EXHIBIT 2 – RATE BASE & DSP

2022 Cost of Service

Ottawa River Power Corp.
EB-2021-0052

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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 those 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 2022 Rate Base to be $13,279,193. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6. The table below presents ORPC's Rate Base calculations for the Test Year compared to the 2016 Board Approved.

Table 1 - Test Year Rate Base

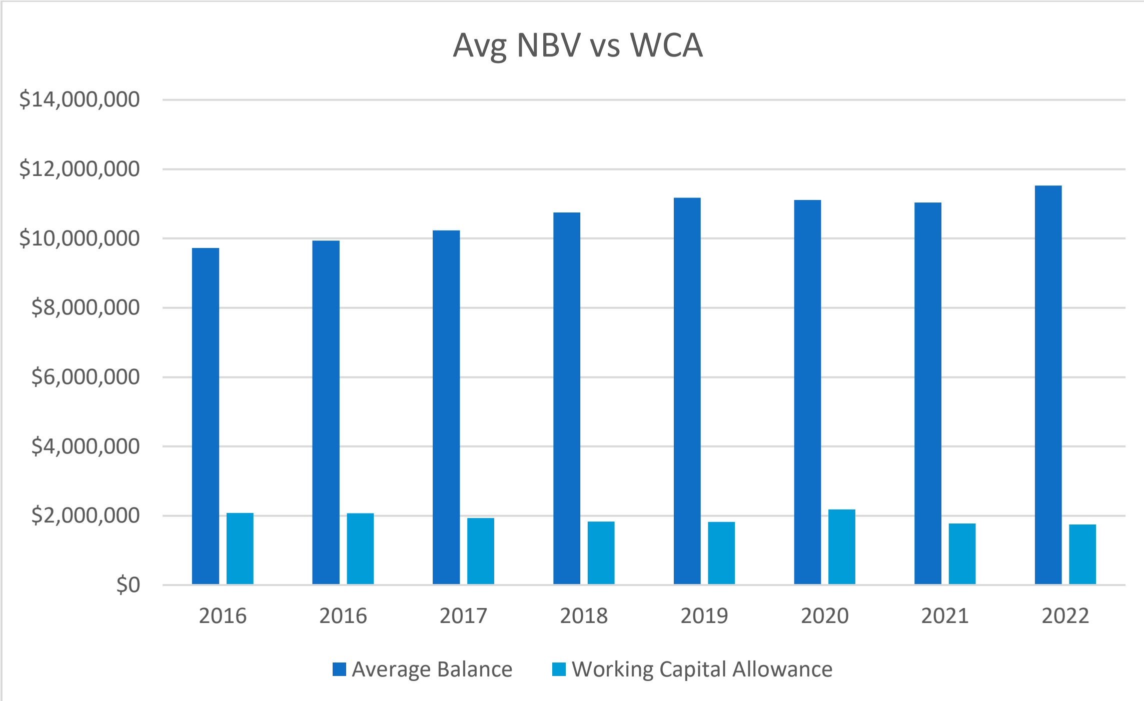
	MIFRS	MIFRS	
Particulars	**Last Board Approved**	**2022**	**Var from last BA**
Net Capital Assets in Service:			
Average Gross Assets	$30,265,128	$19,205,663	-$11,059,465
Average Accumulated Depreciation	-$20,539,657	-$7,678,773	$12,860,884
Average Balance	$9,725,471	$11,526,890	$1,801,419
Working Capital Allowance	$2,076,814	$1,755,507	-$321,307
Total Rate Base	**$11,802,285**	**$13,282,397**	**$1,480,112**
	MIFRS	**MIFRS**	
Expenses for Working Capital	**Last Board Approved**	**2022**	**Var from last BA**
Eligible Distribution Expenses:			
3500-Distribution Expenses - Operation	$572,467	$901,091	$328,624
3550-Distribution Expenses - Maintenance	$728,123	$576,747	-$151,376
3650-Billing and Collecting	$733,000	$962,860	$229,860
3700-Community Relations	$67,000	$42,318	-$24,682
3800-Administrative and General Expenses	$964,375	$1,225,378	$261,003
Total Eligible Distribution Expenses	$3,064,965	$3,708,394	$643,429
3350-Power Supply Expenses	$24,625,882	$19,698,362	-$4,927,520
Total Expenses for Working Capital	$27,690,847	$23,406,757	-$4,284,090
Working Capital factor	7.5%	7.5%	7.5%
Total Working Capital	**$2,076,814**	**$1,755,507**	**-$321,307**

2.1.2 RATE BASE TREND

The Rate Base trend table presents ORPC's Rate Base calculations for all required years including the Test Year 2022. Year-over-year variance analysis follows.

Table 2 - Rate Base Trend

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particulars	**Last Board Approved**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Net Capital Assets in Service:								
Average Gross Assets	$30,265,128	$12,684,917	$13,833,139	$15,197,310	$16,364,217	$16,989,599	17,724,210	19,205,663
Average Accumulated Depreciation	-$20,539,657	-$2,746,384	-$3,600,161	-$4,448,158	-$5,190,285	-$5,882,601	-6,686,437	-7,678,773
Average Balance	$9,725,471	$9,938,532	$10,232,978	$10,749,152	$11,173,932	$11,106,997	11,037,773	11,526,890
Working Capital Allowance	$2,076,814	$2,073,726	$1,932,615	$1,828,968	$1,825,450	$2,183,328	1,779,541	1,755,507
Total Rate Base	**$11,802,285**	**$12,012,259**	**$12,165,593**	**$12,578,120**	**$12,999,383**	**$13,290,325**	**12,817,314**	**13,282,397**
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**Last Board Approved**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Eligible Distribution Expenses:								
3500-Distribution Expenses - Operation	$572,467	$630,729	$565,513	$484,252	$513,327	$785,741	815,322	901,091
3550-Distribution Expenses - Maintenance	$728,123	$613,081	$692,292	$500,384	$645,567	$501,236	562,975	576,747
3650-Billing and Collecting	$733,000	$747,071	$804,067	$668,041	$748,224	$837,380	951,322	962,860
3700-Community Relations	$67,000	$55,936	$79,674	$71,838	$64,147	$30,338	41,362	42,318
3800-Administrative and General Expenses	$964,375	$886,993	$1,121,542	$1,076,915	$1,235,810	$1,203,797	1,158,155	1,225,378
Total Eligible Distribution Expenses	$3,064,965	$2,933,810	$3,263,088	$2,801,430	$3,207,076	$3,358,492	3,529,137	3,708,394
3350-Power Supply Expenses	$24,625,882	$24,715,874	$22,505,110	$21,584,813	$21,132,260	$25,752,551	20,198,073	19,698,362
Total Expenses for Working Capital	$27,690,847	$27,649,684	$25,768,198	$24,386,243	$24,339,335	$29,111,042	23,727,210	23,406,757
Working Capital factor	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$2,076,814**	**$2,073,726**	**$1,932,615**	**$1,828,968**	**$1,825,450**	**$2,183,328**	**1,779,541**	**1,755,507**



The Rate Base for the 2022 Test Year has decreased by $7,929 over the last actual (2020) and increased by $1,270,138 above 2016 Actuals. The reason for the increase from the 2016 Cost of Service is mainly attributed to the projects listed in the Rate Base Variance Analysis at the next section 2.1.3:

Decreased Power Supply Expenses

ORPC has forecasted a decrease in the 2022 Power Supply Expenses of $5,017,512 over its 2016 Cost of Service. This is due to a reduction in RPP supply cost which is used to calculate the Cost of Power as well as the Ontario Electricity Rebate credit being applied to Regulated Price Plan billing components in the Test Year 2022.

Increased Distribution Expenses

The 2022 forecast for OM&A reflects an increase of $643,431 from the 2016 Board Approved. The details of the increases in OM&A are provided in Exhibit 4, however the key drivers include:

- Increases to regulatory expenses; and
- Increase in wages.

The Working Capital Allowance has decreased by $321,307 over the 2016 Board Approved. The reason for the decrease from the 2016 Board Approved to the Test Year 2022 is due to the decrease in Power Supply Expenses.

Year-over-year variances are presented in the next section.

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 2016 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 2022 proposed base 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:

- ✓ 2022 Test Year (MIFRS) against 2021 Bridge Year (MIFRS)
- ✓ 2021 Bridge Year (MIFRS) against 2020 Actual (MIFRS)
- ✓ 2020 Actual (MIFRS) against 2019 Actual (MIFRS)
- ✓ 2019 Actual (MIFRS) against 2018 Actual (MIFRS)
- ✓ 2018 Actual (MIFRS) against 2017 Actual (MIFRS)
- ✓ 2017 Actual (MIFRS) against 2016 Actual (MIFRS)

2016 BOARD APPROVED VS. 2016 ACTUAL:

Table 3 – 2016 BA to 2016 Actual Rate Base Variance

	MIFRS	MIFRS		
Particulars	**Last Board Approved**	**2016**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$30,265,128	$12,684,917	-$17,580,211	-58.09%
Ending Net Assets	-$20,539,657	-$2,746,384	$17,793,273	-86.63%
Average Balance	$9,725,471	$9,938,532	$213,061	2.19%
Working Capital Allowance	$2,076,814	$2,073,726	-$3,087	-0.15%
Total Rate Base	**$11,802,285**	**$12,012,259**	**$209,974**	**1.78%**
Expenses for Working Capital	**Last Board Approved**	**2016**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$572,467	$630,729	$58,262	10.18%
3550-Distribution Expenses - Maintenance	$728,123	$613,081	-$115,042	-15.80%
3650-Billing and Collecting	$733,000	$747,071	$14,071	1.92%
3700-Community Relations	$67,000	$55,936	-$11,064	-16.51%
3800-Administrative and General Expenses	$964,375	$886,993	-$77,382	-8.02%
	$0	$0		
Total Eligible Distribution Expenses	$3,064,965	$2,933,810	-$131,155	-4.28%
3350-Power Supply Expenses	$24,625,882	$24,715,874	$89,992	0.37%
Total Expenses for Working Capital	$27,690,847	$27,649,684	-$41,163	-0.15%
Working Capital factor	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$2,076,814**	**$2,073,726**	**-$3,087**	**-0.15%**

The total Rate Base in 2016 Actual of $12,012,259 was $209,974 higher or 1.78% more than the 2016 Board Approved. The main reason for the variance is:

- System Access: Orchard View by the Mississippi Almonte at $79,812
  - Externally initiated retirement housing development in Almonte resulting in 34 new customers.
- System Renewal: Martin Street and Paul Street at $124,628
  - Pole and conductor replacement project on Martin Street South and St Paul Street in Almonte. The assets had reached end of life had visible signs of deterioration and required replacement to company standard.
- System Renewal: Paul Martin Drive Pole Conflicts Road Rebuild at $107,282
  - Externally initiated project to relocate poles and conductor which interfered with the upgrades on the roads, sidewalks and ditches.

- System Service: Sub 6 Ground Grid at $72,244
    - The Pembroke MS#6 ground grid reached its end of life and was posing health and safety risks resulting in its replacement. The purpose of the grounding grid is to serve the dual purpose of carrying currents into the earth without exceeding the operating tolerances of any protected equipment while assuring that personnel in the vicinity are not exposed to electric shock as would result from excessive step or touch potentials.
- System Service: Station 2 Rebuild $61,445
    - The Pembroke MS#2 ground grid, feeder cables, riser poles and associated equipment reached their end of life and were replaced. The purpose of the grounding grid is to serve the dual purpose of carrying currents into the earth without exceeding the operating tolerances of any protected equipment while assuring that personnel in the vicinity are not exposed to electric shock as would result from excessive step or touch potentials.
- General Plant: Transportation Equipment - Truck Purchase at $113,525
    - This represented the chassis for a 2017 International Tandem RBD which replaced a 1994 International. The 1994 vehicle no longer had sufficient lift capacity to support ongoing operations. Poles and transformers have become larger, taller and heavier minimizing the vehicle's usefulness.
- General Plant: Leasehold Improvement at $54,222
    - This represented a renovation to the board room and service department. The renovation consisted of replacing an aluminum door assembly to increase heating efficiency, replacement of old carpets and paint, and changes to room layout to create more storage for IT equipment.

Total working capital expenses saw a small decrease and reduced the working capital by $3,087.

2016 ACTUAL VS. 2017 ACTUAL:

Table 4 - 2016-2017 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2016**	**2017**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$12,684,917	$13,833,139	$1,148,222	9.05%
Ending Net Assets	-$2,746,384	-$3,600,161	-$853,777	31.09%
Average Balance	$9,938,532	$10,232,978	$294,445	2.96%
Working Capital Allowance	$2,073,726	$1,932,615	-$141,111	-6.80%
Total Rate Base	**$12,012,259**	**$12,165,593**	**$153,334**	**1.28%**
Expenses for Working Capital	**2016**	**Var $**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$630,729	$565,513	-$65,216	-10.34%
3550-Distribution Expenses - Maintenance	$613,081	$692,292	$79,212	12.92%
3650-Billing and Collecting	$747,071	$804,067	$56,996	7.63%
3700-Community Relations	$55,936	$79,674	$23,738	42.44%
3800-Administrative and General Expenses	$886,993	$1,121,542	$234,549	26.44%
	$0	$0		
Total Eligible Distribution Expenses	$2,933,810	$3,263,088	$329,278	11.22%
3350-Power Supply Expenses	$24,715,874	$22,505,110	-$2,210,764	-8.94%
Total Expenses for Working Capital	$27,649,684	$25,768,198	-$1,881,486	-6.80%
Working Capital factor	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$2,073,726**	**$1,932,615**	**-$141,111**	**-6.80%**

The total Rate Base in 2017 Actual of $12,165,593 was $153,334 or 1.28% greater than the 2016 Actual. The main reason for the variance is:

- System Access: Riverfront Phase 4 $86,544
    - Externally initiated housing development in Almonte resulting in 68 new customers.
- System Renewal: Boundary Road - Pole Replacements at $86,692
    - Installed 14 45' Class 3 Poles, 2,000m 2.36 AAW primary conductor and 692m of secondary bus to replace poles which had reached their end of life.
- System Service: Almonte MS#1 Scada Upgrade at $58,745
    - This was a required upgrade to the Almonte MS#1 Scada system which was no longer functional. Upgrading the system permitted ORPC to have a line of sight into the substation and enable operation of the station from the control

room. The upgrade was also required to continue to interface with an embedded generator within the utility’s service territory.

