.4	50.6	52.7	54.9	57.1	59.3	62.1	65.0	67.8	70.5	73.3	75.7	78.1	80.5	83.6
ELLWOOD MTS	47.0	39.5	43.6	47.7	51.7	55.6	59.5	63.0	66.5	70.0	73.5	76.9	80.5	84.2	87.7	91.0	94.6	97.9	101.3	104.6	104.6
FALLOWFIELD MTS	27.2	13.3	15.8	18.3	22.8	25.2	27.5	29.7	31.8	34.0	36.2	38.4	42.1	45.9	49.7	53.3	57.1	59.4	61.7	64.1	64.1
GREELY DS	25.2	27.1	27.4	27.7	28.2	28.5	29.0	29.4	29.7	30.1	30.6	31.3	32.3	33.2	34.2	35.1	36.1	36.7	37.1	37.1	37.1
HAWKESBURY MTS #1	18.0	13.0	13.5	13.9	14.4	14.9	15.3	15.7	16.1	16.6	17.1	17.5	17.9	18.4	18.8	19.3	19.8	20.3	20.8	21.3	21.8
HAWTHORNE TS	171.6	132.7	140.4	147.7	155.2	162.4	169.8	177.3	184.8	192.5	200.1	207.9	214.9	222.1	228.8	235.2	242.2	248.1	253.8	236.3	236.3
HINCHEY TS	95.0	54.4	62.2	69.7	77.3	84.5	91.8	96.9	102.0	107.2	112.4	117.5	123.4	129.4	135.1	140.6	146.5	151.7	156.8	161.9	161.9
HYDRO RD MTS	123.5	-	-	10.0	14.3	18.5	22.8	25.6	28.5	31.3	34.1	37.0	37.9	38.8	39.7	40.6	41.6	42.0	42.4	42.9	42.9
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	53.9	56.1	63.5	65.6	67.6	69.6	71.8	74.1	76.5	78.9	81.2	83.2	85.3	87.2	89.1	91.1	93.4	95.7	98.0	98.0
KING EDWARD TS	90.3	89.6	99.1	108.3	117.5	126.5	135.5	145.2	153.7	162.3	170.8	179.2	188.5	198.0	207.0	215.6	224.8	233.7	242.5	251.3	251.3
LIMEBANK MTS	75.0	60.9	66.8	72.6	78.4	83.9	89.4	92.9	96.5	100.1	103.9	107.6	111.4	115.3	119.1	122.9	126.7	130.6	134.5	138.4	138.4
LINCOLN HEIGHTS TS	113.1	53.8	59.0	64.0	69.1	73.9	78.7	82.5	86.2	90.0	93.9	97.7	102.3	106.9	111.4	115.8	120.3	124.2	128.2	132.1	132.1
LISGAR TS	105.1	77.0	84.6	91.8	112.8	119.8	126.8	143.3	148.8	154.4	159.9	165.3	171.3	177.3	182.9	188.2	194.1	199.5	205.0	210.4	210.4
LONGUEUIL TS	133.0	50.7	53.4	56.0	57.8	58.3	58.9	59.6	60.2	60.9	61.7	62.7	63.7	64.8	66.0	67.1	68.3	69.5	70.6	71.9	73.1
MANORDALE MTS	9.6	9.5	10.4	11.2	12.1	12.9	13.7	14.5	15.2	16.0	16.8	17.5	18.4	19.3	20.1	20.9	21.7	22.6	23.4	24.2	24.2

MANOTICK DS	10.4	12.0	12.1	12.2	12.4	12.5	12.8	12.9	13.1	13.3	13.5	13.8	14.2	14.6	15.0	15.4	15.8	16.1	16.3	16.3	16.3
MARCHWOOD MTS	32.3	32.5	35.4	38.3	41.2	43.9	46.7	48.6	50.5	52.5	54.5	56.5	58.8	61.1	63.3	65.4	67.7	69.7	71.7	73.7	73.7
MARIONVILLE DS	13.5	18.4	18.6	18.8	19.0	19.2	19.5	19.7	19.9	20.1	20.3	20.8	21.3	21.9	22.5	23.0	23.7	24.0	24.2	24.2	24.2
Mer Bleue MTS	123.5	-	-	-	75.4	81.3	87.2	91.5	95.8	100.3	104.8	109.2	114.0	118.9	123.6	128.3	133.1	138.0	142.9	147.8	147.8
MERIVALE MTS	37.3	15.4	17.3	19.1	20.9	22.7	24.5	25.8	27.2	28.7	30.1	31.4	33.0	34.7	36.2	37.7	39.3	40.7	42.2	43.6	43.6
MOULTON MTS	32.0	18.6	20.5	22.3	37.9	39.6	41.2	42.6	43.9	45.3	46.7	48.1	49.5	50.9	52.2	53.5	54.9	56.1	57.3	58.6	58.6
CTS-2	14.0	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
NRC TS	87.7	6.1	6.0	5.9	20.3	20.0	19.7	19.6	19.6	19.5	19.4	19.2	19.0	18.9	18.9	18.9	18.9	18.9	18.8	18.8	18.8
NAVAN DS	13.5	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.9	5.0	5.0	5.1	5.2	5.2	5.3
NEPEAN EPWORTH MTS	12.9	10.1	11.1	12.0	13.0	13.9	14.8	15.6	16.5	17.3	18.2	19.0	19.9	20.8	21.6	22.5	23.3	24.2	25.0	25.8	25.8
NEPEAN TS	160.7	116.4	127.3	137.8	148.4	158.7	169.0	176.2	183.5	190.9	198.1	205.2	213.9	222.9	231.2	239.1	247.8	257.1	266.3	275.6	275.6
ORLEANS TS	134.5	78.2	78.0	77.6	70.6	73.3	90.5	93.3	96.1	97.8	99.6	101.5	103.6	104.8	106.0	107.1	108.4	109.6	110.7	111.9	113.1
OVERBROOK TS	135.6	87.7	96.6	105.2	113.8	122.2	130.6	138.2	145.8	153.5	161.1	168.5	176.4	184.3	191.8	199.0	206.7	214.2	221.6	228.9	228.9
PIPERVILLE MTS	117.0	-	3.0	5.9	8.8	11.7	14.5	15.5	16.4	17.4	18.4	19.4	20.8	22.2	23.6	25.0	26.4	27.4	28.4	29.4	29.4
RICHMOND South MTS	49.0	17.9	19.5	42.2	49.9	51.2	52.5	53.7	54.9	56.2	64.7	66.0	67.3	68.7	70.1	71.3	72.7	74.1	75.5	76.9	76.9
RIVERDALE TS	117.0	97.7	107.3	116.6	125.9	134.9	144.0	150.9	157.8	164.9	171.9	178.7	186.6	194.7	202.3	209.7	217.6	224.7	231.8	238.9	238.9
ROCKLAND DS	10.5	6.9	7.2	7.4	7.6	9.0	10.2	11.3	12.5	13.6	16.2	17.8	19.3	20.9	22.4	24.0	25.6	27.1	28.7	30.2	31.8
ROCKLAND EAST DS	20.9	12.4	13.0	13.6	14.2	14.7	15.3	15.8	16.3	16.9	17.4	18.0	18.6	19.2	19.9	20.5	21.2	21.9	22.2	22.5	22.8
RUSSELL DS	8.6	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.1	6.2	6.4	6.6	6.8	6.9	7.1	7.1	7.1	7.1
RUSSELL TS	79.9	67.7	78.5	86.8	93.1	99.1	105.2	109.8	114.5	119.2	123.9	128.5	133.5	138.6	143.3	147.8	163.0	167.6	172.1	176.6	176.6
SLATER TS	163.0	89.9	94.6	99.1	103.6	107.8	112.2	116.2	120.2	124.3	128.3	132.2	137.8	143.4	148.8	153.8	159.3	164.0	168.7	173.4	173.4
SOUTH GLOUCESTER DS	8.6	5.9	6.0	6.0	6.1	6.2	6.3	6.4	6.4	6.5	6.6	6.8	7.0	7.2	7.4	7.6	7.8	7.9	8.0	8.0	8.0
SOUTH MARCH TS	113.7	98.0	105.9	111.7	119.4	123.7	132.0	142.7	147.0	150.7	158.2	162.3	167.9	172.9	178.8	183.8	189.6	193.9	198.8	203.3	208.1
ST. ISIDORE TS	124.5	47.7	50.3	51.9	53.5	54.9	56.3	57.8	59.4	60.4	62.6	63.4	64.2	65.2	66.2	67.1	68.2	69.2	70.2	69.1	70.1
STEWARTVILLE TS	56.7	27.8	28.2	28.6	29.0	29.2	29.6	29.9	30.2	30.6	31.0	31.5	34.5	35.0	35.6	36.1	36.6	37.2	37.7	38.3	38.8
TERRY FOX MTS	105.8	50.3	55.5	60.5	65.5	70.3	75.0	79.0	83.1	87.2	91.4	95.6	100.6	105.6	110.6	115.5	120.5	124.8	129.1	133.4	133.4
UPLANDS MTS	65.8	25.9	28.6	31.2	33.9	36.4	38.9	41.0	43.1	45.3	47.5	49.6	51.8	54.1	56.2	58.3	60.5	62.7	64.8	66.9	66.9
WENDOVER DS	35.1	16.2	16.6	16.9	17.2	17.4	17.7	18.0	18.2	18.7	19.0	19.4	19.8	20.2	20.7	21.1	21.6	22.0	22.5	22.8	23.3
WILHAVEN DS	41.4	7.4	7.4	7.5	7.6	7.6	7.7	7.8	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.7	8.8	8.9	9.0	9.1
WOODROFFE TS	102.4	47.6	52.6	57.4	62.2	66.8	71.5	75.4	79.4	83.5	87.6	91.6	95.1	98.6	102.0	105.3	108.8	112.8	116.8	120.8	120.8

Table A.3: Greater Ottawa region – Summer - High Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Albion TS	86.5	59.9	60.9	61.8	62.7	63.5	64.4	66.4	68.3	70.4	72.5	74.5	76.0	77.5	79.1	80.7	82.3	83.9	85.5	87.1	87.1
ALMONTE TS	96.7	55.6	56.5	57.0	57.8	58.3	64.8	64.6	65.5	70.3	73.6	73.4	74.7	76.1	77.5	78.8	80.3	81.7	83.2	84.7	86.3
ARNPRIOR TS	54.9	39.7	40.0	40.0	41.1	41.7	45.7	48.9	49.2	49.1	49.6	50.0	50.7	51.3	52.0	52.5	53.4	54.0	54.7	55.2	56.0
BILBERRY CREEK TS	85.3	64.4	65.0	65.5	14.3	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	22.4	22.7	23.0	23.4	23.6	23.9	24.5	25.1	25.8	26.4	27.1	27.6	28.2	28.7	29.3	29.8	30.4	30.9	31.4	31.4
CAMBRIAN MTS	114.0	59.8	64.7	71.3	73.8	76.1	78.3	82.5	86.0	89.6	93.3	97.0	101.1	103.1	102.5	102.7	103.3	104.1	104.8	105.5	106.2
CARLING TS	95.0	91.7	93.4	94.8	109.4	110.5	111.5	131.9	146.0	147.6	149.4	151.8	153.2	154.8	156.6	158.4	160.3	162.5	164.6	166.8	166.8
CENTREPOINT MTS	13.3	13.0	13.2	13.4	13.6	13.8	14.0	14.5	15.1	15.6	16.1	16.6	17.1	17.6	18.1	18.6	19.1	19.5	20.0	20.5	20.5
CLARENCE DS	7.8	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.1	3.1	3.2	3.2	3.3	3.4	3.4	3.5
CUMBERLAND DS	6.8	6.1	6.2	6.2	6.2	6.3	6.3	6.4	6.5	6.5	6.7	6.7	6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.8
CYRVILLE MTS	47.5	32.4	35.3	35.4	57.6	49.5	49.0	49.1	48.9	49.3	49.1	49.6	50.0	50.4	50.8	50.5	50.5	51.0	51.4	51.6	52.1
ELLWOOD MTS	47.0	41.9	46.8	48.5	48.9	50.0	49.4	49.2	49.1	49.3	49.1	49.4	49.7	50.0	50.3	50.5	50.9	51.3	51.6	51.9	52.4
FALLOWFIELD MTS	27.2	24.3	29.1	32.2	34.6	33.4	33.3	33.4	33.4	33.2	33.2	33.3	33.5	33.8	33.8	33.8	34.1	34.3	34.7	34.8	35.1
GREELY DS	20.7	22.4	22.6	22.9	23.2	23.4	23.9	24.2	24.5	24.9	25.2	25.9	26.6	27.6	28.4	29.3	30.1	30.6	30.9	30.9	30.9
HAWKESBURY MTS #1	18.0	12.2	12.4	12.5	12.7	12.8	12.9	13.0	13.2	13.3	13.5	13.7	14.0	14.3	14.6	14.8	15.1	15.4	15.7	16.0	16.4
HAWTHORNE TS	144.8	136.6	137.3	137.3	138.2	138.4	139.2	139.7	140.3	141.2	142.0	143.4	143.8	144.7	145.7	146.4	147.4	148.1	148.8	148.6	148.8
HINCHEY TS	85.6	21.9	22.5	32.8	41.4	43.4	47.0	49.2	50.6	51.5	52.2	52.6	52.2	52.3	52.3	52.1	52.2	52.9	53.4	81.7	71.1
HYDRO RD MTS	114.0	-	-	14.2	19.0	24.4	29.8	33.2	36.8	40.4	43.9	47.5	47.9	48.4	48.9	49.3	49.8	49.9	50.1	50.3	50.3
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	54.1	54.1	53.7	53.8	53.5	53.5	53.5	53.3	53.4	53.5	53.6	54.0	54.5	54.9	55.2	55.4	55.9	56.3	56.6	57.0
KING EDWARD TS	86.9	79.0	80.8	82.4	84.0	85.5	87.1	90.8	93.4	96.0	98.6	101.0	103.6	106.2	109.0	111.7	114.5	117.7	120.9	124.1	124.1
LIMEBANK MTS	75.0	51.7	60.8	66.3	71.7	72.9	74.8	76.9	78.8	80.4	81.3	82.7	84.5	86.0	87.8	89.3	90.9	91.2	91.7	92.1	92.9
LINCOLN HEIGHTS TS	99.4	46.4	46.8	47.6	48.5	49.2	50.1	51.3	52.6	53.9	55.2	56.4	57.6	58.8	60.0	61.3	62.6	63.9	65.3	66.7	66.7
LISGAR TS	83.4	78.5	80.7	82.7	98.3	100.0	101.9	112.7	112.7	112.7	112.7	113.5	113.5	113.5	113.7	113.9	114.1	115.5	116.9	118.3	118.3
LONGUEUIL TS	123.5	46.3	49.4	51.6	52.5	52.3	52.8	53.3	53.7	65.8	66.2	65.5	70.5	70.2	71.4	72.4	73.5	74.4	75.4	76.3	77.3
MANORDALE MTS	9.6	10.3	10.5	10.6	10.7	10.9	11.0	11.4	11.8	12.2	12.6	13.0	13.3	13.7	14.1	14.6	15.0	15.3	15.7	16.1	16.1
MANOTICK DS	7.7	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7	11.9	12.1	12.4	12.6	12.9	13.2	13.5	13.8	14.1	14.4	14.7	15.0
MARCHWOOD MTS	32.3	51.6	52.6	53.2	54.8	56.1	57.4	58.6	59.9	61.4	61.9	61.5	62.0	62.4	62.7	63.0	63.3	63.8	64.2	64.6	65.0

MARIONVILLE DS	13.5	15.5	15.6	15.7	15.9	16.0	16.3	16.4	16.6	16.8	17.0	17.3	17.8	18.2	18.7	19.2	19.7	20.0	20.2	20.1	20.1
Mer Bleue MTS	114.0	0.0	0.0	0.0	67.5	68.7	70.1	72.2	74.5	76.8	79.1	81.4	83.3	85.1	87.1	89.0	90.9	92.6	94.4	96.1	96.1
MERIVALE MTS	32.9	18.5	18.3	18.1	17.9	17.9	18.1	18.1	18.2	18.3	18.4	18.5	18.6	18.7	18.9	19.0	19.2	19.5	19.7	20.0	20.0
MOULTON MTS	32.0	24.4	23.9	23.5	36.8	36.8	36.7	37.0	37.3	37.7	38.0	38.3	38.6	38.9	39.2	39.5	39.9	40.2	40.6	40.9	40.9
CTS-2	14.0	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
NRC TS	77.4	5.1	5.1	5.0	17.1	16.8	16.5	16.4	16.4	16.3	16.2	16.0	15.8	15.8	15.8	15.8	15.8	15.7	15.7	15.7	15.7
NAVAN DS	13.5	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.4	5.4	5.4	5.5	5.7	5.7	5.8	5.9	6.0	6.0	6.1	6.2
NEPEAN EPWORTH MTS	12.9	12.6	12.7	12.8	12.9	13.0	13.1	13.3	13.5	13.7	14.0	14.2	14.4	14.6	14.9	15.1	15.4	15.6	15.9	16.1	16.1
NEPEAN TS	144.1	126.1	127.0	127.0	127.5	127.7	128.1	128.0	127.7	128.1	128.2	128.7	129.8	130.7	131.6	132.3	133.2	134.1	135.0	135.8	136.8
ORLEANS TS	118.2	119.6	125.4	119.9	125.6	128.1	153.8	148.5	151.2	152.6	154.4	156.7	159.7	161.1	163.0	164.8	166.7	168.7	170.4	172.2	174.2
OVERBROOK TS	116.8	89.4	91.9	94.1	96.3	98.4	100.6	103.1	105.7	108.3	110.9	113.6	115.9	118.4	120.9	123.5	126.0	128.8	131.6	134.4	134.4
PIPERVILLE MTS	108.0	0.0	2.4	4.8	7.2	9.5	11.8	12.1	12.5	12.9	13.3	13.7	14.2	14.7	15.2	15.7	16.2	16.6	16.9	17.3	17.3
RICHMOND SOUTH MTS	49.0	21.4	26.3	28.6	31.2	33.3	35.4	40.5	44.2	47.6	51.0	54.0	57.3	56.6	57.5	58.2	58.8	59.1	59.5	59.8	60.2
RIVERDALE TS	110.8	98.6	102.4	105.9	109.4	112.6	116.0	117.8	119.7	121.6	123.5	125.3	127.2	129.3	131.5	133.7	135.9	138.7	141.4	144.2	144.2
ROCKLAND DS	7.8	8.4	8.7	8.9	9.1	11.1	12.1	13.2	14.3	15.4	18.9	19.6	21.2	22.7	24.3	25.8	27.3	28.9	30.4	31.9	33.5
ROCKLAND EAST DS	15.5	15.5	16.2	16.6	17.2	17.7	18.3	18.8	19.3	19.8	20.4	20.9	21.6	22.3	23.0	23.6	24.3	25.0	25.2	25.6	26.0
RUSSELL DS	6.8	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.1	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.9	5.9
RUSSELL TS	72.7	74.2	78.9	79.0	79.8	80.4	81.2	81.6	82.2	82.8	83.6	84.2	84.7	85.1	85.6	86.1	96.7	97.5	98.4	99.3	99.3
SLATER TS	158.7	96.6	97.3	98.8	104.4	109.4	114.4	118.0	118.7	119.8	119.4	119.6	120.5	121.1	121.8	122.5	123.0	124.1	124.8	125.6	126.5
SOUTH GLOUCESTER DS	6.8	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.6	6.7	6.7	6.7
SOUTH MARCH TS	99.2	98.5	104.1	111.0	112.3	111.6	113.8	123.4	121.0	121.6	126.9	126.7	127.9	128.9	130.0	131.0	132.0	133.3	134.3	135.4	136.6
ST. ISIDORE TS	117.8	45.6	48.7	49.2	50.6	51.8	53.1	58.5	62.8	62.2	64.8	64.7	65.5	66.5	67.3	68.0	69.0	69.8	70.7	71.6	72.5
STEWARTVILLE TS	49.5	28.6	29.0	29.1	29.5	29.7	30.0	30.2	30.5	31.0	31.4	31.8	36.4	36.0	36.4	36.9	37.4	37.9	38.4	38.9	39.5
TERRY FOX MTS	91.7	63.6	64.7	65.2	66.1	66.7	67.6	66.9	66.9	66.9	66.9	67.0	66.6	66.4	66.2	65.9	65.9	66.5	67.1	67.5	68.0
UPLANDS MTS	57.6	29.8	35.6	45.2	44.5	45.7	46.0	46.7	47.3	48.0	48.7	49.7	50.7	51.2	52.1	52.8	53.5	53.6	54.0	54.3	54.7
WENDOVER DS	30.4	16.0	16.2	16.4	16.6	16.8	17.0	17.3	17.5	18.1	18.3	18.6	19.0	19.4	20.0	20.3	25.7	24.3	24.7	25.1	25.6
WILHAVEN DS	34.2	7.9	7.9	7.9	8.0	8.0	8.1	8.1	8.2	8.3	8.4	8.9	8.9	9.2	9.3	9.4	9.5	9.6	9.7	9.9	10.0
WOODROFFE TS	97.4	50.2	51.5	52.6	53.7	54.8	55.9	57.1	58.5	59.8	61.2	62.5	63.8	65.2	66.6	68.1	69.6	70.9	72.3	73.7	73.7

Table A.4: Greater Ottawa region – Winter - High Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	101.7	71.2	78.6	85.7	92.9	99.8	106.8	111.3	115.8	120.5	125.1	129.7	135.1	140.6	145.8	151.0	156.3	161.2	166.0	170.9	170.9
ALMONTE TS	0.0	52.7	53.6	54.4	55.4	56.0	62.6	62.4	63.2	64.2	65.0	66.4	67.7	69.1	70.6	72.0	73.5	75.0	76.5	78.1	79.6
ARNPRIOR TS	59.4	39.6	40.0	40.4	41.6	42.3	42.4	43.0	44.8	44.8	45.3	45.9	46.6	47.3	48.0	48.7	49.4	50.1	50.8	51.6	52.2
BILBERRY CREEK TS	95.5	62.2	67.2	72.1	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	20.5	22.6	24.6	26.7	28.6	30.6	32.0	33.4	34.8	36.3	37.7	39.3	40.9	42.5	44.0	45.6	47.1	48.6	50.1	50.1
CAMBRIAN MTS	123.5	56.0	62.5	68.9	85.2	91.2	97.2	101.3	121.8	126.0	130.3	134.6	138.3	142.0	145.6	149.3	153.0	157.7	162.5	167.3	167.3
CARLING TS	124.3	101.9	112.7	123.1	146.7	156.8	186.1	192.2	211.4	218.2	224.9	232.3	239.9	247.8	255.1	262.1	269.8	276.8	283.8	290.8	290.8
CENTREPOINT MTS	13.3	15.0	16.6	18.2	19.8	21.3	22.8	24.1	25.4	26.7	28.0	29.3	30.7	32.0	33.3	34.6	36.0	37.2	38.5	39.7	39.7
CLARENCE DS	10.5	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.1
CUMBERLAND DS	8.6	5.3	5.3	5.4	5.5	5.5	5.6	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.8	6.9	7.0
CYRVILLE MTS	47.5	38.1	42.5	46.9	51.3	55.5	59.8	62.4	65.1	67.9	70.7	73.4	76.4	79.4	82.3	85.2	88.2	90.8	93.5	96.1	96.1
ELLWOOD MTS	47.0	48.3	53.3	58.3	63.2	68.0	72.8	76.7	80.7	84.7	88.6	92.5	96.5	100.4	104.2	107.9	111.8	115.4	119.1	122.7	122.7
FALLOWFIELD MTS	27.2	19.0	22.4	25.7	31.0	34.2	37.4	40.3	43.3	46.2	49.2	52.1	55.9	59.6	63.4	67.0	70.7	73.3	75.8	78.4	78.4
GREELY DS	25.2	27.4	27.6	27.9	28.4	28.6	29.3	29.5	29.9	30.3	30.8	31.7	32.7	33.7	34.7	35.6	36.6	37.0	37.3	37.1	37.1
HAWKESBURY MTS #1	18.0	13.2	13.7	14.2	14.7	15.1	15.5	15.9	16.4	16.9	17.4	17.7	18.1	18.6	19.1	19.5	20.0	20.5	21.0	21.5	22.1
HAWTHORNE TS	171.6	150.0	158.2	166.2	174.2	182.0	190.0	197.2	204.5	211.9	219.3	226.8	234.9	243.1	250.9	258.3	266.4	272.6	278.5	285.9	285.9
HINCHEY TS	95.0	67.8	76.7	85.3	93.9	102.3	110.7	116.2	121.9	127.6	133.3	138.9	145.0	151.1	157.0	162.7	168.7	174.0	179.2	184.5	184.5
HYDRO RD MTS	123.5	-	-	10.0	14.3	18.5	22.8	25.7	28.6	31.4	34.3	37.2	38.0	38.9	39.8	40.7	41.6	41.6	41.6	41.6	41.6
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	60.3	63.1	71.2	73.9	76.5	79.1	81.1	83.1	85.2	87.2	89.2	92.0	94.9	97.6	100.2	103.0	105.4	107.9	110.3	110.3
KING EDWARD TS	90.3	108.4	119.5	130.2	141.0	151.4	162.0	172.2	181.3	190.4	199.4	208.3	218.6	228.9	238.8	248.4	258.6	267.8	277.0	286.2	286.2
LIMEBANK MTS	75.0	71.7	79.3	86.7	94.2	101.3	108.4	112.5	116.7	121.0	125.3	129.6	134.1	138.6	142.9	147.2	151.7	156.0	160.3	164.6	164.6
LINCOLN HEIGHTS TS	113.1	64.5	70.9	77.3	83.6	89.7	95.8	99.9	104.0	108.2	112.4	116.5	121.7	127.0	132.1	137.1	142.3	146.6	150.9	155.2	155.2
LISGAR TS	105.1	90.7	98.9	106.8	128.4	136.0	143.8	160.2	165.8	171.4	177.0	183.5	189.8	196.3	202.4	208.2	214.5	219.8	225.1	230.4	230.4
LONGUEUIL TS	133.0	51.2	54.8	57.4	58.6	58.5	59.2	59.9	60.6	61.3	62.2	63.2	64.2	65.4	66.5	67.7	68.9	70.1	71.2	72.5	73.7
MANORDALE MTS	9.6	11.6	12.8	13.9	15.1	16.2	17.3	18.3	19.2	20.1	21.1	22.0	23.0	24.1	25.1	26.0	27.0	28.0	29.0	29.9	29.9
MANOTICK DS	10.4	12.0	12.3	12.5	12.8	13.0	13.4	13.7	14.1	14.5	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.2	21.7	21.6	21.6
MARCHWOOD MTS	32.3	37.5	41.0	44.5	47.9	51.2	54.6	56.9	59.2	61.6	64.0	66.3	68.8	71.3	73.8	76.1	78.6	80.8	83.1	85.3	85.3

MARIONVILLE DS	13.5	18.4	18.6	18.9	19.2	19.7	19.9	20.5	20.8	21.2	21.7	22.2	23.2	24.4	25.7	27.0	28.4	30.1	30.9	31.4	31.4
Mer Bleue MTS	123.5	0.0	0.0	0.0	92.5	100.1	107.7	112.6	117.5	122.6	127.7	132.7	138.2	143.8	149.3	154.8	160.3	165.5	170.7	175.9	175.9
MERIVALE MTS	37.3	19.5	21.6	23.7	25.8	27.8	29.9	31.3	32.7	34.1	35.5	36.9	38.5	40.2	41.8	43.3	44.9	46.3	47.7	49.2	49.2
MOULTON MTS	32.0	22.0	24.1	26.2	42.0	43.9	45.9	47.3	48.7	50.2	51.7	53.1	54.7	56.2	57.7	59.2	60.8	62.1	63.4	64.8	64.8
CTS-2	14.0	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
NRC TS	87.7	6.1	6.0	5.9	20.3	20.0	19.7	19.6	19.6	19.5	19.4	19.2	19.0	18.9	18.9	18.9	18.9	18.9	18.8	18.8	18.8
NAVAN DS	13.5	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.7	4.8	4.8	4.9	5.0	5.1	5.1	5.2	5.3	5.3
NEPEAN EPWORTH MTS	12.9	12.3	13.5	14.6	15.8	16.9	18.0	18.9	19.8	20.8	21.7	22.6	23.6	24.5	25.5	26.4	27.3	28.2	29.1	29.9	29.9
NEPEAN TS	160.7	138.9	152.2	165.2	178.1	190.8	203.6	212.1	220.6	229.3	237.8	246.1	255.9	265.8	275.1	284.0	293.7	303.5	313.4	323.2	323.2
ORLEANS TS	134.5	82.9	90.3	96.7	72.2	74.7	101.0	94.7	97.6	98.6	100.4	102.5	104.6	105.4	106.6	107.7	109.0	110.2	111.3	112.6	113.6
OVERBROOK TS	135.6	105.5	116.3	126.8	137.3	147.6	157.9	166.2	174.6	183.0	191.4	199.6	208.4	217.4	225.9	234.1	242.9	250.7	258.6	266.4	266.4
PIPERVILLE MTS	117.0	0.0	3.7	7.3	10.9	14.4	17.9	19.0	20.1	21.2	22.3	23.5	25.1	26.6	28.2	29.8	31.4	32.5	33.7	34.8	34.8
RICHMOND South MTS	49.0	21.6	23.7	47.0	55.3	57.0	58.9	60.4	61.9	63.4	72.2	73.8	75.4	77.1	78.7	80.3	81.9	83.5	85.1	86.7	86.7
RIVERDALE TS	117.0	112.3	123.7	134.9	146.0	156.8	167.7	175.5	183.4	191.4	199.2	207.0	215.3	223.8	231.9	239.7	248.0	255.7	263.2	270.8	270.8
ROCKLAND DS	10.5	7.0	7.3	7.5	7.8	9.8	10.8	12.0	13.1	14.2	17.8	18.6	20.1	21.7	23.3	24.8	26.4	28.0	29.5	31.1	32.6
ROCKLAND EAST DS	20.9	12.6	13.3	13.9	14.5	15.0	15.6	16.1	16.6	17.1	17.7	18.3	18.9	19.6	20.2	20.9	21.5	22.2	22.3	22.7	23.0
RUSSELL DS	8.6	5.3	5.4	5.5	5.6	5.7	5.8	6.0	6.1	6.2	6.4	6.5	6.8	7.2	7.6	8.1	8.5	9.0	9.2	9.4	9.4
RUSSELL TS	79.9	79.2	90.5	99.5	106.3	112.9	119.6	124.2	128.8	133.5	138.1	142.6	147.7	152.9	157.8	162.4	166.9	171.4	175.8	180.3	180.3
SLATER TS	163.0	100.4	105.7	110.9	116.0	121.0	126.0	130.5	134.9	139.5	143.9	148.3	153.8	159.4	164.6	169.6	175.1	179.4	183.7	187.9	187.9
SOUTH GLOUCESTER DS	8.6	5.9	6.0	6.1	6.2	6.4	6.5	6.7	6.8	6.9	7.1	7.3	7.6	8.1	8.6	9.1	9.6	10.1	10.4	10.6	12.5
SOUTH MARCH TS		100.1	110.2	114.8	123.5	125.9	136.5	148.7	149.3	152.6	162.2	164.4	170.9	175.5	181.8	186.4	192.7	196.1	201.2	205.6	210.6
ST. ISIDORE TS	124.5	48.2	51.7	52.7	54.3	55.6	57.1	58.5	60.2	61.0	63.7	63.8	64.7	65.7	66.7	67.6	68.8	69.8	70.7	68.6	70.6
STEWARTVILLE TS	56.7	28.0	28.4	28.7	29.2	29.4	29.7	30.1	30.4	30.8	31.2	31.7	36.1	35.3	35.8	36.4	36.9	37.5	38.0	38.5	39.0
TERRY FOX MTS	105.8	62.5	69.4	76.0	82.7	89.1	95.5	100.8	106.2	111.7	117.1	122.6	127.7	132.9	137.9	142.9	148.0	152.8	157.6	162.4	162.4
UPLANDS MTS	65.8	31.7	35.0	38.3	41.5	44.7	47.8	50.1	52.5	54.8	57.2	59.5	62.0	64.6	67.1	69.5	72.0	74.3	76.6	78.9	78.9
WENDOVER DS	35.1	16.4	16.7	17.0	17.3	17.5	17.8	18.1	18.4	19.0	19.2	19.6	20.0	20.5	20.9	21.3	21.8	22.3	22.7	23.0	23.5
WILHAVEN DS	41.4	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.9	7.9	8.0	8.1	8.2	8.4	8.5	8.6	8.7	8.9	9.0	9.1	9.2
WOODROFFE TS	102.4	57.9	64.1	70.2	76.2	82.0	87.9	92.2	96.5	100.9	105.3	109.6	113.7	117.8	121.7	125.5	129.6	133.8	138.1	142.3	142.3

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Albion TS	230	M30A, M31A
2	Almonte TS	230	E34M, T33E
3	Arnprior TS	115	W6CS, C7BM
4	Bilberry Creek TS**	115	A2, H9A
5	Bridlewood MTS	115	S7M
6	Cambrian MTS	230/115	S7M, E34M
7	Carling TS	115	M4G, M5G
8	Centrepoint MTS	115	C7BM
9	Clarence DS	115	79M1
10	CTS -1	230	B5D, D5A
11	CTS-2	115	A8M
12	Cumberland DS	115	H9A
13	Cyrville MTS	115	A2, A4K
14	Ellwood MTS	230	M30A, M31A
15	Fallowfield MTS	115	S7M
16	Greely DS	115	M1R
17	Hawkesbury MTS #1	115	79M1
18	Hawthorne TS*	230/115	A6R M30A A8M H9A D5A A42T M31A A3RM A4K A2 A41T A5RK L24A
19	Hinchey TS	115	F10MV, V12M
20	Kanata MTS	230	C3S, M32S
21	King Edward TS	115	A4K, A5RK
22	Limebank MTS	115	S7M
23	Lincoln Heights TS	115	C7BM, F10MV
24	Lisgar TS	115	M4G, M5G
25	Longueuil TS	230	B5D, D5A
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M

29	Merivale MTS	115	-
30	Merivale TS*	230	M30A S7M E34M A8M M5G M32S M1R M31A F10MV C7BM A3RM M4G V12M L2M
31	Moulton MTS	115	A4K
32	National Research Council TS	115	A2
33	Navan DS	115	H9A
34	Nepean Epworth MTS	115	M5G M4G
35	Nepean TS	230	M32S
36	Orleans TS	230/115	D5A, H9A
37	Overbrook TS	115	A5RK, A6R
38	Richmond South MTS	115	S7M
39	Riverdale TS	115	A3RM, A5RK, A6R
40	Rockland DS	115	79M1
41	Rockland East DS	115	79M1
42	Russell DS	115	L2M, M1R
43	Russell TS	115	A5RK, A6R
44	Slater TS	115	A3RM, A5RK, M4G
45	South Gloucester DS	115	M1R
46	South March TS	230	C3S, M32S
47	St. Isidore TS	230	B5D, D5A
48	Stewartville TS	115	W3B, W6CS
49	Terry Fox MTS	230	E34M
50	Uplands MTS	115	A8M
51	Wendover DS	115	79M1
52	Wilhaven DS	115	H9A
53	Woodroffe TS	115	C7BM, F10MV

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hawthorne TS – Merivale TS	M30A, M31A	230
2	Hawthorne TS – St Isidore TS	D5A	230
3	Merivale TS – Almonte TS	E34M	230
4	Merivale TS – South March TS	M32S	230
5	South March SS – Chats Falls SS	C3S	230
6	Hawthorne TS – Bilberry Creek TS	A2	115
7	Hawthorne TS - Merivale TS	A3RM, A8M	115
8	Hawthorne TS – Overbrook TS	A4K, A5RK	115
9	Hawthorne TS – Riverdale TS	A6R	115
10	Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
11	Merivale TS – Chats Falls TS	C7BM	115
12	Merivale TS – Hinchey TS	F10MV, V12M	115
13	Merivale TS – Lisgar TS	M4G, M5G	115
14	Merivale TS – South March SS	S7M	115
15	Stewartville TS – South March SS	W6CS	115
16	Stewartville TS – Barrett Chute TS	W3B	115
17	Hawthorne TS – Merivale TS	M30A, M31A	230
18	Hawthorne TS – St Isidore TS	D5A	230
19	Merivale TS – Almonte TS	E34M	230
20	Merivale TS – South March TS	M32S	230
21	South March SS – Chats Falls SS	C3S	230
22	Hawthorne TS – Bilberry Creek TS	A2	115
23	Hawthorne TS - Merivale TS	A3RM, A8M	115
24	Hawthorne TS – Overbrook TS	A4K, A5RK	115
25	Hawthorne TS – Riverdale TS	A6R	115
26	Hawthorne TS – Hawkesbury MTS	H9A/79M1	115

27	Merivale TS – Chats Falls TS	C7BM	115
28	Merivale TS – Hinchey TS	F10MV, V12M	115
29	Merivale TS – Lisgar TS	M4G, M5G	115
30	Merivale TS – South March SS	S7M	115
31	Stewartville TS – South March SS	W6CS	115
32	Stewartville TS – Barrett Chute TS	W3B	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Hydro One
2	Hydro Ottawa Ltd.
3	Hydro 2000 Inc.
4	Hydro Hawkesbury
5	Ottawa River Power Corporation
6	Renfrew Hydro Inc.