- System Service: Almonte MS#2 Upgrades at $58,599
    - The Almonte MS#2 feeder cables, riser poles and associated equipment reached their end of life and were replaced.
- General Plant: Transportation Equipment - Truck Purchase $319,920
    - This represents the remainder of the 2017 International Tandem RBD which replaced a 1994 International. The 1994 vehicle no longer had sufficient lift capacity to support ongoing operations. Poles and transformers have become larger, taller and heavier minimizing the vehicle’s usefulness.

Power Supply Expenses continued to decrease and reduced the working capital by a further $141,111.

2017 ACTUAL VS. 2018 ACTUAL:

Table 5 - 2017-2018 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2017**	**2018**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$13,833,139	$15,197,310	$1,364,171	9.86%
Ending Net Assets	-$3,600,161	-$4,448,158	-$847,997	23.55%
Average Balance	$10,232,978	$10,749,152	$516,174	5.04%
Working Capital Allowance	$1,932,615	$1,828,968	-$103,647	-5.36%
Total Rate Base	**$12,165,593**	**$12,578,120**	**$412,528**	**3.39%**
Expenses for Working Capital	**2017**	**2018**	**Var $**	**Var %**
Eligible Distribution Expenses:		-		
3500-Distribution Expenses - Operation	$565,513	$484,252	-$81,261	-14.37%
3550-Distribution Expenses - Maintenance	$692,292	$500,384	-$191,909	-27.72%
3650-Billing and Collecting	$804,067	$668,041	-$136,026	-16.92%
3700-Community Relations	$79,674	$71,838	-$7,836	-9.83%
3800-Administrative and General Expenses	$1,121,542	$1,076,915	-$44,627	-3.98%
	$0	$0		
Total Eligible Distribution Expenses	$3,263,088	$2,801,430	-$461,658	-14.15%
3350-Power Supply Expenses	$22,505,110	$21,584,813	-$920,297	-4.09%
Total Expenses for Working Capital	$25,768,198	$24,386,243	-$1,381,955	-5.36%
Working Capital factor	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$1,932,615**	**$1,828,968**	**-$103,647**	**-5.36%**

The total Rate Base in 2018 Actual of $12,578,120 is $412,528 or 3.39% greater than 2017 Actual. The primary capital projects in 2018 are:

- System Access: Pembroke Place Condominiums $57,116
  - Externally initiated system access located on Maple Avenue in Pembroke consisting of 2 buildings of 12 units each.
- System Access: Riverfront Phase 4 and Phase 5 $57,467
  - Externally initiated housing development in Almonte which saw 68 and 141 customers respectively for each phase added to the ORPC customer base.
- System Renewal: Pembroke Voltage Conversion MS#1 and MS#3 at $371,389
  - To replace distribution transformers to enable the utility to remove 2 4.16 kV substations out of service and transfer the load onto the 12.4KV system. The physical age of MS#1 and MS#3 indicates that the substations are approaching their useful life expectancy and parts are becoming obsolete

indicating that should the substations fails, replacement parts may not be possible to obtain. Additionally, the MS#1 transformer is showing degradation of the quality of oil. Moving the entire system to a 12.4kV system allows for redundancy in the system.

- System Service: Almonte MS#3 Station Upgrades $64,813
  - Updated feeder cables and riser poles for Almonte MS#3 including new gravel and paint for the property. These assets were replaced due to aging to bring condition of assets to current standards.
- System Service: Almonte MS#2 Upgrade at $56,943
  - Updated feeder cables and riser poles for Almonte MS#2 including new gravel and paint for the property. These assets were replaced due to aging to bring condition of assets to current standards.
- System Service: Almonte MS#4 Construction at $147,575
  - ORPC was approved for an ICM of $1,603,409 to build a new 5 MVA substation (MS-4) in the Almonte Ward in the Town of Mississippi Mills, which was expected to be in-service by June 2019. Almonte MS#4 was a necessary and prudent expenditure to meet system and reliability needs due to growth in Almonte. This asset was above the $50,000 materiality threshold, however it was not included as an asset in service. The asset went into service in 2020, however will only be transferred to the rate based on May 1st, 2022 when the Cost of Service rates are intended to be effective.

Power Supply Expenses continued to decrease and reduced the working capital by a further $103,647.

2018 ACTUAL VS. 2019 ACTUAL:

Table 6 - 2018-2019 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2018**	**2019**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$15,197,310	$16,364,217	$1,166,908	7.68%
Ending Net Assets	-$4,448,158	-$5,190,285	-$742,127	16.68%
Average Balance	$10,749,152	$11,173,932	$424,780	3.95%
Working Capital Allowance	$1,828,968	$1,825,450	-$3,518	-0.19%
Total Rate Base	**$12,578,120**	**$12,999,383**	**$421,262**	**3.35%**
Expenses for Working Capital	**2018**	**2019**	**Var $**	**Var %**
Eligible Distribution Expenses:		-		
3500-Distribution Expenses - Operation	$484,252	$513,327	$29,075	6.00%
3550-Distribution Expenses - Maintenance	$500,384	$645,567	$145,184	29.01%
3650-Billing and Collecting	$668,041	$748,224	$80,183	12.00%
3700-Community Relations	$71,838	$64,147	-$7,691	-10.71%
3800-Administrative and General Expenses	$1,076,915	$1,235,810	$158,895	14.75%
	$0	$0		
Total Eligible Distribution Expenses	$2,801,430	$3,207,076	$405,645	14.48%
3350-Power Supply Expenses	$21,584,813	$21,132,260	-$452,553	-2.10%
Total Expenses for Working Capital	$24,386,243	$24,339,335	-$46,908	-0.19%
Working Capital factor	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$1,828,968**	**$1,825,450**	**-$3,518**	**-0.19%**

The total Rate Base in 2019 Actual of $12,999,383 is $421,262 or 3.35% greater than 2018 Actual. The main reasons for the variance are:

- System Access: Riverfront Phase 5 $172,940
  - Externally initiated housing development in Almonte which saw 141 customers added to the ORPC customer base.
- System Renewal: Voltage Conversion $55,663
  - To replace distribution transformers to enable the utility to remove 2 4.16 kV substations out of service and transfer the load onto the 12.4KV system. The physical age of MS#1 and MS#3 indicates that the substations are approaching their useful life expectancy and parts are becoming obsolete indicating that should the substations fails, replacement parts may not be possible to obtain. Additionally, the MS#1 transformer is showing

degradation of the quality of oil. Moving the entire system to a 12.4kV system allows for redundancy in the system.

- System Renewal: Victoria Street Underground Conversion $55,480
  - Externally initiated project to renovate the downtown core of the City of Pembroke. The project encompassed renewal of infrastructure including relocation of overhead power distribution infrastructure to underground.
- System Renewal: Beachburg Road Pole Replacement $55,480
  - Replacement of rotten poles along Beachburg road to bring them to standard. Replaced 35’ foot poles with 45’ poles.
- System Service: Almonte MS#4 Construction $1,305,025
  - ORPC was approved for an ICM of $1,603,409 to build a new 5 MVA substation (MS-4) in the Almonte Ward in the Town of Mississippi Mills, which was expected to be in-service by June 2019. Almonte MS#4 was a necessary and prudent expenditure to meet system and reliability needs due to growth in Almonte. This asset was above the $50,000 materiality threshold, however it was not included as an asset in service. The asset went into service in 2020, however will only be transferred to the rate based on May 1st, 2022 when the Cost of Service rates are intended to be effective.
- System Renewal: Almonte Feeder Relocation $64,350
  - A substation distribution feeder in Almonte was attached to a private building. As a result of health and safety issues, the feeder was relocated. The project required a new pole line, a river crossing and external engineering to complete.
- General Plant: Transport Equipment $364,485
  - The utility purchased a 2018 International RBD to replace a non-functional and unsafe 2010 international RBD which did not reach its intended life. The truck was fully depreciated for accounting purposes.

Power Supply Expenses continued to decrease and reduced the working capital by a further $3,518.

2019 ACTUAL VS. 2020 ACTUAL:

Table 7 - 2019-2020 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2019**	**2020**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$16,364,217	$16,989,599	$625,381	3.82%
Ending Net Assets	-$5,190,285	-$5,882,601	-$692,316	13.34%
Average Balance	$11,173,932	$11,106,997	-$66,935	-0.60%
Working Capital Allowance	$1,825,450	$2,183,328	$357,878	19.60%
Total Rate Base	**$12,999,383**	**$13,290,325**	**$290,943**	**2.24%**
Expenses for Working Capital	**2019**	**2020**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$513,327	$785,741	$272,413	53.07%
3550-Distribution Expenses - Maintenance	$645,567	$501,236	-$144,331	-22.36%
3650-Billing and Collecting	$748,224	$837,380	$89,156	11.92%
3700-Community Relations	$64,147	$30,338	-$33,809	-52.71%
3800-Administrative and General Expenses	$1,235,810	$1,203,797	-$32,012	-2.59%
	$0	$0		
Total Eligible Distribution Expenses	$3,207,076	$3,358,492	$151,416	4.72%
3350-Power Supply Expenses	$21,132,260	$25,752,551	$4,620,291	21.86%
Total Expenses for Working Capital	$24,339,335	$29,111,042	$4,771,707	19.60%
Working Capital factor	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$1,825,450**	**$2,183,328**	**$357,878**	**19.60%**

The total Rate Base in 2020 Actual of $13,290,325 is $290,943 or 2.24% greater than 2019 Actual.

- System Service: Almonte MS#4 Construction $695,875
    - ORPC was approved for an ICM of $1,603,409 to build a new 5 MVA substation (MS-4) in the Almonte Ward in the Town of Mississippi Mills, which was expected to be in-service by June 2019. Almonte MS#4 was a necessary and prudent expenditure to meet system and reliability needs due to growth in Almonte. This asset was above the $50,000 materiality threshold, however it was not included as an asset in service. The asset went into service in 2020, however will only be transferred to the rate based on May 1st, 2022 when the Cost of Service rates are intended to be effective.
- General Plant: Transport Equipment $53,554

- The utility purchased an electric vehicle to replace aging smaller vehicles. The purchase was also required for health and safety purposes related to social distancing measures as a result of the pandemic as well.

Power Supply and OM&A Expense escalated the working capital portion by $357,878.

2020 ACTUAL VS. 2021 TEST YEAR:

Table 8 - 2020-2021 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2020**	**2021**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$16,989,599	17,724,210	734,611	4.32%
Ending Net Assets	-$5,882,601	-6,686,437	-803,836	13.66%
Average Balance	$11,106,997	11,037,773	**-69,224**	**-0.62%**
Working Capital Allowance	$2,183,328	1,779,541	-403,787	-18.49%
Total Rate Base	**$13,290,325**	**12,817,314**	**-473,012**	**-3.56%**
Expenses for Working Capital	**2020**	**2021**	**Var $**	**Var %**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	$785,741	815,322	29,582	3.76%
3550-Distribution Expenses - Maintenance	$501,236	562,975	61,740	12.32%
3650-Billing and Collecting	$837,380	951,322	113,943	13.61%
3700-Community Relations	$30,338	41,362	11,024	36.34%
3800-Administrative and General Expenses	$1,203,797	1,158,155	-45,642	5.80%
	$0			
Total Eligible Distribution Expenses	$3,358,492	3,529,137	**170,646**	**5.08%**
3350-Power Supply Expenses	$25,752,551	20,198,073	-5,554,478	-21.57%
Total Expenses for Working Capital	$29,111,042	23,727,210	**- 5,383,832**	**-18.49%**
Working Capital factor	7.5%	7.5%		
Total Working Capital	**$2,183,328**	**1,779,541**	**-403,787**	**-18.49%**

The total planned Rate Base in 2021 Bridge Year is $12,817,314, -$473,012 or -3.63% greater than the 2020 Actual. The main reasons for the variance are:

- System Renewal: 44kV OHL Relocation $106,391
  - One of the main 44 kV feeds in Almonte runs across private property. The property has been sold and will be a future subdivision. There is no easement and ORPC must relocate the feed.
- General Plant: Server $106,585
  - The existing server ran out of computing power and space. In order to accommodate the Elster Connexo Upgrade and the CIS upgrade, a new server was required. This also results in improved security since the previous software was out of date.
- General Plant: Elster Connexo AMI Upgrade $76,153

  - The existing meter platform has reached its end of support and in order to continue supporting meter reading and to remain compatible with newer types of meters, an upgrade is required. Upgrading to the AMI will also allow real-time meter data acquisition which may help identify outages in a timelier manner.
- General Plant: Customer Information System Version Upgrade $100,000
  - The existing CIS version is seeing stability, security and functionality decreases. An upgrade has improved these and has ultimately led to increased productivity.

Power Supply and OM&A Expense are projected to decrease the working capital by $403,787.