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	City of Ottawa
2	City of Clarence-Rockland
3	Town of Arnprior
4	Town of Carleton Place
5	Municipality of Mississippi Mills
6	Municipality of The Nation
7	Township of East Hawkesbury
8	Township of Champlain
9	Township of Alfred and Plantagenet
10	Township of Russell
11	Township of Beckwith
12	Township of Drummond/North Elmsley
13	Township of Tay Valley
14	Township of North Frontenac
15	Township of Lanark Highlands
16	Township of McNab/Braeside
17	Township of Greater Madawaska

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	Electricity Demand Side Management
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.

NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station
TAO	Transmission Asset Owner
TWG	Technical Working Group

APPENDIX E – GREATER OTTAWA REGION NEEDS ASSESSMENT

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Greater Ottawa

Date: December 20, 2022

Prepared by: Greater Ottawa Region Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Ottawa Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group (TWG) for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that:
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Executive Summary

REGION Greater Ottawa Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: August 23, 2022 **END DATE:** December 20, 2022

1. INTRODUCTION

The second regional planning cycle for the Greater Ottawa Region was completed in December 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of regional planning for the region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
(i) require further assessment and regional coordination (and hence, proceed to the next phases of regional planning); and,
ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") met in April 2022 and decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the Greater Ottawa Region NA includes:

a) Reaffirm and update needs/plans identified in the previous regional planning cycle RIP;
b) Identify any new needs resulting from this assessment;
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and Regional Infrastructure Plan (RIP), based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. INPUTS/DATA

The TWG representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Greater Ottawa Region regarding capacity needs, system reliability, operational issues, and major high-voltage (HV) transmission equipment requiring replacement over the planning horizon.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

6. NEEDS

I. Update on needs identified during the previous regional planning cycle

The following needs and projects discussed in the Greater Ottawa 2nd Cycle RIP report have been completed:

- Hawthorne T5/T6 autotransformer replacement was completed in 2021;
- King Edward TS transformer T3 replacement was completed in 2021;
- Cambrian MTS was in-serviced in 2022;
- Overbrook TS LV transformer cable capacity limitation review. Hydro One has completed its review of the LV cables and determined they are not limiting the station LTR.

a) 115kV Transmission Supply Capacity

- L2M Supply Capacity: The loading line section between Merivale TS and Limebank MTS has been reassessed is expected to reach its limit in 2031 based on the net extreme summer weather coincident peak load forecast.

b) Transformation Capacity

- Kanata-Stittsville Capacity: Based on the net extreme summer weather non-coincident peak load forecast, Marchwood MTS, Kanata MTS and Terry Fox MTS are expected to exceed their respective station capacity limits during the study period.

c) Voltage Performance

- Monitor voltage on line 79M1. As a result of the long distance and circuit loading on 115 kV circuit 79M1, lower voltage is expected at the end of the line.

The remaining near/medium-term needs and projects discussed in the Greater Ottawa 2nd Cycle RIP report are underway and an update on their status is discussed in section 7 of this report.

II. Newly identified needs

The following are new needs that were identified as part of this assessment:

d) Asset Renewal for Major HV Transmission System Equipment

Based on asset condition assessment, the following asset renewal needs have been identified over the planning horizon:

- Lisgar TS: Replace transformer T1
- South March TS: Replace transformers T1/T2
- S7M Line Refurbishment

e) Transformation Capacity

- Many areas are growing and have stations near or exceeding their limits, please refer to the load forecast in Appendix A. While load transfers can mitigate the need in the near term, station capacity should be reviewed as part of this cycle.

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) Further assessment and regional coordination is required in the next phases of the regional planning cycle to develop a preferred plan for the following needs:
   - Asset renewal needs for South March TS and Lisgar TS to right-size the transformer replacement (discussed in sections 7.1.1 and 7.1.2);
   - Asset renewal needs for sections of circuit S7M to determine prefer supply configuration for the area (discussed in section 7.1.4);
   - L2M Supply Capacity (discussed in section 7.2.2); and,
   - Review of station transformation capacity, including the Kanata-Stittville capacity need (discussed in section 7.2.3).

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1 INTRODUCTION

The second cycle of the Regional Planning process for the Greater Ottawa Region was completed in December 2020 with the publication of the Regional Infrastructure Plan ("RIP") Report.

The purpose of this Needs Assessment ("NA") is to identify any new needs in the region, reaffirm and update needs identified in the previous Greater Ottawa regional planning cycle, and recommend which needs require further assessment and regional coordination and which do not.

This report was prepared by the Greater Ottawa Region Technical Working Group ("TWG"), led by Hydro One Networks Inc. Participants of the TWG are listed below in Table 1. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: Greater Ottawa Region TWG Participants

1	Hydro 2000
2	Hydro Hawkesbury
3	Hydro One Networks (Distribution)
4	Hydro One Networks (Lead Transmitter)
5	Hydro Ottawa Limited
6	Independent Electricity System Operator
7	Ottawa River Power Corporation
8	Renfrew hydro

2 REGIONAL ISSUE/TRIGGER

In accordance with the regional planning process, the regional planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the TWG met in April 2022 and decided that the third Regional Planning cycle be triggered in advance of the 5-year period.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Greater Ottawa region and includes:

- Reaffirm and update needs/plans identified in the previous regional planning cycle RIP;
- Identify any new needs resulting from this assessment;
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The TWG may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), IRRP, and/or RIP based on best available information at that time.

The planning horizon of this NA assessment is 10 years.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the west to Hawkesbury in the east and north of Highway 43. At the center of this Region is the City of Ottawa. Please see Figure 1 for the map of the Greater Ottawa region. Electrical supply to the region is provided from fifty-two (52) 230kV and 115kV step-down transformer stations.

Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230kV autotransformers at Hawthorne TS and a network of 230kV and 115kV transmission lines and step-down transformation facilities.

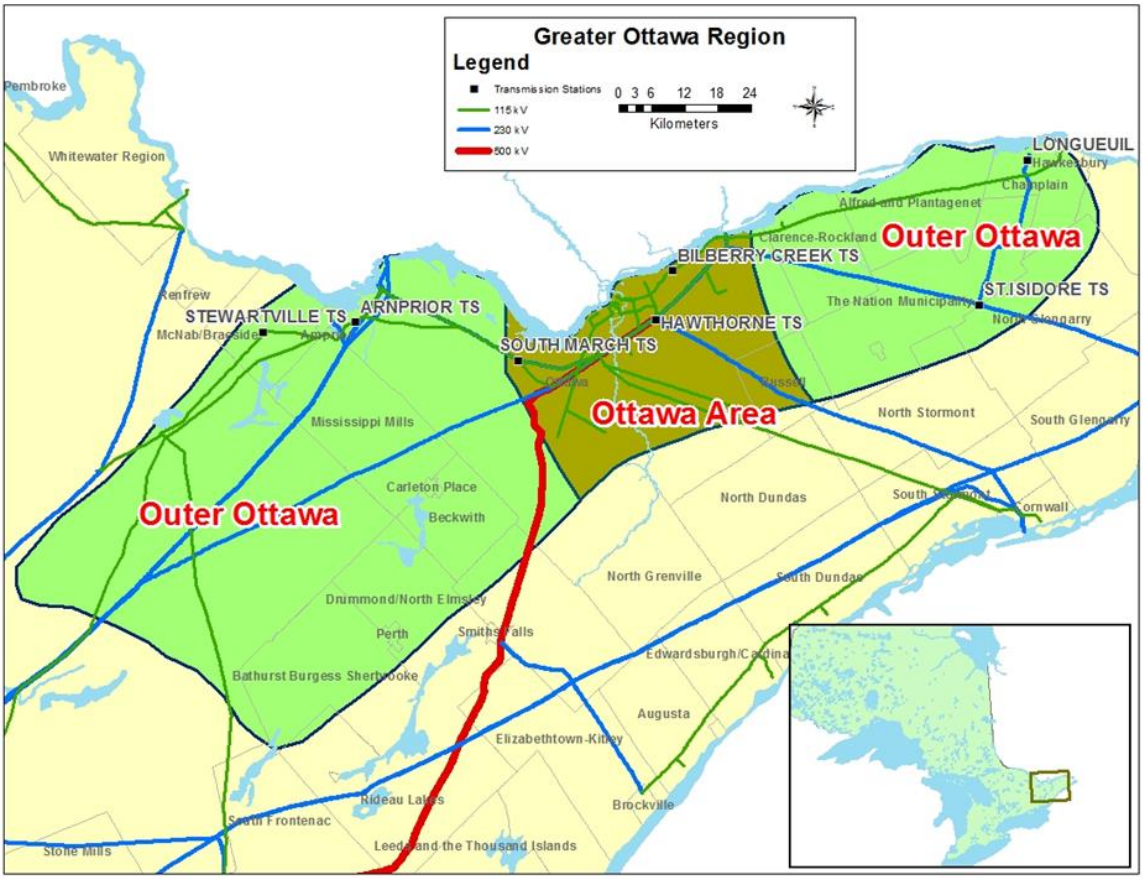


Figure 1: Map of Greater Ottawa Regional Planning Area

As shown in Figure 1, the region is divided into two (2) subregions: The Outer Ottawa and Ottawa Area subregions.

The Ottawa Area Sub-region comprises primarily the City of Ottawa. It is supplied by two (2) 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS), eight (8) 230 kV and thirty-three 115 kV transformer stations stepping down to a lower voltage. Local generation in the area consists of the 74 MW Ottawa Health Science Non-Utility Generator ("NUG") located near the downtown area and connected to the 115 kV network. The Ottawa Area Sub-region is shown in Figure 2 below. Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to end users, including industrial, commercial, and residential customers.

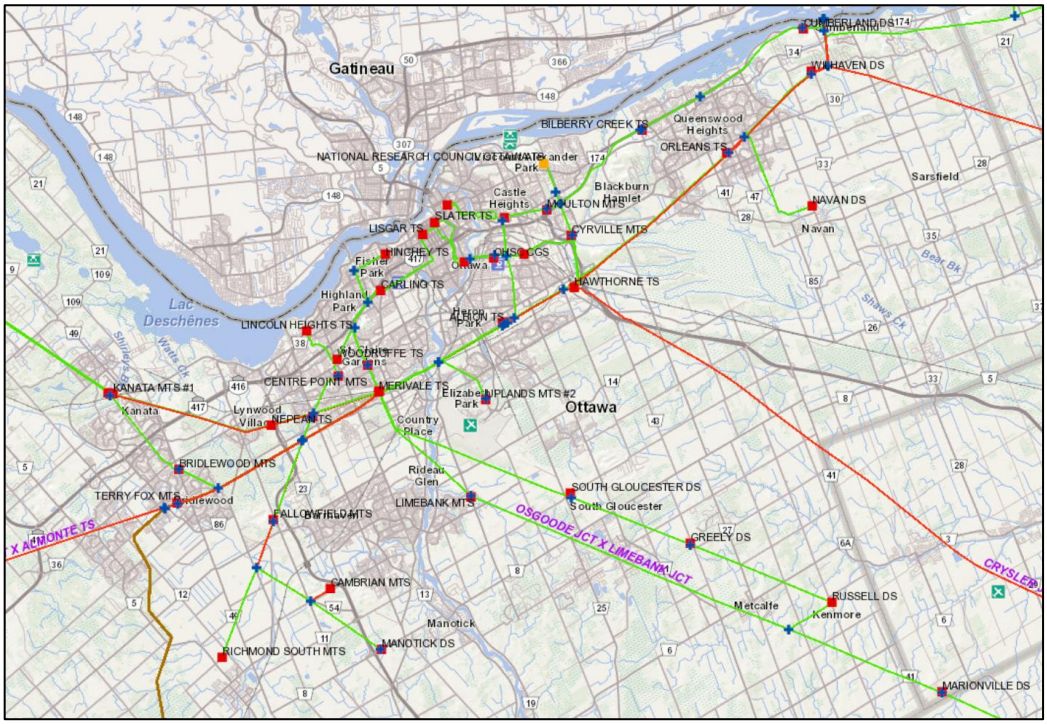


Figure 2: Ottawa Area Sub-region Map

The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area (shown in Figure 3) is served by three (3) 230kV and five (5) 115kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to their end use customers. Hydro 2000 is embedded LDC that supplies its customers from Longueuil TS via Hydro One Distribution's 44kV feeders. This area also includes a large industrial customer in L'Orignal, Ontario.

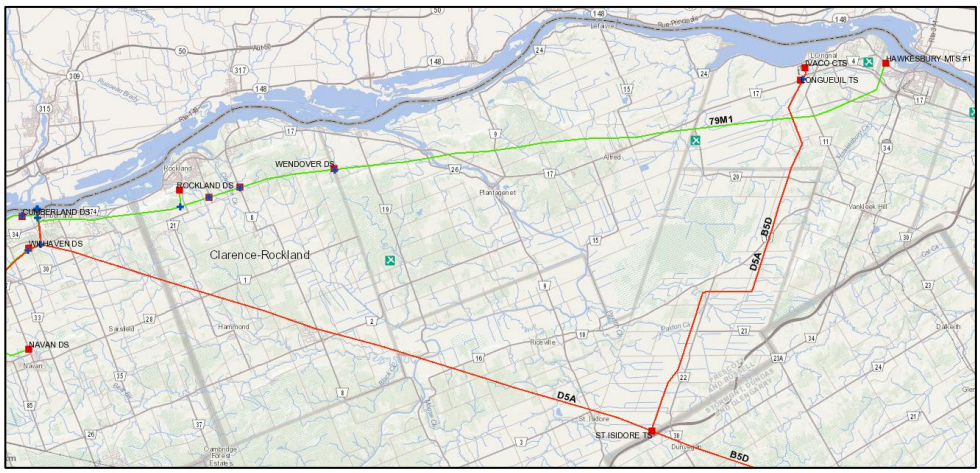


Figure 3: Outer Ottawa Sub-region Map (Eastern Area)

The western area of the Outer Ottawa Sub-Region, shown in Figure 4, is served by one (1) 230kV and two (2) 115kV step-down transformer stations. Hydro One Distribution is the LDC that supplies its end use customers from these stations. Ottawa River Power Corp. is embedded LDC that supplies its customers from Almonte TS via Hydro One Distribution's 44kV feeders. Renfrew Hydro is embedded LDC that supplies its customers from Stewartville TS via Hydro One Distribution's 44kV feeders. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS, and Stewartville GS with a peak generation capacity of about 450 MW.

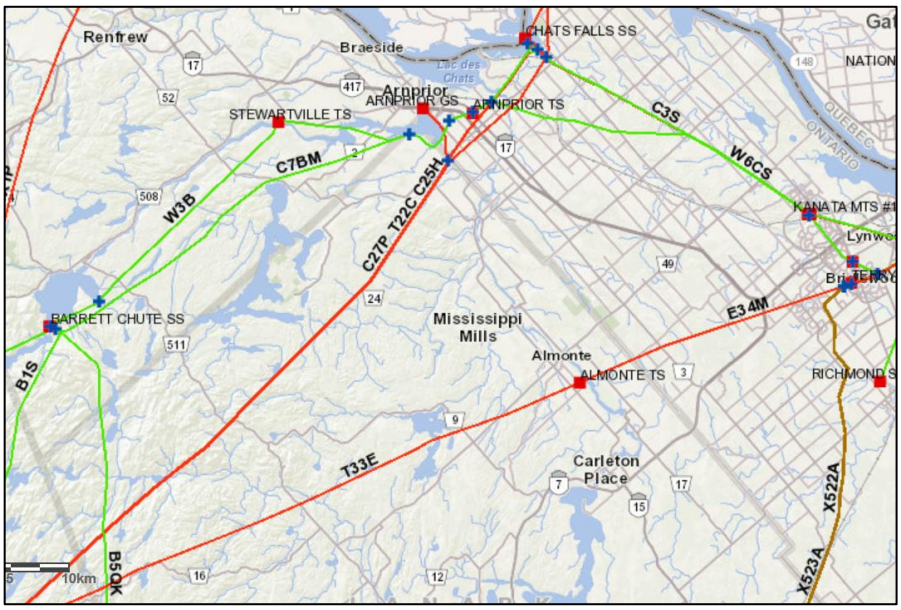


Figure 4: Outer Ottawa Sub-region Map (Western Area)

The existing Greater Ottawa Region transmission single line diagram is shown in Figure 5 below.

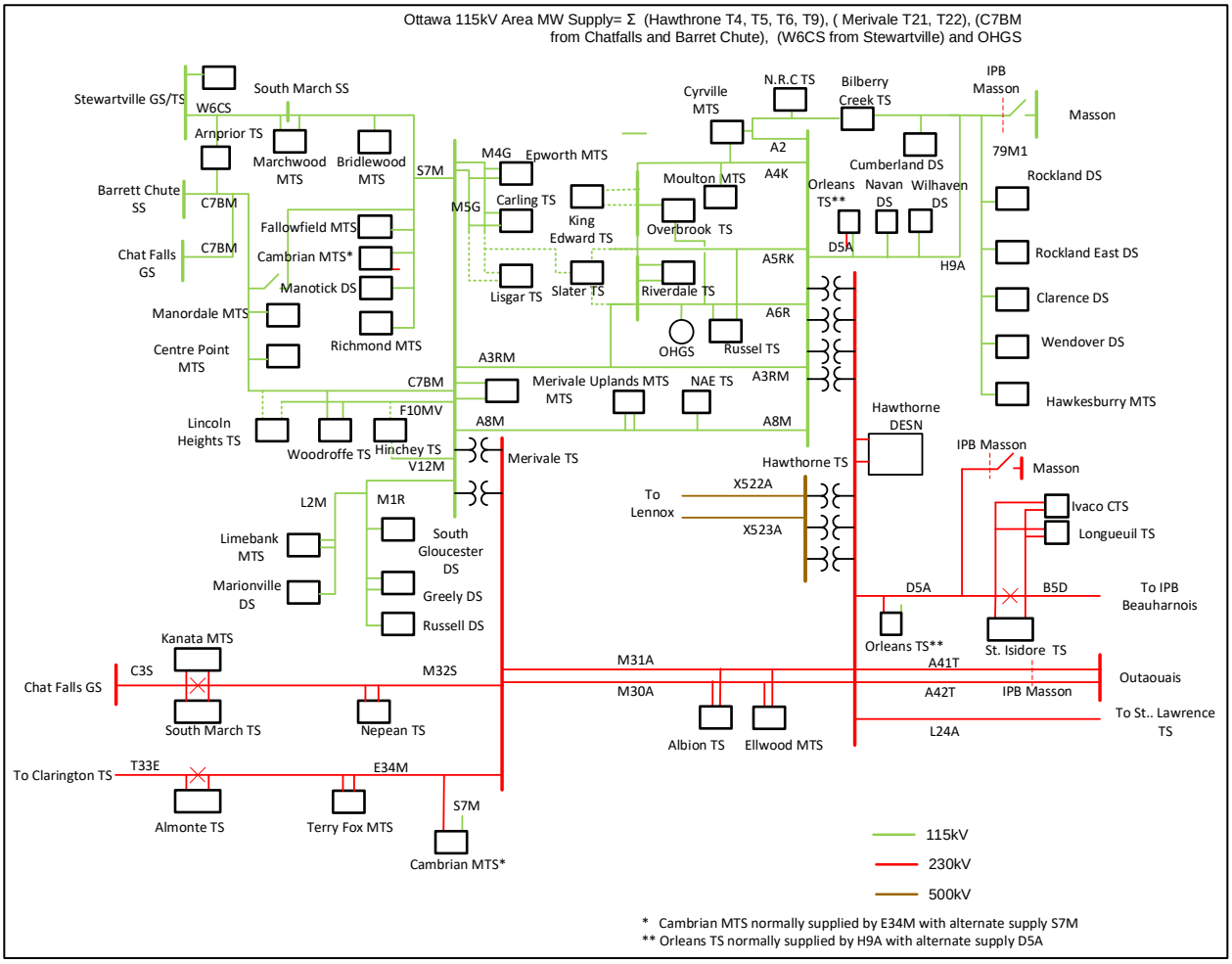


Figure 5: Greater Ottawa Region Single Line Diagram

5 INPUTS AND DATA

Technical Working Group (TWG) participants, including representatives from LDCs, IESO, and Hydro One, provided information and input for the Greater Ottawa NA. The information provided includes the following:

- Greater Ottawa Load Forecast for all supply stations;
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Greater Ottawa Region.

With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). Accordingly, the OEB RPPAG also recently developed a guideline called "Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector", which lists the key MEP/CEP outputs to improve LDC load forecasts going forward. Hydro One has undertaken a screening of CEPs in the area, such as the City of Ottawa CEP and found some visionary information to reduce greenhouse gases that could have an impact due to electrification. The TWG recommends that further engagement and analysis be undertaken during the next phases of regional planning.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the Greater Ottawa region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Greater Ottawa region. The region's extreme summer non-coincident peak gross load forecast for each station was prepared by applying the LDC load forecast growth rates to the actual 2021 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It should be noted that as contracts for existing DG resources in the region begin to expire, there will be a decreasing contribution from local DG resources at that point and hence, an increase in net demand. The extreme summer weather corrected net non-coincident peak load forecast for the individual stations in the Greater Ottawa region is given in Appendix A Table A.1. The extreme summer weather corrected net coincident peak load forecast for the individual stations in the Greater Ottawa region is given in Appendix A, Table A.2.

- Sensitivity Analysis: A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.
- Relevant information regarding system reliability and operational issues in the region; and
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for regional planning purposes. The scope of equipment considered is given in section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment;
- System reliability assessment and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Sensitivity analysis to capture uncertainty in the load forecast.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2022-2031.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Transmission system adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Output of generating stations in the area is based on 98% dependable generation availability for transmission connected run of river hydro-electric stations as per Ontario Resource Transmission Assessment Criteria (ORTAC) criteria.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC) considering normal and N-1 supply condition.

In addition, several developments since the completion of the last RIP are considered in this report.

- Planned connection of a new Hydro Ottawa 230kV/44kV station near Hawthorne TS on 230kV circuits M30A/M31A to supply a large industrial customer load.
- The Gatineau Corridor EOL Study Report (Gatineau Report) was completed. For the Ottawa area, the recommendations include the refurbishment of sections of 230kV circuit T33E, and up to 230MW of additional system cost-effective energy efficiency in the Ottawa area.

- The Ottawa 115kV System Supply studies recommendations is nearing completion. Based on its recommendation and following discussions between IESO and Hydro One, a third autotransformer will be installed at Merivale TS.
- IESO, Hydro Ottawa and Hydro One reviewed the east Ottawa supply, especially Bilberry Creek TS and Orleans TS. Findings of this study will be published as part of the Ottawa 115kV System Supply study mentioned above. Based on the recommendations of the report, Bilberry Creek TS will be retired instead of refurbished. Transformation capacity will be provided by a new 230kV supply, the connection of a new station and upgrade to existing Orleans TS. The planned in-service for this system configuration change is end of 2027. The existing system and new systems considered are shown in Figure 6, 7, and 8 below. At the time of completing this NA report, the decision on which 230kV supply configuration was not finalized, but system configuration shown in Figure 7 was assumed. Please note, Figure 7 is one of the options considered which changes the 115kV system configuration.

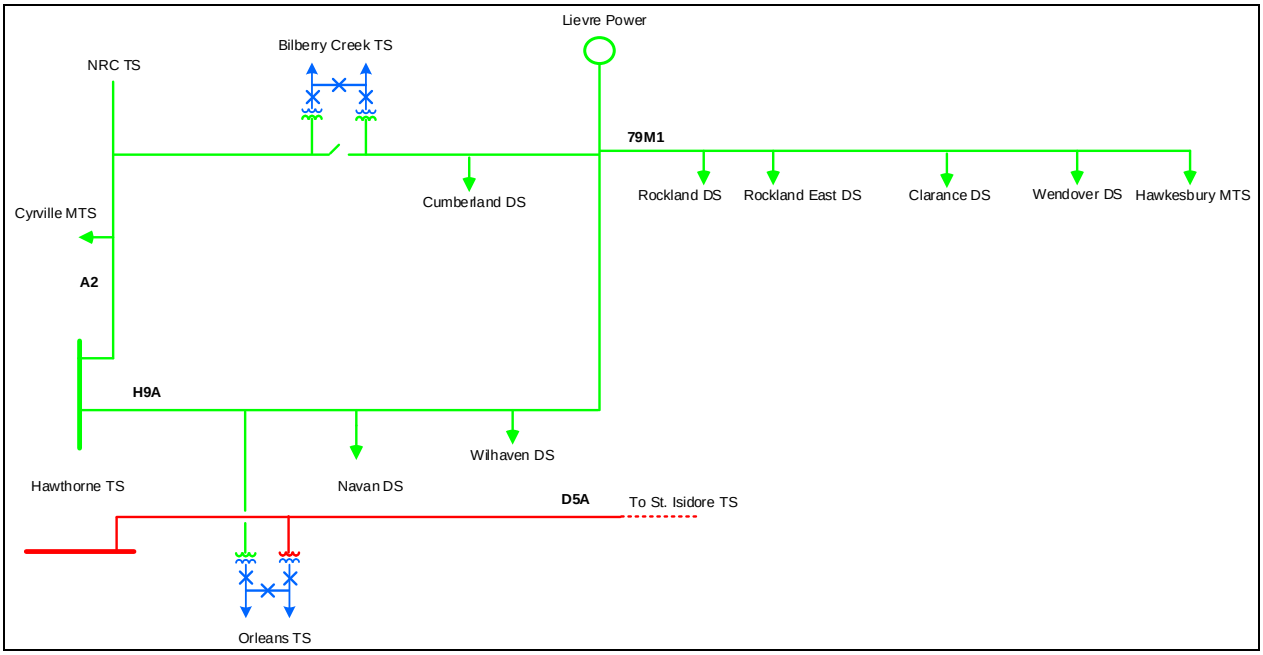


Figure 6: Existing east Ottawa system (red – 230kV; green 115kV).

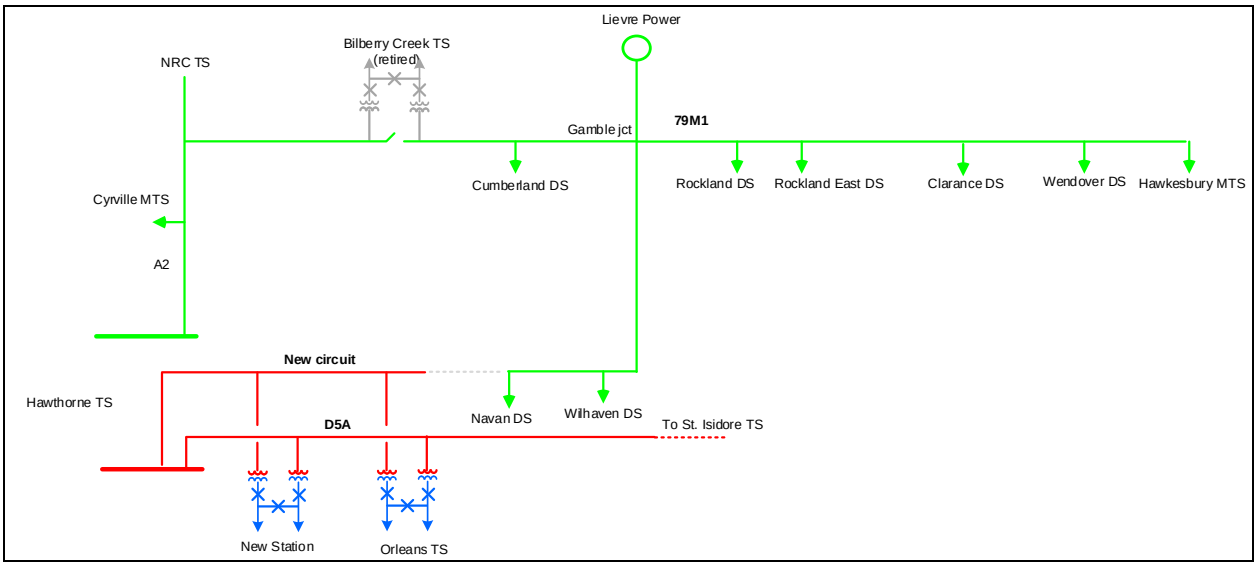


Figure 7: Proposed East Ottawa system configuration - Option 1 (red – 230kV; green 115kV).

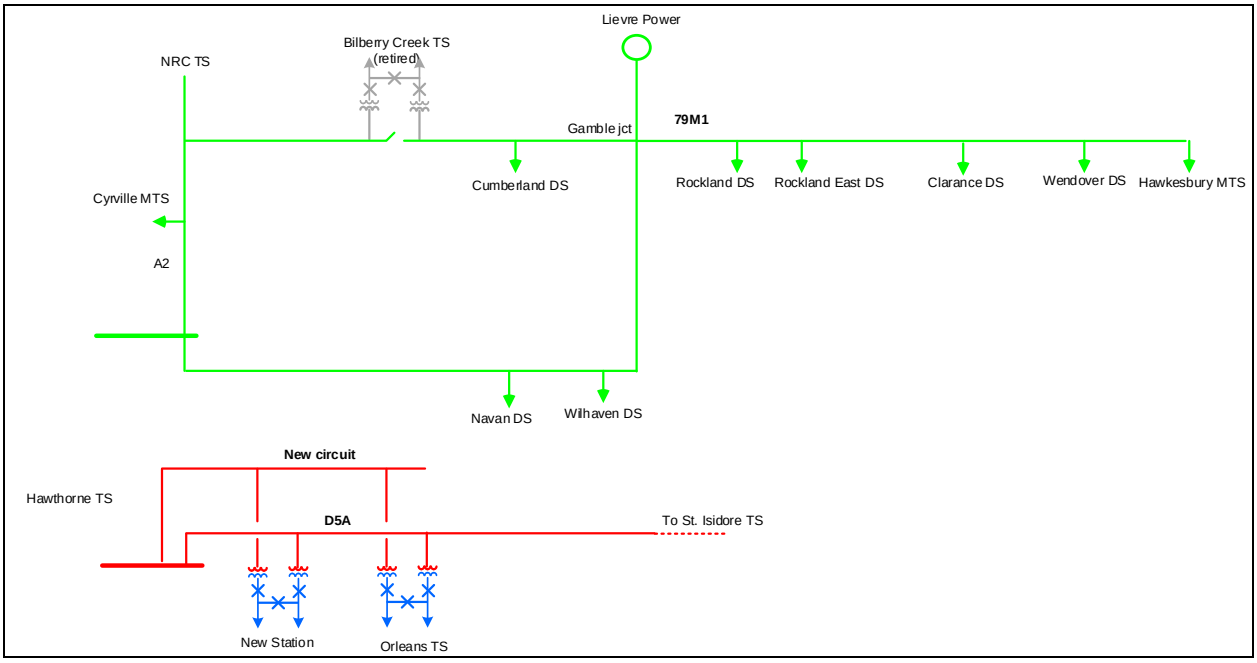


Figure 8: Proposed East Ottawa system configuration - Option 2 (red – 230kV; green 115kV).