2021 BRIDGE VS. 2022 TEST YEAR:

Table 9 - 2021-2022 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2021**	**2022**	**Var**	**%**
Net Capital Assets in Service:				
Opening Net Assets	$17,724,210	$19,205,663	$1,481,453	8.36%
Ending Net Assets	-$6,686,437	-$7,678,773	-$992,336	14.84%
Average Balance	$11,037,773	$11,526,890	$489,117	4.43%
Working Capital Allowance	$1,775,993	$1,755,507	-$20,486	-1.15%
Total Rate Base	**$12,813,766**	**$13,282,397**	**$468,631**	**3.65%**
Expenses for Working Capital	**2021**	**2022**	**Var $**	**Var %**
Eligible Distribution Expenses:		-		
3500-Distribution Expenses - Operation	$815,322	$901,091	$85,768	10.52%
3550-Distribution Expenses - Maintenance	$562,975	$576,747	$13,771	2.45%
3650-Billing and Collecting	$951,322	$962,860	$11,538	1.21%
3700-Community Relations	$41,362	$42,318	$957	2.31%
3800-Administrative and General Expenses	$1,158,155	$1,225,378	$67,223	5.80%
	$0	$0		
Total Eligible Distribution Expenses	$3,529,137	$3,708,394	$179,257	5.08%
3350-Power Supply Expenses	$20,198,073	$19,698,362	-$499,711	-2.47%
Total Expenses for Working Capital	$23,727,210	$23,406,757	-$320,454	-1.35%
Working Capital factor	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$1,779,541**	**$1,755,507**	**-$24,034**	**-1.35%**

The total planned Rate Base in 2022 Test Year is $13,282,397, $468,631 or 3.65% greater than the 2021 Bridge Year. The main reasons for the variance are:

- System Access: 44 kV O/H Line Relocation at $93,600
  - One of the main 44 kV feeds in Almonte runs across private property. The property has been sold and will be a future subdivision. There is no easement and ORPC must relocate the feed.
- System Access: Orchard View Suites (Phase 2) at $64,502
  - Externally initiated retirement housing development in Almonte.
- System Access: Highway 148 Upgrade at $100,000
  - One of the feeds from Quebec into Pembroke has pole conflicts that interfere with planned reconstruction of sidewalks and ditching and require relocation.
- System Renewal: Esther Street Pembroke $51,591

- End of life pole replacement. Identified as needing replacement in 2020 and replacement confirmed through third party pole testing.

- System Renewal: Third Avenue Pembroke $61,231
  - End of life pole replacement. Identified as needing replacement in 2020 and replacement confirmed through third party pole testing.
- System Renewal: Larose Street Almonte $80,959
  - End of life pole replacement. Identified as needing replacement in 2020 through the distribution system plan.
- System Renewal: Evelyn Street Almonte $50,592
  - End of life pole replacement. Identified as needing replacement in 2020 through the distribution system plan.
- System Service: Pembroke MS4 - Replace RTU and Relay $60,000
  - Data inputs and controls and operation of the equipment through the Scada system at Pembroke MS#4 is no longer possible due to asset aging and non-functional assets. This substation is one of the main stations in Pembroke connected to the feed from Hydro One.
- System Service: Pembroke MS6 - Transformer Replacement $750,000
  - At the end of June 2021, a transformer at Pembroke MS#6 was damaged. Through assessment from a third party, it was determined that a bushing failure resulted in damage to one of the transformers which remains offline. The damaged transformer is 47 years old. Although repair is the preferred option for financial reasons, the transformer has PCB contamination of 20ppm which, according to the third party, would result in repairs that would exceed the price of a new transformer if any vendor would even be willing to quote. This cost assumes a new transformer including disposal of the former transformer, shipping, unloading, commissioning, engineering and other related fees.

Power Supply decreases are projected to decrease the working capital by $23,690.

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 2016 to 2019 Actuals and 2021 Bridge and 2022 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 utility notes that it applied for and received approval for an Incremental Capital Module (ICM) in its 2019 IRM application (EB-2018-0063) to build a new 5 MVA substation (MS-4) in the Almonte Ward in the Town of Mississippi Mills. Final allocation of the regulatory assets and termination of the ICM rate riders are discussed in section 2.5.7.

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in ORPC's 2022 Distribution System Plan.

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

Below are the Fixed Asset Continuity Schedules for 2016 to 2022 which show the capital additions by traditional function. Following each continuity schedule is that the gross fixed additions by RRFE as a result of the capital investment.

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

Table 10 – 2016 Continuity Schedule

Year 2016 IFRS

			Gross Assets				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$202,932.06	$21,070.00		$224,002.06	$159,124	$31,159		$190,283	$33,719	$213,467	$174,703
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84			$2,747.84	$670	$335		$1,005	$1,743	$2,748	$838
N/A	1805	Land	$130,499.26			$130,499.26				$0	$130,499	$130,499	$0
47	1808	Buildings	$169,065.84			$169,065.84	$6,916	$3,458		$10,374	$158,692	$169,066	$8,645
13	1810	Leasehold Improvements	$229,612.33	$54,222.45		$283,834.78	$24,810	$14,392		$39,202	$244,633	$256,724	$32,006
47	1820	Distribution Station Equipment <50 kV	$1,202,331.51	$215,585.51		$1,417,917.02	$127,887	$69,125		$197,011.80	$1,220,905	$1,310,124	$162,449
47	1830	Poles, Towers & Fixtures	$2,013,138.26	$269,378.29		$2,282,516.55	$339,533	$158,182		$497,715	$1,784,802	$2,147,827	$418,624
47	1835	Overhead Conductors & Devices	$2,751,043.94	$189,649.63		$2,940,693.57	$238,489	$124,892		$363,381	$2,577,313	$2,845,869	$300,935
47	1840	Underground Conduit	$684,876.53	$10,252.68		$695,129.21	$175,622	$77,926		$253,548	$441,581	$690,003	$214,585
47	1845	Underground Conductors & Devices	$794,240.16	$25,027.79		$819,267.95	$50,007	$29,496		$79,503	$739,765	$806,754	$64,755
47	1850	Line Transformers	$1,500,350.86	$127,653.03		$1,628,003.89	$187,097	$89,144		$276,241	$1,351,763	$1,564,177	$231,669
	1850	Transformer Inventory	$268,760.00	-$16,389.00		$252,371.00				$0	$252,371	$260,566	$0
47	1855	Services (Overhead & Underground)	$1,121,323.67	$93,631.49		$1,214,955.16	$94,884	$50,923		$145,807	$1,069,148	$1,168,139	$120,346
47	1860-15	Meters	$1,645,231.00	$36,172.07		$1,681,403.07	$654,368	$110,888		$765,256	$916,147	$1,663,317	$709,812
47	1860-25	Meters >50	$97,695.47	$3,098.85		$100,794.32	$8,495	$4,588		$13,084	$87,711	$99,245	$10,790
	1860	Meter Inventory	$87,293.12	-$32,605.99		$54,687.13	$0	$0		$0	$54,687	$70,990	$0
8	1915	Office Furniture & Equipment (10 years)	$13,903.30	$27,072.09		$40,975.39	$2,644	$3,021		$5,665	$35,310	$27,439	$4,155
10	1920-2	Computer Equipment - Hardware	$84,929.41	$1,668.77		$86,598.18	$56,242	$16,507		$72,750	$13,849	$85,764	$64,496
10	1930-8	Transportation Equipment	$871,753.41	$116,565.00		$988,318.41	$320,589	$136,044		$456,633	$531,685	$930,036	$388,611
8	1940	Tools, Shop & Garage Equipment	$74,405.91	$14,006.95		$88,412.86	$16,323	$8,284		$24,607	$63,806	$81,409	$20,465
8	1945	Measurement & Testing Equipment	$23,637.80			$23,637.80	$3,941	$2,454		$6,395	$17,243	$23,638	$5,168
8	1955	Communications Equipment	$26,170.96			$26,170.96	$5,094	$4,989		$10,083	$16,088	$26,171	$7,588
8	1960	Miscellaneous Equipment	$11,498.80			$11,498.80	$2,421	$1,210		$3,631	$7,868	$11,499	$3,026
47	1980	System Supervisor Equipment	$3,088.72			$3,088.72	$2,699	$288		$2,987	$102	$3,089	$2,843
47	1995	Contributions & Grants	-$1,526,788.80			-$1,526,788.80	-$142,363	-$71,182		-$213,545	-$1,313,244	-$1,526,789	-$177,954
47	2440	Deferred Revenues	-$328,404.66	-$96,899.30		-$425,303.96	-$12,217	-$19,905		-$32,121	-$393,183	-$376,854	-$22,169
						$0.00				$0	$0	$0	$0
		Sub-Total	$12,155,336.70	$1,059,160.31	$0.00	$13,214,497.01	$2,323,275	$846,218	$0	$3,169,493	$10,045,004	$12,684,917	$2,746,384
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0.00				$0	$0		
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0.00				$0	$0		
		Total PP&E	$12,155,336.70	$1,059,160.31	$0.00	$13,214,497.01	$2,323,275	$846,218	$0	$3,169,493	$10,045,004		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						$846,218					

Table 11 – 2016 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1810	1820	1830	1835	1840	1845	1850	1850	1855	1855	1860	1915	1920	1611	1930	1940	2440	Total
							OH	UG	OH	UG								
System Access																		
New Services and Service Upgrades			3,463	175	3,351	802		2,951	20,541	34,263	3,098.85						(72,563)	(3,918)
Orchard View by the Mississippi Almonte						6,512		90,258		7,378							(24,336)	79,812
Sub-Total	-	-	3,463	175	3,351	7,314	-	93,210	20,541	41,640	3,099	-	-	-	-	-	(96,899)	75,894
System Renewal																		
Minor Capital Betterments		79,486	145,748	40,063	4,293	343	3,503	1,131	15,609	3,520								293,696
Martin Street and Paul Street			44,329	75,370			4,929											124,628
Sub 4 Cable Replacement						13,800												13,800
Paul Martin Drive Pole Conflicts Road Rebuild			45,388	35,741	2,337	3,227	8,492		634	7,897	3,566							107,282
Paul Martin Drive Install New 60' 44kV Pole			10,872	2,123														12,995
Boundary Road East Pole Upgrade			9,356	6,582														15,938
Alfred and Cecelia Upgrade Secondary Conductors				8,656					3,789									12,444
Sub-Total	-	79,486	255,694	168,534	6,629	17,370	16,923	1,131	20,033	11,418	3,566	-	-	-	-	-	-	580,784
System Service																		
Minor Capital Betterments																		-
Sub 2 Rebuild		33,655	8,991	18,527	272													61,445
Sub 3 and 7 Ground Grid & Fence		31,500	1,230	936		346												34,011
Sub 6 Ground Grid		70,945		1,477														72,422
Sub-Total	-	136,100	10,221	20,940	272	346	-	-	-	-	-	-	-	-	-	-	-	167,879
General Plant																		
Office Equipment												27,072						27,072
Computer Equipment - Hardware													1,669					1,669
Computer Software														21,070				21,070
Transportation Equipment - Misc															3,040			3,040
Transportation Equipment - Truck Purchase (Cab & Chassis)															113,525			113,525
Small Tools																14,007		14,007
Measurement and Testing Equipment																		-
Leasehold Improvement	54,222																	54,222
Sub-Total	54,222	-	-	-	-	-	-	-	-	-	-	27,072	1,669	21,070	116,565	14,007	-	234,605
Total	**54,222**	**215,586**	**269,378**	**189,649**	**10,253**	**25,030**	**16,923**	**94,341**	**40,574**	**53,058**	**6,664**	**27,072**	**1,669**	**21,070**	**116,565**	**14,007**	**(96,899)**	**1,059,161**

Table 12 – 2017 Continuity Schedule

Year 2017 **IFRS**

CCA Class	OEB	Description	Gross Assets: Opening Balance	Gross Assets: Additions	Gross Assets: Disposals	Gross Assets: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions (Depr Exp must match 2.9)	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$224,002.06	$33,880.61		$257,882.67	$190,283	$25,720		$216,003	$41,880	$240,942	$203,143
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84			$2,747.84	$1,005	$335		$1,340	$1,408	$2,748	$1,173
N/A	1805	Land	$130,499.26	$39,130.00		$169,629.26	$0			$0	$169,629	$150,064	$0
47	1808	Buildings	$169,065.84	$731.25		$169,797.09	$10,374	$3,466		$13,840	$155,957	$169,431	$12,107
13	1810	Leasehold Improvements	$283,834.78	$3,278.27		$287,113.05	$39,202	$15,542		$54,744	$232,370	$285,474	$46,973
47	1820	Distribution Station Equipment <50 kV	$1,417,917.02	$48,459.71		$1,466,376.73	$197,012	$71,681		$268,692	$1,197,684	$1,442,147	$232,852
47	1830	Poles, Towers & Fixtures	$2,282,516.55	$162,879.07		$2,445,395.62	$497,715	$153,689		$651,403	$1,793,992	$2,363,956	$574,559
47	1835	Overhead Conductors & Devices	$2,940,693.57	$291,806.26		$3,232,499.83	$363,381	$129,035		$492,416	$2,740,084	$3,086,597	$427,898
47	1840	Underground Conduit	$695,129.21	$31,940.21		$727,069.42	$253,548	$68,063		$321,611	$405,458	$711,099	$287,580
47	1845	Underground Conductors & Devices	$819,267.95	$140,969.86		$960,237.81	$79,503	$31,570		$111,073	$849,165	$889,753	$95,288
47	1850	Line Transformers	$1,628,003.89	$140,853.33		$1,768,857.22	$276,241	$89,236		$365,476	$1,403,381	$1,698,431	$320,858
	1850	Transformer Inventory	$252,371.00	$68,215.00		$320,586.00	$0			$0	$320,586	$286,479	$0
47	1855	Services (Overhead & Underground)	$1,214,955.16	$126,453.61		$1,341,408.77	$145,807	$53,308		$199,115	$1,142,293	$1,278,182	$172,461
47	1860-15	Meters	$1,681,403.07	$35,397.20		$1,716,800.27	$765,256	$113,273		$878,529	$838,271	$1,699,102	$821,892
47	1860-25	Meters >50	$100,794.32			$100,794.32	$13,084	$4,545		$17,628	$83,166	$100,794	$15,356
	1860	Meter Inventory	$54,687.13	$4,011.67		$58,698.80	$0			$0	$58,699	$56,693	$0
8	1915	Office Furniture & Equipment (10 years)	$40,975.39	$4,397.75		$45,373.14	$5,665	$4,595		$10,260	$35,113	$43,174	$7,962
10	1920-2	Computer Equipment - Hardware	$86,598.18	$6,396.67		$92,994.85	$72,750	$10,515		$83,265	$9,730	$89,797	$78,007
10	1930-8	Transportation Equipment	$988,318.41	$322,428.24		$1,310,746.65	$456,633	$158,892		$615,525	$695,221	$1,149,533	$536,079
8	1940	Tools, Shop & Garage Equipment	$88,412.86	$3,354.45		$91,767.31	$24,607	$8,943		$33,550	$58,217	$90,090	$29,078
8	1945	Measurement & Testing Equipment	$23,637.80	$999.00		$24,636.80	$6,395	$2,504		$8,899	$15,738	$24,137	$7,647
8	1955	Communications Equipment	$26,170.96			$26,170.96	$10,083	$4,832		$14,915	$11,256	$26,171	$12,499
8	1960	Miscellaneous Equipment	$11,498.80			$11,498.80	$3,631	$1,210		$4,842	$6,657	$11,499	$4,236
47	1980	System Supervisor Equipment	$3,088.72	$35,234.31		$38,323.03	$2,987	$5,974		$8,961	$29,362	$20,706	$5,974
47	1995	Contributions & Grants	-$1,526,788.80			-$1,526,788.80	-$213,545	-$71,182		-$284,727	-$1,242,062	-$1,526,789	-$249,136
47	2440	Deferred Revenues	-$425,303.96	-$263,532.76		-$688,836.72	-$32,121	-$24,410		-$56,531	-$632,305	-$557,070	-$44,326
						$0.00				$0	$0	$0	$0
		Sub-Total	**$13,214,497.01**	**$1,237,283.71**	**$0.00**	**$14,451,780.72**	**$3,169,493**	**$861,335**	**$0**	**$4,030,829**	**$10,420,952**	$13,833,139	$3,600,161
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0.00				$0	$0		
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0.00				$0	$0		
		Total PP&E	**$13,214,497.01**	**$1,237,283.71**	**$0.00**	**$14,451,780.72**	**$3,169,493**	**$861,335**	**$0**	**$4,030,829**	**$10,420,952**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$861,335**					