7 NEEDS

This section identifies any new emerging needs in the Greater Ottawa Region, and reaffirms and provides an update on near, and mid-term needs identified in the previous regional planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed or underway were reaffirmed and are briefly described below with relevant updates. Asset renewal projects took "right-sizing" into consideration. These projects include:

1. Hawthorne T5/T6 autotransformer replacement was completed in 2021.
2. King Edward TS transformer T3 replacement was completed in 2021.
3. Cambrian MTS was in-serviced in 2022.
4. Overbrook TS LV transformer cable capacity limitation review. Hydro One has completed its review of the LV cables and determined they are not limiting the station LTR.
5. Arnprior TS: Project for like-for-like replacement of transformers T1/T2. The planned in-service date is 2023.
6. M30A/M31A: This capacity upgrade project is intended to increase the power interface limit between Hawthorne TS and Merivale TS by replacing the existing conductor with new twin-bundled 1843.2 kcmil conductor. The project is underway and is being led by Hydro One. The planned in-service date is 2023.
7. Slater TS: Project for replacement of transformers T2/T3 is currently underway and is being led by Hydro One in coordination with Hydro Ottawa. The existing transformers will be upgraded to 60/80/100 MVA unit. The planned in-service date is 2024.
8. Lincoln Heights TS: Project for like-for-like replacement of transformers T1/T2 is underway and is being led by Hydro One in coordination with Hydro Ottawa. The planned in-service date is 2024.
9. Russell TS: Project for replacement of transformers T1/T2 is underway and is being led by Hydro One in coordination with Hydro Ottawa. The transformers will be upgraded with 60/80/100MVA units. The planned in-service date is 2026-2028.
10. Longueuil TS: Project for replacement of transformers T1/T2 is underway and is being led by Hydro One in coordination with Hydro One Distribution. The previous RIP mentioned that the transformers will either be replaced with like-for-like units or upgraded to 75/100/125MVA units. Hydro One and Hydro One Distribution decided to replace both transformers with new like-for-like 50/66.7/83MVA units which will be sufficient based on the current load forecast. The planned in-service date is 2025-2027.
11. Riverdale TS: Project for replacement of two 115kV circuit breakers is underway and is being led by Hydro One in coordination with Hydro Ottawa. The planned in-service date is 2030, but subject to change based on coordination with Hydro Ottawa's planned work at the station.
12. Albion TS: Project for replacement of transformers T1/T2 with standard size 60/80/100MVA units is underway and is being led by Hydro One in coordination with Hydro Ottawa. The planned in-service date is 2031-2033.
13. Hawkesbury MTS: Project for transformer upgrade with a new 15MVA transformer unit is underway and is being let by Hydro Hawkesbury. The planned in-service date is 2026.

14. Transformation Capacity in South East Ottawa: A new 230kV station connecting to 230kV L24A. This project is underway and is being led by Hydro Ottawa. The planned in-service date in 2026.
15. Merivale TS: project to replace autotransformer T22, six (6) 230kV circuit breakers and four (4) 115kV circuit breakers, and the installation of a new autotransformer T23 is underway and is being led by Hydro One. The in-service date is 2026-2028.

Note: The planned in-service year for the above projects is tentative and is subject to change.

All other near and mid-term needs are summarized in Table 2 below.

Table 2: Near/Medium Term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
South March TS: transformer T1/T2 transformer replacement	New need identified to replace the two station transformers.	N/A	7.1.1
Lisgar TS: transformer T1 asset replacement.	New need identified to replace transformer T1	N/A	7.1.2
Bilberry Creek TS: transformers T1/T2 and addition of two new LV circuit breakers for Hydro Ottawa.	Plan for Bilberry Creek TS changed based on TWG decision. The station is now planned to be retired. New 230kV circuit, upgrade to Orleans TS, and a new station is now planned. In-service in 2027.	7.6	7.1.3
S7M: line refurbishment	Full line refurbishment plan from Manotick JCT to Richmond MTS, and STR 673N JCT to Manordale JCT	7.1 of second cycle NA	7.1.4
Capacity Needs			
L2M Supply Capacity	Line section between Merivale and Limebank overload. To be reviewed as part of this cycle of regional planning.	7.4	7.2.2
Kanata-Stittsville Area Capacity	Load growth at Marchwood MTS, Kanata MTS and Terry Fox MTS exceeding transformation capacity. Managed through load transfers in short term. Long term solution to be evaluated in this cycle of regional planning	7.2	7.2.3
Voltage Performance Needs			
79M1 voltage	Low voltage at end of circuit.	7.7	7.3.1

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle RIP report (shown in table 4 below), Hydro One and the TWG have identified some new major HV equipment replacement needs over the next 10 years in the Greater Ottawa Region (shown in Table 3 below). These needs are determined by asset condition assessment, which is based on a range of considerations such as equipment deterioration; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. The scope, timing, and prioritization of these replacement needs are based on current available information and are subject to change.

The major high voltage transmission equipment considered in this assessment includes the following:

1. 230/115kV autotransformers;
2. 230 and 115kV load serving step-down transformers;
3. 230 and 115kV breakers where:
    - Replacement of six breakers or more than 50% of station breakers, the lesser of the two
4. 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like.
5. 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like.

The asset renewal assessment considers options for "right-sizing" the equipment such as:

- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all the load to other existing facilities;
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement); and,
- Replacing equipment with higher ratings and built to current standards.

Table 3: New Asset Renewal Needs over the next 10 years

Station	Timing	Need Description	NA Section
South March TS: Transformers T1/T2	2030-32	T1/T2 requires replacement in the medium term.	7.1.2
Lisgar TS: Transformer T1	2031-33	T1 requires replacement in the medium term.	7.1.3

Table 4: Previously identified Asset Renewal Needs occuring over the next 10 years

Station/Circuit	Needs & Recommended Plan	Planned ISD	Previous RIP Report Section
Arnprior TS	Asset replacement need of T1/T2 Transformers: Replace with new 25/33/42 MVA Transformers	2023	4
Slater TS	Asset replacement need of T2/T3 Transformers: Replace with new 60/80/100 MVA Transformers	2024	4
S7M	Line refurbishment: Full line refurbishment plan from Manotick JCT to Richmond MTS, and S7M N1 JCT to Manordale JCT	2024	7.1 of second cycle NA
Lincoln Heights TS	Asset replacement need of T1/T2 Transformers: Replace with new 45/75 MVA Transformers	2024	7.10
Russel TS	Asset replacement need of T1/T2 Transformers: Replace with new 60/100 MVA Transformers	2026/2028	7.14
Longueuil TS	Asset replacement need of T3/T4 Transformers: Replace with new 50/83 MVA Transformers	2025-2027	7.11
Merivale TS	Asset replacement need of T22 autotransformer, 230kV breakers and 115kV oil circuit breakers: Replace with new assets and addition of autotransformer T23 for capacity upgrade.	2026-2028	7.5
Riverdale TS	Asset replacement need of 115kV breakers: Replace with new 115kV breakers	2030	7.12
Albion TS	Asset replacement need of T1/T2 Transformers: Replace with new 60/100 MVA Transformers	2031-2033	7.13
Bilberry Creek TS	Asset replacement need of T1/T2 transformers: Plan modified since the previous RIP, TWG decided to retire the station, and a new station is now planned.	2027	7.6 & 7.1.3 of this NA

Note: The planned in-service year for the above projects is tentative and is subject to change.

7.1.1 South March TS

South March TS is supplied from 230kV circuits M32S and C3S. The station supplies Hydro Ottawa and Hydro One Distribution customers.

The station has two (2) 230kV/44kV, 50/67/83MVA transformers that were in-serviced in 1971 and based on their asset condition are in need of replacement. The in-service date will be determined as the project definition progresses and is tentatively planned for 2030-2032. The station LTR is 116.2MW and based on the non-coincident load forecast it is expected to be exceeded by 2026.

The TWG recommends that the capacity need for the area be further reviewed to determine if the transformers should be replaced with similar 50/67/83MVA units or if the size should be upgraded to 75/100/125MVA units.

7.1.2 Lisgar TS

Lisgar TS is a transformer station located in the City of Ottawa. The station is supplied by two 115 kV circuits, M4G and M5G. The station supplies electricity to Hydro Ottawa customers. The 10-day summer LTR of the station is 74.7MW. Based on the non-coincident forecast, the station capacity is reached in 2026.

Transformer T2 at the station was replaced in 2011 due to a failure. Transformer T1 was in-serviced in 1974 and based on its asset condition needs replacement. The two (2) transformers at the station are 115kV/13.8kV/13.8kV, 45/60/75MVA transformers. The in-service date will be determined as the project definition progresses and is tentatively planned for 2031-2033 for the replacement of transformer T1.

The TWG recommends the capacity need for the area be further reviewed to determine if the transformer should be replaced with a 45/60/75MVA unit or upgraded to 60/80/100MVA unit.

7.1.3 Bilberry Creek TS

Bilberry Creek TS is a transformer station supplied by two (2) 115 kV circuits A2 and H9A from Hawthorne TS. The station supplies electricity to Hydro Ottawa and Hydro One Distribution customers. The two (2) 50/67/83.3MVA transformers T1 and T2 are 61 years old.

The previous cycle of regional planning had recommended Hydro One proceed with the replacement of the transformers based on asset condition assessment. In addition, two (2) new 27.6kV circuit breakers were to be installed to address Hydro Ottawa's load growth. However, since the completion of the last RIP in 2020, the IESO, Hydro Ottawa and Hydro One met to discuss load growth in the area and other options to supply the growing load in east Ottawa.

An IESO-led study has reviewed different options to address the load growth. Based on the findings of the study, the plan for the area has changed and it was determined that Bilberry Creek TS is no longer required and will be retired. The station will be replaced by a new Hydro Ottawa owned station to serve Hydro Ottawa's load in the area, and by the conversion of existing station Orleans TS to a full 230kV DESN with increased capacity (from its current 230kV and 115kV supply). Please see Figure 6, 7, and 8.

Based on the recommendation of the IESO-led study, the work planned at Bilberry Creek will not proceed. The in-service date for the proposed new supply for the area will be determined as the project definition progresses and is tentatively planned for in-service date by end of 2027.

7.1.4 S7M Circuit Refurbishment

The previous cycle Needs Assessment identified sections of S7M that needs replacement based on their asset condition. Two sections identified were rebuilt as part of the connection of Cambrian MTS. The remaining two sections are shown in Figure 9 and listed below:

- Manotick Jct x Richmond MTS (about 5.2km)
- STR 673N Jct x Manordale MTS (about 1.4km)

These line sections are currently planned for refurbishment in 2024. There is development anticipated in the area that could require change to the supply configuration. The TWG recommends that the need be further reviewed to determine preferred supply option for the area.

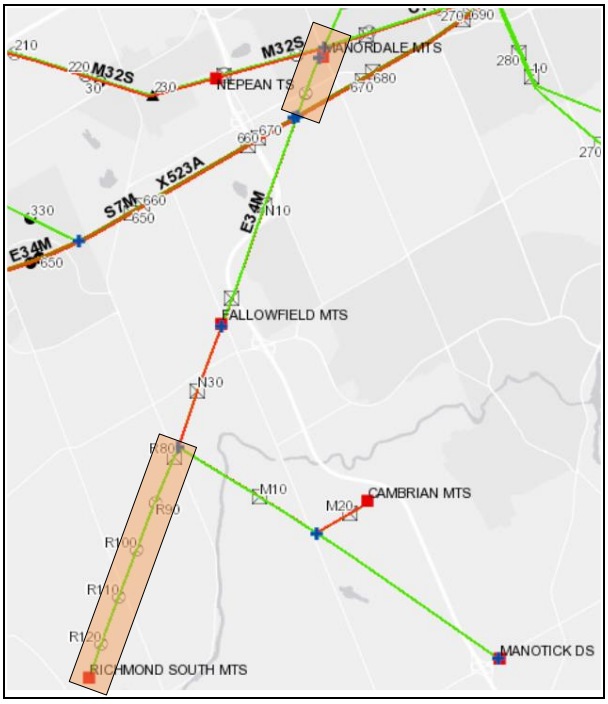


Figure 9: 115kV Circuit S7M with Sections Requiring Replacement Identified.

7.2 Station and Transmission Capacity Needs in the Greater Ottawa Region

The station and transmission supply capacities have been reviewed and the following needs have been identified in the Greater Ottawa region during the study period of 2022 to 2031.

7.2.1 230/115 kV Autotransformers

Almost sixty percent of the Region load is supplied from the 115 kV transmission system. The primary source of 115 kV supply is from 230/115 kV autotransformers at Hawthorne TS and Merivale TS. Additional support is provided from 115 kV generation at Barrett Chute GS, Stewartville GS, part of Chats Falls GS, and the Ottawa Health Science NUG and the Ottawa River generation at Chaudière as well as distributed generation.

The loading of the autotransformers is sensitive to the availability and dispatch of hydraulic generation from Barrett Chute GS, Stewartville GS, and Chats Falls GS from which the results are based on 98% dependable generation availability as per ORTAC criteria. This corresponds to about 31 MW of available generation.

The previous RIP identified overloading of the continuous and LTR rating of the autotransformers at Merivale TS. Using the coincident forecast, the loading of the autotransformers is shown in Figures 10 and 11 below. As discussed in Section 6, the Ottawa 115kV study is recommending the addition of a third

autotransformer at Merivale, in addition to the replacement of existing autotransformer T22 which was recommended for replacement in the past IRRP. The results shown below have taken into consideration these recommendations and are assuming new T22 and T23.

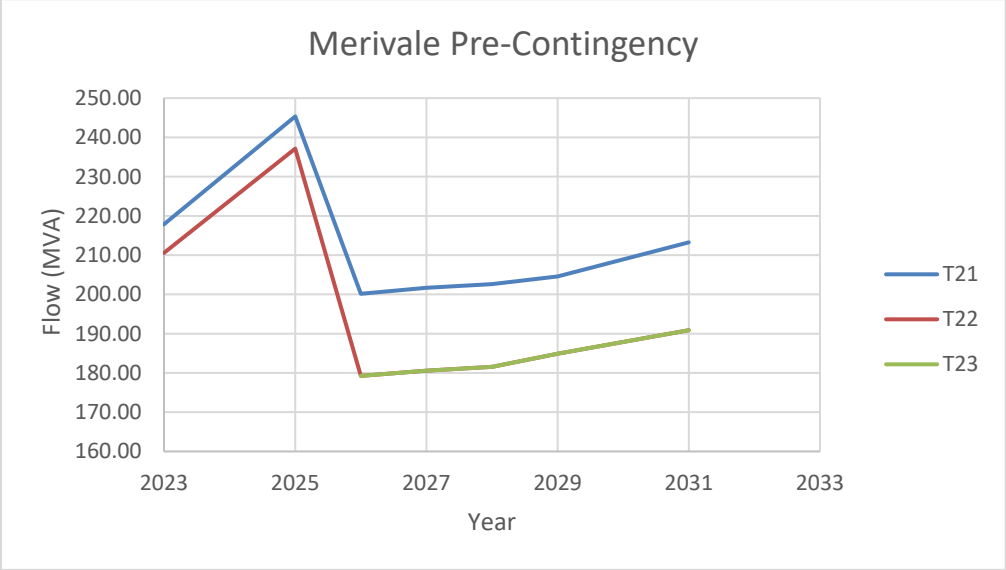


Figure 10: Merivale autotransformer loading under normal condition.

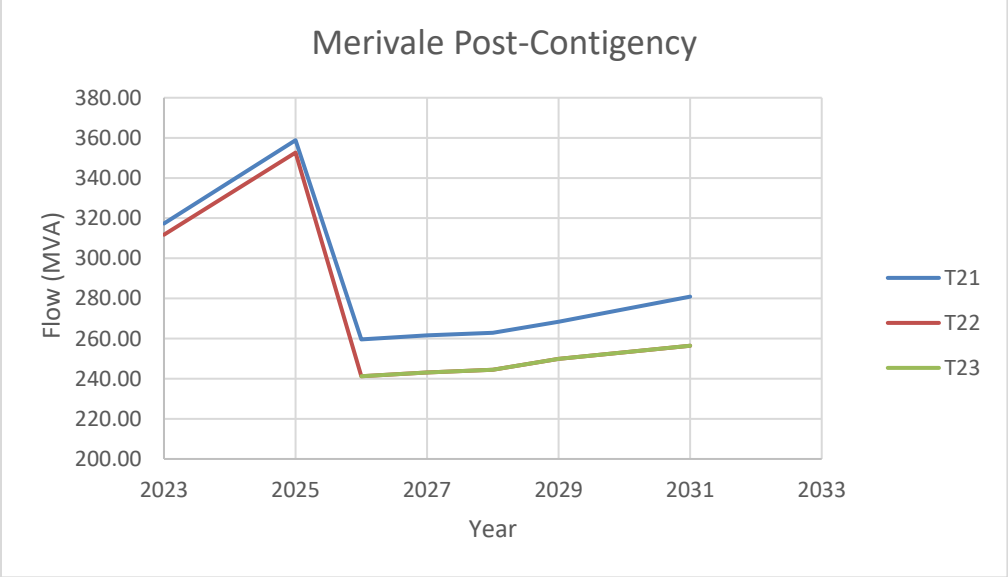


Figure 11: Merivale autotransformer loading under contingency condition.

As can be seen from Figures 10 and 11, following the capacity upgrade at Merivale TS in 2026, the 230/115 kV autotransformers are within their ratings (250MVA continuous, about 340MVA LTR) for the loss of a

single unit and are adequate to supply the forecasted load over the study period. For T22 and T23, loss of T21 was studied and for T21, loss of T22 was studied.

The new autotransformer at Merivale TS also has an impact on the Hawthorne TS autotransformers. Using the updated coincident forecast developed for this NA, the loading of the Hawthorne TS autotransformers is shown in Figures 12 and 13 below.

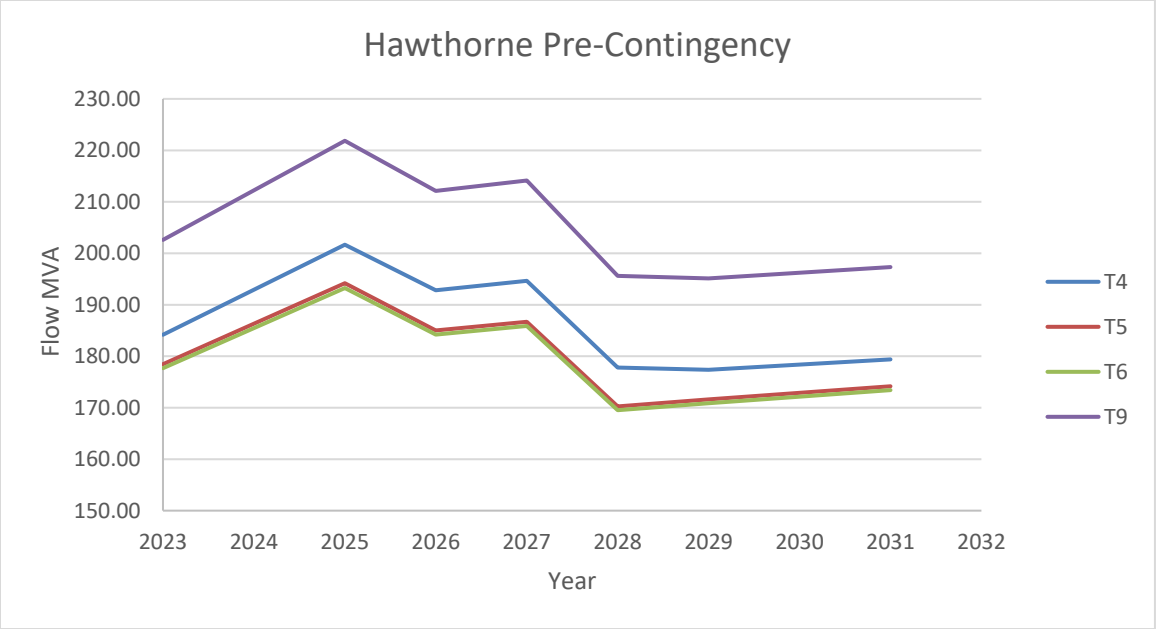


Figure 12: Existing Hawthorne autotransformer loading under normal condition.

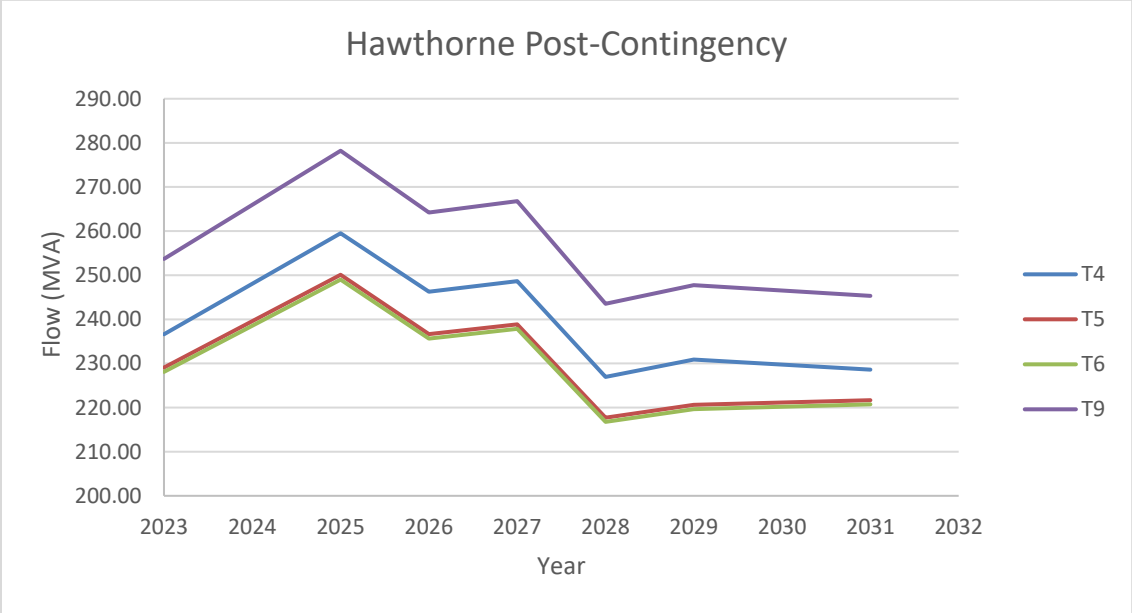


Figure 13: Existing Hawthorne autotransformer loading under contingency conditions.

In Figures 12 and 13, the reduction seen in the autotransformer loading in 2026 is due to the addition of the third autotransformer at Merivale TS. The reduction seen in 2028 is based on the retirement of Bilberry Creek TS and the transfer of load from the 115kV system to the 230kV system. In Figure 11, the most limiting contingency is shown for each autotransformer (the loss of T9 for T4/T5/T6, and the loss of T4 for T9).

As the load is expected to continue to growth beyond 2031, the loading of the autotransformers will continue to be monitored and will also be reviewed as part of the next phases of this regional planning cycle.

7.2.2 115kV Transmission Lines

L2M Supply Capacity: L2M is a 115 kV circuit supplying two stations in southern Ottawa from Merivale TS: Limebank MTS and Marionville DS. The circuit extends to St Lawrence TS 115 kV network via a normally opened point at Chesterville TS (fed from St Lawrence TS). Stations transfers between the Merivale L2M network and the St Lawrence L2M network is possible for operating measures. Limebank MTS and Marionville DS are normally radially supplied by L2M from Merivale TS. The circuit is thermally limited to 480A (approximately 86 MW).

The circuit was identified as reaching its limit in 2029 in the previous RIP. Several options were considered to address this capacity need. The decision was made to wait for the conclusion of the Gatineau Study and the Ottawa 115kV Supply study and to re-evaluate the need at the next cycle of regional planning since potential supply changes may be recommended by these reports. No supply changes for the area was recommended as part of these reports.

Re-evaluation of the circuit still identifies it reaching its limit in 2031 based on the coincident load forecast. The TWG recommends that further assessment and regional coordination during the next phases of this regional planning cycle.

7.2.3 Station Transformation Capacity

There is a total of fifty-two step-down transmission connected transformer stations and two industrial customer stations in the Greater Ottawa Region. The stations have been grouped based on the geographical area and transmission supply configuration in Table 5 below. The table below shows the transformation capacity and total demand in each area. However, transfers between stations in each area, or between areas, can be limited by factors such as distribution voltage and availability of feeder ties. This can in turn limit the ability of an area to meet its load growth or address an overload at a station.

Table 5 below shows demand for each area. As can be seen there is significant growth over the study period. Several stations are reaching and/or exceeding their capacity. Please refer to Appendix A for individual station forecast.

Table 5: Adequacy of Step-Down Transformer Stations.

Area	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Center 115kV	614.8	456.6	483.3	503.8	521.0	535.1	544.8	549.8	553.6	552.8	567.2
Center 230kV	290.0[1]	230.5	238.0	250.9	258.4	266.3	288.3	298.2	313.6	329.3	343.1
East 115kV	421.7[2]	211.9	216.3	219.9	224.3	228.8	233.4	133.5	136.6	137.1	137.5
East 230kV	123.5[3]	53.8	54.7	55.5	56.6	58.2	59.4	188.4	189.4	190.5	191.5
Outer East 115kV	56.0	52.4	53.0	53.0	53.1	53.3	53.5	53.7	53.9	54.0	54.2
Outer East 230kV	308.3	156.1	156.6	156.4	156.9	157.3	157.5	158.0	158.5	159.0	161.0
Outer West 115kV	96.6	67.4	68.3	68.7	69.0	69.3	69.5	69.9	69.9	71.7	73.6
Outer West 230kV	104.0	53.4	54.9	55.6	56.6	57.8	58.8	59.9	60.7	65.7	67.5
South 115kV	305.0	195.1	209.3	216.5	228.9	238.9	233.7	250.1	260.4	269.0	276.5
West 115kV	465.5	310.3	318.7	336.6	377.8	390.0	396.4	416.0	423.0	424.5	424.6
West 230kV	488.8	381.6	408.5	434.3	445.6	452.8	452.9	471.7	473.7	489.0	509.9
Total	3251.2	2169.1	2261.7	2351.3	2448.2	2507.7	2548.4	2649.2	2693.2	2742.5	2806.6

[1]Existing total LTR shown. The two new stations are planned in this area will add to the capacity.
[2]Existing total LTR shown. Following retirement of Bilberry Creek TS and conversion of Orleans TS, new LTR is expected to be 208MW.
[3]Existing LTR shown. LTR will increase with the connection of Brian Coburn MTS and conversion of Orleans TS (~162MW).

For many stations, the load increase above the station LTR can be managed through load transfers to nearby stations.

Ottawa West: Kanata-Stittsville Area

One area where load growth is significant is in the Kanata-Stittsville area, located in the outskirts of the city. This area is supplied by multiple transformer stations, including Kanata MTS, Marchwood MTS, and Terry Fox MTS. Based on the non-coincident forecast, these three stations are expected to be loaded above their LTR over the study period with about 10MW over in 2022, increasing to 47MW in 2031.

This area was identified as a growing area in the previous cycle of regional planning. The conclusion of the RIP report was to review the Gatineau Study EOL report to determine if any recommendation would modify the supply to the area before proceeding with review of wires alternative. In the near term, the overload could be managed through load transfers.

No change of supply to the area was recommended in the report, however up to 230MW of energy efficiency measures were recommended to be implemented in the Ottawa region over the next 20 years.

As part of this cycle of regional planning, the energy efficiency measures should be reviewed for this area in combination with available load transfers to determine the timing for wire alternatives to address this capacity need.

7.3 Voltage Performance

7.3.1 Voltage on 79M1

The 115 kV circuit 79M1 supplies Rockland DS, Rockland East DS, Clarence DS, Wendover DS, and Hawkesbury MTS as shown in Figure 14. The circuit is supplied from Hawthorne TS via circuit H9A. Total distance to the end station Hawkesbury MTS is approximately 80km. As a result of this long distance and circuit loading, lower voltage can be expected at the end of the line. The previous Greater Ottawa RIP report identified that the voltage at Hawkesbury MTS will approach ORTAC limits under peak load with A2 out of service. The recommendation of the previous RIP report was to continue to monitor the situation and re-evaluate the situation based on the new forecast.

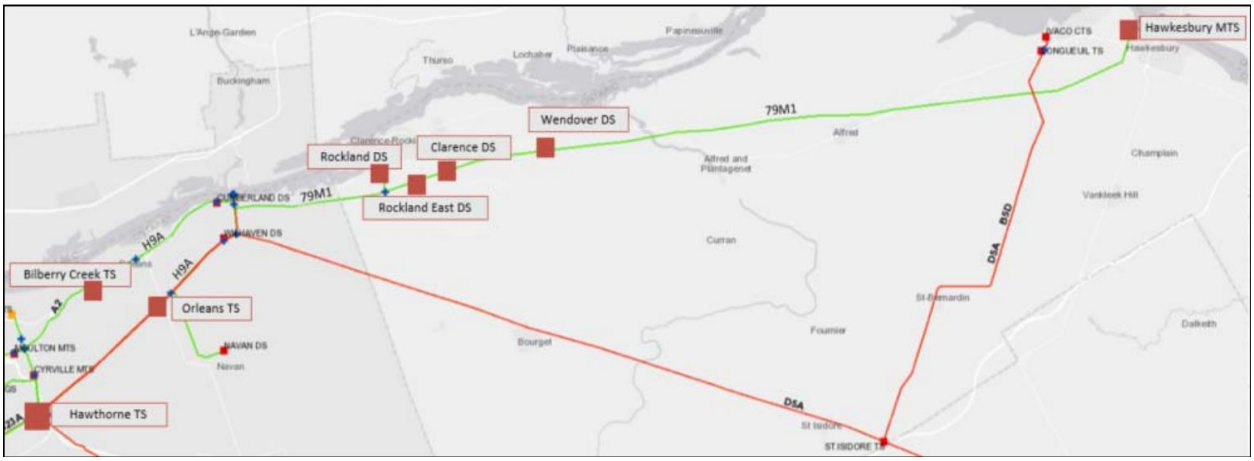


Figure 14: East Ottawa stations supplied by 115kV circuits H9A and 79M1

As discussed in section 7.1, Bilberry Creek TS is planned to be retired and the load move to stations supplied by the 230kV system. Based on this new system configuration, no voltage issues were found over the study period.

7.4 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues have been identified for this Region. Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

8 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Greater Ottawa region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 5% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 2%.

The impact of sensitivity analysis for the high and low growth scenarios identified the following updates or new station capacity needs. Please refer to Table 6 below.

Under the high growth scenario, the capacity need at the station is advanced by about 1-2 years. At Moulton MTS, under the high growth scenario, the station marginally exceeds its capacity for the years 2024-2026. Under the low growth scenario, several stations are near or reaching their capacity, but do not exceed it.

Table 6: Needs Resulting from Sensitivity Analysis

No.	Station Capacity Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1.	Carling TS	2028	2028	2029
2.	Cyrville MTS	2028	2027	2028
3.	Greely DS	2024	2022	2024
4.	King Edward TS	2024	2023	2025
5.	Lisgar TS	2026	2024	2028
6.	Moulton MTS	N/A	2024-2026	N/A
7.	Nepean Epworth	N/A	2022	N/A
8.	Riverdale TS	2029	2027	N/A
9.	Russell TS*	2028	2026	N/A
10.	South March TS	2026	2024	2027

* Based on the existing station LTR. As discussed in Section 7, the transformers will be upgraded by 2026.

The high growth sensitivity analysis did not identify additional capacity needs at other stations.

Review of the loading on L2M also shows that under the high growth scenario, the need is advanced from 2031 to 2029.

9 CONCLUSION AND RECOMMENDATIONS

The TWG's recommendations are as follows:

a) Further assessment and regional coordination is required in the next phases of the regional planning cycle to develop a preferred plan for the following needs:
   - Asset renewal needs for South March TS and Lisgar TS to right-size the transformer replacement (discussed in sections 7.1.1 and 7.1.2);
   - Asset renewal needs for section of circuit S7M to determine prefer supply configuration for the area (discussed in section 7.1.4);
   - L2M Supply Capacity (discussed in section 7.2.2); and,
   - Review of station transformation capacity, including the Kanata-Stittville capacity need (discussed in section 7.2.3).