Table 13 – 2017 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1805	1808	1810	1820	1830	1835	1840	1845	1850	1850	1855	1855	1860	1915	1920	1611	1930	1940	1945	1980	2440	Total
									O/H	U/G	O/H	U/G										
System Access																						
New Services and Service Upgrades					15,486	14,678	5,557	26,508	12,331	14,720	24,422	28,143	34,673									176,518
Martin Street Pole Upgrades					11,287	4,772			2,164		7,866	4,640										30,729
Riverfront Phase 4							425	40,597	1,086	2,057		42,379										86,544
Upper Valley Drive Upgrades							9,767	6,094		29,038												44,899
Boundary Road - SRB Technologies								6,627		17,565		34	724									24,951
Contributions																					(263,533)	(263,533)
Sub-Total	-	-	-	-	26,773	19,450	15,750	79,826	15,582	63,379	32,288	75,195	35,397	-	-	-	-	-	-	-	(263,533)	100,107
System Renewal																						
Minor Capital Betterments		731		12,632	82,149	121,369	241	3,992	86,166	3,225	2,634	3,523	4,012									320,675
Almonte Martin Street and St Paul Street Renewal					8,966	16,882			226		8,779											34,853
Angus Campbell Drive Damage					8,649	6,626	559	2,394														18,227
Boundary Road - Pole Replacements					8,534	66,342			8,367		3,448											86,692
Beachburg Road Pole and Secondary Replacement					9,289	31,321			4,861		215	371										46,057
Replace 1000kVa Transformer								6,641		27,262												33,903
Pembroke MS#4 Feeder#1 Rebuild				12,316																		12,316
Pembroke MS#4 Pole Upgrades					18,201	3,647	772	8,455														31,075
Boundary Road - 44KV Upgrade						22,167																22,167
Sub-Total	-	731	-	24,949	135,788	268,356	1,573	21,481	99,620	30,487	15,077	3,894	4,012	-	-	-	-	-	-	-	-	605,967
System Service																						
Almonte MS#1 Scada Upgrade				23,511																35,234		58,745
Almonte MS#1 Land	39,130																					39,130
Almonte MS#2 Upgrades					318	4,001	14,618	39,662														58,599
Sub-Total	39,130	-	-	23,511	318	4,001	14,618	39,662	-	-	-	-	-	-	-	-	-	-	-	35,234	-	156,475
General Plant																						
Office Equipment														4,398								4,398
Computer Equipment - Hardware															6,397							6,397
Computer Software																33,881						33,881
Transportation Equipment - Misc																	2,508					2,508
Transportation Equipment - Truck Purchase																	319,920					319,920
Small Tools																		3,354				3,354
Measurement and Testing Equipment																			999			999
Leashold Improvements			3,278																			3,278
Sub-Total	-	-	3,278	-	-	-	-	-	-	-	-	-	-	4,398	6,397	33,881	322,428	3,354	999	-	-	374,735
Total	**39,130**	**731**	**3,278**	**48,460**	**162,879**	**291,806**	**31,940**	**140,969.86**	**115,201**	**93,867**	**47,364**	**79,089**	**39,409**	**4,398**	**6,397**	**33,881**	**322,428**	**3,354**	**999**	**35,234**	**(263,533)**	**1,237,284**

Table 14 – 2018 Continuity Schedule

Year 2018 **IFRS**

			Gross Assets				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$257,882.67	$11,474.01		$269,356.68	$216,003	$23,340		$239,343	$30,014	$263,620	$227,673
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84			$2,747.84	$1,340	$335		$1,675	$1,073	$2,748	$1,508
N/A	1805	Land	$169,629.26	$88,721.06		$258,350.32	$0			$0	$258,350	$213,990	$0
47	1808	Buildings	$169,797.09	$1,572.78		$171,369.87	$13,840	$3,474		$17,314	$154,056	$170,583	$15,577
13	1810	Leasehold Improvements	$287,113.05			$287,113.05	$54,744	$15,639		$70,382	$216,731	$287,113	$62,563
47	1820	Distribution Station Equipment <50 kV	$1,466,376.73	$94,618.86		$1,560,995.59	$268,692	$72,302		$340,994	$1,220,001	$1,513,686	$304,843
47	1830	Poles, Towers & Fixtures	$2,445,395.62	$169,618.68		$2,615,014.30	$651,403	$147,861		$799,264	$1,815,750	$2,530,205	$725,334
47	1835	Overhead Conductors & Devices	$3,232,499.83	$310,709.38		$3,543,209.21	$492,416	$134,224		$626,640	$2,916,570	$3,387,855	$559,528
47	1840	Underground Conduit	$727,069.42	$42,831.57		$769,900.99	$321,611	$62,016		$383,627	$386,274	$748,485	$352,619
47	1845	Underground Conductors & Devices	$960,237.81	$115,159.44		$1,075,397.25	$111,073	$34,772		$145,845	$929,552	$1,017,818	$128,459
47	1850	Line Transformers	$1,768,857.22	$521,399.67		$2,290,256.89	$365,476	$52,467		$417,944	$1,872,313	$2,029,557	$391,710
	1850	Transformer Inventory	$320,586.00	$45,552.00		$366,138.00	$0			$0	$366,138	$343,362	$0
47	1855	Services (Overhead & Underground)	$1,341,408.77	$65,935.10		$1,407,343.87	$199,115	$55,447		$254,562	$1,152,782	$1,374,376	$226,839
47	1860-15	Meters	$1,716,800.27	$107,964.17		$1,824,764.44	$878,529	$118,052		$996,581	$828,183	$1,770,782	$937,555
47	1860-25	Meters >50	$100,794.32			$100,794.32	$17,628	$4,498		$22,126	$78,668	$100,794	$19,877
	1860	Meter Inventory	$58,698.80	-$692.59		$58,006.21	$0			$0	$58,006	$58,353	$0
8	1915	Office Furniture & Equipment (10 years)	$45,373.14	$4.57		$45,377.71	$10,260	$4,815		$15,074	$30,303	$45,375	$12,667
10	1920-2	Computer Equipment - Hardware	$92,994.85	$5,446.05		$98,440.90	$83,265	$7,162		$90,427	$8,014	$95,718	$86,846
10	1930-8	Transportation Equipment	$1,310,746.65	$30,997.23		$1,341,743.88	$615,525	$161,599		$777,125	$564,619	$1,326,245	$696,325
8	1940	Tools, Shop & Garage Equipment	$91,767.31	$368.11		$92,135.42	$33,550	$9,129		$42,679	$49,456	$91,951	$38,115
8	1945	Measurement & Testing Equipment	$24,636.80	$3,180.25		$27,817.05	$8,899	$2,713		$11,612	$16,205	$26,227	$10,256
8	1955	Communications Equipment	$26,170.96			$26,170.96	$14,915	$4,674		$19,589	$6,582	$26,171	$17,252
8	1960	Miscellaneous Equipment	$11,498.80			$11,498.80	$4,842	$1,210		$6,052	$5,447	$11,499	$5,447
47	1980	System Supervisor Equipment	$38,323.03	$12,648.09		$50,971.12	$8,961	$13,853		$22,814	$28,157	$44,647	$15,888
47	1995	Contributions & Grants	-$1,526,788.80			-$1,526,788.80	-$284,727	-$71,182		-$355,908	-$1,170,880	-$1,526,789	-$320,318
47	2440	Deferred Revenues	-$688,836.72	-$136,450.00		-$825,286.72	-$56,531	-$23,743		-$80,275	-$745,012	-$757,062	-$68,403
						$0.00				$0	$0	$0	$0
		Sub-Total	**$14,451,780.72**	**$1,491,058.43**	**$0.00**	**$15,942,839.15**	**$4,030,829**	**$834,658**	**$0**	**$4,865,487**	**$11,077,352**	$15,197,310	$4,448,158
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0.00		$0	$0	$0	$0		
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0.00				$0	$0		
		Total PP&E	**$14,451,780.72**	**$1,491,058.43**	**$0.00**	**$15,942,839.15**	**$4,030,829**	**$834,658**	**$0**	**$4,865,487**	**$11,077,352**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$834,658**					

Table 15 – 2018 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1805	1808	1820	1830	1835	1840	1845	1850	1850	1855	1855	1860	1915	1920	1611	1930	1940	1945	1980	2440	Total
								O/H	U/G	O/H	U/G										
System Access																					
New Services and Service Upgrades				9,731	5,645	6,909	1,938	90,905	5,045	(5,789)	34,947	90,238									239,569
Firehall							9,135	5,725	24,575												39,434
Tie Line - Horace Street				1,985	39,809			2,117													43,911
Pembroke Place Condo				1,917	3,051	304	16,763	7,039	27,587			455									57,116
Orchardview						298	24,346	718	1,645		10,940	670									38,617
Riverfront Phase 4 and Phase 5						1,320	8,120	47,958	35		35										57,467
Patricia Street Townhomes						1,150	1,739	8,486			6,010										17,386
Contributions																				(136,450)	(136,450)
Sub-Total	-	-	-	13,633	48,505	9,981	62,041	162,948	58,886	(5,789)	51,931	91,363	-	-	-	-	-	-	-	(136,450)	357,050
System Renewal																					
Minor Capital Betterments			2,633	73,434	100,398	2,266		6,914	886	10,079	3,826	15,875									216,312
Replace U/G Riser				3,457	4,090		3,904														11,451
Pole Upgrade - Pembroke Street East				9,154	4,597			4,737													18,488
Shepherd Street				17,220	14,743		2,666			749	3,834										39,211
Euphemia Street				10,910	29,127			1,752			997										42,785
Beachburg Road				11,105	8,655																19,760
O'Brien Street				203	667	19,064	16,485														36,419
Industrial Drive 44kV Pole Installation				4,455	7,632						307	34									12,428
Pembroke Voltage Conversion MS#1 and MS#3				2,604	37,957			330,828													371,389
Almonte MS#2 and 3 Station Insulator Upgrades			3,369	1,238	5,718																10,324
Almonte MS#3 Station Upgrades			2,029	13,085	29,746	5,377	14,575														64,813
Pembroke MS#6 Copper			17,278																		17,278
Sub-Total	-	-	25,309	146,862	243,329	26,707	37,630	344,231	886	10,828	8,964	15,908	-	-	-	-	-	-	-	-	860,657

Table 16 – 2018 Gross Fixed Asset Additions by RRFE (Cont'd)

System Service																					
Minor Capital Betterments		1,573	3,145																		4,718
Almonte MS#1 Scada Upgrades																			12,648		12,648
Almonte MS#2 Upgrades			7,313	9,124	18,875	6,144	15,488														56,943
Almonte MS#4 Construction	88,721		58,854																		147,575
Sub-Total	88,721	1,573	69,313	9,124	18,875	6,144	15,488	-	-	-	-	-	-	-	-	-	-	-	12,648	-	221,884
General Plant																					
Office Equipment													5								5
Computer Equipment - Hardware														5,446							5,446
Computer Software															11,474						11,474
Transportation Equipment - Truck #8 Exhaust																16,466					16,466
Transportation Equipment - Truck #31 Exhaust																14,532					14,532
Small Tools																	368				368
Measurement and Testing Equipment																		3,180			3,180
Sub-Total	-	-	-	-	-	-	-	-	-	-	-	-	5	5,446	11,474	30,997	368	3,180	-	-	51,470
Total	**88,721**	**1,573**	**94,622**	**169,619**	**310,709**	**42,832**	**115,159**	**507,179**	**59,773**	**5,039**	**60,896**	**107,272**	**5**	**5,446**	**11,474**	**30,997**	**368**	**3,180**	**12,648**	**(136,450)**	**1,491,061**

Table 17 – 2019 Continuity Schedule

Year 2019 **IFRS**

			Gross Assets				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$269,356.68	$16,660.16		$286,016.84	$239,343	$21,407		$260,750	$25,267	$277,687	$250,046
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84			$2,747.84	$1,675	$335		$2,010	$738	$2,748	$1,843
N/A	1805	Land	$258,350.32			$258,350.32	$0			$0	$258,350	$258,350	$0
47	1808	Buildings	$171,369.87			$171,369.87	$17,314	$3,474		$20,788	$150,582	$171,370	$19,051
13	1810	Leasehold Improvements	$287,113.05	$4,189.19		$291,302.24	$70,382	$15,754		$86,136	$205,166	$289,208	$78,259
47	1820	Distribution Station Equipment <50 kV	$1,560,995.59	-$58,854.18		$1,502,141.41	$340,994	$72,887		$413,882	$1,088,260	$1,531,569	$377,438
47	1830	Poles, Towers & Fixtures	$2,615,014.30	$147,244.97		$2,762,259.27	$799,264	$140,161		$939,425	$1,822,834	$2,688,637	$869,345
47	1835	Overhead Conductors & Devices	$3,543,209.21	$219,090.76		$3,762,299.97	$626,640	$138,792		$765,432	$2,996,868	$3,652,755	$696,036
47	1840	Underground Conduit	$769,900.99	$22,971.79		$792,872.78	$383,627	$56,744.79		$440,372	$352,501	$781,387	$412,000
47	1845	Underground Conductors & Devices	$1,075,397.25	$131,837.42		$1,207,234.67	$145,845	$37,860		$183,705	$1,023,530	$1,141,316	$164,775
47	1850	Line Transformers	$2,290,256.89	$304,783.27	-$151,106.64	$2,443,933.52	$417,944	$141,288		$559,231	$1,884,702	$2,367,095	$488,588
	1850	Transformer Inventory	$366,138.00	$120,624.00		$486,762.00	$0			$0	$486,762	$426,450	$0
47	1855	Services (Overhead)	$1,407,343.87	$167,646.61		$1,574,990.48	$254,562	$58,182		$312,744	$1,262,247	$1,491,167	$283,653
47	1860-15	Meters	$1,824,764.44	$66,700.65		$1,891,465.09	$996,581	$123,874		$1,120,455	$771,010	$1,858,115	$1,058,518
47	1860-25	Meters >50	$100,794.32			$100,794.32	$22,126	$4,413		$26,539	$74,256	$100,794	$24,332
	1860	Meter Inventory	$58,006.21	$34,715.66		$92,721.87	$0			$0	$92,722	$75,364	$0
8	1915	Office Furniture & Equipment (10 years)	$45,377.71			$45,377.71	$15,074	$4,815		$19,889	$25,488	$45,378	$17,482
10	1920-2	Computer Equipment - Hardware	$98,440.90	$13,428.49		$111,869.39	$90,427	$7,162		$97,589	$14,280	$105,155	$94,008
10	1930-8	Transportation Equipment	$1,341,743.88	$390,985.00	-$277,694.84	$1,455,034.04	$777,125	$161,268.15	-$277,695	$660,698	$794,336	$1,398,389	$718,911
8	1940	Tools, Shop & Garage Equipment	$92,135.42	$1,834.00		$93,969.42	$42,679	$9,239		$51,918	$42,051	$93,052	$47,299
8	1945	Measurement & Testing Equipment	$27,817.05			$27,817.05	$11,612	$2,872		$14,484	$13,333	$27,817	$13,048
8	1955	Communications Equipment	$26,170.96			$26,170.96	$19,589	$4,460		$24,049	$2,122	$26,171	$21,819
8	1960	Miscellaneous Equipment	$11,498.80			$11,498.80	$6,052	$1,210		$7,262	$4,236	$11,499	$6,657
47	1980	System Supervisor Equipment	$50,971.12			$50,971.12	$22,814	$15,961		$38,775	$12,196	$50,971	$30,794
47	1995	Contributions & Grants	-$1,526,788.80			-$1,526,788.80	-$355,908	-$71,182		-$427,090	-$1,099,699	-$1,526,789	-$391,499
47	2440	Deferred Revenues	-$825,286.72	-$312,299.72		-$1,137,586.44	-$80,275	-$23,686		-$103,960	-$1,033,626	-$981,437	-$92,117
						$0.00				$0	$0	$0	$0
		Sub-Total	**$15,942,839.15**	**$1,271,558.07**	**-$428,801.48**	**$16,785,595.74**	**$4,865,487**	**$927,291**	**-$277,695**	**$5,515,083**	**$11,270,513**	$16,364,217	$5,190,285
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0.00				$0	$0		
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0.00				$0	$0		
		Total PP&E	**$15,942,839.15**	**$1,271,558.07**	**-$428,801.48**	**$16,785,595.74**	**$4,865,487**	**$927,291**	**-$277,695**	**$5,515,083**	**$11,270,513**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$927,291**					

Table 18 – 2019 ICM MS4 Substation: Incremental Capital Assets (Acct 1508)

Incremental Capital Module - Almonte MS#4 Year 2019 **IFRS**

			Gross Assets				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value
47	1508-1820	Distribution Station Equipment <50 kV	$0.00	$1,337,463.65		$1,337,463.65	$0			$0	$1,337,464
47	1508-1830	Poles, Towers & Fixtures	$0.00	$17,761.65		$17,761.65	$0			$0	$17,762
47	1508-1835	Overhead Conductors & Devices	$0.00	$7,673.60		$7,673.60	$0			$0	$7,674
47	1508-1840	Underground Conduit	$0.00	$494.66		$494.66	$0			$0	$495
47	1508-1845	Underground Conductors & Devices	$0.00	$485.14		$485.14	$0			$0	$485
47	1508-1850	Line Transformers	$0.00			$0.00	$0			$0	$0
47	1508-1980	System Supervisory Equipment	$0.00			$0.00	$0			$0	$0
		Sub-Total	**$0.00**	**$1,363,878.70**	**$0.00**	**$1,363,878.70**	**$0**	**$0**	**$0**	**$0**	**$1,363,879**

Table 19 – 2019 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1810	1820	1508-1820	1830	1508-1830	1835	1508-1835	1840	1508-1840	1845	1508-1845	1850	1850	1855	1855	1860	1920	1611	1930	1940	2440	Total
												O/H	U/G	O/H	U/G							
System Access																						
New Services and Service Upgrades				3,118		1,161		247				276,346	290	7,647	24,142	101,416						414,367
Orchardview										87			373		2,146							2,606
Riverfront Phase 5								5,495		49,518			19,550		98,376							172,940
Petro Canada						482						11,446		229								12,157
Install and Connect Pad Mount Transformer										15,352			22,878									38,230
Blakely Crescent						198				4,922			5,746									10,865
Contributions																					(183,075)	(183,075)
Sub-Total	-	-	-	3,118	-	1,840	-	5,742	-	69,879	-	287,793	48,837	7,876	124,665	101,416	-	-	-	-	(183,075)	468,091
System Renewal																						
Minor Capital Betterments				46,457		68,128				2,860		(56,262)	375	14,948	12,379							88,885
Voltage Conversion - Feeder 1 - 1						207						1,990	2,222									4,419
Voltage Conversion - Feeder 1 - 2				1,064		14,844						37,825	1,930									55,663
Voltage Conversion - Feeder 1 - 3						7,789						28,097										35,886
Voltage Conversion - Feeder 1 - 4						32,979						2,675	50									35,703
Voltage Conversion - Feeder 3 - 1						26,502						612										27,115
Voltage Conversion - Feeder 3 - 2												254										254
Almonte MS#3 Station Upgrades				9,310		11																9,320
Beachburg Road Pole Replacement				9,481		25,571		4,899		15,529												55,480
Victoria Street Underground Conversion				15,537		9,010		2,085		41,828			69,010	4,979	2,800						(129,225)	16,023
Sub-Total	-	-	-	81,848	-	185,041	-	6,984	-	60,217	-	15,192	73,586	19,927	15,179	-	-	-	-	-	(129,225)	328,749
System Service																						
Almonte Feeder Relocation				27,126		28,967		7,414		842												64,350
Almonte MS#4 Line Extension				35,152		3,243		2,831		900												42,126
Almonte MS#4 Construction		(58,854)	1,337,464		17,762		7,674		495		485											1,305,025
Sub-Total	-	(58,854)	1,337,464	62,279	17,762	32,210	7,674	10,246	495	1,741	485	-	-	-	-	-	-	-	-	-	-	1,411,501
General Plant																						
Computer Equipment - Hardware																	13,428					13,428
Computer Software																		11,266				11,266
Computer Software - Cyber Security																		5,395				5,395
Transportation Equipment - Trailer																			26,500			26,500
Transportation Equipment - New Truck																			364,485			364,485
Small Tools																				1,834		1,834
Leasehold Improvements	4,189																					4,189
Sub-Total	4,189	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13,428	16,660	390,985	1,834	-	427,097
Total	**4,189**	**(58,854)**	**1,337,464**	**147,244.97**	**17,762**	**219,091**	**7,674**	**22,972**	**495**	**131,837**	**485**	**302,984**	**122,423**	**27,803**	**139,844**	**101,416**	**13,428**	**16,660**	**390,985**	**1,834**	**(312,300)**	**2,635,437**

*Columns in yellow represent the capital assets related to the ICM going in service.

Table 20 –2020 Continuity Schedule

Year 2020 IFRS

			Gross Assets				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$286,016.84	$5,473.34	-$103,007.47	$188,482.71	$260,750	$15,937	-$103,007	$173,679	$14,804	$237,250	$217,214
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84	$0.00	$0.00	$2,747.84	$2,010	$335	$0	$2,345	$403	$2,748	$2,178
N/A	1805	Land	$258,350.32	$0.00	$0.00	$258,350.32	$0	$0	$0	$0	$258,350	$258,350	$0
47	1808	Buildings	$171,369.87	$0.00	$0.00	$171,369.87	$20,788	$13,560	$0	$34,348	$137,022	$171,370	$27,568
13	1810	Leasehold Improvements	$291,302.24	$50,191.89	$0.00	$341,494.13	$86,136	$14,396	$0	$100,532	$240,962	$316,398	$93,334
47	1820	Distribution Station Equipment <50 kV	$1,502,141.41	$15,684.12	$0.00	$1,517,825.53	$413,882	$65,022	$0	$478,903	$1,038,922	$1,509,983	$446,393
47	1830	Poles, Towers & Fixtures	$2,762,259.27	$59,280.98	$0.00	$2,821,540.25	$939,425	$134,272	$0	$1,073,697	$1,747,843	$2,791,900	$1,006,561
47	1835	Overhead Conductors & Devices	$3,762,299.97	$128,129.85	$0.00	$3,890,429.82	$765,432	$141,785	$0	$907,217	$2,983,213	$3,826,365	$836,325
47	1840	Underground Conduit	$792,872.78	$15,277.66	-$8,025.01	$800,125.43	$440,372	$35,863.13	-$8,025	$468,210	$331,915	$796,499	$454,291
47	1845	Underground Conductors & Devices	$1,207,234.67	$23,419.10	$0.00	$1,230,653.77	$183,705	$39,800	$0	$223,505	$1,007,149	$1,218,944	$203,605
47	1850	Line Transformers	$2,443,933.52	$206,692.18	-$4,669.71	$2,645,955.99	$559,231	$100,769	-$4,670	$655,331	$1,990,625	$2,544,945	$607,281
	1850	Transformer Inventory	$486,762.00	-$81,413.00	$0.00	$405,349.00	$0	$0	$0	$0	$405,349	$446,056	$0
47	1855	Services (Overhead)	$1,574,990.48	$70,151.67	$0.00	$1,645,142.15	$312,744	$60,950	$0	$373,694	$1,271,448	$1,610,066	$343,219
47	1860-15	Meters	$1,891,465.09	$89,486.12	$0.00	$1,980,951.21	$1,120,455	$129,080	$0	$1,249,536	$731,415	$1,936,208	$1,184,996
47	1860-25	Meters >50	$100,794.32	$0.00	$0.00	$100,794.32	$26,539	$4,354	$0	$30,893	$69,902	$100,794	$28,716
	1860	Meter Inventory	$92,721.87	-$36,065.91	$0.00	$56,655.96	$0	$0	$0	$0	$56,656	$74,689	$0
8	1915	Office Furniture & Equipment (10 years)	$45,377.71	$5,574.39	$0.00	$50,952.10	$19,889	$4,799	$0	$24,689	$26,263	$48,165	$22,289
10	1920-2	Computer Equipment - Hardware	$111,869.39	$32,756.85	-$25,493.22	$119,133.02	$97,589	$12,817	-$25,493	$84,913	$34,220	$115,501	$91,251
10	1930-8	Transportation Equipment	$1,455,034.04	$53,553.90	$0.00	$1,508,587.94	$660,698	$177,821.31	$0	$838,519	$670,069	$1,481,811	$749,609
8	1935	Stores Equipment	$0.00	$3,472.21	$0.00	$3,472.21	$0	$174	$0	$174	$3,299	$1,736	$87
8	1940	Tools, Shop & Garage Equipment	$93,969.42	$0.00	-$1,888.94	$92,080.48	$51,918	$9,214	-$1,889	$59,244	$32,837	$93,025	$55,581
8	1945	Measurement & Testing Equipment	$27,817.05	$4,971.36	$0.00	$32,788.41	$14,484	$3,121	$0	$17,605	$15,183	$30,303	$16,045
8	1955	Communications Equipment	$26,170.96	$0.00	$0.00	$26,170.96	$24,049	$2,122	$0	$26,171	$0	$26,171	$25,110
8	1960	Miscellaneous Equipment	$11,498.80	$2,499.00	$0.00	$13,997.80	$7,262	$1,335	$0	$8,598	$5,400	$12,748	$7,930
47	1980	System Supervisor Equipment	$50,971.12	$3,247.00	$0.00	$54,218.12	$38,775	$10,630	$0	$49,404	$4,814	$52,595	$44,090
47	1995	Contributions & Grants	-$1,526,788.80	$0.00	$0.00	-$1,526,788.80	-$427,090	-$71,182	$0	-$498,272	-$1,028,517	-$1,526,789	-$462,681
47	2440	Deferred Revenues	-$1,137,586.44	-$101,292.73	$0.00	-$1,238,879.17	-$103,960	-$28,856	$0	-$132,816	-$1,106,063	-$1,188,233	-$118,388
						$0.00				$0	$0	$0	$0
		Sub-Total	**$16,785,595.74**	**$551,089.98**	**-$143,084.35**	**$17,193,601.37**	**$5,515,083**	**$878,121**	**-$143,084**	**$6,250,119**	**$10,943,482**	$16,989,599	$5,882,601
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0.00				$0	$0		
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$0.00				$0	$0		
		Total PP&E	**$16,785,595.74**	**$551,089.98**	**-$143,084.35**	**$17,193,601.37**	**$5,515,083**	**$878,121**	**-$143,084**	**$6,250,119**	**$10,943,482**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$878,121**					