10 REFERENCES

1. Hydro One, RIP Report – Greater Ottawa (Second cycle), published on December 18, 2020
2. Independent Electricity System Operator, IRRP Report – Greater Ottawa (Second cycle), published on March 4, 2020
3. Independent Electricity System Operator, SA Report – Greater Ottawa (Second cycle), published on September 12, 2018
4. Hydro One, NA Report – Greater Ottawa (Second cycle), published on June 15, 2018
5. Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 August 07, 2007
6. City of Ottawa, Community Energy Plan Terms of Reference
7. Independent Electricity System Operator, Gatineau Corridor End-of-Life Study, published on December 2022

Appendix A: Extreme Summer Weather Net Non-Coincident Load Forecast

Table A.1: Non-Coincident- Normal Growth Net Load Forecast (all number shown in MW)

Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Center 115kV											
King Edward TS	87	78.2	83.5	87.9	89.8	90.4	90.2	89.6	89.0	88.4	90.1
Lisgar TS	74.7	62.2	69.5	71.5	72.7	75.0	76.2	77.2	79.7	79.5	91.7
Overbrook TS	119.4	68.1	71.4	78.1	84.6	89.0	92.9	93.5	93.8	93.7	93.9
Riverdale TS	105.8	84.9	90.4	93.8	96.4	99.2	101.2	104.6	106.6	107.0	107.6
Russell TS	73.9	58.9	62.5	64.7	67.7	70.6	72.9	74.3	74.7	75.2	74.7
Slater TS	154	104.3	106.1	107.8	109.7	110.9	111.4	110.6	109.8	109.1	109.1
Center 230kV											
Albion TS	94.4	63.0	66.0	66.9	70.0	71.2	72.2	72.0	71.5	71.0	70.5
Ellwood MTS	45	46.5	48.3	50.2	50.5	50.2	49.9	49.5	49.2	48.8	48.5
Hawthorne TS	150.6	121.0	122.9	127.5	129.8	130.5	111.8	113.2	114.3	115.4	116.6
230-44 KV MTS	TBD	0.0	0.9	6.3	8.1	14.4	22.5	28.8	40.5	52.2	63.0
New South-East Station	TBD	0.0	0.0	0.0	0.0	0.0	31.9	34.6	38.2	41.8	44.5
East 115kV											
Bilberry Creek TS	90.2	56.9	57.5	57.8	58.1	58.3	58.1	0.0	0.0	0.0	0.0
Cumberland DS	7	5.8	5.9	6.0	6.0	6.0	6.1	6.2	6.2	6.3	6.3
Cyrville MTS	45	31.2	33.9	35.5	38.5	41.3	44.9	48.3	51.5	52.1	52.7
Moulton MTS	30	28.1	28.1	28.9	28.9	28.8	28.6	28.4	28.1	28.0	27.8
Navan DS	14	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8
NRC TS	77	22.3	22.3	22.3	22.3	22.3	22.3	36.7	36.7	36.7	36.7
Orleans TS[1]	123.5	53.8	54.7	55.5	56.6	58.2	59.4	0.0	0.0	0.0	0.0
Wilhaven DS	35	9.1	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
East 230kV											
Brian Coburn MTS	TBD	0.0	0.0	0.0	0.0	0.0	0.0	81.7	82.5	83.4	84.3
Orleans TS[1]	123.5	53.8	54.7	55.5	56.6	58.2	59.4	106.8	106.9	107.1	107.2
Outer East 115kV											
Clarence DS	3	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8
Hawkesbury MTS	18	13.8	14.2	14.1	14.1	14.2	14.3	14.4	14.4	14.5	14.6
Rockland DS	13	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.3	8.3	8.3
Rockland East DS	8	13.6	13.6	13.7	13.7	13.7	13.7	13.8	13.8	13.8	13.8
Wendover DS	14	14.1	14.3	14.3	14.4	14.4	14.5	14.6	14.7	14.7	14.8
Outer East 230kV											
Ivaco CTS	100	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9	70.9
Longueuil TS	87.8	43.2	43.4	43.2	43.5	43.7	43.7	44.0	44.3	44.6	44.9
St. Isidore TS	120.5	41.9	42.2	42.3	42.5	42.7	42.9	43.1	43.3	43.6	45.2

Outer West 115kV											
Arnprior TS	46.2	38.3	38.5	38.5	38.5	38.7	38.7	38.9	39.0	40.5	42.2
Stewartville TS	50.4	29.1	29.8	30.2	30.4	30.6	30.8	31.0	31.0	31.2	31.4
Outer West 230kV											
Almonte TS	104	53.4	54.9	55.6	56.6	57.8	58.8	59.9	60.7	65.7	67.5
South 115kV											
Greely DS	21	20.8	21.0	21.8	23.1	24.4	25.6	26.8	28.0	28.0	28.1
Limebank MTS	89	47.8	54.0	62.0	66.1	70.2	61.1	65.2	69.1	73.1	77.0
Marionville DS	14	14.8	15.0	15.6	16.1	16.1	16.1	16.1	16.1	16.1	16.1
NRC Uplands	14	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Russell DS	7	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.5
South Gloucester DS	7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Uplands MTS	54	36.2	39.8	40.3	41.0	41.2	39.8	40.0	40.1	40.2	40.8
Fallowfield DS	23	26.7	28.9	23.5	24.7	25.6	25.8	31.4	31.2	31.0	30.8
Manotick DS	8	10.0	10.7	11.4	12.1	12.1	12.2	12.2	12.3	12.3	12.4
Richmond MTS	68	20.1	20.9	23.1	27.0	30.4	34.1	39.3	44.6	49.2	52.4
West 115kV											
Bridlewood MTS	23	18.3	19.8	19.7	19.6	20.3	20.2	20.0	20.7	20.6	20.4
Carling TS	100.7	70.5	76.0	87.0	91.9	94.4	95.8	101.0	106.5	106.7	106.7
Centrepoint MTS	13	17.8	17.6	17.5	17.4	17.3	17.2	17.0	16.9	16.8	16.7
Hinchey TS	86	29.0	34.2	38.8	46.8	51.2	55.4	58.9	60.7	61.9	63.0
Lincoln Heights TS	71.8	47.4	48.3	48.9	56.8	57.8	59.5	68.0	67.9	67.8	67.7
Manordale MTS	9	8.6	8.6	8.6	8.5	8.5	8.5	8.4	8.4	8.4	8.3
Marchwood MTS	30	49.8	42.0	42.1	45.8	48.6	49.2	49.3	49.0	49.6	49.3
Merivale MTS	23	15.8	18.3	18.2	18.0	17.9	17.8	17.6	17.5	17.4	17.3
Nepean Epworth MTS	13	12.5	12.5	12.4	12.7	12.6	12.6	12.5	12.4	12.6	12.5
Woodroffe TS	96	40.6	41.3	43.4	60.4	61.4	60.6	63.2	63.0	62.8	62.6
West 230kV											
Cambrian MTS	90	20.7	24.7	38.7	40.9	42.9	44.2	62.1	63.4	72.2	84.6
Kanata MTS	49	53.2	55.3	60.4	64.2	64.1	61.0	60.6	60.9	63.4	63.0
Nepean TS	152.6	141.2	144.8	135.9	136.1	137.5	137.5	137.5	136.5	140.1	139.2
South March TS	116.2	98.7	101.9	113.8	116.0	118.1	118.8	119.3	120.2	120.1	128.5
Terry Fox MTS	81	67.8	81.7	85.5	88.4	90.2	91.5	92.2	92.6	93.1	94.5

[1]Current Orleans TS supply configuration is from 230kV circuit D5A and 115kV circuit H9A. Each circuit is assumed to supply half the station load. As discussed in Section 6, once Bilberry Creek TS is retired and Orleans TS converted to dual 230kV supply, the capacity will increase, and the station will only be part of the East 230kV.

Table A.2: Coincident- Normal Growth Net Load Forecast (all number shown in MW)

Station	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Center 115kV										
King Edward TS	77.2	82.6	86.9	88.9	89.5	89.2	88.7	88.0	87.5	89.2
Lisgar TS	59.1	66.3	68.4	69.6	71.9	73.1	74.1	76.5	76.4	88.6
Overbrook TS	68.1	71.4	78.1	84.6	89.0	92.9	93.5	93.8	93.7	93.9
Riverdale TS	84.9	90.4	93.8	96.4	99.2	101.2	104.6	106.6	107.0	107.6
Russell TS	58.9	61.3	62.3	63.4	64.2	64.6	64.5	64.0	63.6	63.2
Slater TS	104.3	106.1	107.8	109.7	110.9	111.4	110.6	109.8	109.1	109.1
Center 230kV										
Albion TS	60.7	63.6	64.4	67.6	68.8	69.8	69.9	69.4	68.9	68.4
Ellwood MTS	43.3	45.1	47.0	47.3	47.0	46.7	46.3	46.0	45.6	45.3
Hawthorne TS	120.4	122.2	126.9	129.1	129.8	111.2	112.5	113.6	114.7	115.9
230-44 KV MTS	0.0	0.9	6.3	8.1	14.4	22.5	28.8	40.5	52.2	63.0
New South-East Station	0.0	0.0	0.0	0.0	0.0	31.9	34.6	38.2	41.8	44.5
East 115kV										
Bilberry Creek TS	56.9	57.5	57.8	58.1	58.3	58.1	0.0	0.0	0.0	0.0
Cumberland DS	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3
Cyrville MTS	31.2	33.9	35.5	37.5	38.4	39.2	39.8	40.3	40.9	41.4
Moulton MTS	26.8	26.8	27.6	27.6	27.4	27.2	27.0	26.8	26.6	26.5
Navan DS	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8
NRC TS	5.2	5.2	5.2	5.2	5.1	5.1	16.9	16.8	16.7	16.7
Orleans TS	47.9	49.1	50.3	51.9	54.1	56.0	0.0	0.0	0.0	0.0
Wilhaven DS	8.9	8.9	8.9	8.9	8.9	8.9	8.9	9.0	9.0	9.0
East 230kV										
Brian Coburn MTS	0.0	0.0	0.0	0.0	0.0	0.0	71.0	71.8	72.7	73.6
Orleans TS	47.9	49.1	50.3	51.9	54.1	56.0	102.1	103.4	103.6	103.6
Outer East 115kV										
Clarence DS	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Hawkesbury MTS	13.6	13.9	13.8	13.8	13.9	14.0	14.0	14.1	14.1	14.2
Rockland DS	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.3	8.3	8.3
Rockland East DS	13.6	13.6	13.7	13.7	13.7	13.7	13.8	13.8	13.8	13.8
Wendover DS	5.1	5.1	5.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Outer East 230kV										
Ivaco CTS	63.8	63.8	63.7	63.5	63.4	63.2	63.2	63.1	62.9	62.8
Longueuil TS	30.4	30.5	30.5	30.5	30.5	30.5	30.6	30.9	31.0	31.3
St. Isidore TS	31.3	31.4	31.4	31.4	31.5	31.5	31.7	31.7	31.8	33.3
Outer West 115kV										
Arnprior TS	33.5	33.5	33.5	33.5	33.6	33.6	33.7	33.7	35.2	36.8
Stewartville TS	26.9	27.0	27.0	27.0	27.1	27.2	27.3	27.3	27.4	27.5

Outer West 230kV										
Almonte TS	46.2	46.8	46.9	47.0	47.0	47.4	47.8	48.0	52.2	53.3
South 115kV										
Greely DS	19.0	20.4	21.8	23.1	24.4	25.6	26.8	28.0	28.0	28.1
Limebank MTS	47.8	54.0	62.0	66.1	70.2	61.1	65.2	69.1	73.1	77.0
Marionville DS	14.4	15.0	15.6	16.1	16.1	16.1	16.1	16.1	16.1	16.1
NRC Uplands CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Russell DS	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4
South Gloucester DS	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Uplands MTS	35.3	39.0	39.5	40.1	40.3	39.0	39.1	39.2	39.4	39.9
Fallowfield DS	26.7	28.9	23.5	24.7	25.6	25.8	31.4	31.2	31.0	30.8
Manotick DS	10.0	10.7	11.4	12.1	12.1	12.2	12.2	12.3	12.3	12.4
Richmond MTS	11.1	12.0	14.1	18.0	21.5	25.1	30.3	35.6	40.2	43.4
West 115kV										
Bridlewood MTS	18.3	19.8	19.7	19.6	20.3	20.2	20.0	20.7	20.6	20.4
Carling TS	65.4	70.9	82.0	86.8	89.4	90.7	95.9	101.5	101.7	101.6
Centrepoint MTS	17.8	17.6	17.5	17.4	17.3	17.2	17.0	16.9	16.8	16.7
Hinchey TS	29.0	34.2	38.8	46.8	51.2	55.4	58.9	60.7	61.9	63.0
Lincoln Heights TS	47.4	48.3	48.9	56.8	57.8	59.5	68.0	67.9	67.8	67.7
Manordale MTS	8.6	8.6	8.6	8.5	8.5	8.5	8.4	8.4	8.4	8.3
Marchwood MTS	37.6	42.0	41.2	42.2	42.8	43.4	43.5	43.2	43.8	43.5
Merivale MTS	14.9	17.3	17.2	17.1	17.0	16.8	16.7	16.6	16.5	16.3
Nepean Epworth MTS	11.2	11.2	11.1	11.4	11.3	11.3	11.2	11.1	11.3	11.2
Woodroffe TS	37.2	37.9	40.0	57.0	58.1	57.2	59.8	59.6	59.4	59.3
West 230kV										
Cambrian MTS	20.7	24.7	38.7	40.9	42.9	44.2	45.9	47.2	53.7	55.4
Kanata MTS	53.2	55.3	60.4	64.2	64.1	61.0	60.6	60.9	63.4	63.0
Nepean TS	131.0	134.6	125.7	125.9	127.3	127.3	127.3	126.3	129.9	129.1
South March TS	54.3	56.8	68.2	69.9	71.5	71.6	71.6	72.0	71.4	77.2
Terry Fox MTS	67.8	81.7	85.5	88.4	90.2	91.5	92.2	92.6	93.1	94.5

Appendix B: Distributors in the Greater Ottawa Region

Distributor Name	Station Name	Connection Type
Hydro 2000	Longueuil TS	Dx
Hydro Hawkesbury	Hawkesbury MTS	Tx
	Longueil TS	Dx
Hydro One	Almonte TS	Tx
	Arnprior TS	Tx
	Bilberry Creek TS	Tx
	Clarence DS	Tx
	Cumberland DS	Tx
	Greely DS	Tx
	Hawthorne TS	Tx
	Longueil TS	Tx
	Manotick DS	Tx
	Marionville DS	Tx
	Navan DS	Tx
	Orleans TS	Tx
	Rockland DS	Tx
	Rockland East DS	Tx
	Russell DS	Tx
	South Gloucester DS	Tx
	St Isidore TS	Tx
	Stewartville TS	Tx
	Wilhaven DS	Tx
Hydro Ottawa	Albion TS	Tx
	Almonte TS	Dx
	Bilberry Creek TS	Tx
	Bridlewood MTS	Tx
	Cambrian MTS	Tx
	Carling TS	Tx
	Centrepoint MTS	Tx
	Cyrville MTS	Tx
	Ellwood MTS	Tx
	Nepean Epworth MTS	Tx
	Fallowfield DS	Tx
	Hawthorne TS	Tx
	Hinchey TS	Tx
	Kanata MTS	Tx
	King Edward TS	Tx
Hydro Ottawa	Limebank MTS	Tx

	Lincoln Heights TS	Tx
	Lisgar TS	Tx
	Manordale MTS	Tx
	Marchwood MTS	Tx
	Moulton MTS	Tx
	Merivale MTS	Tx
	Nepean TS	Tx
	Orleans TS	Tx
	Overbrook TS	Tx
	Richmond MTS	Tx
	Riverdale TS	Tx
	Russell TS	Tx
	Slater TS	Tx
	South Gloucester DS	Dx
	South March TS	Dx, Tx
	St Isidore TS	Dx
	Terry Fox MTS	Tx
	Upland MTS	Tx
	Woodroffe TS	Tx
Ottawa River Power Corporation	Almonte TS	Dx
Renfrew Hydro	Stewartville TS	Dx

Appendix C: Lists of Transmission Circuits

Location	Circuit Designations	Voltage (kV)
Hawthorne TS – Merivale TS	M30A, M31A	230
Hawthorne TS – St Isidore TS	D5A	230
Merivale TS – Almonte TS	E34M (formerly M29C)	230
Merivale TS – South March TS	M32S	230
South March SS – Chats Falls SS	C3S	230
Hawthorne TS – Bilberry Creek TS	A2	115
Hawthorne TS - Merivale TS	A3RM, A8M	115
Hawthorne TS – Overbrook TS	A4K, A5RK	115
Hawthorne TS – Riverdale TS	A6R	115
Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
Merivale TS – Chats Falls TS	C7BM	115
Merivale TS – Hinchey TS	F10MV, V12M	115
Merivale TS – Lisgar TS	M4G, M5G	115
Merivale TS – South March SS	S7M	115
Stewartville TS – South March SS	W6CS	115
Stewartville TS – Barrett Chute TS	W3B	115

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

APPENDIX F – RENFREW RIP REPORT



Renfrew

REGIONAL INFRASTRUCTURE PLAN

July 13, 2023

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Ottawa River Power Corporation (ORPC)

Disclaimer

This Regional Infrastructure Plan (RIP) Report for Renfrew region was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Technical Working Group.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Regional Infrastructure Plan Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Regional Infrastructure Plan Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE RENFREW REGION.

The participants of the Renfrew Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process. Hydro One, as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Renfrew region was initiated with Needs Assessment (NA) and the report was published in May 2021 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in August 2021 and December 2022, respectively, by the Independent Electricity System Operator (IESO).

The Renfrew RIP provides a consolidated summary of needs and recommended plans for the region over a study period of 2022-2042 based on available information. In this regional planning cycle, plans are recommended for the near to medium-term needs. The needs for the longer term were assessed but due to uncertainties in the load growth, long-term needs will be monitored and further reviewed in next regional planning cycle.

I. Following Major projects were completed during the last ten years:

- Chenaux TS: 230/115 kV, T3 & T4 Autotransformers replaced with new 75/100/125 MVA units along with regulators TR3 and TR4, 115kV oil circuit breakers 4X6 and 4X2Y, completed in 2021.

II. Following Major projects are underway:

- 115kV D6 Circuit: Complete line refurbishment of 76.8 km Line section between Des Joachims TS and Petawawa/Craig DS, planned in-service date in 2025.

III. New needs identified during the second cycle regional planning:

a. Asset Renewal for Major HV Transmission Equipment

- No new major HV Transmission Asset renewal identified.

b. Station Capacity

- Pembroke TS: Currently exceeding summer station LTR.
- Forest Lea DS: Currently exceeding summer station LTR.
- Petawawa DS: Update on need as identified in IRRP.

c. Transmission Line Capacity

- No new Transmission Line capacity identified.

d. System Reliability, Operation and Load restoration

- No System Reliability, Operation and Load restoration issues identified.

e. Long term needs

- Des Joachims sub-system supply capacity: Monitor load growth in the area.

The major infrastructure investments in this second cycle recommended by the TWG in the Renfrew Region over the near, medium and long-term period are given in Table 1 below, along with their planned in-service date and estimate for planning purposes.

Table 1. Renfrew Region - Recommended Plans over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE RENFREW REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Renfrew region is located in Eastern Ontario with the majority of load along the Ottawa river. For electrical planning purposes this region includes eighteen municipalities including the towns of Arnprior, Deep River, Laurentian Hills, Petawawa and Renfrew. As well as the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke. Figure 1-1 represents the Renfrew Region Map.

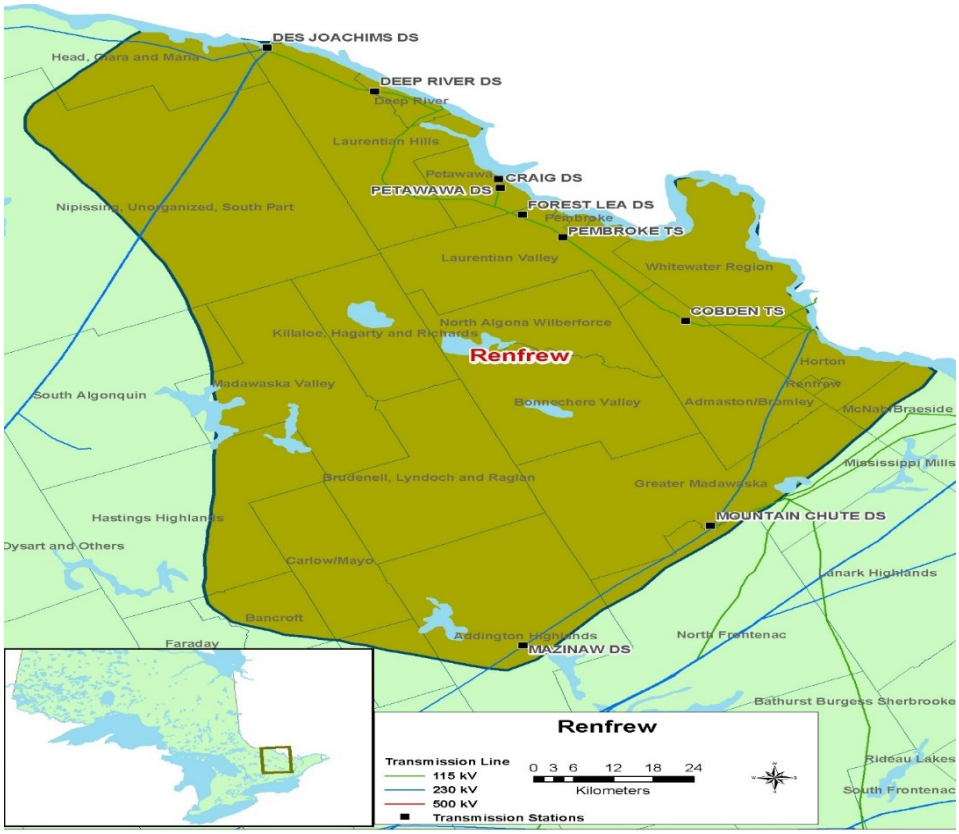


Figure 1-1 Renfrew Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the Renfrew Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the region;
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the study period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Renfrew IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities in the region over the study period and identifies the needs.
- Section 7 discusses the needs, provides alternatives to address each need, and recommends a preferred solutions; and,
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: The Needs Assessment ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) assess, and document which of the needs that,

a. can be addressed directly between the customer and transmitter along with a recommended plan, and;
b. require further regional coordination and identification of LDCs to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs,

a. are local in nature,
b. require limited investments in wires (transmission or distribution) solutions, and;
c. do not require upstream transmission investments.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. The approach is either a RIP,

which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region were identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.
The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2 -1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

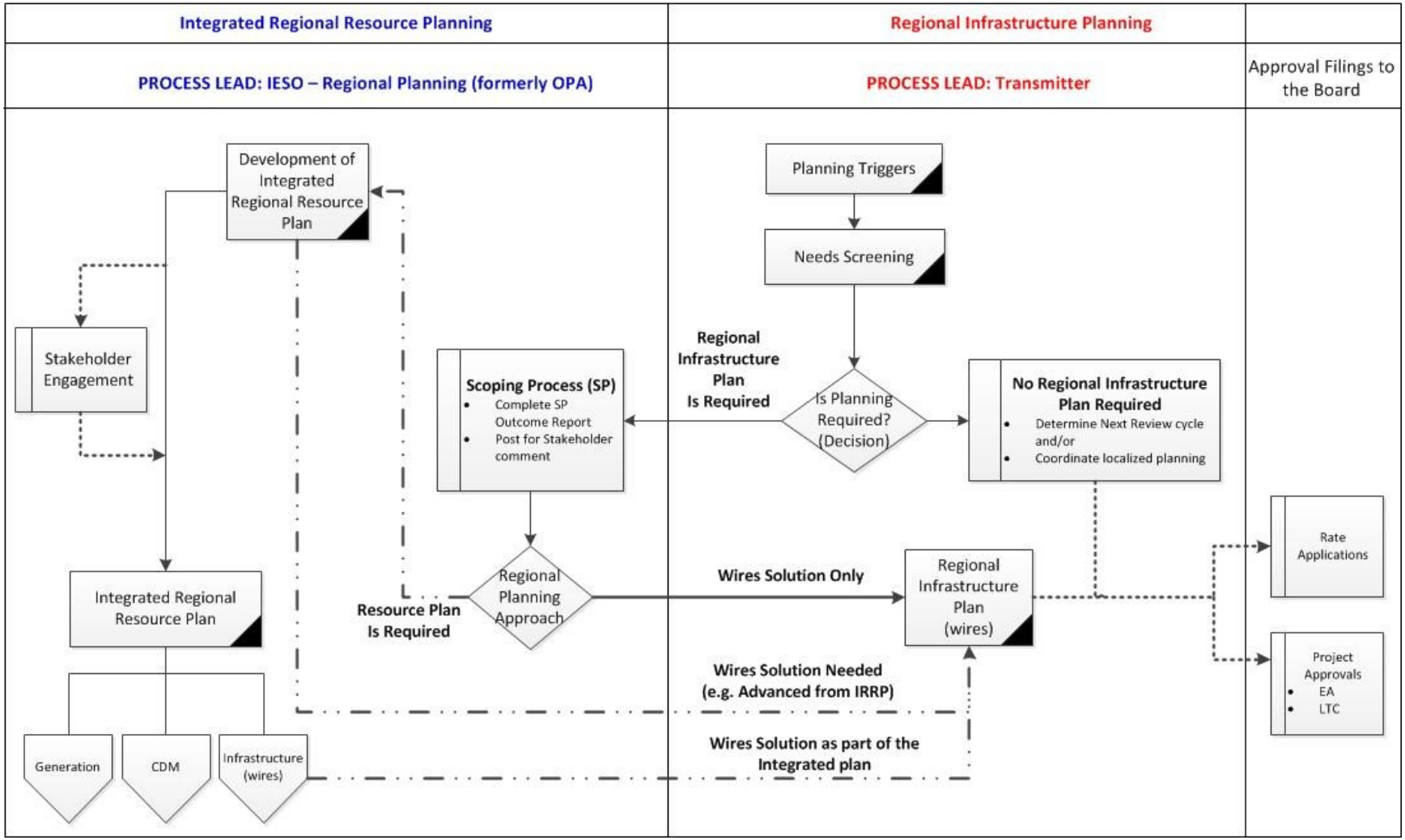


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four-step process (see **Error! Reference source not found.**) as follows:

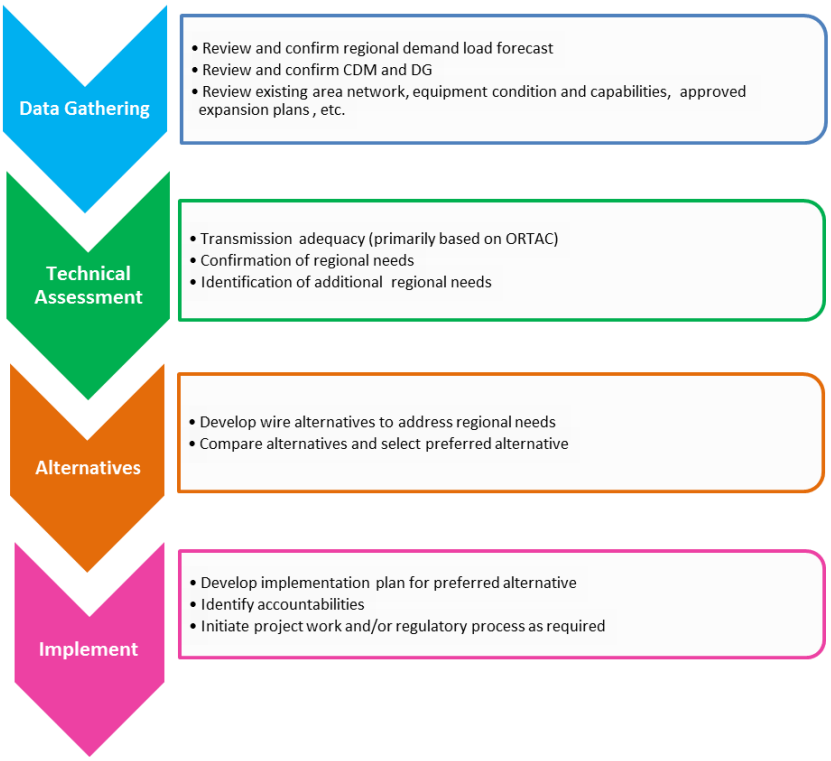


Figure 2-2 RIP Methodology

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was adopted for this RIP, with the exception of Petawawa DS.
    - Review and confirm electrification, other growth scenarios, etc. which effects the projects recommended in in previous stages.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

3. REGIONAL CHARACTERISTICS

THE RENFREW REGION IS LOCATED IN EASTERN ONTARIO WITH THE MAJORITY OF LOAD ALONG THE OTTAWA RIVER. THE ELECTRICITY SUPPLY TO THE REGION IS PROVIDED THROUGH ONE 230KV CIRCUIT X1P AND THREE 115 KV RADIAL CIRCUITS: D6, X6 AND X2Y. THE 115KV CIRCUITS ARE SUPPLIED BY 230/115 KV AUTOTRANSFORMERS AT CHENAUX TRANSFORMER STATION (TS) FROM THE EAST AND DES JOACHIMS TS FROM THE WEST. A NORMALLY OPENED 115KV SWITCH AT PEMBROKE TS ISOLATES THE EAST AND THE WEST SIDES OF THE REGION.

The Renfrew region is bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the South. The distribution system in this region consists of voltage levels 44 kV and 12.5 kV. The main generation facilities in the Renfrew region are Chenaux Generation Station (GS) of 143.7 MW, Mountain Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW

Hydro One Networks Inc. (Distribution) is the main LDC in the area. Other LDCs supplied from electrical facilities in the Renfrew region include Ottawa River Power Corporation and Renfrew Hydro Inc., both are embedded into Hydro One's distribution system. Renfrew Hydro Inc. customers are being fed from Stewartville TS which is part of the Greater Ottawa Regional Planning. As such, Renfrew Hydro Inc. has not been included as part of this NA.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1.

- Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y
- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Customer Transformer Station (CTS-1).
- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.
- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Customer Transformer Station (CTS-2)
- Bryson GS from Hydro Quebec can be radially connected to Renfrew region via X2Y, when required.
- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region.

The circuits and stations of the area are summarized in the Table 2-1 below:

Table 1-1: Transformer Station and Circuits in the Renfrew region

115kV circuits	230kV circuits	Transformer Stations	Generation Stations
D6, X6 and X2Y	X1P	Des Joachims TS*, Des Joachims DS, CTS-1, Deep River DS, Chalk Craig DS, Petawawa DS, Forest Lea DS, Pembroke TS, Cobden TS, Cobden DS, CTS-2, Chenaux TS*, Mountain Chute DS and Mazinaw DS.	Mountain Chute GS (170.2MW) Des Joachims GS (432.5MW) Chenaux GS (143.7MW)

*Stations with Autotransformers installed

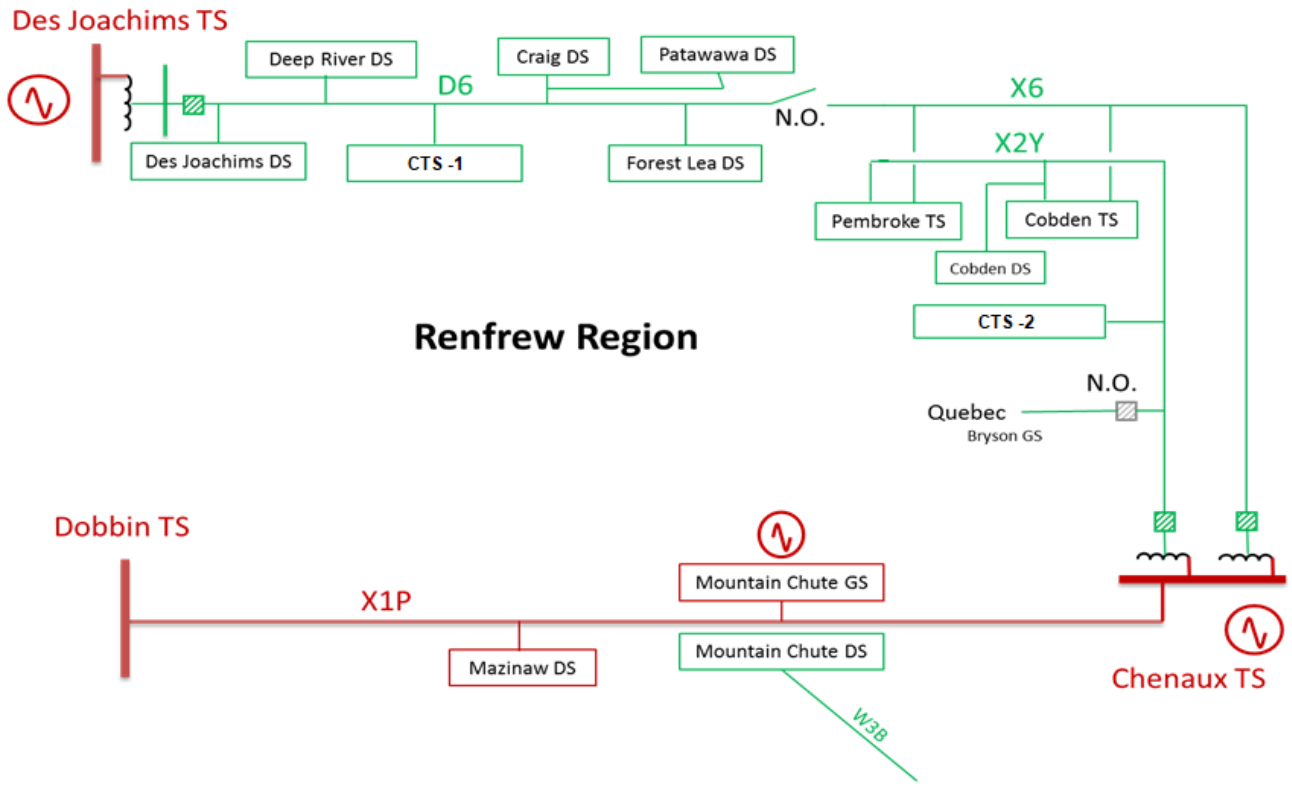


Figure 3-1 Renfrew Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE RENFREW REGION.

A list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Renfrew region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner(TAO) in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Chenaux TS Autotransformer Replacement (2021): The 230/115 kV T3/T4 Autotransformers were replaced by new 75/100/125 MVA units along with associated facilities.

II. Following Major projects are underway:

1. 115kV D6 Line refurbishment (2025): This project is currently underway and includes complete refurbishment of 76.8km line between Des Joachims TS and Petawawa/Craig DS due to its condition assessment.

Note: The planned in-service year for the above projects is tentative and is subject to change.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The TWG adopted the IRRP load forecasts for this RIP as no material change was identified, with the exception of Petawawa DS. At Petawawa DS, the load increased abnormally in June 2020 due to generator refurbishment work at a customer facility connected to Petawawa DS which resulted in adding about 3.1 MW to station peak. The load returned to its normal value after the work was completed in July 2020. The updated load forecast for Petawawa DS considers the updated actual peak load recorded in 2021.

The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight on the future load growth and was considered during IRRP load forecast development. During the study period, the load in the Renfrew region is expected to grow at an average annual rate of approximately 1.5% in summer from 2022 to 2042. The assessment is based on both summer and winter peak loads.