Table 21 – 2020 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1810	1820	1508-1820	1830	1508-1830	1835	1508-1835	1840	1508-1840	1845	1508-1845	1850	1508-1850	1850	1855	1855	1860	1915	1920	1611	1930	1935	1945	1960	1980	1508-1980	2440	Total
												O/H	O/H	U/G	O/H	U/G												
System Access																												
New Services and Service Upgrades												1,640			3,838	33,513	33,749										(2,378)	70,362
UG Primary - Town Homes on Blakely Crescent				100																								100
Bennett Street - Cell Tower				1,449		1,485						20,203				426											(3,600)	19,963
Food Basics - 1500 kVa Padmounted Transformer						810				11,479		21,939		4,878			723											39,829
Diocese of Pembroke - New 50'/3 Pole				2,343		2,597						10,252															(15,191)	-
Victoria Street Reconstruction - Pole Removals, Cable U/G				2,293		6,966				6,649		(3,055)			2,002													14,854
RCCDSB - Service Upgrade						2,361						8,712				938											(12,011)	-
Phoenix Centre - Vault Removal						731						10,923			1,469												(13,123)	-
Patricia Street - Robert Morre 10 Unit Building								869								796												1,665
Guy Bourgon - Offer to Connect																											(23,050)	(23,050)
Sub-Total	-	-	-	6,184	-	14,949	-	869	-	18,128	-	70,613	-	4,878	7,309	35,672	34,472	-	-	-	-	-	-	-	-	-	(69,352)	123,723
System Renewal																												
Minor Capital Betterments				12,688		21,104		10,750				26,238			9,318	12,396	18,949											111,442
Voltage Conversion - Feeder 1 - 1						254																						254
Voltage Conversion - Feeder 1 - 2												1,259																1,259
PCB Transformer - T550 1283 Pembroke Street West												2,912																2,912
PCB Transformer - 183 Cecil Street												966																966
PCB Transformer - 201 Cecil Street												1,452																1,452
Esther Street - OH Secondary Service Replacement															4,536													4,536
PCB Transformer - T438 Boundary and McGee												3,705																3,705
32 Pembroke Street West - Replace Pole				2,931		3,905																						6,836
Upgrade Riser Disconnects at L557 and T1011										1,688																		1,688
672 & 708 Gordon Street Pole Replacements				6,624		1,127						947				248												8,947
174 Albert Street - Replace pole and transformers				3,390		3,688						9,276																16,353
Garden Street - Replace Leaking Padmount Transformer														3,032														3,032
O'Brien Street North - Install Underground Road Crossings						12,232																						12,232
John Street Killaloe - Re-insulate 2 poles						2,481																						2,481
277 Cecelia Street - Replace wood pole				4,988		1,119																						6,107
5 Smith Street - Replace wood pole and install new anchor				4,682		2,619																						7,301
Beachburg Road - Replace 3 wood poles				7,882		9,157																						17,039
119 Arnolds Lane - Replace wood pole				2,155		1,792																						3,948
473 Christink Lane - Replace wood pole				1,623		1,397										671												3,692
281 Maple Avenue - Replace wood pole				2,323		2,053		835																				5,212
Sub-Total	-	-	-	49,287	-	62,930	-	11,585	-	1,688	-	46,755	-	3,032	13,854	13,316	18,949	-	-	-	-	-	-	-	-	-	-	221,396

Table 22 – 2020 Gross Fixed Asset Additions by RRFE (Cont'd)

System Service																												
Almonte Feeder Relocation				2,325		13,178																					(31,941)	(16,438)
1F3 Switch Upgrade						4,840																						4,840
Pembroke MS#6 Insulation Upgrades						12,162																						12,162
Almonte MS#3 Upgrades		15,684																										15,684
Almonte MS#4 Line Extension				1,485		20,072		2,823		3,603																		27,983
Almonte MS#4 Construction			581,083		29,817		54,249		275		9,814		9,429													11,208		695,875
Sub-Total	-	15,684	581,083	3,810	29,817	50,251	54,249	2,823	275	3,603	9,814	-	9,429	-	-	-	-	-	-	-	-	-	-	-	-	11,208	(31,941)	740,106
General Plant																												
Computer Equipment - Hardware																			32,757									32,757
Computer Software																				5,473								5,473
Office Equipment																		5,574										5,574
Transportation Equipment																					53,554							53,554
Stores Equipment																						3,472						3,472
Small Tools																							4,971					4,971
Miscellaneous Equipment																								2,499				2,499
System Supervisory Equipment																									3,247			3,247
Leasehold Improvements - Pembroke Office Glass Barrier	10,265																											10,265
Leasehold Improvements - Air Conditioner Repair	8,776																											8,776
Leasehold Improvements - Paving	16,500																											16,500
Leasehold Improvements - Wall	1,168																											1,168
Leasehold Improvements - Almonte Pole Barn	2,942																											2,942
Leasehold Improvements - Almonte New Office	10,542																											10,542
Sub-Total	50,192	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,574	32,757	5,473	53,554	3,472	4,971	2,499	3,247	-	-	161,740
Total	**50,192**	**15,684**	**581,083**	**59,281**	**29,817**	**128,130**	**54,249**	**15,278**	**275**	**23,419**	**9,814**	**117,368**	**9,429**	**7,911**	**21,163**	**48,988**	**53,420**	**5,574**	**32,757**	**5,473**	**53,554**	**3,472**	**4,971**	**2,499**	**3,247**	**11,208**	**(101,293)**	**1,246,965**

Table 23 – Bridge Year 2021 Continuity Schedule

Year 2021 **IFRS**

CCA Class	OEB	Description	Gross Assets: Opening Balance	Gross Assets: Additions	Gross Assets: Disposals	Gross Assets: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions (Depr Exp must match 2.9)	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$188,482.71	$194,419.95		$382,902.66	$173,679	$41,693		$215,373	$167,530	$285,693	$194,526
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84			$2,747.84	$2,345	$335		$2,680	$68	$2,748	$2,513
N/A	1805	Land	$258,350.32			$258,350.32	$0			$0	$258,350	$258,350	$0
47	1808	Buildings	$171,369.87			$171,369.87	$34,348	$5,612		$39,960	$131,410	$171,370	$37,159
13	1810	Leasehold Improvements	$341,494.13	$10,343.36		$351,837.49	$100,532	$15,278		$115,810	$236,027	$346,666	$108,171
47	1820	Distribution Station Equipment <50 kV	$1,517,825.53	$1,134.00		$1,518,959.53	$478,903	$53,729		$532,632	$986,327	$1,518,393	$505,768
47	1830	Poles, Towers & Fixtures	$2,821,540.25	$228,352.03		$3,049,892.28	$1,073,697	$127,614		$1,201,311	$1,848,581	$2,935,716	$1,137,504
47	1835	Overhead Conductors & Devices	$3,890,429.82	$179,105.87		$4,069,535.69	$907,217	$144,433		$1,051,651	$3,017,885	$3,979,983	$979,434
47	1840	Underground Conduit	$800,125.43	$5,973.83		$806,099.26	$468,210	$32,195		$500,405	$305,694	$803,112	$484,308
47	1845	Underground Conductors & Devices	$1,230,653.77	$55,439.44		$1,286,093.21	$223,505	$40,786		$264,291	$1,021,802	$1,258,373	$243,898
47	1850	Line Transformers	$2,645,955.99	$192,990.27		$2,838,946.26	$655,331	$102,838		$758,169	$2,080,777	$2,742,451	$706,750
	1850	Transformer Inventory	$405,349.00			$405,349.00	$0			$0	$405,349	$405,349	$0
47	1855	Services (Overhead)	$1,645,142.15	$78,455.81		$1,723,597.96	$373,694	$62,393		$436,086	$1,287,512	$1,684,370	$404,890
47	1860-15	Meters	$1,980,951.21	$115,736.50		$2,096,687.71	$1,249,536	$135,921		$1,385,457	$711,231	$2,038,819	$1,317,497
47	1860-25	Meters >50	$100,794.32			$100,794.32	$30,893	$4,320		$35,213	$65,582	$100,794	$33,053
	1860	Meter Inventory	$56,655.96			$56,655.96	$0			$0	$56,656	$56,656	$0
8	1915	Office Furniture & Equipment (10 years)	$50,952.10	$36,560.70		$87,512.80	$24,689	$6,483		$31,172	$56,340	$69,232	$27,931
10	1920-2	Computer Equipment - Hardware	$119,133.02	$141,853.26		$260,986.28	$84,913	$39,945		$124,858	$136,128	$190,060	$104,886
10	1930-8	Transportation Equipment	$1,508,587.94	$13,602.00		$1,522,189.94	$838,519	$145,477		$983,997	$538,193	$1,515,389	$911,258
8	1935	Stores Equipment	$3,472.21			$3,472.21	$174	$347		$521	$2,951	$3,472	$347
8	1940	Tools, Shop & Garage Equipment	$92,080.48	$2,000.00		$94,080.48	$59,244	$8,942		$68,186	$25,895	$93,080	$63,715
8	1945	Measurement & Testing Equipment	$32,788.41			$32,788.41	$17,605	$3,369		$20,974	$11,814	$32,788	$19,290
8	1955	Communications Equipment	$26,170.96			$26,170.96	$26,171			$26,171	$0	$26,171	$26,171
8	1960	Miscellaneous Equipment	$13,997.80			$13,997.80	$8,598	$1,460		$10,058	$3,940	$13,998	$9,328
47	1980	System Supervisor Equipment	$54,218.12			$54,218.12	$49,404	$3,190		$52,595	$1,623	$54,218	$50,999
47	1995	Contributions & Grants	-$1,526,788.80			-$1,526,788.80	-$498,272	-$71,182		-$569,453	-$957,335	-$1,526,789	-$533,863
47	2440	Deferred Revenues	-$1,238,879.17	-$194,750.00		-$1,433,629.17	-$132,816	-$32,556		-$165,373	-$1,268,257	-$1,336,254	-$149,094
						$0.00				$0	$0	$0	$0
		Sub-Total	**$17,193,601.37**	**$1,061,217.02**	**$0.00**	**$18,254,818.39**	**$6,250,119**	**$872,625**	**$0**	**$7,122,744**	**$11,132,074**	$17,724,210	$6,686,437
		Less Socialized Renewable Energy Generation Investments **(input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)**				$0.00				$0	$0		
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)Less Other Non Rate-Regulated Utility Assets (i***				**$0.00**				**$0**	**$0**		
		Total PP&E						**$872,625**	**$0**	**$7,122,744**	**$11,132,074**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$872,625**					

CCA Class	OEB	Description
10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$872,625

Table 24 – Bridge Year 2021 ICM MS4 Substation: Incremental Capital Assets (Acct 1508)

Incremental Capital Module - Almonte MS#4 Year 2021 IFRS

			Gross Assets				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value
47	508-182	Distribution Station Equipment <50 kV	$1,918,546.72			$1,918,546.72	$23,982	$47,964		$71,946	$1,846,601
47	508-183	Poles, Towers & Fixtures	$47,578.64			$47,578.64	$490	$980		$1,469	$46,109
47	508-183	Overhead Conductors & Devices	$61,922.68			$61,922.68	$532	$1,063		$1,595	$60,328
47	508-184	Underground Conduit	$10,308.64			$10,308.64	$103	$206		$309	$9,999
47	508-184	Underground Conductors & Devices	$760.14			$760.14	$10	$19		$29	$732
47	508-185	Line Transformers	$9,429.00			$9,429.00	$118	$236		$354	$9,075
47	508-198	System Supervisory Equipment	$11,207.73			$11,207.73	$560	$1,121		$1,681	$9,527
		Sub-Total	**$2,059,753.55**	**$0.00**	**$0.00**	**$2,059,753.55**	**$25,794**	**$51,588**	**$0**	**$77,383**	**$1,982,371**

Table 25 – 2021 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1810	1820	1830	1835	1840	1845	1850	1855	1860	1915	1920	1611	1930	1940	2440	Total
System Access																
New Services and Service Upgrades				11,622			20,000	14,176	47,889							93,686
Water Storage			12,893	4,508	-	8,815	16,892	46	-						(43,153)	0
4 Semi-detached Single Storey Homes			-	541	-	240	2,652	2,894	-						(2,011)	4,315
Roger Telecom Tower			2,520	1,505	68	90	4,588	1,345	-						(6,900)	3,216
Pembroke Street West Upgrade (Phase 2)			44,400	9,576	-	-	-	11,692	-						(42,393)	23,276
Pembroke Street West Upgrade (Phase 1 - Strut Guy)			898	643	-	-	-	-	-						(1,039)	502
Pembroke Street West Upgrade (Phase 1 - Pole Stabilization)			4,665	-	-	-	-	-	-						(4,665)	-
4-Plex at 759 Mary Street			976	2,090	135	179	5,708	2,061	675						(4,400)	7,424
Golfview Subdivision			-	-	-	31,740	24,150	17,250	6,234						(35,719)	43,655
Service Upgrade at 299 Boundary Road East			1,052	654	-	-	-	474	3,175						(5,354)	-
143 Marshall Street			-	248	135	817	6,023	1,573	883						(5,600)	4,078
467 Pembroke Street West			-	242	68	343	7,176	1,748	493						(10,069)	-
Mississippi Mills Industrial Park Phase 3			3,905	7,578	4,000	-	1,019	-	-						(10,000)	6,502
Service Upgrade at 297 Boundary Road East			408	127	68	744	5,772	842	689						(8,650)	-
Town of Mississippi Mills - Construct OH Line and PAD			8,097	6,699											(14,796)	-
Sub-Total	-	-	79,815	46,032	4,474	42,967	93,979	54,100	60,038	-	-	-	-	-	(194,750)	186,655
System Renewal																
Minor Capital Betterments			3,136	26,202		12,106	26,197	10,692	55,698							134,031
Gemmell Park Project			11,401	10,527	1,500	96		8,401								31,926
Re-Insulate and Adjust Sage on Feeder 6-2				6,145												6,145
Install New Tie Switches 4-4 TS 4-5 Coolidge Street				4,864												4,864
Pole Replacement due to Fire on Pembroke SW at Blakely			4,829	5,931			923									11,683
Pole Replacement due to Fire on Sussex at John			7,553	3,385												10,937
Replace 45' Pole at481 Isabella Street			2,668	3,341												6,010
Replace 2 40' Wood Poles with New 45'/3 Wood Poles			5,043	3,679												8,722
Set Pole for Bell Canada			3,448	6,240			598									10,286
Install 44kV Pole on Front Street at Alongquin Trail			4,753	5,399												10,152
Pole and Transformer Upgrade at Beachburg Arena			2,047	1,834			10,292	5,133								19,305
Stub Pole Relocation			2,994	2,618												5,612
44kV OHL Relocation			71,071	34,920		270		130								106,391
Replace 6 45' and 1 50' Pole on Mill Street Killaloe			29,596	17,989			1,162									48,747
PCB Transformer Replacements							30,000									30,000
Pembroke Voltage Conversion							29,840									29,840
Sub-Total	-	-	148,538	133,074	1,500	12,472	99,012	24,355	55,698	-	-	-	-	-	-	474,649