Figure-5-1 & 5-2 shows the Renfrew region extreme summer & winter weather non-coincident load forecast from 2022 to 2042. The load forecast from the Renfrew region IRRP was adopted as agreed to by the TWG, except for Petawawa DS. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident forecast for the individual stations in the region is available in Appendix E and is used to determine any need for station capacity relief in the region.

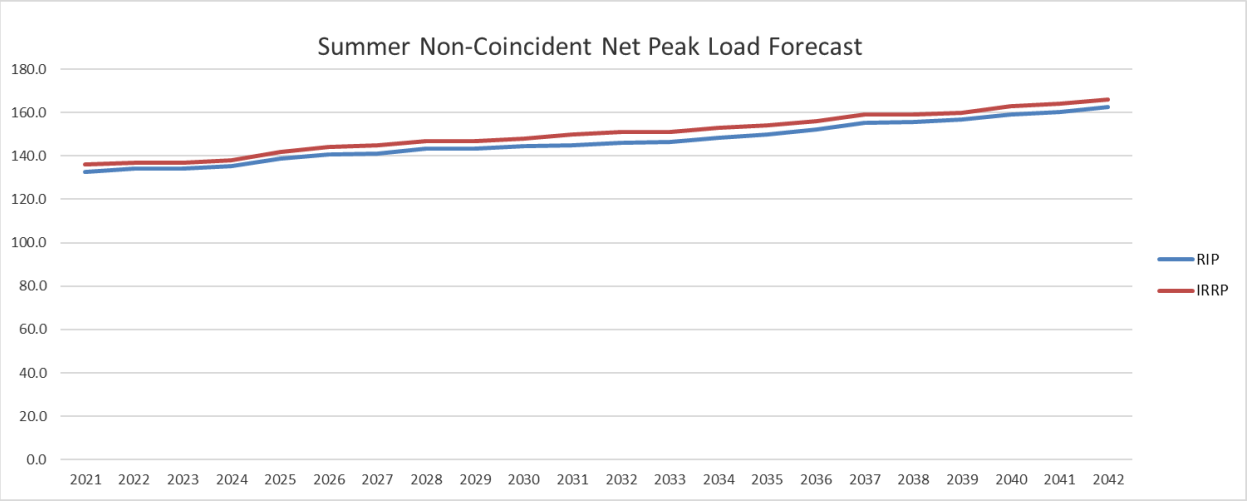


Figure 5-1 Renfrew Region Non–Coincident Net Summer Peak Load Forecast

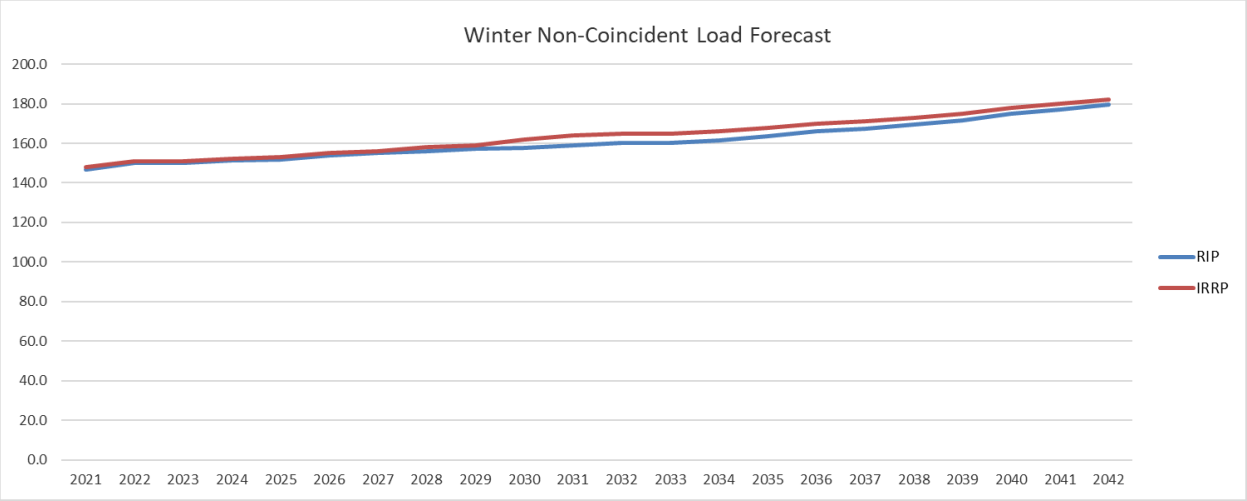


Figure 5-2 Renfrew Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2042.
- LDCs reconfirmed load forecasts up to 2042 in the area are the same as the IRRP(except for Petawawa DS).
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE RENFREW REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Renfrew region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- Renfrew region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- Renfrew region Second cycle Integrated Regional Resource Plan Report, Completed in December 2022 by the IESO

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near, mid and long-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the Renfrew Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service.

Sections 6.1- 6.5 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 Station Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transformer Stations within the Renfrew region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 6-1 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 6-1 Renfrew Region – Station capacity needs

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2022 Loading (MW) (Summer/Winter)	Need Date
1	Pembroke TS	47/57 MW	48/53 MW	Current
2	Forest Lea DS	8.6/11.6 MW	9/11 MW	Current
3	Petawawa DS	16.3/20.2 MW	10/10 MW	*

* Identified during IRRP phase but was eliminated in RIP following the load forecast update for Petawawa DS.

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Transmission Line Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Renfrew region. It was determined that all Transmission Lines are within the thermal limits of the circuits and within the voltage range as per ORTAC over the study period adequate over the study period for the loss of a single 230/115 kV circuit in the Region.

6.3 Asset Renewal for Major HV Transmission Equipment

Hydro One is the only Transmission Asset Owner (TAO) in the Renfrew region. Hydro One facilities in the region that will require replacement over the near-medium -term period as listed in Table 6-2 below.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers.
- 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 6-2 Renfrew Region - Planned Replacement Work

Station/Circuit	Need Description	Planned ISD
D6	Complete 76.8kM line refurbishment between Des Joachims TS and Petawawa/Craig DS	2025

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

6.5 Long Term Needs

During IRRP phase, a long-term supply capacity issue has been identified under high growth scenarios in the Des Joachims sub-system. The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region.
The options and preferred solution to address this need is discussed further in Section 7 of the report.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE RENFREW REGION.

The electrical infrastructure needs for the Renfrew Region are summarized in Table 7-1. These needs include those previously identified in the NA and IRRP for the Renfrew region. All estimated costs included in the alternative analysis are considered as planning estimates and are used for comparative purposes only.

Table 7-1 Renfrew Region – Near, Medium- and Long-Term Needs

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Station Capacity Needs			
Pembroke TS	Station has exceeded its summer LTR	Current	7.1.1
Forest Lea DS	Station has exceeded its summer LTR	Current	7.1.2
Petawawa DS	Station was expected to exceed its summer LTR	*	7.1.3
Long Term Needs			
Des Joachims sub-system	Supply capacity issue in long-term under high growth scenario	2034	7.5.1

* Identified during IRRP phase but was eliminated in RIP following the load forecast update.

7.1 Station Capacity Needs

A station capacity assessment was performed over the study period 2022-2042 for the 230kV and 115kV transforming stations in the Renfrew region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following station capacity needs have been identified in the during the study period:

7.1.1 Pembroke TS – 115kV

Pembroke TS supplies Hydro One Dx while ORPC is an embedded LDC. It is a 115/44 kV Transmission Station (TS) with two 25/33/42 MVA (T1/T2) transformers supplied by circuits X2Y & X6 with a summer and winter LTR of 47 MW and 57 MW, respectively.

Pembroke TS has three distribution feeders which supplies Hydro One Distribution, with ORPC as an embedded LDC on two feeders. This station has exceeded its normal supply capacity in 2019 and TWG has agreed that a wires solution is required to address this need.

The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Build a new HVDS:
A new HVDS would be built near Pembroke TS. An HVDS would provide 18 MW of capacity at an approximate cost of $14M, which includes $11M for building the station and at a least an additional $3M for distribution costs. The new HVDS would be connected to 115kV circuit X6 as during contingency it is less limiting than X2Y as the overall circuit have a higher thermal rating compared to X2Y. The Pembroke DS load, which is expected to be 6 MW, will be transferred to the new HVDS, therefore freeing up capacity for new load on Pembroke TS. The remaining capacity of new HVDS would also be able to supply an additional 12MW of new load at 12kV in the area. Although connecting a HVDS to one circuit is less reliable than a TS connected to both circuits as it does not provide full redundant supply, there is an existing transmission 115kV switch at Cobden TS that can be used to tie X2Y and X6 to restore the load on the new HVDS for in case of a fault East of Cobden TS. All of ORPC load is currently supplied by the existing two 44kV feeders from Pembroke TS. Due to the current distribution configuration of the ORPC system, future ORPC load from the new HVDS will require further modifications at ORPC's operating system within its service territory.

From a capacity standpoint, this option would be able to supply all the forecasted load in area for the long term.

Alternative 3 – Build a new Transmission Station (TS):
Build a new TS consisting of two 115/44 kV 25/33/42 MVA step-down transformers near the existing Pembroke TS, connected to both the X2Y and X6 circuits. This would cost approximately $30M. The new supply station will be able to supply 47 MW, which is more than sufficient for the 20-year load forecast, including Pembroke TS long term growth. Similar to the HVDS option, 115kV circuit X2Y is more limiting and during a contingency situation, the thermally limiting sections on X2Y will prevent the new TS from supplying the full 47 MW station capacity.

Recommendation:
Both alternatives 2 and 3 addresses the need for additional capacity at Pembroke TS during normal operations. However, building a new TS is significantly more expensive than building a new HVDS and will also require an additional cost for transmission line upgrades to utilize the full station capacity. Building a new HVDS which is a less costly alternative, has its own operational limitations and complications for ORPC. As the assessment of both alternatives are very complex, further discussion between Hydro One Tx and the impacted LDCs is required. Both Hydro One Dx and ORPC will continue to explore these two options to determine the most feasible solution to address the capacity need at Pembroke TS.

7.1.2 Forest Lea DS – 115kV

Forest Lea DS is located in Laurentian Valley Hills, outside the city of Pembroke. It is connected at the tail end of the circuit D6, after Petawawa DS and Craig DS. This station is owned and operated by Hydro One Dx. Forest Lea DS is a 115/13.4 kV Step down station and is radially supplied by circuit D6 it has two 7.5/11 MVA (T1/T2) transformers with a summer LTR of 8.6 MW and winter LTR of 11.1 MW.

This station has already exceeded its normal supply capacity but will only increase by slightly over the station LTR at the end of the study period. The TWG has agreed that a solution is required to address this need.
The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Load Transfer:
Through existing Dx interties, there is a possibility of transferring load to the Pembroke DS and Craig DS. TWG confirmed that a 1 MW load transfer to Craig DS can be done with minimal work with a capital cost of only $50k. A transfer to Pembroke DS, is also technically feasible, but would result in a further overload of the upstream Pembroke TS and the outcome of the preferred solution for Pembroke TS station capacity issue could affect the load transfer. In light of all these reasons, load transfer at Craig DS is preferred.

Alternative 3 – Upgrading the supply capacity:
The capacity of Forest Lea station can be upgraded using two methods which are:
i) Upgrading the transformers to add 10 MW of capacity for a capital cost of $4.5M or,
ii) Installing fan cooling and SCADA monitoring system to the existing transformers to add 4 MW at a capital cost of $0.6M.

Alternative 4 – Building new HVDS:
It is also possible to build a new HVDS for the Forest Lea area which will add 18 MW of load at a capital cost of $12M. This option will provide a higher capacity, which is not required at this moment, even under consideration of a high growth scenario.

Recommendation:
The need of station capacity at Forest Lea DS is current, but the expected load growth is very low. The load at this station is only expected to grow to slightly over 1 MW in the long-term. Hence, load transfer to Craig TS is considered as the most appropriate as well as cost effective alternative. TWG recommends and agrees to transfer 2 MW load to Craig DS. The expected completion date for this load transfer is 2026.

7.1.3 Petawawa DS – 115kV

Petawawa DS supplies the town of Petawawa and a large customer. The majority of the load i.e., 80% of the total load, is consumed by this large customer. The station is radially supplied by D6 and is located at the end of the circuit, right after Craig DS. It has two 115/13.4 kV Step down 7.5/10/13 MVA (T1/T2) transformers with a summer LTR of about 16 MW and winter LTR of 20 MW.

As per the IRRP Load Forecast the station reaches its summer LTR in 2030 and hence recommended to build a new HVDS transformer station at Petawawa with in-service date of 2027. During the RIP phase it was observed that the load increased abnormally in June 2020 due to generator refurbishment work at the customer's facility in Petawawa DS and resulted in the net load increase by 3 MW at the station. This work was completed in July 2020. As the load displacement generation is permanently operating, the net load at the station returned to its normal value resulting in a net load of approximately 9.8 MW during the year 2021. Hence, the Load Forecast for

Petawawa DS was updated in the RIP, and the 2022 load was determined by considering the actual load in 2021. The updated load forecast yields a lower Net Load at the end of study period.

Recommendation:
Since the elevated load forecast was updated for actual value, the load at Petawawa DS remains below the summer/winter (16.3/20.2 MW) LTRs for the long-term forecast. However, during the IRRP phase the customers in this area have indicated some possible future expansion and heating load conversion under Canadian Net-Zero Emissions Accountability Act that was considered in a high load growth scenario. Hence, for now it is recommended to defer this need as no additional capacity is required at this station for the short to medium term, but the TWG will continue to monitor the future high load growth scenario and trigger regional planning earlier if and when demand arises at the station.

7.2 Transmission Line Capacity Needs

All line and equipment load shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2022-2042 for the 230kV and 115kV Transmission line circuits in the Renfrew region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, no new Transmission line capacity needs were identified in the region during the study period.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all the load to other existing facilities;
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
- Replacing equipment with higher ratings and built to current standards.

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.
No new major HV Asset Renewal Needs were identified in the region during the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2022-2042 to cater

this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

7.5 Long Term Considerations

7.5.1 Des Joachims sub-system – Supply capacity issue

The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region and ends at Petawawa DS and Forest Lea DS in the east. During IRRP, two high growth scenarios (i.e., increase in load by 20MW & 40MW) were identified as a part of the engagement process for the Des Joachims sub-system. The LMC of Des Joachims sub-system is approximately 80MW and under high growth scenarios, with one element out and a contingency to a generator at Des Joachims TS, under peak coincident demand and low generation conditions, voltage change violations are identified at the stations connected to the end of D6 circuit.

Alternative 1 - Maintain Status Quo:
The need is identified in the medium to long-term, and both high load growth scenarios have fair amount of uncertainties. Monitor the current load growth in the area and maintain status quo until next regional planning cycle.

Alternative 2 – Capacitor banks:
Installing capacitor banks at either Craig DS, Petawawa DS or Forest Lea DS will improve the LMC by approximately 10 MW and can support the first high growth scenario i.e., a load growth of over 20 MW.

Alternative 2 – Transmission options:
For the more aggressive load growth scenario, i.e., load growth of over 40MW, the support provided by capacitor banks will not be enough and there will be a need to construct new transmission line in the area.

Recommendation:
The need is identified in the mid to long-term, and in light of uncertainties of the load growth in the sub-system. Hence, for now it is recommended that TWG will continue to monitor the future high load growth scenario and if required can proceed with the capacitor upgrade if and when need arises.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE RENFREW REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near, medium and long-term are provided in Table 8-1 below, along with their planned in-service dates and estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

9. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Independent Electricity System Operator, Renfrew region IRRP Cycle-2 (December, 2022)

[6] Independent Electricity System Operator, Renfrew region Scoping Assessment Cycle-2 (August, 2021)

[7] Hydro One Networks Inc., Renfrew region Needs Assessment Cycle-2 (May 2021)

APPENDIX A. RENFREW REGION - STATIONS

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Cobden DS (T3)	115/12.5	X2Y
2.	Cobden TS (T1/T2)	115/44	X2Y/X6
3.	Craig DS (T1/T2)	115/12.5	D6
4.	Deep River DS (T1/T2/T3)	115/12.5	D6
5.	Des Joachims DS (T1)	115/12.5	D6
6.	Forest Lea DS (T1/T2)	115/12.5	D6
7.	Mazinaw DS (T1/T2)	230/12.5	X1P
9.	Pembroke TS (T1/T2)	115/44	X2Y/X6
10.	Petawawa DS (T1/T2)	115/12.5	D6

APPENDIX B. RENFREW REGION - TRANSMISSION LINES

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Des Joachims DS to Pembroke TS	D6	115
2	Chenaux TS to Pembroke TS	X6	115
3	Chenaux TS to Pembroke TS	X2Y	115
4	Dobbin TS to Chenaux TS	X1P	230

APPENDIX C. RENFREW REGION - DISTRIBUTORS

Sr. no.	Name of LDC
1	Hydro One Networks Inc.(Distribution)
2	Ottawa River Power Corporation (ORPC)

APPENDIX D. RENFREW REGION - MUNICIPALITIES

Sr. no.	Name of Municipality
1	Town of Arnprior
2	Town of Deep River
3	Town of Laurentian Hills
4	Town of Petawawa and Renfrew
5	Township of Admaston/Bromley
6	Township of Bonnechere Valley
7	Township of Brudenell
8	Township of Lyndoch and Raglan
9	Township of Greater Madawaska
10	Township of Head
11	Township of Clara and Maria Horton
12	Township of Killaloe
13	Township of Hagarty and Richards
14	Township of Laurentian Valley
15	Township of Madawaska Valley
16	Township of McNab/Braeside
17	Township of North Algona Wilberforce and Whitewater Region
18	City of Pembroke

APPENDIX E. RENFREW REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.2	7.3	7.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Cobden DS	Tx	T3	N/A	N/A	9.4	Load	7.1	7.2	7.3	7.3	7.4	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.8	7.8	7.9	8.9	8.9	8.9	8.9	8.9	8.9
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	47.8	Load	23.9	24.1	24.3	25.5	25.7	25.9	26.1	26.3	26.4	26.6	26.8	27.0	27.1	27.2	27.3	28.3	28.3	28.3	28.3	28.3	29.3
						DG	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
						CDM	0.4	0.6	0.8	1	1.2	1.4	1.6	1.8	1.9	2.1	2.3	2.5	2.6	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
						Net	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	24	24	24	24	24	25
Craig DS	Tx	T1/T2	B1B2	N/A	19.9	Load	14.3	14.4	14.5	15.6	15.7	15.9	16.0	16.1	16.2	16.3	16.4	16.5	17.6	17.6	17.7	17.7	17.7	17.7	18.7	18.7	18.8
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.3	0.4	0.5	0.6	0.7	0.9	1	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8
						Net	14	14	14	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17
Deep River DS	Tx	T1/T2/T3	N/A	N/A	8.6	Load	8.2	8.3	8.3	8.4	9.5	9.5	10.6	10.7	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1	1	1	1	1	1	1	1
						Net	8	8	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Des Joachims DS	Tx	T1	N/A	N/A	9.4	Load	**2.0**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Forest Lea DS	Tx	T1/T2	BY	N/A	8.6	Load	**9.1**	**9.2**	**9.3**	**9.4**	**9.4**	**9.5**	**9.6**	**9.7**	**9.7**	**9.8**	**9.9**	**9.9**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1	1	1	1	1	1	1	1	1.1
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Mazinaw DS	Tx	T1	BY	N/A	6.9	Load	**3.1**	**3.1**	**3.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
						Net	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mountain Chute DS	Tx	T1	BY	N/A	8.6	Load	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	47	Load	**48.5**	**48.6**	**49.9**	**50.2**	**51.5**	**51.7**	**52.9**	**53.1**	**54.5**	**54.7**	**55.9**	**56.1**	**57.2**	**58.2**	**59.3**	**60.3**	**60.3**	**61.3**	**62.4**	**63.4**	**64.4**
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.3	0.4	0.7	1	1.3	1.5	1.7	1.9	2.3	2.5	2.7	2.9	3	3	3.1	3.1	3.1	3.1	3.2	3.2	3.2
						Net	48	48	49	49	50	50	51	51	52	52	53	53	54	55	56	57	57	58	59	60	61
Petawawa DS	Tx	T1/T2	BY	N/A	16.3	Load	**10.5**	**10.9**	**11.3**	**11.6**	**11.9**	**12.3**	**12.6**	**12.9**	**13.2**	**13.6**	**13.9**	**14.2**	**14.4**	**14.8**	**15.1**	**15.3**	**15.6**	**15.8**	**16.2**	**16.3**	**16.6**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.5	0.7	0.9	1	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2	2.1	2.1	2.1	2.1	2.2	2.1	2.1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

Winter Net Non-Coincident Load Forecast

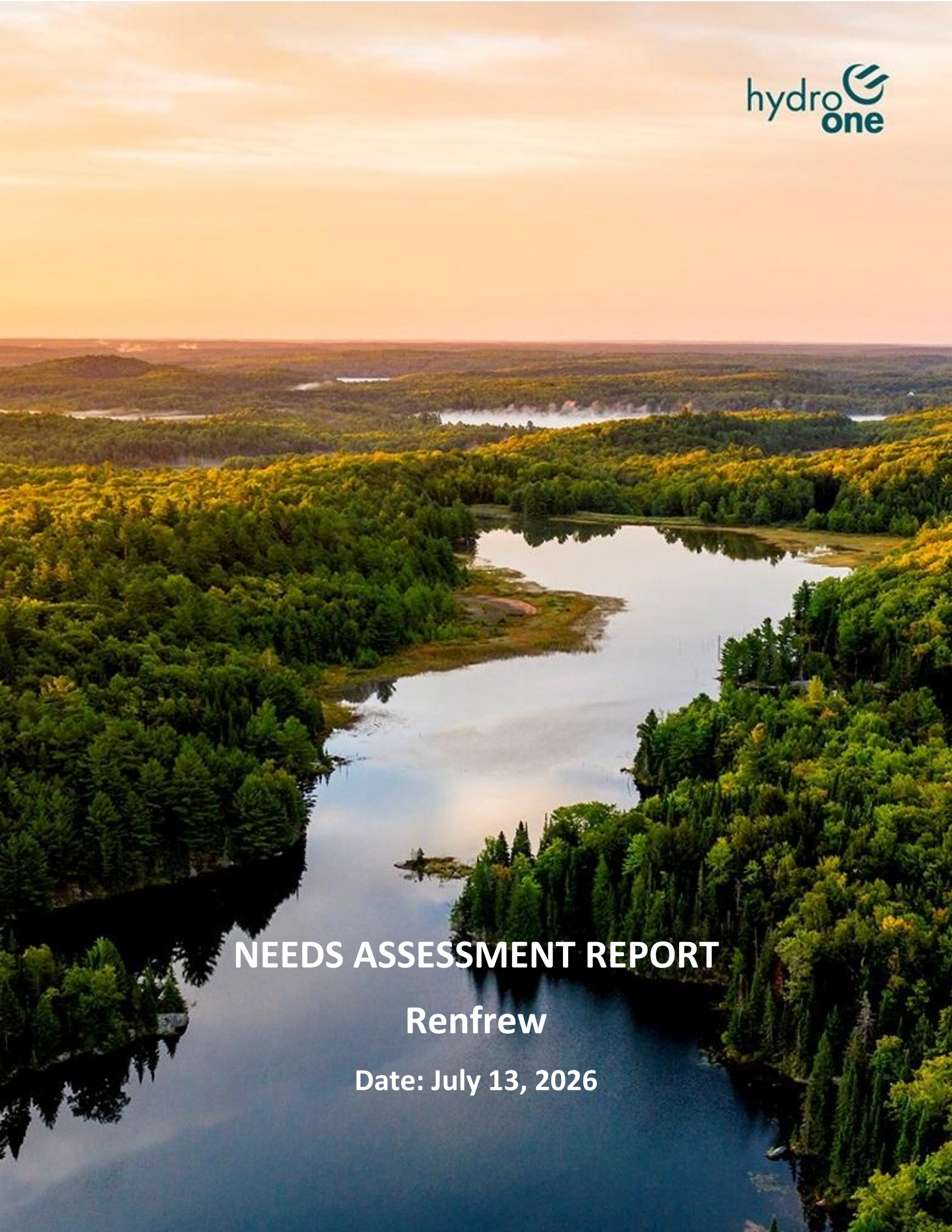
Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	9.0	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.3	10.3	10.2	10.2	10.2	10.2	10.2	10.2
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cobden DS	Tx	T3	N/A	N/A	12	Load	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.5	8.5	8.5	8.5	8.5
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	54.7	Load	25.4	25.6	25.7	25.8	25.9	26.0	26.1	26.3	26.5	26.6	27.8	27.9	28.0	28.1	28.1	28.1	29.1	29.1	29.1	29.1	30.2
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.3	1.4	1.6	1.7	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2
						Net	25	25	25	25	25	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	28
Craig DS	Tx	T1/T2	B1B2	N/A	23.2	Load	12.1	12.2	12.2	12.3	13.3	13.4	13.4	13.5	13.6	13.7	13.7	13.8	13.9	14.9	14.9	14.9	14.9	14.9	14.9	15.9	16.0
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1
						Net	12	12	12	12	13	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
Deep River DS	Tx	T1/T2/T3	N/A	N/A	11.6	Load	10.1	10.2	10.2	10.3	11.3	11.4	12.4	12.5	12.5	12.6	12.6	12.7	12.7	12.7	12.8	12.8	12.8	12.8	12.8	12.8	12.8
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
						Net	10	10	10	10	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Des Joachims DS	Tx	T1	N/A	N/A	12	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.2**	**3.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4	4	4	4
Forest Lea DS	Tx	T1/T2	BY	N/A	11.6	Load	**11.1**	**11.2**	**11.2**	**11.3**	**11.3**	**11.4**	**11.4**	**11.5**	**11.6**	**11.6**	**11.7**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**12.8**	**12.8**	**12.9**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
						Net	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12
Mazinaw DS	Tx	T1	BY	N/A	9.3	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**5.3**	**5.3**	**5.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mountain Chute DS	Tx	T1	BY	N/A	11.6	Load	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	57	Load	**53.1**	**53.2**	**54.5**	**54.8**	**55.0**	**56.2**	**56.3**	**57.6**	**57.9**	**59.1**	**59.3**	**60.5**	**60.6**	**61.6**	**62.5**	**63.6**	**64.6**	**65.6**	**66.5**	**67.5**	**68.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.5	0.8	1	1.2	1.3	1.6	1.9	2.1	2.3	2.5	2.6	2.6	2.5	2.6	2.6	2.6	2.5	2.5	2.5
						Net	53	53	54	54	54	55	55	56	56	57	57	58	58	59	60	61	62	63	64	65	66
Petawawa DS	Tx	T1/T2	BY	N/A	20.2	Load	**10.2**	**10.5**	**10.8**	**11.0**	**11.3**	**11.5**	**11.8**	**12.0**	**12.3**	**12.6**	**12.9**	**13.1**	**13.4**	**13.7**	**13.9**	**14.1**	**14.4**	**14.6**	**14.9**	**15.2**	**15.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1	1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

APPENDIX F. LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
GS	Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resource
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme
TWG	Technical Working Group

APPENDIX G – RENFREW NEEDS ASSESSMENT



NEEDS ASSESSMENT REPORT

Renfrew

Date: July 13, 2026

Needs Assessment Report

Renfrew

Date: July 13, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: Renfrew Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Renfrew Region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on the best available information throughout the planning process.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION Renfrew Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: May 15, 2026 **END DATE:** July 13, 2026

The second Regional Planning cycle for the Renfrew Region was completed in July 2023 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report).

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in January 2026 for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group (TWG) comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and operational concerns.
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Table 1: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.

Table 2: Needs that Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden TS T1/T2	Projected to reach capacity in 2033 under summer High growth scenario.
Transmission Capacity Needs		
2	115 kV D6	Projected to reach capacity in 2031 under summer high growth scenario.
3	115 kV X2Y	Projected to reach capacity limits at the end of study period (2035) during X6 contingency and summer high growth scenario.
System Reliability, Operation and Load restoration Needs		
4	115 kV D6 – Voltage Performance	Voltage issues identified in 2035 for normal summer forecast and in 2031 for High growth summer forecast
5	X2Y Load Restoration	Projected to exceed thermal ratings of X2Y when complete load of Cobden TS needs to be restored under X6 contingency in 2029 under normal growth scenario and 2028 under high growth scenario.

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Ottawa River Power Corporation (ORPC)

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Renfrew Region was completed in July 2023 with the publication of the Regional Infrastructure Plan ("RIP") Report (RIP Report). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the Renfrew Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

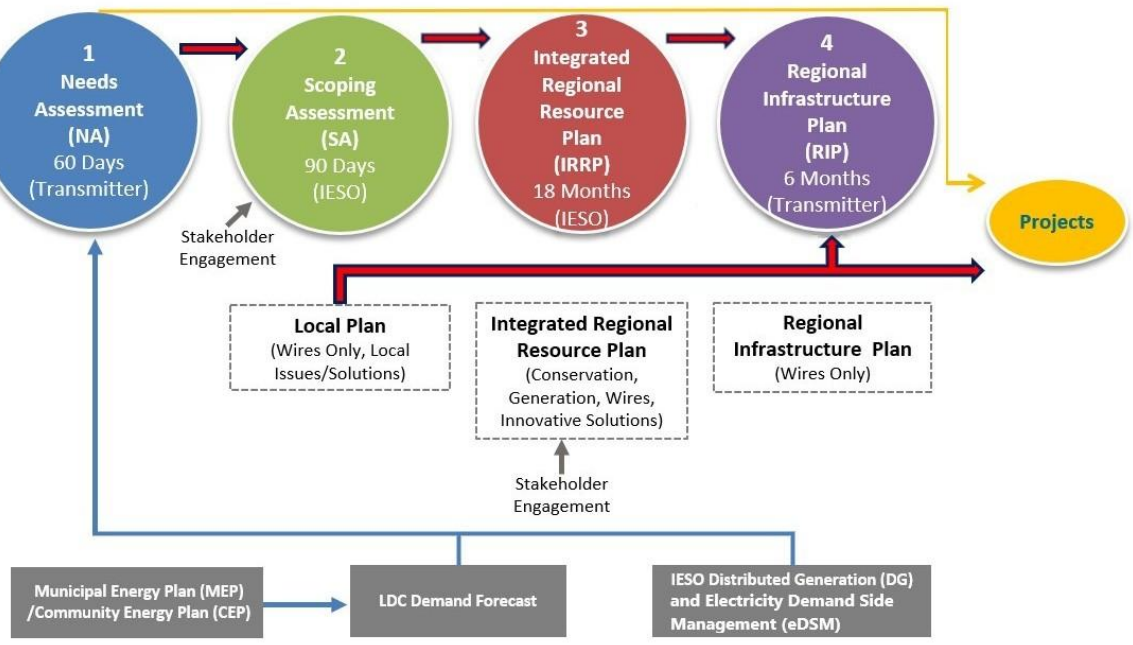


Figure 1: Regional Planning Process

This report was prepared by Renfrew TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 3.

Table 3: Renfrew Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator (IESO)
3	Hydro One Networks Inc. (Hydro One Dx)
4	Ottawa River Power Corporation (ORPC) (embedded to Hydro One Dx)

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the Renfrew region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Renfrew region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Renfrew region is located in Eastern Ontario with the majority of the load along the Ottawa river. For electrical planning purposes this region includes eighteen municipalities including the towns of Arnprior, Deep River, Laurentian Hills, Petawawa and Renfrew. As well as the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke. The geographical boundaries of the Renfrew region are shown in Figure 2 below.

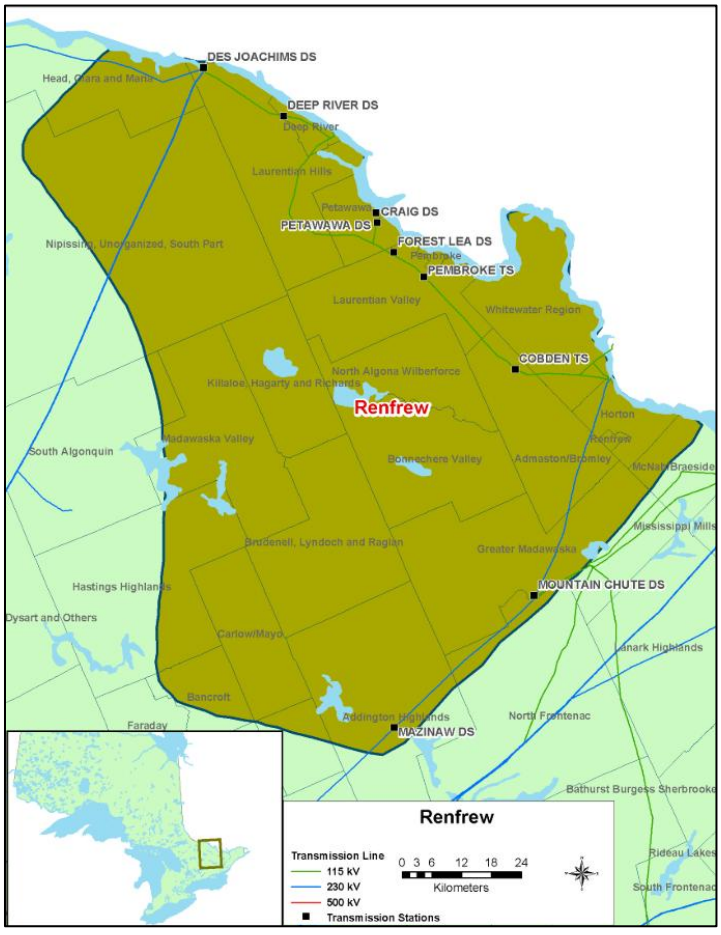


Figure 2: Map of Renfrew Regional Planning Area

The Renfrew region is located in Eastern Ontario, with most of its load concentrated along the Ottawa River. It is bounded by Des Joachims TS to the west, Chenaux TS to the east, and the 230 kV circuit X1P to the south. Electricity supply is provided through one 230 kV circuit (X1P) and three 115 kV radial circuits (D6, X6, and X2Y), with the 115 kV system fed by 230/115 kV autotransformers at Chenaux TS from the east and Des Joachims TS from the west. A normally open 115 kV switch at Pembroke TS separates the eastern and western portions of the region.

The distribution system in the Renfrew region operates at 44 kV and 12.5 kV. The main generation facilities in the area include Chenaux Generation Station (143.7 MW), Mountain Chute Generation Station (170.2 MW), and Des Joachims Generation Station (432.5 MW).

Hydro One Networks Inc. (Distribution) is the main LDC in the area. Other LDCs supplied by electrical facilities in the Renfrew region include Ottawa River Power Corporation and Renfrew Hydro Inc., both are embedded into Hydro One's distribution system. Renfrew Hydro Inc. customers are being fed from Stewartville TS, which is part of the Greater Ottawa Regional Planning. As such, Renfrew Hydro Inc. has not been included as part of this NA.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3.

• Chenaux TS is a major 230 kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230 kV bus. The station connects to the bulk system via a single 230 kV circuit X1P. Two autotransformers step down the voltage to 115 kV to supply two radial circuits X6 and X2Y.

• The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Customer Transformer Station (CTS-2).

• Des Joachims TS is the other major 230 kV transformer station in the Region. There are 432.5 MW of hydraulic generation connecting to the 230 kV bus. The station interconnects to the Bulk Electric System (BES) via five 230 kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115 kV to supply one radial circuit D6.

• The 115 kV circuit D6 from Des Joachims TS 115 kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and CTS-1

• Bryson GS from Hydro Quebec can be radially connected to Renfrew region via X2Y, when required.

• The 230 kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew region: Mountain Chute GS (with hydraulic generation of 170.2 MW) and Mazinaw DS.

• Mountain Chute DS, a 115 kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region.

The circuits and stations of the area are summarized in Table 4 below:

Table 4: Transmission Station and Circuits in the Renfrew Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
D6, X6, and X2Y	X1P	Des Joachims TS*, Des Joachims DS, Deep River DS, Chalk Craig DS, Petawawa DS, Forest Lea DS, Pembroke TS, Cobden TS, Cobden DS, Chenaux TS*, Mountain Chute DS, Mazinaw DS, CTS-1, CTS-2	Mountain Chute GS (170.2MW) Des Joachims GS (432.5MW) Chenaux GS (143.7MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of the Renfrew region is shown in Figure 3 below.

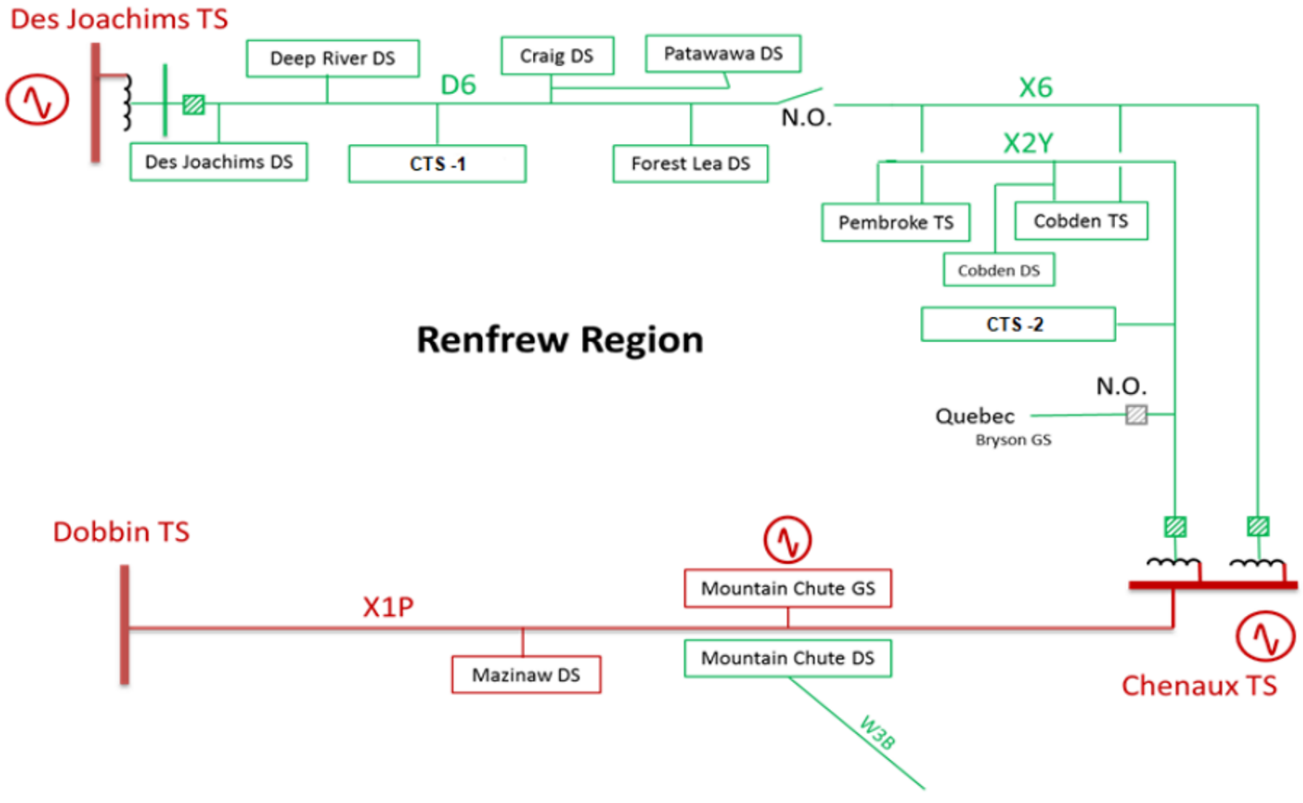


Figure 3: Renfrew Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for Renfrew region NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- Renfrew 10-year summer and winter Load Forecasts for all supply stations inclusive of inputs provided by the municipalities.

  However, sensitivity analysis is undertaken which captures uncertainties via different growth scenarios.

- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and

- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the Renfrew.

- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in development of this Needs Assessment:

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Load forecast data was requested from industrial customers in the region, and

- This assessment is based on summer and winter peak loads. Three forecasts were developed, i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

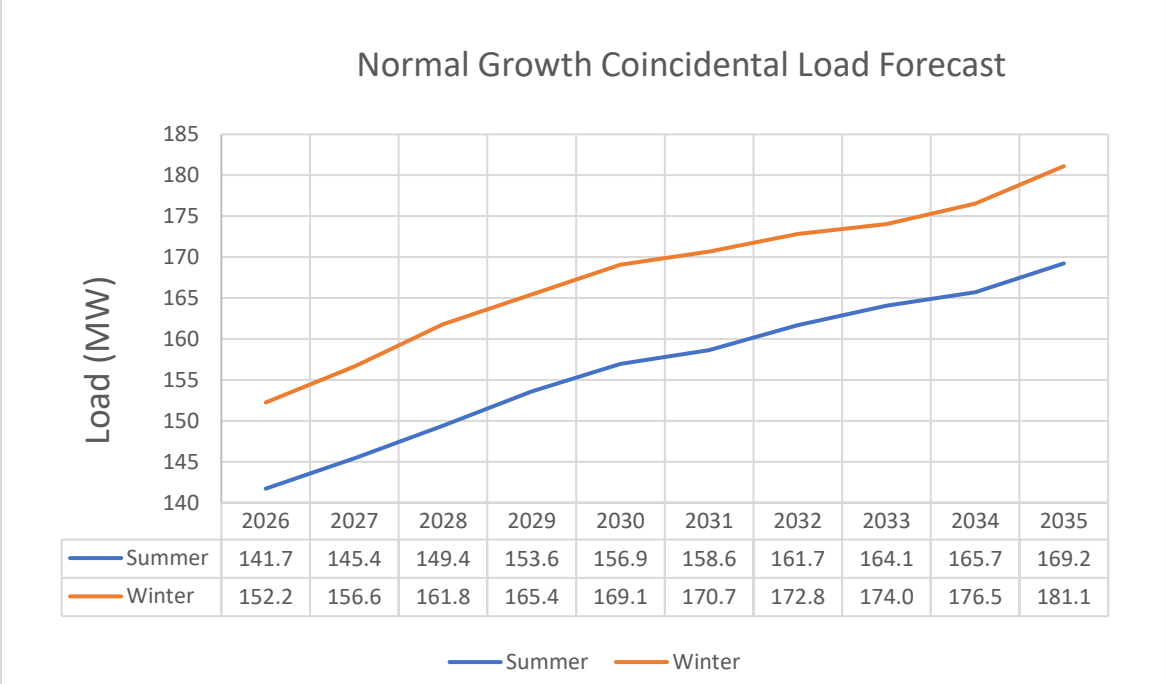
- The study period for this Needs Assessment is 2026-2035.
- The Region is winter peaking; however, system performance was assessed under both summer and winter peak load conditions, including studies for summer peak loads.
- System studies and reported results are based on N-1 (single contingency) conditions, meaning the system is assessed to remain within applicable thermal, voltage, and stability limits following the loss of any one credible transmission element, with the system otherwise in the base configuration.
- No import from Quebec from Bryson CGS.
- Transmission adequacy is assessed based on the system's ability to supply forecast coincident peak demand with all elements in service while maintaining equipment loading within continuous ratings and voltages within normal range, and with one element out of service while maintaining circuit loading within long-term emergency (LTE) ratings and transformer loading within their applicable summer 10-Day Limited Time Rating (LTR).
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day LTR of a single transformer at that station.
- Normal planning supply capacity for distribution stations is determined by the Hydro One summer Peak Loading Limit (PLL) at the station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the Renfrew region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided an Electricity Demand Side Management ("eDSM") , and Distributed Energy Resources ("DER") forecast for the Renfrew region. The region's

extreme summer/winter coincident peak gross load forecasts for each station were prepared in accordance with the Load Forecast Guidelines published by the OEB RPPAG. The LDC load forecast growth rates were calculated (including expected growth, committed customers load etc.) and applied to the actual 2025 summer/winter peak extreme weather corrected loads. The extreme summer/winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage eDSM and then by the amount of effective new DER capacity provided by the IESO for that station. It is to be noted that as contracts for existing DER resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DER resources, and an increase in net demand. This extreme summer/winter weather corrected net load forecast for the individual stations in the Renfrew region is given in Appendix A. The graphical representation of the regional net coincidental load growth for both summer and winter season over the study period is shown in Figure 4 below.



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	141.7	145.4	149.4	153.6	156.9	158.6	161.7	164.1	165.7	169.2
Winter	152.2	156.6	161.8	165.4	169.1	170.7	172.8	174.0	176.5	181.1

Figure 4: Renfrew Region Coincident Load Forecast

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

No new Asset renewal needs were identified during the study period.

6.2.4. System Reliability and Operational Issues:

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

During the studies TWG identified system operational issues on 115 kV D6 line. Under high growth scenarios there are voltage issues observed at end of line stations for Petawawa DS, Forest Lea DS and Craig DS during normal all in-service condition.

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

7. NEEDS

This section describes emerging new needs identified in the Renfrew Region and/or updates on previously identified needs since the completion of previous Regional Planning cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. Pembroke TS T1/T2 – A station capacity need was identified in the previous regional planning cycle. However, based on updated detailed LTR studies with recent loading profile at the station the LTR of the station have been updated and this need no longer exists within the short-term planning cycle due to higher LTR ratings than the value used in the previous regional planning cycle.
2. Forest Lea DS – A load transfer need was identified in the previous regional planning cycle. However, based on the revised PLL, this need no longer exists, as the updated PLL is higher than the value used in the previous regional planning cycle.
3. 115 kV D6 Line Refurbishment - The existing HONI 115 kV circuit D6 will be partially relocated and will reduce the length of the line section between CTS-1 and Petawawa JCT from 38.9 km to 30.7 km and therefore will reduce the overall D6 circuit length from 90.8 km to 82.7 km. The project is expected to be completed in December 2027.
4. Des Joachims T6 Autotransformer- Due to asset condition Replacement of autotransformer T6 with standard 125 MVA 239/121-13.9 kV autotransformer completed in June 2026.

Note: The planned in-service year for the above projects is tentative and is subject to change.

All near and mid-term needs that are discussed as a part of this report are summarized in Table 5 below.

Table 5: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update	NA Report Section
Asset Renewal Needs		
115 kV D6 Line	Complete 76.8 km line refurbishment between Des Joachims TS and Petawawa/Craig DS	7.1.1
Station Capacity Needs		
Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.	7.2.1
Cobden TS T1/T2	Projected to reach capacity in 2033 under summer High growth scenario.	7.2.2

Transmission Line Capacity Needs		
115 kV D6	Projected to reach capacity in 2031 under summer high growth scenario.	7.3.1
115 kV X2Y	Projected to reach capacity limits at the end of study period (2035) during X6 contingency and summer high growth scenario.	7.3.2
System Reliability, Operation and Load Restoration Needs		
115 kV D6 – Voltage Performance	Voltage issues identified in 2035 for normal summer forecast and in 2031 for High growth summer forecast	7.4.1
X2Y Load Restoration	Projected to exceed thermal ratings of X2Y when complete load of Cobden TS needs to be restored under X6 contingency in 2029 under normal growth scenario and 2028 under high growth scenario.	7.4.2

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and the TWG identified no new asset renewal needs for major HV transmission equipment over the next 10 years in the Renfrew Region.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
  replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

Table 6: Major HV Transmission Assets Planned for Replacement in Renfrew Region in next 10 years

Station/Circuit	Need Description	Planned ISD
115 kV D6	Complete 76.8 km line refurbishment between Des Joachims TS and Petawawa/Craig DS	2027

7.1.1 115 kV D6 Line Refurbishment

The 115 kV D6 is a single circuit transmission line that connects Des Joachims TS to Pembroke TS along the Ottawa River in the Laurentian Hills area. Based on asset condition assessment, the circuit was identified for refurbishment and expected to be completed by end of 2027. The planned in-service date for the project is in end of 2027.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2026-2035 for the 230kV and 115kV Transforming stations in the Renfrew Region using either the summer or winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Cobden DS – T3

Cobden DS is located in the eastern part of the Renfrew region and is supplied by the 115 kV X2Y circuit, with provision to be supplied by X6 under contingency conditions. The station has one transformer, T3, with a summer PLL of 8.9 MW, and supplies load to Hydro One Distribution.

Based on the load forecast, Cobden DS is expected to exceed its summer PLL in 2029. Winter loading is forecast to remain within limits throughout the study period. Under the high-growth scenario, the projected summer need date advances to 2028.

The TWG recommends that the identified station capacity needs be addressed through coordinated planning between Hydro One Transmission and Hydro One Distribution. In the near term, feasible mitigation measures should be evaluated, including load transfers, transformer upgrades, and the implementation of SCADA-based fan monitoring to maximize the utilization of existing assets. The TWG further recommends continued monitoring of station loading and demand growth trends, with the objective of developing an appropriate longer-term solution through the Local Planning process when capacity reinforcement is required.

7.2.2 Cobden TS – T1/T2

Cobden TS is an important supply point for customers in and around the Cobden area. The station is supplied by X2Y and X6 circuits and is equipped with two 42 MVA transformers, T1 and T2 with a summer and winter LTR of 41.6 MW and 49.3 MW respectively.

Under the normal load forecast, no station capacity need has been identified at Cobden TS over the study period. However, sensitivity analysis indicates that under the summer high-growth forecast, Cobden TS is expected to exceed its summer LTR in 2033. Given that this need only materializes under the high-growth sensitivity scenario, TWG recommends continued monitoring of actual load growth at the station and revisiting the capacity need in the next phase of regional planning.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2026-2035 for the 230kV and 115kV Transmission line circuits in the Renfrew Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified during the study period:

7.3.1 115 kV D6

The 115 kV Des Joachims subsystem is supplied from Des Joachims TS through 115kV circuit D6 and serves load eastward toward Petawawa DS, Craig DS and Forest Lea DS. Circuit D6 forms a critical supply path in the western Renfrew area, and prior regional planning has recognized the importance of this corridor in maintaining reliable supply to communities including Laurentian Hills, Deep River, Petawawa and Laurentian Valley. As outlined in section 7.1.1 Hydro One's D6 refurbishment project, involving

approximately 76.8 km of 115 kV transmission line between Des Joachims TS and Pembroke TS, was initiated to address end-of-life assets and support continued reliability of supply in the area this refurbishment with larger standard conductors have increased the load meeting capability of the circuit from 50.9 MW to 93.9 MW. Adequacy studies were completed for the Des Joachims subsystem under both a normal growth forecast and a high growth sensitivity with the new conductors are shown in Figure 5 below

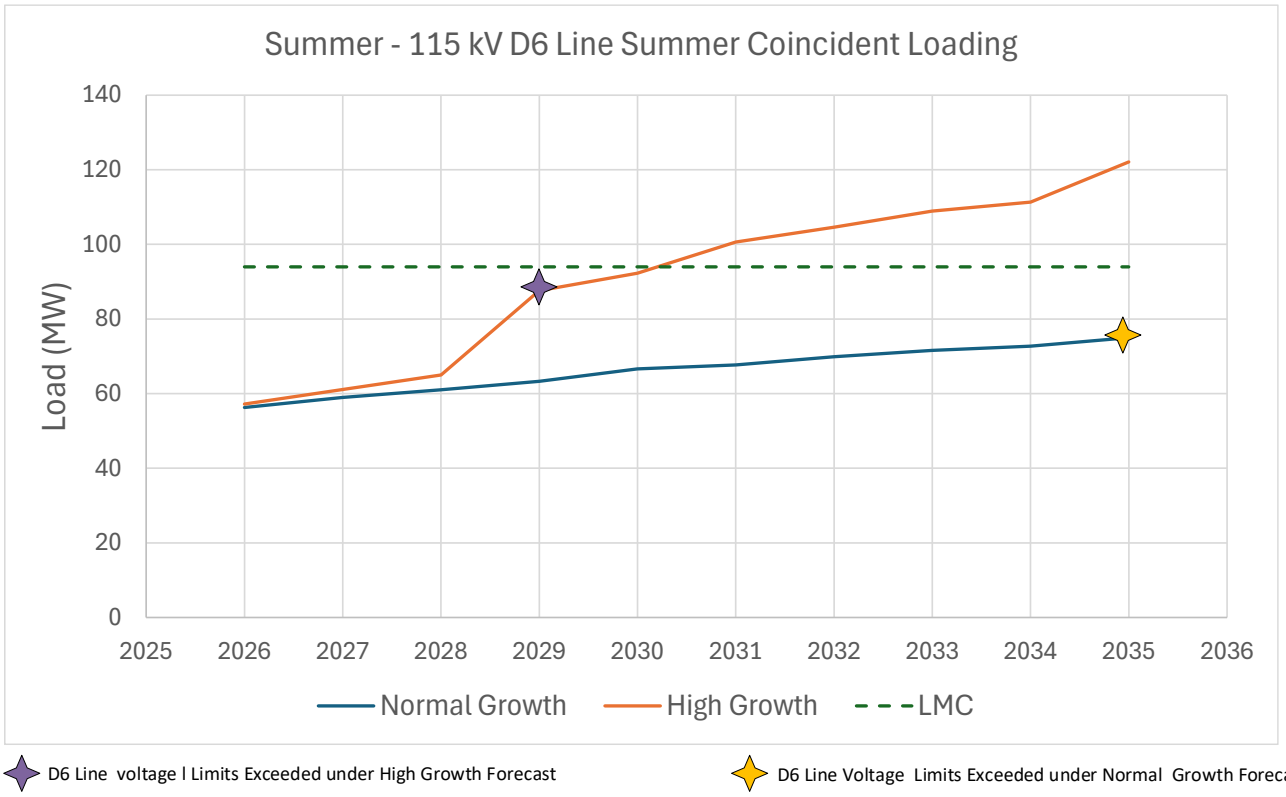


Figure 5: 115 kV D6 Loading

Normal Growth Scenario

Under the normal growth scenario, the 115 kV Des Joachims subsystem is expected to remain thermally adequate over the study period. The D6 line refurbishment project provides sufficient capacity to accommodate the forecast load growth on the subsystem. However, while no thermal capacity concerns were identified, the studies indicate that voltage performance becomes a limiting factor in the later years of the study period. In particular, stations located toward the remote end of Circuit D6, including Petawawa DS, Craig DS and Forest Lea DS, were found to experience voltage levels below the applicable ORTAC minimum voltage criteria. As a result, the subsystem is considered adequate from a line-loading perspective under normal growth, but voltage support or other mitigation measures will be required in the longer term to maintain acceptable voltage performance at the end-of-line stations.

High Growth Scenario

Under the high growth scenario, the adequacy of the 115 kV Des Joachims subsystem becomes more constrained. This sensitivity was developed to reflect increased connection interest along Circuit D6 and assumed 50% higher load growth than the normal forecast, along with potential new transmission-connected load with a high certainty score. Study results indicate that, under this higher load outlook, Circuit D6 exceeds its thermal capability beginning in the 2031 summer forecast year. In addition to the thermal limitation, voltage violations are also observed at the remote stations connected to D6, including Petawawa DS, Craig DS and Forest Lea DS in 2029. These results indicate that the subsystem would not be adequate under the high growth scenario without additional reinforcement or mitigation.

Further studies in next phase should be undertaken to develop solutions (including non-wires alternatives).

7.3.2 115 kV X2Y

X2Y is a 58 km, 115 kV circuit located northwest of the Greater Ottawa area and electrically associated with the Renfrew regional supply area. The circuits provide connection and/or supply to Pembroke TS, Chenaux TS, Cobden TS, Cobden DS, CTS-2, and Bryson CGS in Hydro-Québec. X2Y has an LTE rating of 91.0 MVA and 102.8 MVA in summer and winter respectively.

Under the normal growth forecast the X2Y remains within its thermal limits but under the high growth forecast X2Y approaches its thermal limits under X6 contingency at the end of study period.

TWG recommends studying this need in the next phase of the regional planning for long-term solution for the X2Y limiting section. If the total loading at Pembroke TS, Cobden TS, and Cobden DS exceeds the thermal rating of the limiting X2Y section before solutions are implemented, then operating measures can be deployed in the interim to alleviate the limit.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been carried out, considering the net coincident load forecast and the loss of one element over the study period 2026-2035 to cater for this need**.** Based on the results, the following needs have been identified during the study period:

7.4.1 Voltage Performance of 115 kV D6

A series of system studies were conducted to evaluate the voltage performance of the 115 kV D6 circuit under various operating conditions and long-term load growth assumptions.

Under the 2035 normal growth scenario and 2029 high growth scenario the analysis shows that the pre-contingency voltage on D6 violates ORTAC limits. Specifically, the voltage on the affected sections of

D6 falls below the minimum ORTAC limit of 113 kV, indicating inadequate voltage performance in this scenario.

TWG recommends further review of this need in the next phase of regional planning.

7.4.2 X2Y Load Restoration

Under normal configuration, Cobden TS is supplied from X6 and X2Y, with the low-voltage bus tie normally open. Following an X6 contingency, restoration of the full Cobden TS load requires manual closure of the LV tie switch. This restoration configuration transfers additional load onto X2Y, resulting in the circuit exceeding its LTE rating in the near term.

When restoring the load of Cobden TS from X2Y under X6 contingency the need is expected to emerge in 2029 under the normal summer growth scenario and advance to 2028 under the high-growth scenario whereas for the winter time the need is expected to emerge in 2028 for both normal and high growth scenarios. Accordingly, the restoration need is considered a near- to medium-term transmission loading need, depending on the growth scenario. As load loss is less than 150 MW for the contingency, it will be restored within 8 hours as per load restoration criteria in section 6.2.4

TWG recommends further review of this need in the next phases of regional planning.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Renfrew region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%. The High Growth scenario incorporates EV scenarios, includes consideration of potential additional demand from electrification as well as anticipated large industrial and commercial customers expected to connect in the near to mid-term.

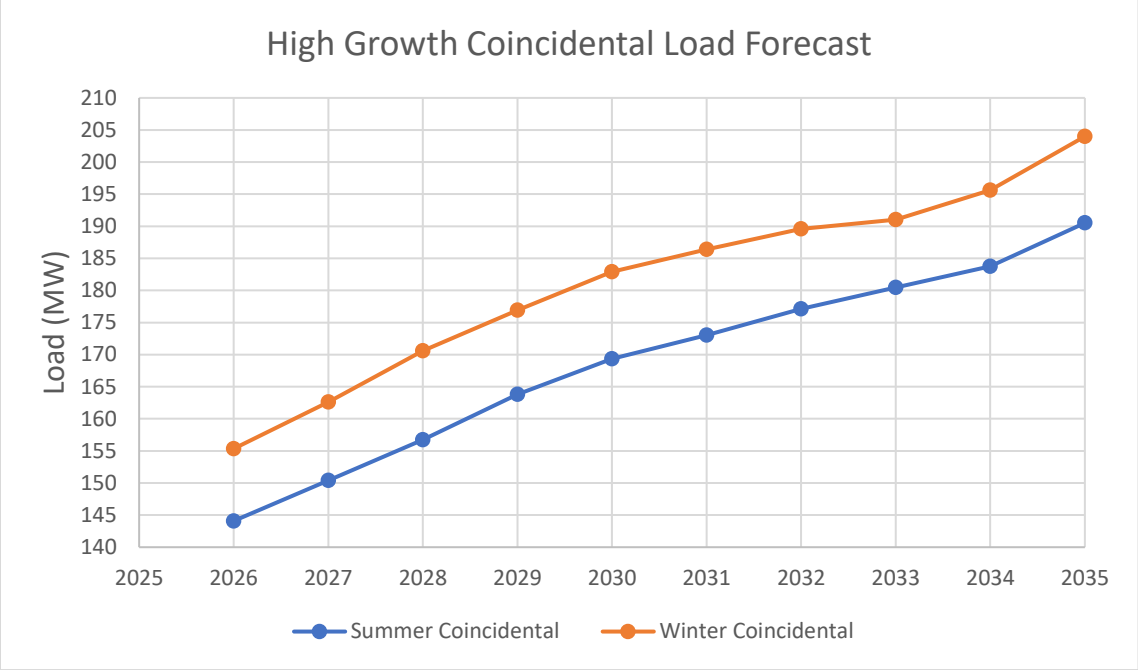


Figure 6: High Growth Forecast for existing station

The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 7: Impact of Sensitivity Analysis on Station/Line capacity Needs in the Region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Cobden DS	2029	2028	-
2	Cobden TS T1/T2	-	2033	-
3	115 kV D6 Line	-	2031	-
4	115 kV X2Y Line	-	~2035	-
5	Voltage Performance of 115 kV D6	2035	2031	-
6	X2Y Load Restoration	2029	2028	-

9. CONCLUSION AND RECOMMENDATION

The Needs Assessment has considered N-1 contingency scenarios to identify needs in the area. The next phases will include a revised forecast and additional outage/contingency analysis beyond what was assessed here. These studies may find further limits on the system's ability to supply additional load. Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs that Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.

Table 9: Needs that Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.
2	Cobden TS T1/T2	Projected to reach capacity in 2033 under summer High growth scenario.
Transmission Line Capacity Needs		
3	115 kV D6	Projected to reach capacity in 2031 under summer high growth scenario.
4	115 kV X2Y	Projected to reach capacity in 2035 under summer high growth scenario.
System Reliability, Operation and Load restoration Needs		
5	115 kV D6 – Voltage Performance	Voltage issues identified in 2035 for normal summer forecast and in 2031 for High growth summer forecast.
6	X2Y Load Restoration	Projected to exceed thermal ratings of X2Y when complete load of Cobden TS needs to be restored under X6 contingency in 2029 under normal growth scenario and 2028 under high growth scenario.

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Ottawa River Power Corporation (ORPC)

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

10. REFERENCES

[1] Hydro One, RIP Report – Renfrew Region (Second cycle) , published in July, 2023

[2] Independent Electricity System Operator, IRRP Report (Second Cycle) , published in December 2022

[3] Hydro One, NA Report – Renfrew Region (Second cycle) , published in May, 2021

[4] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 6.0 September 10, 2025)

[5] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[6] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Renfrew Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Station Name	Summer LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	8.9	8.4	8.6	8.8	9.0	9.0	9.0	9.1	9.1	9.2	9.3
Cobden TS	41.6	30.8	32.4	34.4	35.2	35.4	35.6	36.6	37.0	37.3	37.8
Craig DS	28.5	16.7	17.4	18.2	18.9	19.7	20.0	20.1	20.2	20.4	20.6
Deep River DS	16.4	9.7	9.9	10.2	10.3	10.3	10.3	10.3	10.3	10.4	10.4
Des Joachims DS	8.9	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Forest Lea DS	16.4	10.2	10.5	10.7	10.8	11.0	11.1	11.3	11.4	11.6	11.7
Mazinaw DS	6.6	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.3	4.3
Mountain Chute DS	8.2	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS	59.9	49.6	49.8	49.2	50.4	50.7	50.9	51.2	51.7	52.1	52.5
Petawawa DS	28.5	11.6	12.7	13.5	14.7	15.9	15.9	15.9	15.9	16.0	16.1
CTS-1		8	8	8.5	9	10	10.75	12.25	13.5	14	16
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		155.7	160.0	164.4	169.2	173.0	174.8	177.8	180.4	182.1	185.7

Table A.2: Renfrew Region – Winter Non-Coincident- Normal Growth Net Load Forecast

Station Name	Winter LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	11.4	7.3	7.6	7.7	7.8	7.9	7.9	8.0	8.0	8.1	8.2
Cobden TS	49.3	29.2	30.7	32.8	33.5	33.6	33.7	33.8	34.0	34.2	34.6
Craig DS	28.5	13.0	13.7	14.6	15.3	16.1	16.4	16.5	16.6	16.7	17.0
Deep River DS	22.1	10.5	10.7	11.1	11.2	11.2	11.2	11.2	11.3	11.3	11.4
Des Joachims DS	11.4	4.0	4.0	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1
Forest Lea DS	22.1	9.0	9.3	9.5	9.6	9.9	10.0	10.1	10.3	10.4	10.6
Mazinaw DS	8.8	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	4.0	4.0
Mountain Chute DS	11.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pembroke TS	67.5	54.3	54.6	54.9	55.0	55.2	55.4	55.7	55.0	56.3	57.7
Petawawa DS	28.5	11.6	12.7	13.5	14.8	16.1	16.1	16.1	16.1	16.1	16.3
CTS-1		8.0	8.0	8.5	9.0	10.0	10.8	12.3	13.5	14.0	16.0
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		154.8	159.3	164.6	168.3	172.1	173.7	175.9	177.1	179.6	184.2

Table A.3: Renfrew Region Summer Non-Coincident – High Growth Net Load Forecast

Station Name	Summer LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	8.9	8.5	8.9	9.3	9.5	9.6	9.7	9.8	9.9	10.0	10.2
Cobden TS	41.6	31.7	34.2	37.3	38.7	39.2	39.7	41.0	41.7	42.4	43.3
Craig DS	28.5	17.2	18.4	19.7	21.0	22.4	23.0	23.3	23.6	24.0	24.4
Deep River DS	16.4	9.8	10.2	10.7	10.9	11.0	11.0	11.1	11.2	11.3	11.4
Des Joachims DS	8.9	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0
Forest Lea DS	16.4	10.5	10.9	11.3	11.5	11.9	12.1	12.4	12.7	13.0	13.3
Mazinaw DS	6.6	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6
Mountain Chute DS	8.2	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Pembroke TS	59.9	52.8	53.3	52.7	54.7	55.3	56.0	56.6	57.4	58.2	59.0
Petawawa DS	28.5	12.1	14.0	15.2	17.5	19.7	19.8	19.8	19.9	20.1	20.3
CTS-1		8.0	8.0	8.5	9.0	10.0	11.5	13.0	14.0	15.0	19.0
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		161.4	168.7	175.7	183.9	190.3	194.2	198.5	202.0	205.5	212.5

Table A.4: Renfrew Region –Winter Non- Coincident – High Growth Net Load Forecast

Station Name	Winter LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	11.4	7.4	7.9	8.2	8.4	8.5	8.6	8.7	8.8	8.9	9.0
Cobden TS	49.3	30.0	32.4	35.4	36.6	37.0	37.3	37.6	38.0	38.4	39.1
Craig DS	28.5	13.5	14.7	16.1	17.3	18.7	19.3	19.5	19.8	20.1	20.5
Deep River DS	22.1	10.7	11.1	11.6	11.8	11.9	12.0	12.1	12.2	12.3	12.4
Des Joachims DS	11.4	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3
Forest Lea DS	22.1	9.3	9.7	10.1	10.3	10.7	11.0	11.2	11.5	11.8	12.1
Mazinaw DS	8.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3
Mountain Chute DS	11.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1
Pembroke TS	67.5	58.1	58.6	59.2	59.7	60.2	60.7	61.2	60.3	62.5	64.8
Petawawa DS	28.5	12.1	14.0	15.3	17.7	19.9	20.0	20.1	20.2	20.4	20.6
CTS-1		8.0	8.0	8.5	9.0	10.0	11.5	13.0	14.0	15.0	19.0
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		160.9	168.4	176.6	183.2	189.4	192.9	196.1	197.6	202.3	210.7

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Cobden DS (T3)	115/12.5	X2Y
2	Cobden TS (T1/T2)	115/44	X2Y/X6
3	Craig DS (T1/T2)	115/12.5	D6
4	Deep River DS (T1/T2/T3)	115/12.5	D6
5	Des Joachims DS (T1)	115/12.5	D6
6	Forest Lea DS (T1/T2)	115/12.5	D6
7	Mazinaw DS (T1/T2)	230/12.5	X1P
8	Pembroke TS (T1/T2)	115/44	X2Y/X6
9	Petawawa DS (T1/T2)	115/12.5	D6

Appendix C: List of Transmission Lines

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Des Joachims DS to Pembroke	D6	115
2	Chenaux TS to Pembroke TS	X6	115
3	Chenaux TS to Pembroke TS	X2Y	115
4	Dobbin TS to Chenaux TS	X1P	230

Appendix D: List of Municipalities in the Renfrew Region

No.	Name of Municipality
1	Town of Arnprior
2	Town of Deep River
3	Town of Laurentian Hills
4	Town of Petawawa and Renfrew
5	Township of Admaston/Bromley
6	Township of Bonnechere Valley
7	Township of Brudenell
8	Township of Lyndoch and Raglan
9	Township of Greater Madawaska
10	Township of Head
11	Township of Clara and Maria Horton
12	Township of Killaloe
13	Township of Hagarty and Richards
14	Township of Laurentian Valley
15	Township of Madawaska Valley
16	Township of McNab/Braeside
17	Township of North Algona Wilberforce and Whitewater Region
18	City of Pembroke

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resources
DS	Distribution Station
eDSM	Electricity Demand Side Management
EV	Electric Vehicle
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IPL	International Power Lines
IRRP	Integrated Regional Resource Plan
kV	Kilo Volt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation

Acronym	Description
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PLL	Planned Loading Limit
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RPPAG	Regional Planning Process Advisory Group
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TAO	Transmission Asset Owner
TS	Transformer Station
TWG	Technical Working Group

APPENDIX H – CUSTOMER ENGAGEMENT SURVEY REPORT

Ottawa River Power Company

2026 Customer Survey Report

BBA Document No. R0
August 4th, 2026

FINAL REPORT

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1. Introduction

ORPC promoted its DSP customer survey through a broad outreach campaign that included direct email communications, website advertising, and a participant incentive. The survey received 50 responses over the 31-day survey period, for June 11th, 2026 – July 12th, 2026 (inclusive). Although the sample is not intended to be statistically representative of ORPC's full customer base, the feedback provides meaningful qualitative insight into customer satisfaction, customer priorities, and emerging areas of interest that support the development of the DSP.