Table 26 – 2021 Gross Fixed Asset Additions by RRFE (Cont'd)

System Service																
Battery		1,134														1,134
Sub-Total	-	1,134	-	-	-	-	-	-	-	-	-	-	-	-	-	1,134
General Plant																
Server											106,585					106,585
Switches, Hard Drives, Networking, Laptops, Printers											35,268					35,268
Garage Fixtures, Paint and Blinds	10,343															10,343
Patch Management Platform												3,317				3,317
Elster Connexo Upgrade												76,153				76,153
Engine Control Unit													3,602			3,602
Tools, Shop and Garage Equipment														2,000		2,000
Truck 8 and 31 Painting													10,000			10,000
Credit Control Automation Platform												14,950				14,950
Customer Information System Version Upgrade												100,000				100,000
Postage Machine										16,834						16,834
Folding Machine										19,727						19,727
Sub-Total	10,343	-	-	-	-	-	-	-	-	36,561	141,853	194,420	13,602	2,000	-	398,779
Total	**10,343**	**1,134**	**228,352**	**179,106**	**5,974**	**55,439**	**192,990**	**78,456**	**115,737**	**36,561**	**141,853**	**194,420**	**13,602**	**2,000**	**(194,750)**	**1,061,217**

Table 27 – Test Year 2022 Continuity Schedule

ICM Closing Balance from 2021 added to 2022 Opening Balances

Year 2022 **IFRS**

			Gross Assets				Accumulated Depreciation						
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$382,902.66	$55,000.00		$437,902.66	$215,373	$78,574.46		$293,947	$143,956	$410,403	$254,660
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$2,747.84			$2,747.84	$2,680	$67.84		$2,748	$0	$2,748	$2,714
N/A	1805	Land	$258,350.32			$258,350.32	$0			$0	$258,350	$258,350	$0
47	1808	Buildings	$171,369.87			$171,369.87	$39,960	$5,612.11		$45,572	$125,798	$171,370	$42,771
13	1810	Leasehold Improvements	$351,837.49	$42,000.00		$393,837.49	$115,810	$16,306.60		$132,117	$261,720	$372,837	$123,964
47	1820	Distribution Station Equipment <50 kV	$1,518,959.53	$810,000.00		$2,328,959.53	$604,578	$103,570.20		$708,148	$1,620,812	$1,923,960	$656,363
47	1830	Poles, Towers & Fixtures	$3,049,892.28	$370,975.75		$3,420,868.03	$1,202,781	$120,447.99		$1,323,229	$2,097,639	$3,235,380	$1,263,005
47	1835	Overhead Conductors & Devices	$4,069,535.69	$239,691.50		$4,309,227.19	$1,053,246	$149,108.98		$1,202,355	$3,106,872	$4,189,381	$1,127,800
47	1840	Underground Conduit	$806,099.26	$59,970.29		$866,069.55	$500,715	$29,748.78		$530,464	$335,606	$836,084	$515,589
47	1845	Underground Conductors & Devices	$1,286,093.21	$154,432.64		$1,440,525.85	$264,319	$43,409.41		$307,729	$1,132,797	$1,363,310	$286,024
47	1850	Line Transformers	$2,838,946.26	$311,611.99		$3,150,558.25	$758,523	$104,893.00		$863,416	$2,287,143	$2,994,752	$810,969
	1850	Transformer Inventory	$405,349.00			$405,349.00	$0			$0	$405,349	$405,349	$0
47	1855	Services (Overhead)	$1,723,597.96	$80,918.15		$1,804,516.11	$436,086	$63,720.80		$499,807	$1,304,709	$1,764,057	$467,947
47	1860-15	Meters	$2,096,687.71	$113,530.89		$2,210,218.60	$1,385,457	$139,820.35		$1,525,278	$684,941	$2,153,453	$1,455,367
47	1860-25	Meters >50	$100,794.32			$100,794.32	$35,213	$4,264.33		$39,477	$61,317	$100,794	$37,345
	1860	Meter Inventory	$56,655.96			$56,655.96	$0			$0	$56,656	$56,656	$0
8	1915	Office Furniture & Equipment (10 years)	$87,512.80	$5,000.00		$92,512.80	$31,172	$8,432.90		$39,605	$52,908	$90,013	$35,389
10	1920-2	Computer Equipment - Hardware	$260,986.28	$11,000.00		$271,986.28	$124,858	$62,274.79		$187,133	$84,853	$266,486	$155,995
10	1930-8	Transportation Equipment	$1,522,189.94	$5,000.00		$1,527,189.94	$983,997	$119,641.57		$1,103,638	$423,552	$1,524,690	$1,043,817
8	1935	Stores Equipment	$3,472.21			$3,472.21	$521	$347.27		$868	$2,604	$3,472	$695
8	1940	Tools, Shop & Garage Equipment	$94,080.48	$2,000.00		$96,080.48	$68,186	$8,266.20		$76,452	$19,629	$95,080	$72,319
8	1945	Measurement & Testing Equipment	$32,788.41	$19,210.00		$51,998.41	$20,974	$4,329.80		$25,304	$26,694	$42,393	$23,139
8	1955	Communications Equipment	$26,170.96			$26,170.96	$26,171			$26,171	$0	$26,171	$26,171
8	1960	Miscellaneous Equipment	$13,997.80			$13,997.80	$10,058	$1,460.30		$11,518	$2,479	$13,998	$10,788
47	1980	System Supervisor Equipment	$54,218.12	$45,000.00		$99,218.12	$54,276	$4,453.10		$58,729	$40,489	$76,718	$56,502
47	1995	Contributions & Grants	-$1,526,788.80			-$1,526,788.80	-$569,453	-$71,181.67		-$640,635	-$886,154	-$1,526,789	-$605,044
47	2440	Deferred Revenues	-$1,433,629.17	-$423,652.00		-$1,857,281.17	-$165,373	-$40,286.38		-$205,659	-$1,651,622	-$1,645,455	-$185,516
						$0.00				$0	$0	$0	$0
		Sub-Total	**$18,254,818.39**	**$1,901,689.21**	**$0.00**	**$20,156,507.60**	**$7,200,127**	**$957,283**	**$0**	**$8,157,410**	**$11,999,098**	$19,205,663	$7,678,773
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$0.00				$0	$0		
		Less Other Non Rate-Regulated Utility Assets *(input as negative)Less Other Non Rate-Regulated Utility Assets (i*				$0.00				$0	$0		
		Total PP&E						$957,283	$0	$8,157,410	$11,999,098		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						$957,283					

Table 28 – Bridge Year 2022 ICM MS4 Substation: Incremental Capital Assets (Acct 1508)

Incremental Capital Module - Almonte MS#4 Year **2022** **IFRS**

			Gross Assets				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions (Depr Exp must match 2.9)	Disposals	Closing Balance	Net Book Value
47	1508-1820	Distribution Station Equipment <50 kV	$1,918,546.72		-$1,918,546.72	$0.00	$71,946		-$71,946	$0	$0
47	1508-1830	Poles, Towers & Fixtures	$47,578.64		-$47,578.64	$0.00	$1,469		-$1,469	$0	$0
47	1508-1835	Overhead Conductors & Devices	$61,922.68		-$61,922.68	$0.00	$1,595		-$1,595	$0	$0
47	1508-1840	Underground Conduit	$10,308.64		-$10,308.64	$0.00	$309		-$309	$0	$0
47	1508-1845	Underground Conductors & Devices	$760.14		-$760.14	$0.00	$29		-$29	$0	$0
47	1508-1850	Line Transformers	$9,429.00		-$9,429.00	$0.00	$354		-$354	$0	$0
47	1508-1980	System Supervisory Equipment	$11,207.73		-$11,207.73	$0.00	$1,681		-$1,681	$0	$0
		Sub-Total	**$2,059,753.55**	**$0.00**	**-$2,059,753.55**	**$0.00**	**$77,383**	**$0**	**-$77,383**	**$0**	**$0**

The above table shows the clearance of incremental capital assets from Account 1508 in 2022 as a result of transferring the assets into the 2022 rate-base.

Table 29 – 2022 Gross Fixed Asset Additions by RRFE

Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account	1810	1820	1830	1835	1840	1845	1850	1855	1860	1915	1920	1611	1930	1940	1945	1980	2440	Total
System Access																		
New Services and Service Upgrades			-	-	-	-	-	-	61,606									61,606
44 kV O/H Line Relocation			47,376	45,958	-	180	-	86	-									93,600
4 Semi-Detached Single Storey Homes			-	1,004	-	240	3,509	2,894	-								(5,450)	2,196
3 Commercial Buildings			6,540	6,774	600	7,953	39,025	-	821								(65,290)	(3,577)
Car Wash			4,161	4,896	-	10,336	37,418	20	4,189								(64,412)	(3,391)
Orchard View Suites (Phase 2)			-	3	-	43,997	52,832	19,570	-								(51,900)	64,502
42 Unit Apartment Building			-	-	-	38,287	31,796	-	13,781								(50,600)	33,263
Commercial Project at 950 Mackay Street			7,500	35,000	-	5,000	25,000	-	2,500								(75,000)	-
Service Upgrade at Pemco Steel			4,000	2,500	-	2,500	4,000	1,000	1,000								(15,000)	-
Burcom Development - 48 Houses			2,500	750	-	21,750	25,000	15,000	2,500								(25,000)	42,500
Highway 148 Upgrade			40,000	35,000	20,000	15,000	20,000	15,000	5,000								(50,000)	100,000
9 Houston Drive Service Upgrade			4,000	3,000	-	3,000	6,000	2,000	2,000								(13,000)	7,000
9 Townhomes at 627 Nelson Street Pembroke			3,000	2,500	-	2,000	6,000	4,500	2,000								(8,000)	12,000
Sub-Total	-	-	119,077	137,385	20,600	150,242	250,580	60,070	95,397	-	-	-	-	-	-	-	(423,652)	409,700
System Renewal																		
Minor Capital Betterments			-	4,497	1,955	-	15,896		9,732									32,081
Esther Street Pembroke			27,061	17,365	-	-	7,165	-	-									51,591
Replace 4 existing 50' and 1 60' pole due to rot at ground level. Feeder 6M1 and 6M2.			41,897	3,518	-	-	-	-	-									45,415
John Street Pembroke			28,371	2,290	-	621	12,068	-	-									43,349
McKenzie Street Pembroke			21,059	387	-	-	3,547	-	-									24,993
Third Avenue Pembroke			35,515	25,806	-	-	-	-	-									61,321
Thompson Street Pembroke			25,914	192	-	-	-	-	-									26,105
Larose Street Almonte			34,434	3,498	13,288	1,464	22,260	6,014	-									80,959
Naismith Drive Almonte			-	16,766	10,527	1,700	96	-	8,401									37,491
Evelyn Street Almonte			13,704	25,117	4,500	-	-	7,272	-									50,592
Florence Street Almonte			23,945	2,870	9,100	406	-	7,562	-									43,883
Sub-Total	-	-	251,899	102,306	39,370	4,190	61,032	20,848	18,134	-	-	-	-	-	-	-	-	497,780
System Service																		
Assessment, Scout and Configuration																45,000		45,000
Pembroke MS4 - Replace RTU and Relay		60,000																60,000
Pembroke MS6 - Transformer Replacement		750,000																750,000
Sub-Total	-	810,000	-	-	-	-	-	-	-	-	-	-	-	-	-	45,000	-	855,000

System Service																		
Assessment, Scout and Configuration																45,000		45,000
Pembroke MS4 - Replace RTU and Relay		60,000																60,000
Pembroke MS6 - Transformer Replacement		750,000																750,000
Sub-Total	-	810,000	-	-	-	-	-	-	-	-	-	-	-	-	-	45,000	-	855,000
General Plant																		
E-Billing System												45,000						45,000
Customer Information System Automation												10,000						10,000
Furniture										5,000								5,000
Almonte Lunchroom Repairs	15,000																	15,000
Pembroke Eavestrough	27,000																	27,000
Latops, Printers and Other Hardware											11,000							11,000
Infrared Camera															19,210			19,210
Transporation Equipment													5,000					5,000
Tools, Shop and Garage Equipment														2,000				2,000
Sub-Total	42,000	-	-	-	-	-	-	-	-	5,000	11,000	55,000	5,000	2,000	19,210	-	-	139,210
Total	**42,000**	**810,000**	**370,976**	**239,692**	**59,970**	**154,433**	**311,612**	**80,918**	**113,531**	**5,000**	**11,000**	**55,000**	**5,000**	**2,000**	**19,210**	**45,000**	**(423,652)**	**1,901,689**

2.2 GROSS ASSETS

2.2.1 GROSS ASSET VARIANCE ANALYSIS

The table on the following page (OEB Appendix 2-AB Capital Expenditures) summarizes the gross capital additions of assets for the current distribution system plan investment period 2016 to 2021 and the proposed period of 2022 to 2026 group by OEB categories.