1.1 Demographics – Questions 1-3

Questions 1 through 3 were included to confirm respondent eligibility, prevent duplicate survey submissions, and allow responses to be segmented by customer type and service territory. These questions help ensure that survey results reflect the perspectives of ORPC customers and support analysis of whether priorities vary across different customer groups or geographic areas. Customer type and service area can influence customer experiences, reliability expectations, and investment priorities. Comparing survey demographics with ORPC's actual customer base also helps identify any areas where survey responses may be over- or under-represented. This section provides details and insights into the types of customers who responded to the survey and associated customer demographics. A total of 50 ORPC customers with representation from all four service areas responded to the survey. The total number of customers that responded to the survey, broken down by service area, is listed in Table 1 and shown in Figure 1.

Table 1: ORPC customer demographic by service area

Service Area	Amount	Percentage
Pembroke	30	60%
Almonte	16	32%
Killaloe	3	6%
Beachburg	1	2%
Total	**50**	**100%**

The majority of respondents fall within the Pembroke service area (60%), followed by Almonte (32%). This is representative of ORPC's customer base, as the most populous service regions are Pembroke and Almonte.

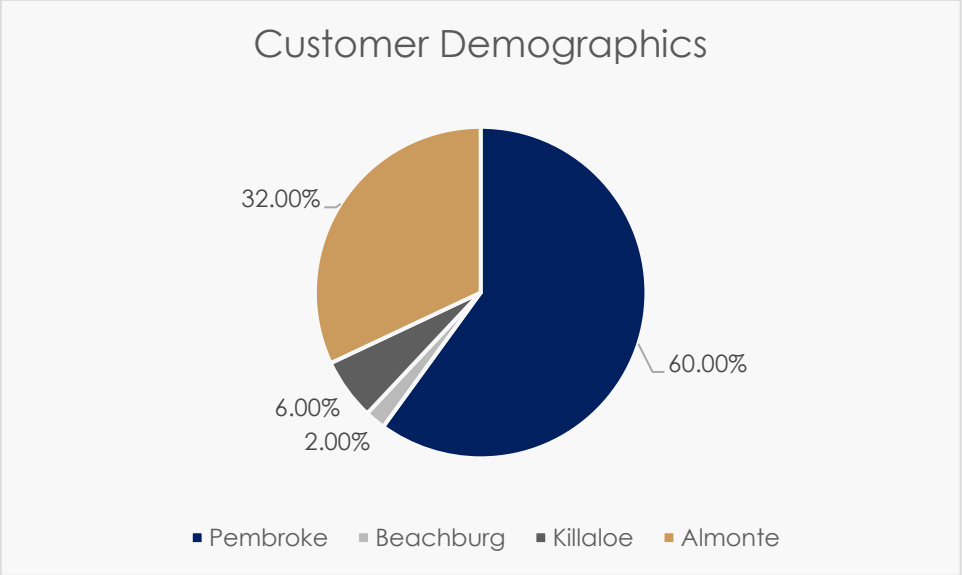


Figure 1: ORPC customer demographics by service area

Of the 50 customers surveyed, 49 were residential customers and 1 was other/multiple accounts customers located within ORPC's service territory, see Table 2.

Table 2: Responding customer account type

Customer Type	Amount	Percent
Residential	49	98%
Other / Multiple Accounts	1	2%
Business	0	0%
Total	50	100%

The survey sample comprised 98% Residential customers and 2% Other / Multiple Accounts customers (Table 2), compared with ORPC's overall customer base of approximately 88% Residential customers and 12% Other customers (Table 3). As such, Residential customers are proportionally more represented in the survey sample than in the customer base.

Table 3: Historical Breakdown of representative ORPC customer base

Annual Year	Residential	Other / Multiple Accounts	Residential %	Other / Multiple Account %
2021	10127	1422	88%	12%
2022	10223	1415	88%	12%
2023	10326	1406	88%	12%
2024	10367	1408	88%	12%
2025	10411	1408	88%	12%

1.2 Performance – Question 4

Prior to discussing performance, respondents were asked about their familiarity with ORPC's operations. Familiarity levels may indicate whether respondents are well positioned to provide meaningful feedback on reliability, communications, and future investment priorities.

As displayed in Figure 2, the majority of customers indicated that they are familiar with ORPC's operations, with 92% reporting they are somewhat or very familiar. Only 8% reported that they were not familiar with ORPC's operations. These results suggest that customers generally feel informed about ORPC's activities and services within their communities.

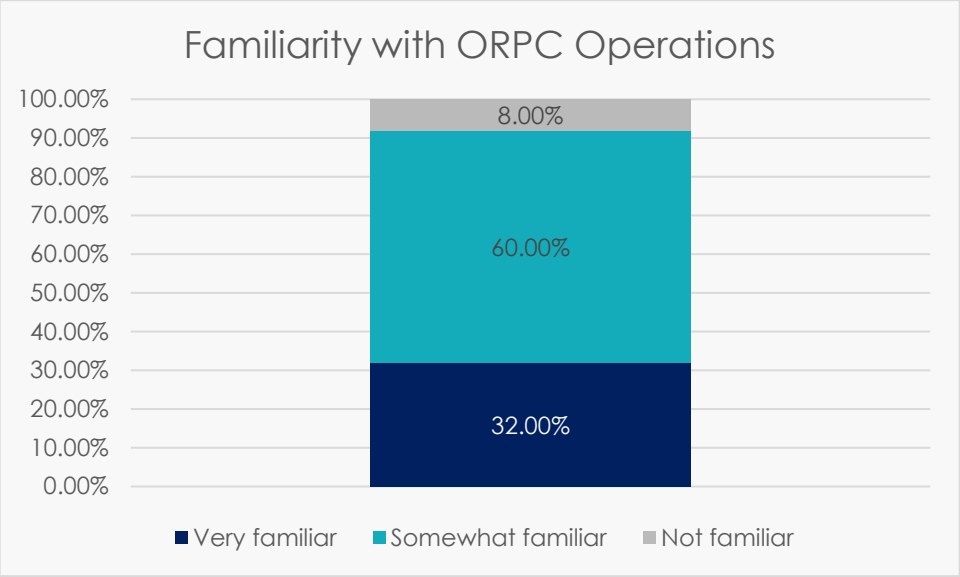


Figure 2: ORPC customer familiarity with ORPC operations

1.3 Customer Satisfaction – Questions 5-6

To assess customer perceptions of ORPC's performance, respondents were asked about their satisfaction with both ORPC's overall service and the reliability of the electricity service they receive. These questions provide insight into customer experience and help identify areas where ORPC is meeting customer expectations as well as opportunities for improvement.

As shown by the survey results in Figure 3, overall customer satisfaction with ORPC services is high. A total of 84% of customers indicated that they were either somewhat or very satisfied with the services received from ORPC. Only 6% of respondents indicated they were somewhat or very dissatisfied, while 10% were neither satisfied nor dissatisfied. No respondents selected unsure.

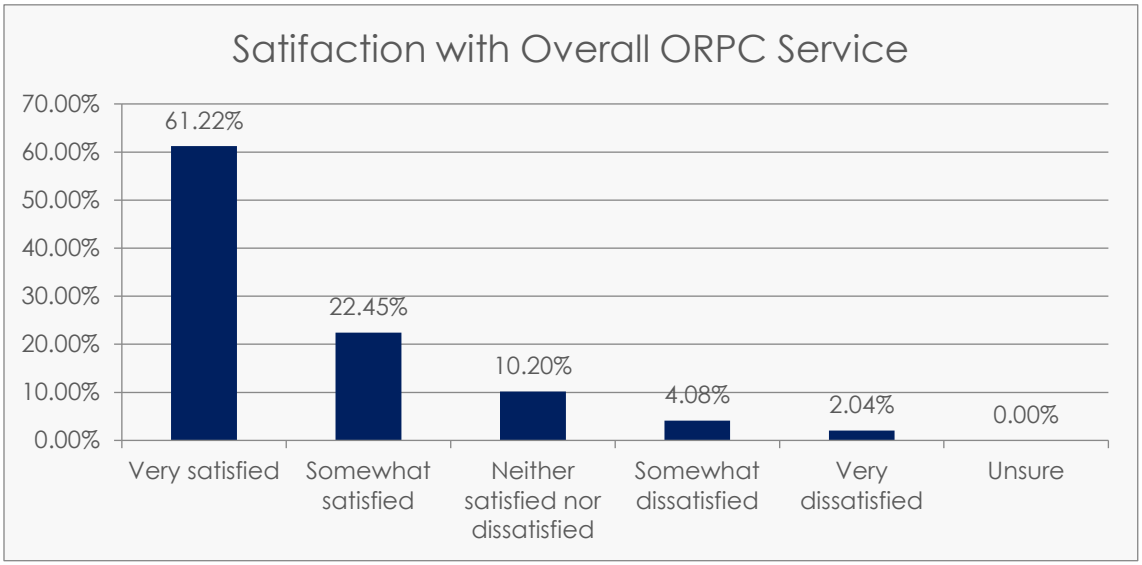


Figure 3: ORPC overall service customer satisfaction

Overall, the survey results demonstrate strong customer satisfaction with ORPC's overall level of service. While there remains a small portion of customers expressing dissatisfaction, the majority of respondents are satisfied with the services they receive. ORPC should continue focusing on maintaining service quality and proactively addressing customer concerns to sustain and further improve satisfaction levels.

Figure 4 illustrates ORPC's customer satisfaction levels with respect to the reliability of electricity services provided, including outage management performance. Similar to the overall service satisfaction results, customers are generally satisfied with the reliability of their electricity service. Overall, 86% of respondents reported being somewhat or very satisfied with current reliability and outage management. In comparison, 8% of respondents indicated dissatisfaction. An additional 6% were neither satisfied nor dissatisfied.

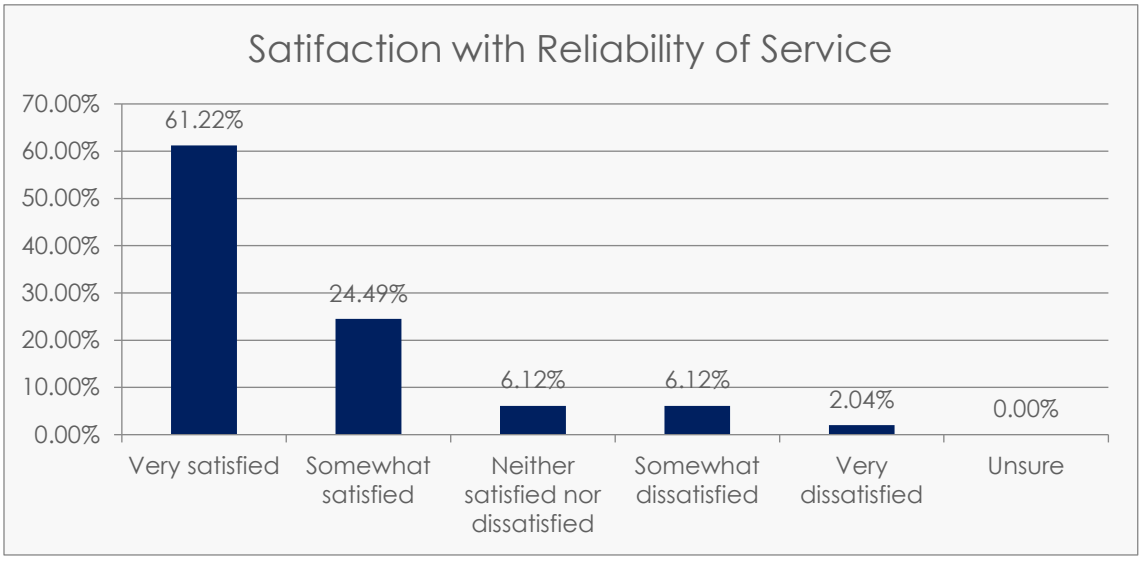


Figure 4: Satisfaction with Service Reliability

1.4 Power Restoration Performance – Question 7

Timely restoration of electricity service following outages is an important component of customer satisfaction. Customers were asked to share their level of satisfaction with ORPC's restoration to better understand how outage response efforts are perceived across the service territory.

A total of 76% of respondents were somewhat satisfied or very satisfied with restoration times following outages, while 12% were dissatisfied and 8% remained neutral. These results, shown in Figure 5, indicate that customers generally recognize ORPC's efforts to restore power promptly following service interruptions.

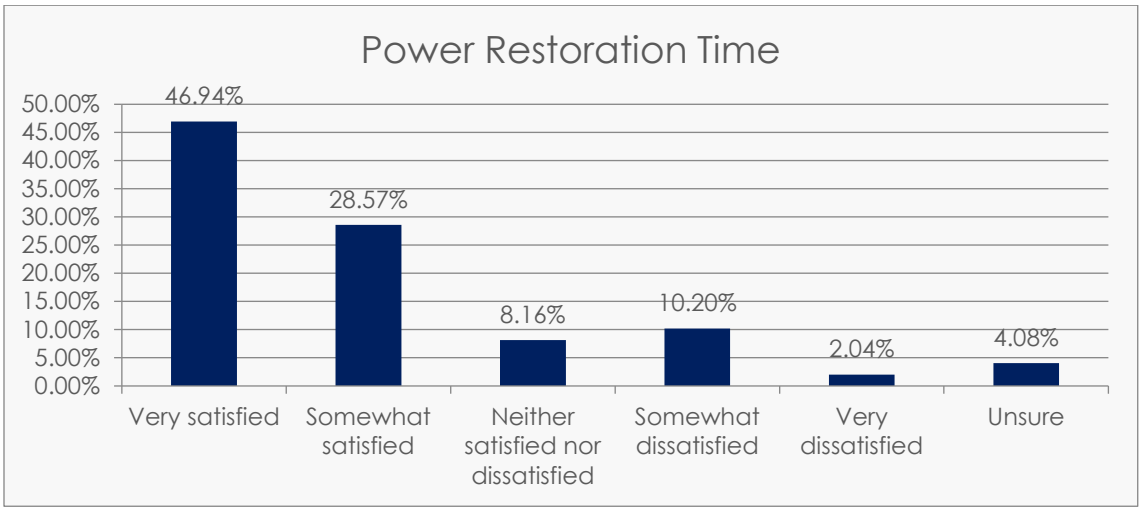


Figure 5: Satisfaction with Restoration Times

1.5 Outage Communications and Trends– Question 8 & 9

Respondents were asked about their satisfaction with outage communications as well as their perception of outage frequency over the past two years. Together, these questions provide insight into customer experiences with service interruptions and ORPC's communication efforts.

Customer opinions on outage communications were more mixed than for other service areas, shown in Figure 6. Approximately 65% of respondents were somewhat or very satisfied with outage updates and communications, while 16% were somewhat or very dissatisfied and 12% were neutral or unsure. Customer comments requested additional communication channels, particularly text-message outage notifications and more frequent updates.

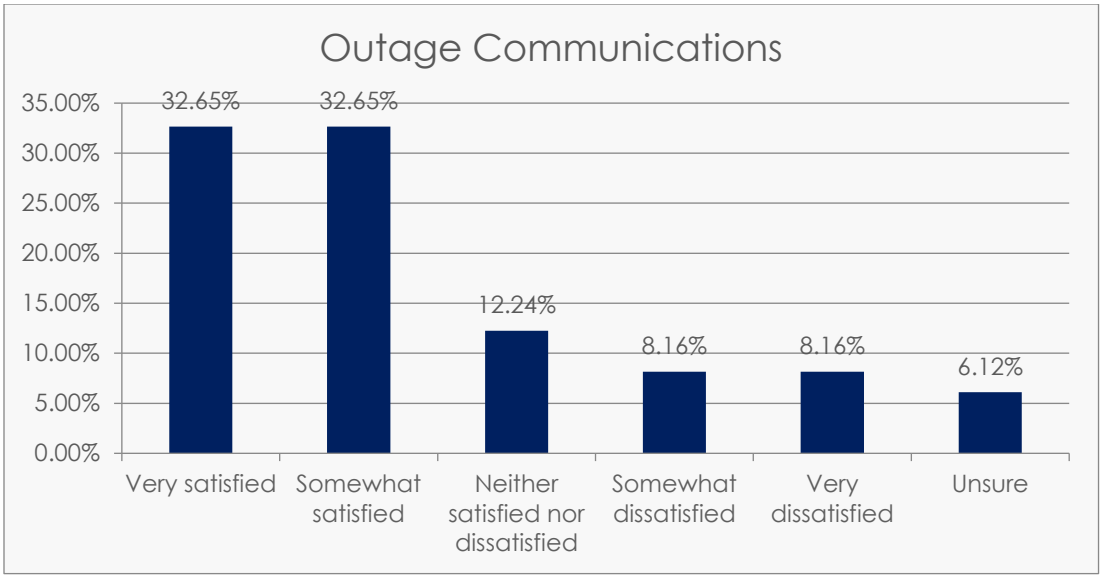


Figure 6: Satisfaction with Outage Communications

When asked about outage frequency over the past two years, 45% reported experiencing about the same number of outages, while 27% reported fewer outages and 14% reported more outages. The fact that almost twice as many customers reported fewer outages than more outages suggest customers generally perceive reliability as stable or improving, shown in Figure 7.

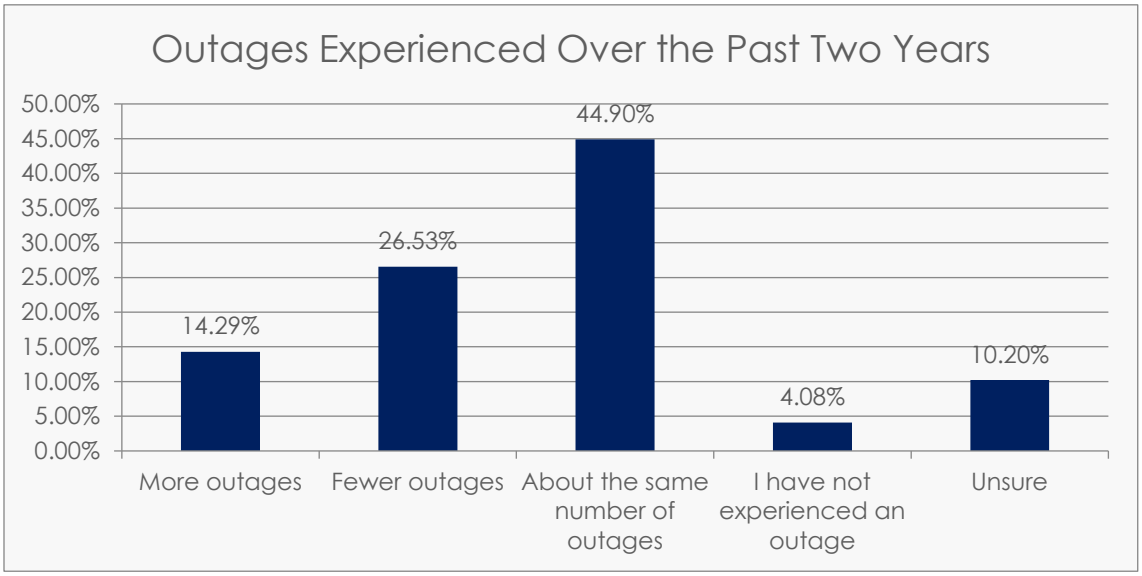


Figure 7: Outage frequency experienced by customers over the past two years

1.6 Customer Priorities – Question 10 & 11

Understanding customer priorities is a key objective of the survey and an important input to ORPC's Distribution System Plan. Customers were asked about their priorities relating to reliability, safety, affordability, customer service, and future growth.

Respondents were questioned on their needs and preferences for ORPC service through ranking the following five priorities:

- Reliability of electricity services
- Safety of electricity service
- Maintaining reasonable electricity distribution rates
- Customer service and communications
- Preparing the system for future growth, including new housing, businesses, electric vehicles, heat pumps, and customer-owned generation

Results are presented in Table 4 as the number and percentage of responses assigned to each priority ranking (1–5) for each statement with 1 being the top priority. The table also includes a weighted average score for each priority (1-5), where higher scores indicate higher overall importance.

Table 4: Weighted scoring results of customer ranked priorities

Priority Rank	ORPC Priorities	Weighted Score
1	Reliability of electricity services	4.57
2	Maintaining reasonable electricity distribution rates	3.78
3	Safety of electricity service	2.90
4	Customer service and communications	2.12
5	Preparing the system for future growth, including new housing, businesses, electric vehicles, heat pumps, and customer-owned generation	1.63

Below is the equation used to calculate statement weighted priority score:

$$Score = \sum_{i=1}^{5} \left(\frac{n_i}{N} * i\right)$$

Where;

n_i = Number of respondents selecting rating i

N = Total number or respondents

i = Point value (Rank 1 = 5 points, Rank 2 = 4 points, etc.)

The highest rated priority by ORPC survey respondents was "Reliability of electricity service" with a score of 4.57, followed by "Maintaining reasonable electricity distribution rates" at 3.78 and "Safety of electricity service" at 2.90. The lower ranked priorities by ORPC's survey respondents were "Customer service and communications" and "Preparing the system for future growth, including new housing, businesses, electric vehicles, heat pumps, and customer-owned generation" with scores of 2.12 and 1.63 respectively. Figure 8 depicts the five priority statements with their weighting of importance assigned by ORPC customers.

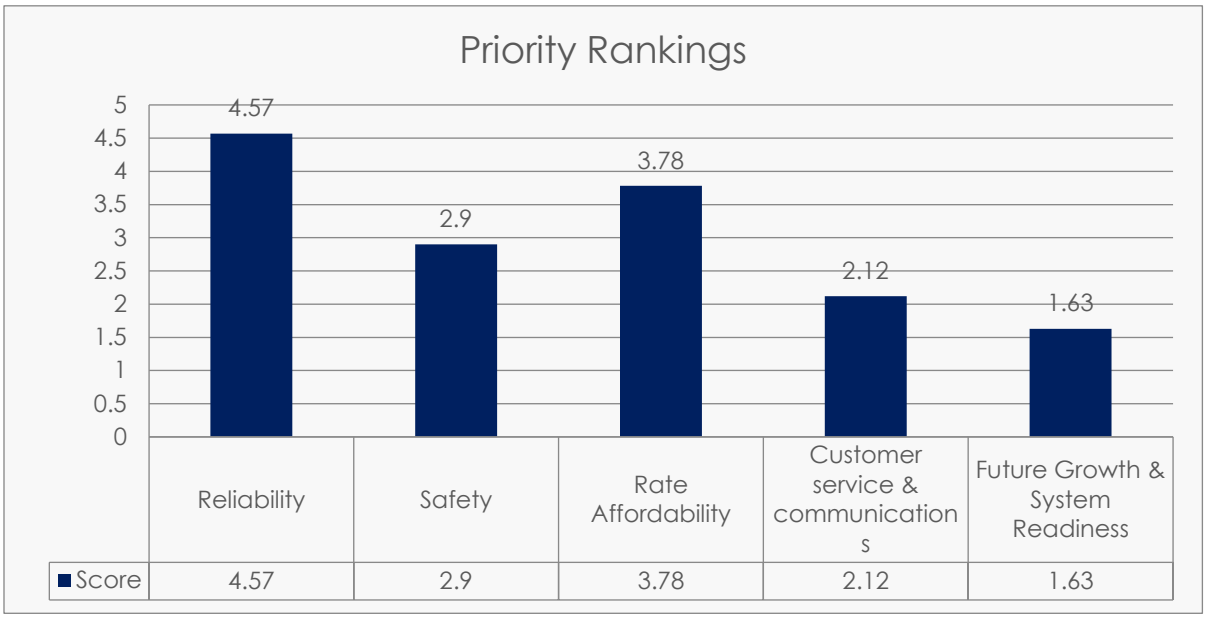


Figure 8: Ranking of top customer priorities

Through open-ended survey responses, customers provided additional comments, questions, and suggestions. Several respondents expressed appreciation for the reliability of service and noted a reduction in outages over the past year. Other respondents identified concerns related to the condition of equipment, vehicles, and availability of staff for maintenance activities and outage response. Respondents suggested that estimated restoration times during outages be made available by text message for customers who do not use Facebook and generally requested for more communications during outages. Another respondent recommended providing customers with the ability to compare historical usage costs under Time-of-Use and Tiered pricing models to support more informed decision-making.

The Open-ended feedback was generally positive, with several customers specifically recognizing the efforts of ORPC line crews and improvements in reliability. Key themes included requests for better outage communications, concerns about vegetation management and corridor maintenance, support for continued infrastructure investment, and concerns about affordability and rising electricity costs.

1.7 Asset Replacement Strategy – Question 12

ORPC's proposed Distribution System Plan includes investments to replace aging electricity infrastructure to maintain and improve system reliability. Customers were asked to indicate their preferred approach to infrastructure replacement and the balance between reliability, asset condition, safety, and distribution rate impacts.

Strong support was expressed for ORPC's proposed asset replacement program, with 88% of respondents supporting the proposed level of investment or indicating support for an even higher level of investment. Only 4% preferred spending less, which suggests most customers agree with a balanced approach that maintains reliability and safety while limiting bill impacts, shown in Table 5.

Table 5: Preferred Asset Replacement Approach

Answer Choices	Responses
Spend approximately the proposed amount, balancing reliability, asset condition, safety, and distribution bill impacts.	75.51%
Spend more than proposed to improve asset condition or reliability sooner, accepting higher distribution bill impacts.	12.24%
Unsure / need more information	8.16%
Spend less than proposed to help reduce near-term distribution bill impacts, accepting a higher risk of equipment failures, outages, or future replacement needs.	4.08%

1.8 General Plant Investments – Question 13

In addition to distribution system assets, ORPC invests in vehicles, facilities, information technology, tools, and equipment that support day-to-day operations. Customers were asked for their views on ORPC's proposed General Plant investments.

Customers also supported ORPC's planned investments in fleet, facilities, information technology, tools, and equipment. 82% supported the proposed spending level or additional investment while 8% preferred lower spending. These results indicate broad recognition of the importance of maintaining operational resources required to provide reliable service, shown in Table 6.

Table 6: Preferred General Plant investment approach

Answer Choices	Responses
Spend approximately the proposed amount to maintain ORPC's operational capability and support reliable service.	69.39%
Spend more than proposed to improve operations, customer service, outage response, or technology sooner, accepting higher distribution bill impacts.	12.24%
Unsure / need more information	10.20%
Spend less than proposed to help reduce near-term distribution bill impacts, accepting a higher risk of delays, reduced operational efficiency, or customer service impacts.	8.16%

1.9 Fleet Electrification Considerations – Question 14

Customers were asked for their views on ORPC's consideration of lower-emission vehicle options as part of future fleet replacement decisions.

Customers expressed moderate support for considering lower-emission vehicles as part of fleet replacement planning. Figure 9 shows that approximately 65% indicated this was either somewhat or very important, while 31% felt ORPC should simply select the lowest-cost suitable vehicle. This suggests environmental considerations are important to many customers, provided operational effectiveness and affordability are maintained.

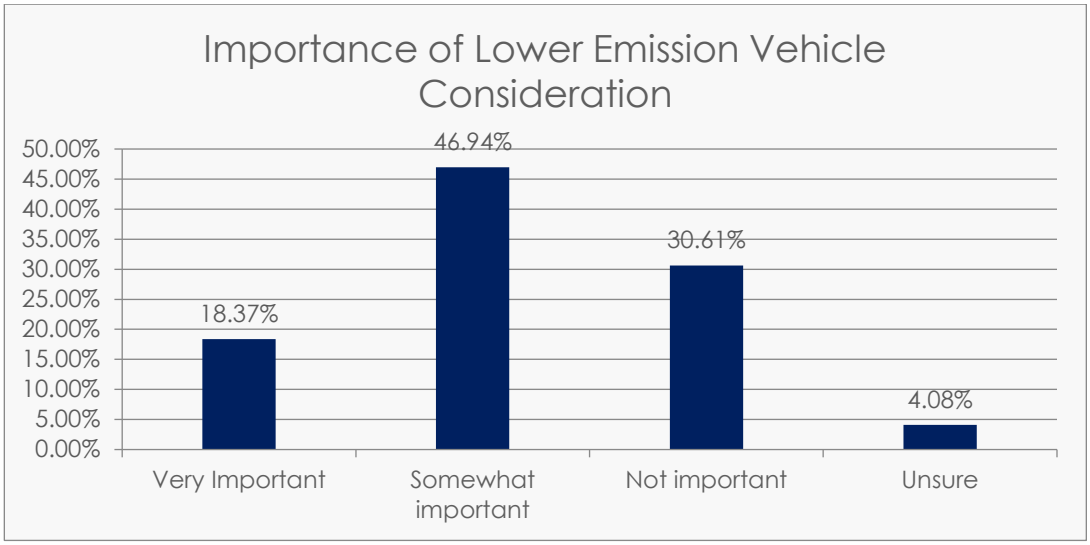


Figure 9: Importance of Considering Lower Emission Vehicles for Replacement

1.10 Testing, Inspections, and Monitoring – Question 15

Routine inspections, testing programs, and monitoring play an important role in identifying equipment issues before failures occur. Customers were asked about the importance of these activities.

Support for proactive maintenance activities was particularly strong, shown in Figure 10. Nearly 90% of respondents considered investments in testing, inspections, and monitoring technologies to be somewhat or very important. Customers appear to recognize the value of identifying aging or defective equipment before failures occur.

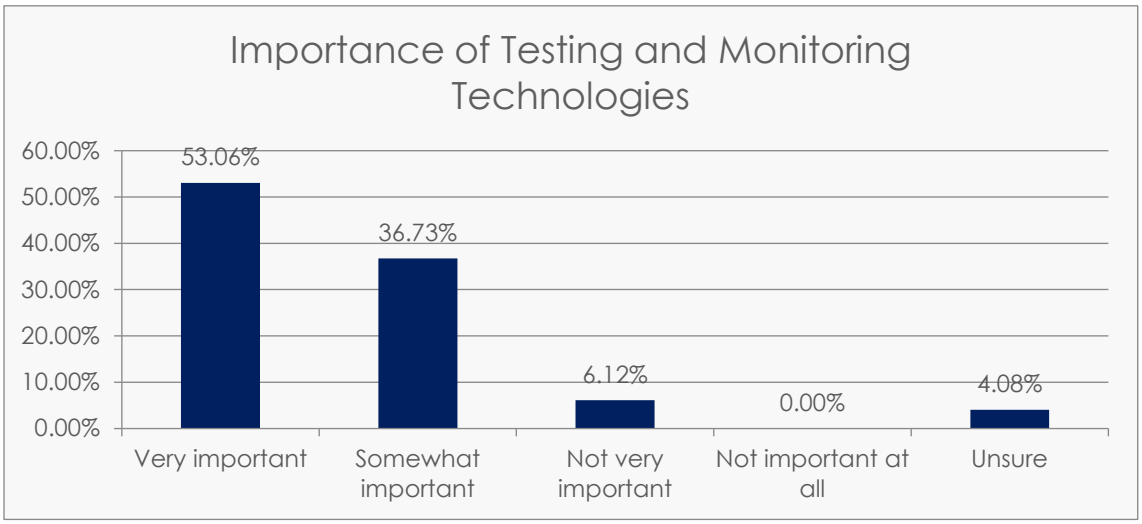


Figure 10: Importance of Investments in Testing and Monitoring Technologies

1.11 Investment Level for Monitoring Programs – Question 16

Investing in new monitoring technology can aid in identifying equipment issues before failures occur. Customers were asked about their preferred level of investment in proactive asset monitoring programs.

Strong support was also expressed for ORPC's proposed testing and monitoring programs, with 86% of respondents supporting the proposed level of investment or indicating support for increased spending, while only 8% preferred reduced spending. The results presented in Figure 11 indicate broad support for maintaining a balanced approach that improves reliability without creating unnecessary cost pressures.

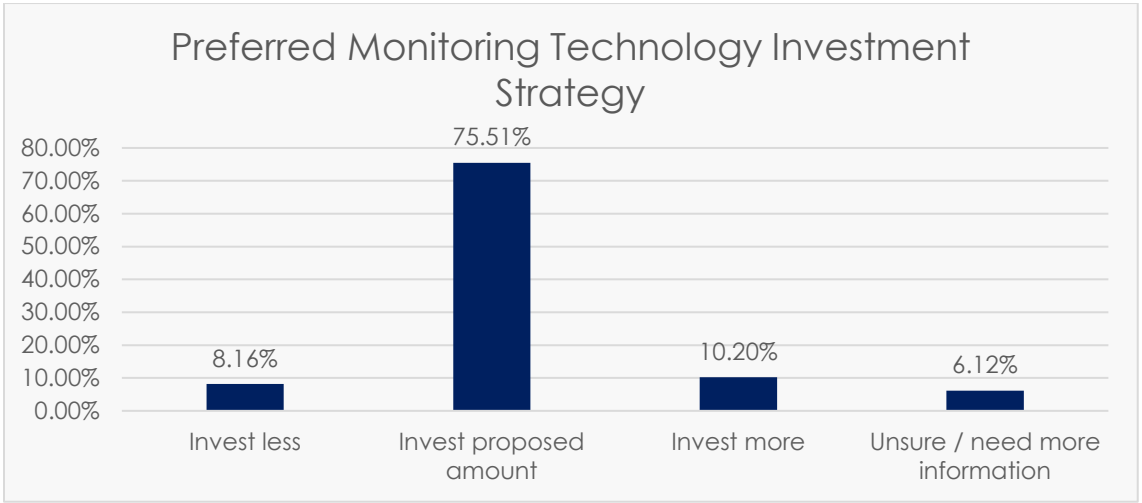


Figure 11: Preferred Monitoring Technology Investment Strategy

1.12 Vegetation Management – Question 17-19

Trees and vegetation are a common cause of outages on overhead electricity systems. To better understand customer expectations, respondents were asked about the importance of vegetation management activities, preferred program funding levels, and any local concerns related to trees and power lines within their communities.

Vegetation management received some of the strongest support in the survey, with 88% of respondents indicating tree trimming and right-of-way clearing are somewhat or very important, shown in Figure 12. These findings reflect customer awareness of the impact trees and vegetation can have on outage frequency and service reliability.

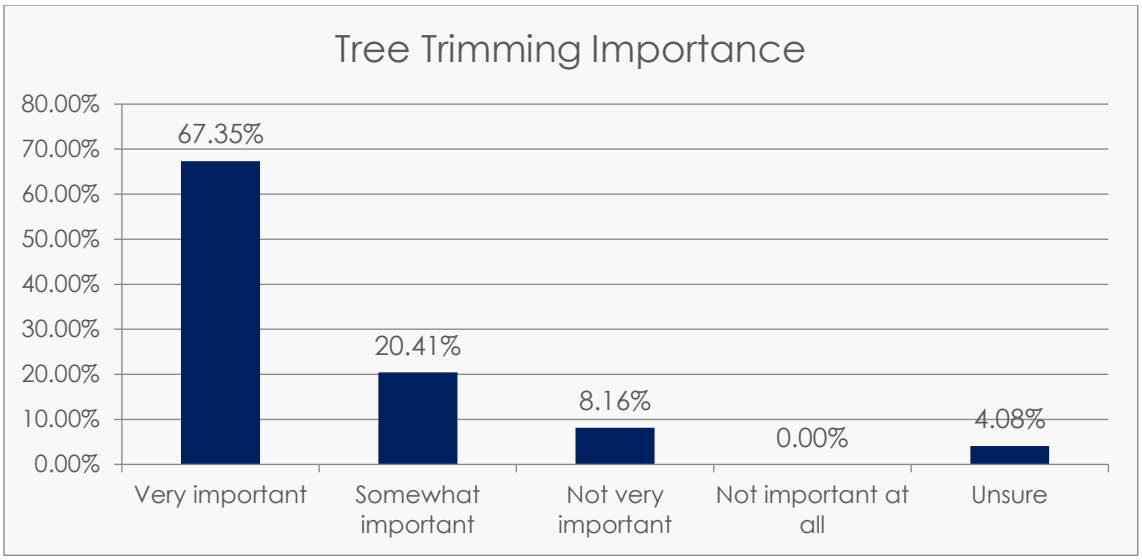


Figure 12: Importance of Tree Trimming

Most customers supported maintaining or increasing current vegetation management efforts, with 51% preferring current levels of trimming and clearing and 35% supporting increased efforts if they help reduce outages, shown in Figure 13. Only 8% supported reducing these activities, while customer comments highlighted concerns about overgrown corridors and delayed vegetation maintenance in some areas.

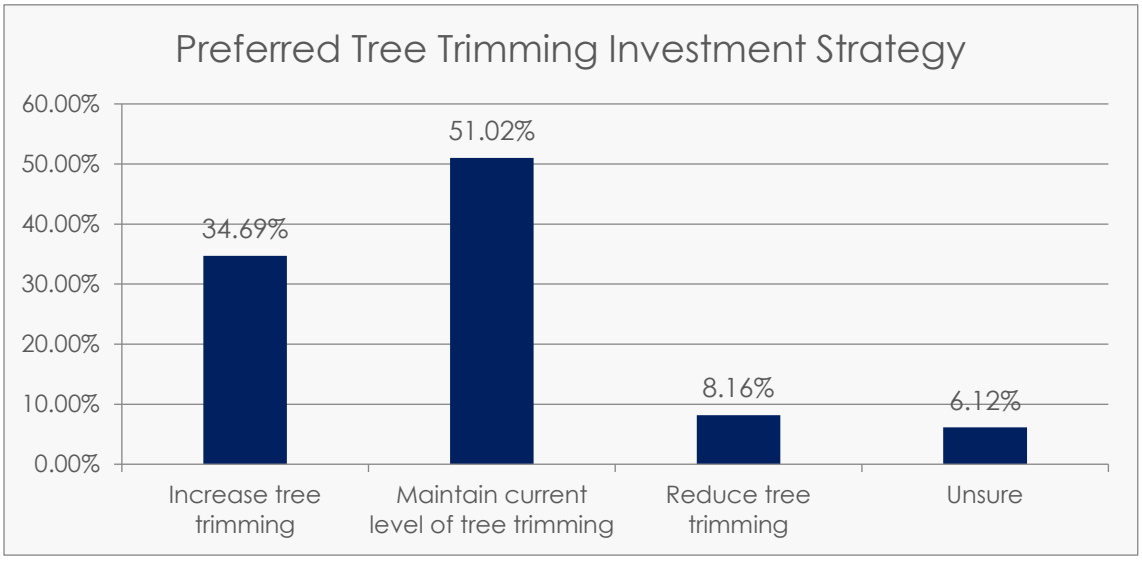


Figure 13: Preferred Tree Trimming Investment Strategy

1.13 Future Growth and System Readiness – Question 20

As electricity demand continues to evolve, ORPC must plan for future customer needs, including population growth, business development, electrification, and customer-owned generation. This question was intended to assess the importance customers place on investments that support future growth and long-term system readiness.

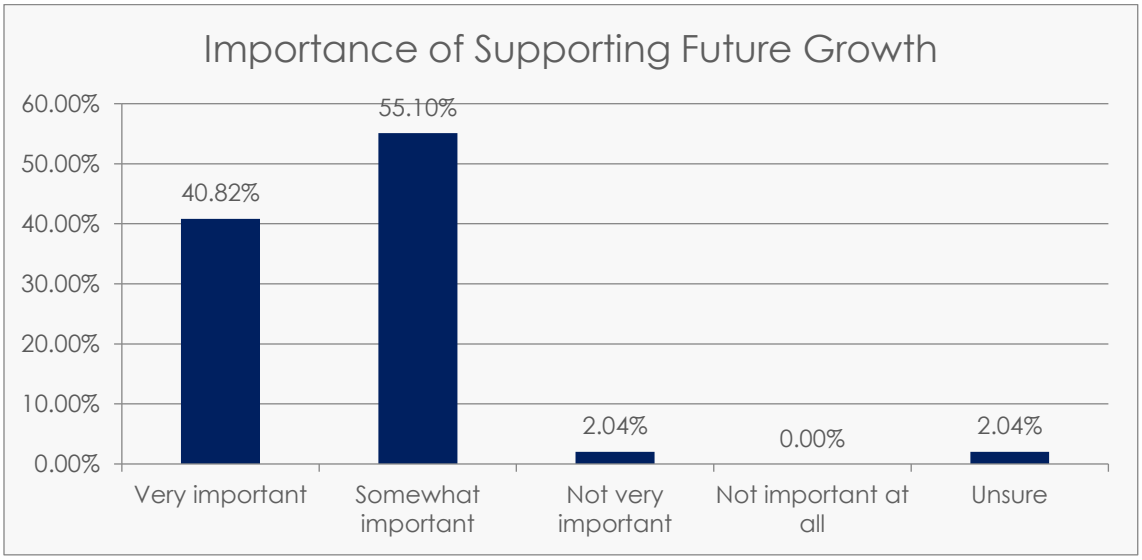


Figure 14: Importance of Supporting Future Growth

Customers showed overwhelming support for preparing the distribution system for future needs, with 96% indicating investments to support future growth are somewhat or very important. Respondents appear to recognize the need to accommodate new housing, business development, electric vehicles, heat pumps, and customer-owned generation, presented in *Figure 14*.

1.14 Overall Distribution System Plan Assessment – Question 21

The proposed 2027–2031 Distribution System Plan was well received by respondents. The largest share of customers (41%) agreed that the plan appropriately balances reliability, safety, system condition, future needs, and affordability. An additional 8% favoured increased investment to further enhance reliability and future readiness. While nearly one third of respondents expressed a preference for placing greater emphasis on limiting distribution bill impacts, the results indicate that customers generally support ORPC's balanced investment strategy while continuing to view affordability as an important consideration, as shown in Table 7.

Table 7: Overall View of the Proposed Distribution System Plan

Answer Choices	Responses
The proposed plan appears to strike a reasonable balance between safety, reliability, system condition, future needs, and distribution bill impacts.	40.82%
The proposed plan should place greater emphasis on limiting distribution bill impacts, even if some investments take longer to complete.	30.61%
Unsure / need more information	20.41%
The proposed plan should place greater emphasis on improving reliability, asset condition, or future readiness, even if distribution bill impacts are higher.	8.16%
Other - please explain in the next question.	0.00%

2. Overall Conclusion

The survey results indicate strong customer support for ORPC's current service delivery and proposed investment strategy. Reliability was the clear priority, receiving the highest-ranking score (4.57/5), while satisfaction levels exceeded 80% for overall service and reliability. Customers broadly support ORPC's proposed spending on asset replacement, vegetation management, testing and monitoring, and future system readiness, while continuing to emphasize affordability and improved outage communications as important considerations for the 2027–2031 planning period.

3. Appendix A – Customer Survey Questions & Preamble

Customer Survey 2026 – ORPC Distribution System Plan (2027-2031)

Introduction

About Ottawa River Power Corporation

Ottawa River Power Corporation (ORPC) is an electricity distributor licensed by the Ontario Energy Board (OEB). ORPC provides electricity distribution services in the City of Pembroke, the former Village of Beachburg in Whitewater Region, the former Village of Killaloe in the Township of Killaloe-Hagarty-Richards, and the former Town of Almonte in the Municipality of Mississippi Mills, serving over 11,800 customers.

ORPC owns and maintains over 346 km of overhead lines, 129 km of underground lines, and 12 substations. ORPC is committed to the pursuit of excellence in safety and reliability for the customers and communities it serves, while seeking practical innovation, conservation, and technology solutions that create value for customers and shareholders.

Purpose of this survey

ORPC is preparing its 2027-2031 Distribution System Plan (DSP). A DSP is a long-term plan that explains how ORPC intends to maintain, renew, and improve the local electricity distribution system so that customers continue to receive safe and reliable electricity service.

This voluntary survey is intended to help ORPC understand customer needs, priorities, and preferences as it develops its investment plan. The feedback collected will be summarized and used as one input into ORPC's upcoming electricity distribution rate application to the OEB.

ORPC only controls the distribution portion of your electricity bill. ORPC does not set the commodity price of electricity, transmission rates, HST, or most other provincial charges. Where this survey refers to bill impacts, it is referring to the distribution portion of the bill unless otherwise noted.

All survey responses will be combined for analysis. Individual responses will remain confidential and will not be attributed to individual customers in ORPC's application materials.

This survey has 22 questions and should take approximately 10 to 15 minutes to complete.

Customer Verification

The following information will be used to confirm customer eligibility, understand responses by customer group and service area, and help prevent duplicate responses. It will not be used to identify individual survey answers in the results submitted to the OEB.



1. Please enter your 10-digit Customer Account Number, without a dash.
Your account number can be found on your ORPC bill. Example format: XXXXXXXXXX

<INSERT NUMBER>

2. Are you responding as a residential or business customer?

- **Residential**
- **Business**
- **Other / multiple accounts**
- **Prefer not to say**

3. Which ORPC service area are you located within?

- **Pembroke**
- **Beachburg**
- **Killaloe**
- **Almonte**
- **Unsure**

4. What is your familiarity with ORPC?

- **Very familiar**
- **Somewhat familiar**
- **Not familiar**

Part A: Overall Customer Experience

This section asks about your experience with ORPC's current service, including reliability, outage restoration, billing, customer service, and communications.

5. Thinking about the services provided to you and your community by ORPC, how satisfied or dissatisfied are you with the overall service you received?

- **Very satisfied**
- **Somewhat satisfied**
- **Neither satisfied nor dissatisfied**
- **Somewhat dissatisfied**
- **Very dissatisfied**
- **Unsure**

6. How satisfied or dissatisfied are you with the reliability of your electricity service, based on the number of outages you have experienced?

- Very satisfied

- Somewhat satisfied

- Neither satisfied nor dissatisfied

- Somewhat dissatisfied

- Very dissatisfied

- Unsure

7. When outages occur, how satisfied or dissatisfied are you with the amount of time it takes to restore power?

- **Very satisfied**
- **Somewhat satisfied**
- **Neither satisfied nor dissatisfied**
- **Somewhat dissatisfied**
- **Very dissatisfied**

- **Unsure**

8. How satisfied or dissatisfied are you with the information ORPC provides during outages, such as outage updates, estimated restoration times, and general communications?

- **Very satisfied**
- **Somewhat satisfied**
- **Neither satisfied nor dissatisfied**
- **Somewhat dissatisfied**
- **Very dissatisfied**
- **Unsure**

9. Over the past two years, have you experienced more, fewer, or about the same number of outages?

- **More outages**
- **Fewer outages**
- **About the same number of outages**
- **Unsure**

10. Considering your overall priorities as an ORPC customer, please rank the following from most important to least important.

- **Reliability of electricity service**
- **Safety of electricity service**
- **Maintaining reasonable electricity distribution rates**
- **Customer service and communications**
- **Preparing the system for future growth, including new housing, businesses, electric vehicles, heat pumps, and customer-owned generation**

11. Do you have any other comments, questions, or suggestions about ORPC's overall performance?

<Open Response>

Part B: ORPC Distribution System Plan

ORPC's Distribution System Plan (DSP) sets out the capital investments and maintenance activities needed to keep the local electricity system safe, reliable, and ready for future needs. It explains what needs to be fixed, replaced, or built so homes and businesses can keep getting safe and reliable power. When making the plan, ORPC looks at what the power system needs, which projects matter most, how much they cost, and when to spend the money.

This part of the survey is to provide specific information regarding ORPC's proposed investment plans from 2027 - 2031 and gather customer feedback on trade-offs and preferences.

On average over the next five years, ORPC proposes to invest about $2.2 million each year in capital projects. The majority of ORPC's investments focus on System Access (which are mandatory projects), System Renewal and General Plant investment

A summary of the categories of proposed annual investments is provided below.

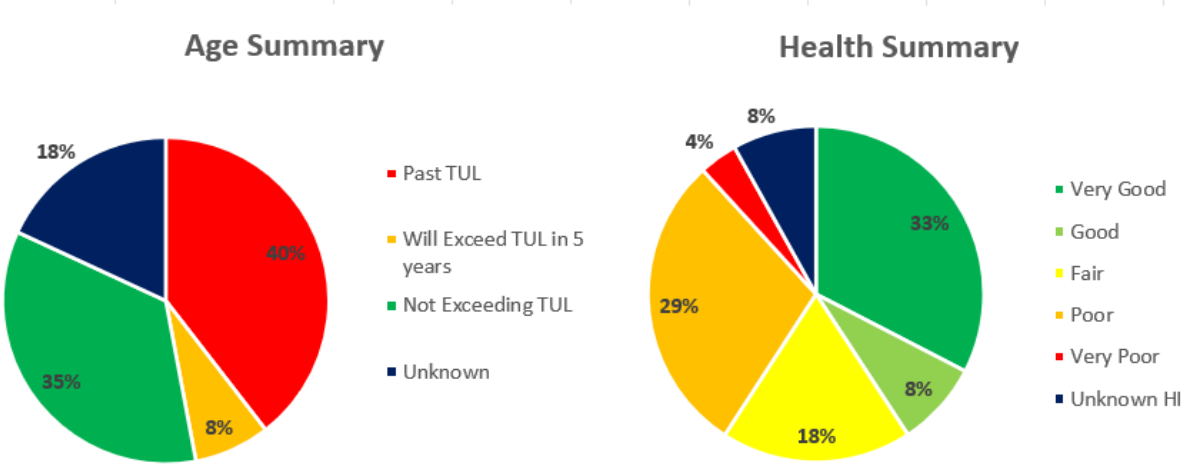
Investment category	Average annual amount	Description
System Access	$693,308	Mandatory or customer-driven work, such as new connections, relocations, and system access requirements.
System Renewal	$945,421	Replacement or renewal of aging or deteriorated assets such as poles, transformers, underground cables, and overhead conductors.
System Service	$20,000	Targeted investments to improve system performance or service quality.
General Plant	$537,064	Fleet, facilities, information technology, tools, and equipment needed to support 24/7 utility operations.
Total	**Approximately $2.2 million**	**Average annual capital investment proposed for 2027-2031.**

System Renewal

System Renewal investments are used to replace or refurbish aging electricity distribution equipment, such as poles, overhead wires, underground cables, transformers, switches, and other assets needed to deliver electricity safely and reliably.

Like other infrastructure, electrical equipment has a limited service life. ORPC considers both the age and condition of its assets when deciding which equipment should be replaced and when. Some assets may continue to operate safely beyond their typical useful life, while others may need earlier replacement due to deterioration, damage, or higher risk of failure.

Timely System Renewal investment can help reduce equipment failures, improve reliability, support safety, and avoid more costly emergency repairs. Deferring this work may help limit short-term costs, but can increase the risk of outages and higher costs in future years.



ORPC's proposed System Renewal plan for 2027–2031 is intended to balance asset condition, reliability, safety, and distribution rate impacts. Based on ORPC's current asset information, approximately 40% of the system is past typical useful life and a further 8% is expected to exceed typical useful life over the next five years. ORPC's health summary also indicates that approximately 29% of assets are in poor condition and 4% are in very poor condition. ORPC's proposed System Renewal investments from 2027-2031 are expected to average approximately $0.9 million per year.

12. Which approach best reflects your preference for replacing again electricity distribution equipment?

- **Spend less than proposed to help reduce near-term distribution bill impacts, accepting a higher risk of equipment failures, outages, or future replacement needs.**
- **Spend approximately the proposed amount, balancing reliability, asset condition, safety, and distribution bill impacts.**
- **Spend more than proposed to improve asset condition or reliability sooner, accepting higher distribution bill impacts.**
- **Unsure / need more information**

General Plant

"General Plant" investments will be focused on initiatives that support the 24/7 operations of ORPC's distribution system, including ongoing maintenance and upgrades to ORPC's facilities and buildings, IT hardware and software as well as tools and equipment that are used by its crew. Additionally, OPRC intends to carry out the replacement of critical Fleet vehicles that transport crews to respond to outages and replacement of equipment.

ORPC's proposed General Plant investments from 2027-2031 are expected to average approximately $0.5 million per year, which is generally aligned with recent historical levels.

13. Which approach best reflects your view on ORPC's proposed General Plant investments, including fleet, facilities, IT, tools, and equipment?

- **Spend less than proposed to help reduce near-term distribution bill impacts, accepting a higher risk of delays, reduced operational efficiency, or customer service impacts.**
- **Spend approximately the proposed amount to maintain ORPC's operational capability and support reliable service.**
- **Spend more than proposed to improve operations, customer service, outage response, or technology sooner, accepting higher distribution bill impacts.**
- **Unsure / need more information**

14. When ORPC replaces vehicles, how important is it that ORPC consider electric or lower-emission vehicles where they are practical, reliable, and cost-effective for utility operations?

- **Very important, even if costs are somewhat higher**
- **Somewhat important, but only where costs and operational performance are reasonable**
- **Not important, ORPC should select the lowest-cost suitable vehicle**
- **Unsure**

System Operating and Maintenance Expenditures

In addition to capital investments, ORPC carries out regular maintenance programs to inspect, maintain, and repair equipment across the distribution system. These programs include activities such as visual inspections, equipment testing, vegetation management, and other work that helps ORPC understand the condition of its assets.

The information gathered through these programs is an important input into ORPC's planning process. It helps identify equipment that may be aging, deteriorating, or at higher risk of failure, and allows ORPC to prioritize repairs or replacements before problems result in outages or emergency repairs.

ORPC is also considering opportunities to enhance its maintenance practices, including additional testing and monitoring programs. These activities may help ORPC better identify issues before equipment fails, improve reliability, and potentially reduce long-term costs by addressing problems proactively rather than reactively.

The projected 2027 OM&A expenditure is $1.8 million.

15. How important is it to you that ORPC invests in testing procedures, inspections, and monitoring technologies to better identify aging or defective equipment before it fails?

- **Very important**
- **Somewhat important**
- **Not very important**
- **Not important at all**
- **Unsure**

16. Which statement best reflects your view on incremental testing, inspections, and monitoring technologies?

- **ORPC should invest less in these activities to help limit near-term distribution bill impacts, accepting more reliance on reactive repairs.**
- **ORPC should invest approximately the proposed amount, balancing proactive maintenance, reliability, and distribution bill impacts.**
- **ORPC should invest more in these activities to improve condition information and reduce the risk of failures, accepting higher distribution bill impacts.**
- **Unsure / need more information**

Tree Trimming / Right-of-Way Clearing

Trees and branches are a common cause of power outages, particularly during storms, high winds, heavy snow, and freezing rain. ORPC performs tree trimming and right-of-way clearing to help reduce outages caused by trees contacting overhead power lines.

ORPC has observed that in years when more staff time and contractor resources are dedicated to tree trimming, the number of outages related to tree contact tends to be lower. Tree trimming can also reduce emergency repair work and help support faster restoration after storms. However, tree trimming requires ORPC staff time and contractor support, and may affect customer properties, streetscapes, and trees located near power lines.

17. How important is it to you that ORPC continue or increase tree trimming and right-of-way clearing to reduce the risk of tree-related outages?

- **Very important**
- **Somewhat important**
- **Not very important**
- **Not important at all**
- **Unsure**

18. Which statement best reflects your view on tree trimming and right-of-way clearing?

- **ORPC should increase tree trimming and right-of-way clearing if it is expected to reduce outages, even if it modestly increases costs.**
- **ORPC should maintain its current level of tree trimming and right-of-way clearing.**
- **ORPC should reduce tree trimming and right-of-way clearing to help limit costs, even if this may increase the risk of tree-related outages.**
- **Unsure / need more information**

19. Have you experienced tree-related outages, or do you have concerns about trees near power lines in your area that ORPC should consider?

<Open Response>

Growth, Electrification, and Future Customer Needs

ORPC must also consider future system needs, including new housing, business growth, electric vehicles, heat pumps, customer-owned generation, and other changes in how customers use electricity.

20. How important is it for ORPC to invest in the local distribution system to support future growth and changing customer needs, such as new housing, business expansion, electric vehicles, heat pumps, and customer-owned generation?

- **Very important**
- **Somewhat important**
- **Not very important**
- **Not important at all**
- **Unsure**

Overall DSP Direction

21. Based on the information provided in this survey, which statement best reflects your overall view of ORPC's proposed 2027-2031 Distribution System Plan?

- **The proposed plan appears to strike a reasonable balance between safety, reliability, system condition, future needs, and distribution bill impacts.**
- **The proposed plan should place greater emphasis on limiting distribution bill impacts, even if some investments take longer to complete.**
- **The proposed plan should place greater emphasis on improving reliability, asset condition, or future readiness, even if distribution bill impacts are higher.**
- **I do not have enough information to provide a view.**
- **Other - please explain in the next question.**

22. Do you have any other comments, questions, or suggestions that ORPC should consider as it develops its capital investment and maintenance plans for 2027-2031?

<Open Response>

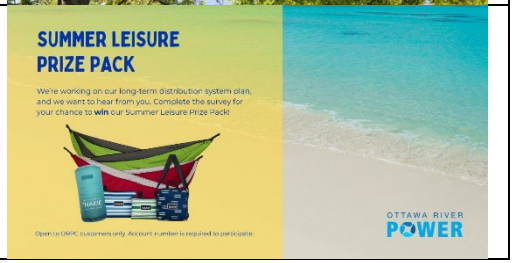
Thank you

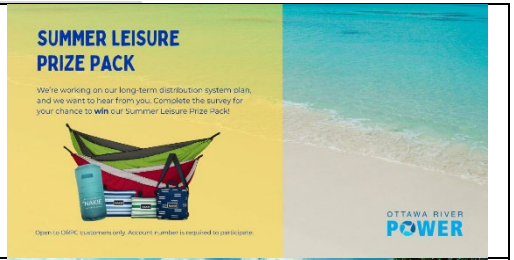
Thank you for taking the time to provide your feedback. Your input will help ORPC better understand customer priorities as it prepares its 2027-2031 Distribution System Plan and electricity distribution rate application.

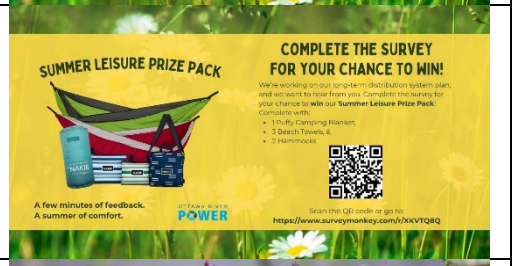
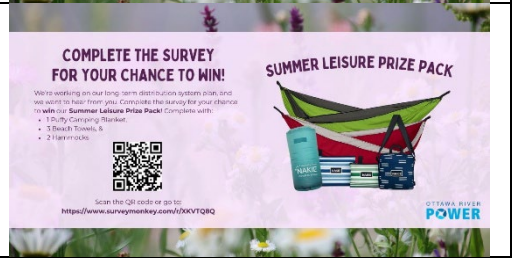
4. Appendix A – Customer Survey Promotion & Communications

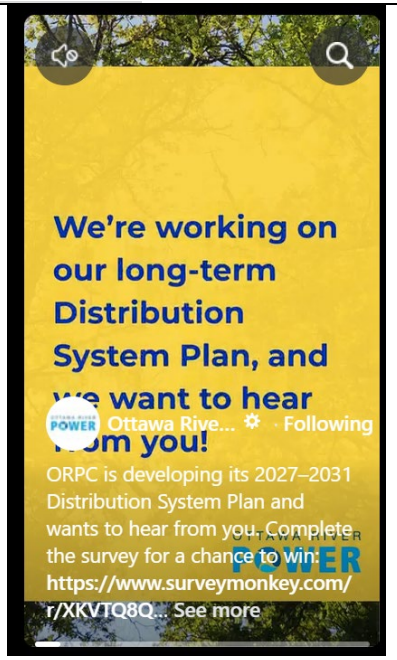
DSP Survey Promotion – Social Media Post History

Date & Time	Platform	Content	Image
Tuesday, June 16, 2026, 2:00 PM	Twitter (X)	Your feedback matters! ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win our Summer Leisure Prize Pack! ⭕ The survey is open to ORPC customers only. A valid ORPC account number is required to participate.	
Tuesday, June 16, 2026, 2:00 PM	Facebook	Your feedback matters! ⚡ ORPC is developing its 2027–2031 Distribution System Plan (DSP) and wants to hear from you. A DSP is a long-term plan that explains how ORPC intends to maintain, renew, and improve the local electricity distribution system so that customers continue to receive safe and reliable electricity service. Complete the survey for a chance to win our Summer Leisure Prize Pack! 📝 22 questions ⁘ 10–15 minutes 🔒 Confidential responses The survey is open to ORPC customers only. A valid ORPC account number is required to participate. Please note that ORPC only controls the distribution portion of your electricity bill. ORPC does not set the commodity price of electricity, transmission rates, HST, or most other provincial charges. Any references to bill impact in the survey relate to the distribution portion of the bill unless otherwise noted.	
Wednesday, June 17, 2026, 8:30 AM	Twitter (X)	Your feedback matters! ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win our Summer Leisure Prize Pack! ⭕ The survey is open to ORPC customers only. A valid ORPC account number is required to participate.	

Wednesday, June 17, 2026, 8:30 AM	Facebook	Your feedback matters! ⚡ ORPC is developing its 2027–2031 Distribution System Plan (DSP) and wants to hear from you. A DSP is a long-term plan that explains how ORPC intends to maintain, renew, and improve the local electricity distribution system so that customers continue to receive safe and reliable electricity service. Complete the survey for a chance to win our Summer Leisure Prize Pack! 📝 22 questions ⁘ 10–15 minutes 🔒 Confidential responses The survey is open to ORPC customers only. A valid ORPC account number is required to participate. Please note that ORPC only controls the distribution portion of your electricity bill. ORPC does not set the commodity price of electricity, transmission rates, HST, or most other provincial charges. Any references to bill impact in the survey relate to the distribution portion of the bill unless otherwise noted.	
Friday, June 19, 2026, 2:00 PM	Twitter (X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win our Summer Leisure Prize Pack! https://www.surveymonkey.com/r/XKVTQ8Q The survey is open to ORPC customers only. A valid ORPC account number is required to participate.	
Friday, June 19, 2026, 2:00 PM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win our Summer Leisure Prize Pack! https://www.surveymonkey.com/r/XKVTQ8Q The survey is open to ORPC customers only. A valid ORPC account number is required to participate.	
Saturday, June 20, 2026, 8:30 AM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	

Saturday, June 20, 2026, 8:30 AM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Tuesday, June 23, 2026, 11:30 AM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Tuesday, June 23, 2026, 11:30 AM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Thursday, June 25, 2026, 11:30 AM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	

Saturday, June 27, 2026, at 9:30 AM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Saturday, June 27, 2026, at 9:30 AM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Sunday, June 28, 2026, at 11:30 AM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Sunday, June 28, 2026, at 11:30 AM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	

Monday, June 29, 2026, at 2:58 PM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	 (VIDEO)
Monday, June 29, 2026, at 6:30 PM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	

Monday, June 29, 2026, at 6:30 PM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Tuesday, June 30, 2026, at 11:30 AM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Tuesday, June 30, 2026, at 11:30 AM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Monday, July 6, 2026, at 12:30 PM	Twitter(X)	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	

Monday, July 6, 2026, at 12:30 PM	Facebook	ORPC is developing its 2027–2031 Distribution System Plan and wants to hear from you. Complete the survey for a chance to win: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only, account number is required to participate.	
Wednesday, July 8, 2026, at 11:00 AM	Twitter(X)	⏰ Last chance! ORPC wants your feedback to help shape our 2027–2031 Distribution System Plan. If you're an ORPC residential or business customer, complete our survey by Sunday, July 12 for a chance to win! https://www.surveymonkey.com/r/XKVTQ8Q ORPC account number required.	
Wednesday, July 8, 2026, at 11:00 AM	Facebook	⏰ Last Chance! ⏰ ORPC is developing its 2027–2031 Distribution System Plan, and we want to hear from you! If you're an ORPC residential or business customer, complete our survey for a chance to win. Your feedback will help shape the future of our electricity distribution system. 🎁 The last day to enter is Sunday, July 12, 2026. Complete the survey today: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only. An ORPC account number is required to participate.	
Friday, July 10, 2026, at 11:00 AM	Twitter(X)	⏰ Last chance! ORPC wants your feedback to help shape our 2027–2031 Distribution System Plan. If you're an ORPC residential or business customer, complete our survey by Sunday, July 12 for a chance to win! https://www.surveymonkey.com/r/XKVTQ8Q ORPC account number required.	

Friday, July 10, 2026, at 11:00 AM	Facebook	⏰ Last Chance! ⏰ ORPC is developing its 2027–2031 Distribution System Plan, and we want to hear from you! If you're an ORPC residential or business customer, complete our survey for a chance to win. Your feedback will help shape the future of our electricity distribution system. 📲 The last day to enter is Sunday, July 12, 2026. Complete the survey today: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only. An ORPC account number is required to participate.	
Saturday, July 11, 2026, at 10:00 AM	Twitter(X)	⏰ Time is running out! ORPC wants your feedback to help shape our 2027–2031 Distribution System Plan. If you're an ORPC residential or business customer, complete our survey by Sunday, July 12 for a chance to win! https://www.surveymonkey.com/r/XKVTQ8Q ORPC account number required.	
Saturday, July 11, 2026, at 10:00 AM	Facebook	⏰ Time is running out! ORPC is developing its 2027–2031 Distribution System Plan, and we want to hear from you! If you're an ORPC residential or business customer, complete our survey for a chance to win. Your feedback will help shape the future of our electricity distribution system. 📲 The last day to enter is Sunday, July 12, 2026. Complete the survey today: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only. An ORPC account number is required to participate.	
Sunday, July 12, 2026, at 11:30 AM	Twitter(X)	⏰ Survey ends today! Last chance to win! ORPC wants your feedback to help shape our 2027–2031 Distribution System Plan. If you're an ORPC residential or business customer, complete our survey today for a chance to win! https://www.surveymonkey.com/r/XKVTQ8Q ORPC account number required.	

Sunday, July 12, 2026, at 11:30 AM	Facebook	⏰ Survey ends today! Last chance to win! ORPC is developing its 2027–2031 Distribution System Plan, and we want to hear from you! If you're an ORPC residential or business customer, complete our survey for a chance to win. Your feedback will help shape the future of our electricity distribution system. ⁘ Today is the last day to enter! Complete the survey today: https://www.surveymonkey.com/r/XKVTQ8Q Open to ORPC customers only. An ORPC account number is required to participate.	