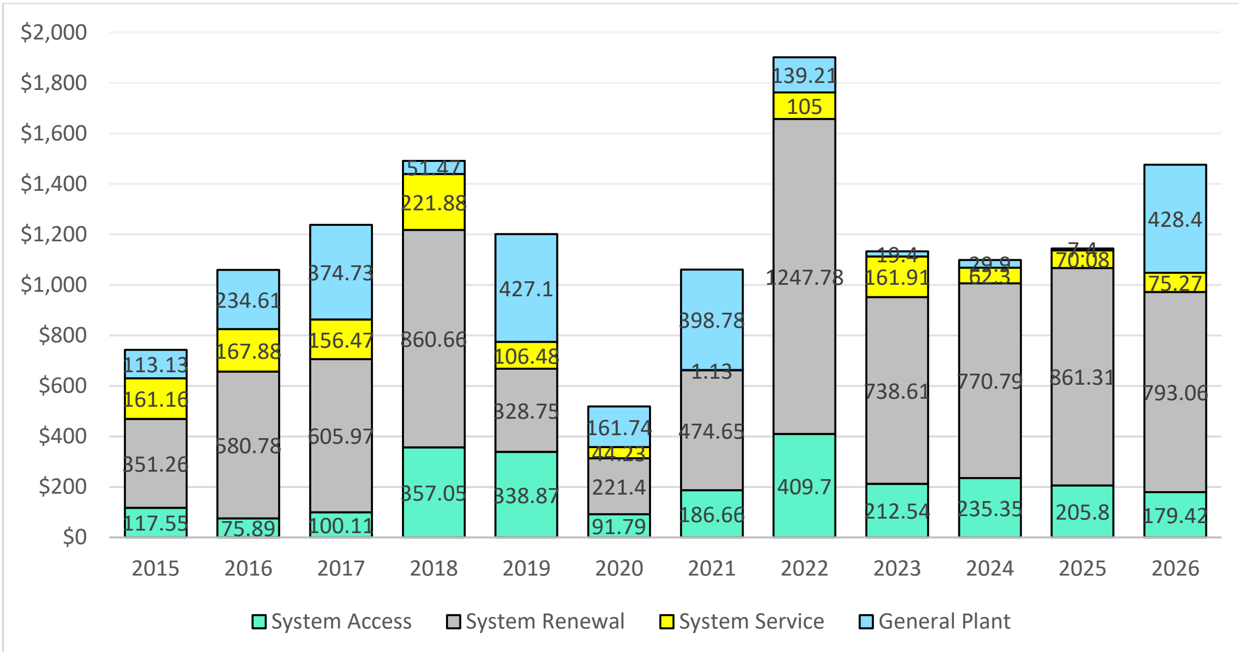
Accounting treatment of the cost of funds for construction work-in-progress

Virtually all of ORPC's capital work is completed within the same fiscal year. In the event that a project does span over multiple years, ORPC will follow the OEB's accounting processes and use account 2055-Work In Progress.

ORPC confirms there were no expenditures for non-distribution activities in the LDC's capital investment plan or actual expenditures for 2016-2021 or for forecasted expenditures for 2022-2026.

The table below compares ORPC's actual capital expenditure versus planned for the historical period 2015 to 2021 and the plan investment period of 2022 to 2026 by OEB investment category:

Table 30 - OEB Appendix 2-AB Capital Expenditures



The table below summarizes (a) ORPC 2016 DSP plan, (b) the Actual CapEx spent by the utility and (c) the variance between Actual to Plan (Budget) all by OEB investment category.

Historical Plan Period - Variances between Plan and Actual

Detailed below are the factors that resulted in a material variance of =/+ $50,000 per year by OEB investment category for the historical 4-year period of 2016-2019 covered by the previous distribution system plan:

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2016 CAPEX PLAN VERSUS ACTUAL:

Table 31 - Variance Analysis: 2016

	2016			
	Plan	Actual	Var	
	$ '000		$	%
System Access	200,850	75,894	-124,956	-62.2%
System Renewal	194,100	580,784	386,684	199.2%
System Service	474,800	167,879	-306,921	-64.6%
General Plant	376,200	234,605	-141,595	-37.6%
TOTAL EXPENDITURE	1,245,950	1,059,161	-186,789	-15.0%

System Access - $124,956 Decrease

The 2016 DSP plan assumed a total of $200,850, net of capital contributions of $300,000, for system access compared to actual incurred expenditures of $75,894. The budget included $400,850 for scattered residential and subdivisions, $100,500 for commercial and $300,000 in capital contributions. In 2016, the actual incurred costs, net of capital contributions of $96,899, amounted to $75,894 which mostly pertained to residential access. This category captures externally initiated development projects that can vary significantly year to year.

System Renewal - $386,684 Increase

Regarding system renewal, the plan included $64,500 for the fully dressed wood pole replacement program, $103,000 for the transformer replacement program and other minor projects composed the remainder of the $194,100.

Actual pole replacements came in at $255,694 for 2016 which was $191,194 over budget while overhead conductor replacement came in at $168,534 which was not accounted for in the 2016 DSP. Material projects included Martin Street and Paul Street pole replacements and the Paul Martin Drive Pole Conflicts Road Rebuild noted in 2.1.3 while projects not meeting the materiality threshold included pole and conductor replacement for Boundary Road East, Alfred Street and Cecelia Street. ORPC also performed a cable replacement for Pembroke MS#4. Actual transformer renewal costs for both overhead and padmount transformers amounted to $18,054 which was $84,946 less than forecasted. Minor renewal costs were also incurred for underground conductor and devices, overhead and underground services and for meters.

System Service - $306,921 Decrease

The system service category assumed a budget of $474,800 in 2016 compared to $167,879 actually incurred for a variance of $306,921.

Actual Projects incurred included $72,422 for the replacement of the ground grid at MS#6. The ground grid reached its end of life and was posing health and safety risks resulting in its replacement. The purpose of the grounding grid is to serve the dual purpose of carrying currents into the earth without exceeding the operating tolerances of any protected equipment while assuring that personnel in the vicinity are not exposed to electric shock as would result from excessive step or touch potentials.

Additionally, the Pembroke MS#2 ground grid, feeder cables, riser poles and associated equipment reached their end of life and were replaced resulting in a cost of $61,445. The purpose of the grounding grid is to serve the dual purpose of carrying currents into the earth without exceeding the operating tolerances of any protected equipment while assuring that personnel in the vicinity are not exposed to electric shock as would result from excessive step or touch potentials.

Material planned projects in 2016 included $86,000 for engineering studies on the substations, $78,000 for an outage management system and $45,000 for Scada upgrades. System renewal projects were prioritized in 2016. As a result, expenses related to engineering studies and the outage management system did not occur. The Scada upgrades were moved back and were incurred in 2017. In total, $209,000 in projects did not occur or were performed at a later date.

General Plant - $141,595 Decrease

ORPC planned a purchase of a new large vehicle with an estimated cost of $328,000. ORPC proceeded with the purchase in 2016, however the delivery time was more than anticipated. In 2016, ORPC purchased only the cab and chassis for $113,525 resulting in $214,475 less capital expense than anticipated in the DSP. The remainder of the vehicle was purchased in 2017.

The remaining variance was offset by increases in capital expenses related to office furniture and equipment and leasehold improvements. ORPC originally budgeted $8,000 towards office furniture and equipment but actually incurred $27,072 representing an increase of $19,072. As for leasehold improvements, ORPC had not planned any expenditures and actually incurred $54,222.

The office furniture consisted of desk replacements for the billing department. The actual cost of the desks came in higher than anticipated.

Leasehold improvements represented a renovation to the board room and service department. The renovation consisted of replacing an aluminum door assembly to increase heating efficiency and replace old carpets and paint. The door replacement became a necessity due to heat loss which resulted in a need to repaint and re-carpet as well. Additional storage space was also created through changes in the department layout to accommodate IT equipment.

Overall, the three differences noted above form a variance from the DSP of $141,181 which is extremely consistent with the actual general plant variance.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2017 CAPEX PLAN VERSUS ACTUAL:

Table 32 - Variance Analysis: 2017

	2017			
	Plan	Actual	Var	
	$ '000		$	%
System Access	452,200	100,107	- 352,093	-77.9%
System Renewal	248,750	605,967	357,217	143.6%
System Service	345,849	156,475	- 189,374	-54.8%
General Plant	255,200	374,735	119,535	46.8%
TOTAL EXPENDITURE	1,301,999	1,237,284	- 64,715	-5.0%

System Access - $352,093 Decrease

The 2017 DSP plan assumed a gross total spend of $452,200 for system access compared to actual net incurred expenditures of $100,107. The actual net incurred expenditures include $263,533 in contributions received from customers which would adjust the actual comparative to $363,640 resulting in an adjusted variance of $88,560 from the plan. The budget included $290,700 for scattered residential and subdivisions and $161,500 for commercial system access. In 2017, the actual incurred costs, excluding capital contributions, amounted to $293,790 in residential access and $69,850 in commercial access resulting in a material variance in the commercial category of $91,650. The commercial variance is consistent with the adjusted variance of $88,560 from the DSP. This category captures externally initiated development projects that can vary significantly year to year.

System Renewal - $357,217 Increase

Regarding system renewal, the plan included $64,500 for the fully dressed wood pole replacement program, $103,000 for the transformer replacement program and other minor projects composed the remainder of the $80,950.

Actual pole replacements came in at $135,788 for 2017 which was $71,288 over budget while overhead conductor replacement came in at $268,356 which was not presented in the 2017 DSP although it was needed. Material projects included Boundary Road pole replacements noted in 2.1.3 while projects not meeting the materiality threshold included pole and conductor replacement for Martin Street, Paul Street and Angus Campbell Drive. ORPC also performed pole upgrades for Pembroke MS#4 and a 44kV upgrade on Boundary Road. Actual transformer renewal costs for both overhead and padmount transformers amounted to $130,107 which was $27,107 more than forecasted. Minor renewal costs were also incurred for underground conductor and devices, overhead and underground services and for meters.

System Service - $189,374 Decrease

The system service category assumed a budget of $345,849 in 2017 compared to $156,475 actually incurred for a variance of $189,374.

Planned material projects for system service included $45,000 for Scada Upgrades, $65,000 for a Power Transformer Fire Barrier and $108,000 for a 44kV breaker replacement. ORPC actually incurred $58,745 in Scada upgrades to Almonte MS#1 whereas the fire barrier and 44kV breaker replacement projects did not occur in 2017.

Actual Projects incurred included the Almonte MS#1 upgrades noted above and Almonte MS#2 upgrades of $58,599. The Almonte MS#1 Scada upgrade was a required upgrade since the Scada system was no longer functional. Upgrading the system permitted ORPC to have a line of sight into the substation and enable operation of the station from the control room. The upgrade was also required to continue to interface with an embedded generator within the utility's service territory. The Almonte MS#2 feeder cables, riser poles and associated equipment reached their end of life and were replaced.

General Plant - $119,535 Increase

The DSP included a planned $60,000 in 2017 for the fleet vehicle replacement program. The remainder of $195,200 was composed of miscellaneous small capital projects per the DSP which would capture office equipment and furniture, computer hardware, computer software, small tools, measurement and testing equipment and leasehold improvements. ORPC actually incurred $374,735 in general plant expenditures which represented an increase of $119,535 from the DSP. The increase was a result of the remaining purchase of a large vehicle in 2017 for a total of $319,920, well above the planned $60,000. Specifically, this represents the remainder of the 2017 International Tandem RBD which replaced a 1994 International. The 1994 vehicle no longer had sufficient lift capacity to support ongoing operations. Poles and transformers have become larger, taller and heavier minimizing the vehicle's usefulness. The DSP assumed the purchase would occur in 2016 but was partially delayed to 2017 as a result of lead times from the vendor. The vehicle purchase was the only material general plant expenditure in 2017.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2018 CAPEX PLAN VERSUS ACTUAL:

Table 33 - Variance Analysis: 2018

	2018			
	Plan	Actual	Var	
	$ '000		$	%
System Access	392,700	357,050	- 35,650	-9.1%
System Renewal	193,200	860,657	667,457	345.5%
System Service	573,650	221,884	- 351,766	-61.3%
General Plant	116,200	51,470	- 64,730	-55.7%
TOTAL EXPENDITURE	1,275,750	1,491,061	215,311	16.9%

System Access - $35,650 Decrease

Amount is below the +/- $50,000 materiality threshold.

System Renewal - $667,457 Increase

Regarding system renewal, the plan included $64,500 for the fully dressed wood pole replacement program, $103,000 for the transformer replacement program and other minor projects composed the remainder of the $25,700. Actual pole replacements came in at $146,862 for 2018 which was $82,362 over budget while overhead conductor replacement came in at $243,329 which was not accounted for in the 2018 DSP amounts.

Material system renewal projects in 2018 included $371,389 for the Pembroke MS#1 and MS#3 and $64,813 for Almonte MS#3 upgrades. The voltage conversion proceeded in order to replace distribution transformers to enable the utility to remove 2 4.16 kV substations out of service and transfer the load onto the 12.4KV system. The physical age of MS#1 and MS#3 indicates that the substations are approaching their useful life expectancy and parts are becoming obsolete indicating that should the substations fails, replacement parts may not be possible to obtain. Additionally, the MS#1 transformer is showing degradation of the quality of oil. Moving the entire system to a 12.4kV system allows for redundancy in the system. The Almonte MS#3 station upgrades consisted of updated feeder cables and riser poles including new gravel and paint for the property. These assets were replaced due to aging to bring condition of assets to current standards.

System Service - $351,766 Decrease

The system service category assumed a budget of $573,650 in 2018 compared to $221,884 actually incurred for a variance of $351,766.

Planned material projects for system service included $228,000 for Pembroke substation upgrades, $280,000 for Almonte substation upgrades and $73,000 for substation design. These projects assumed new re-closure and fault locating devices and new electronic protective relays.

Actual material system service projects incurred included Almonte MS#2 upgrades of $56,943 and Almonte MS#4 engineering and land costs of $147,575. The Almonte MS#2 feeder cables, riser poles and associated equipment reached their end of life and were replaced. For the latter project, ORPC was approved for an ICM of $1,603,409 to build a new 5 MVA substation (MS-4) in the Almonte Ward in the Town of Mississippi Mills, which was expected to be in-service by June 2019. Almonte MS#4 was a necessary and prudent expenditure to meet system and reliability needs due to growth in Almonte. This asset was above the $50,000 materiality threshold, however it was not included as an asset in service. The asset went into service in 2020, however will only be transferred to the rate based on May 1st, 2022 when the Cost of Service rates are intended to be effective. Almonte MS#4 costs in 2018 included preliminary engineering fees of $58,854 and the cost of the acquisition of land of $88,721.

ORPC also performed upgrades at Almonte MS#3 for $64,813 which is noted above in system renewal for 2018. This project was actually classified into system renewal as opposed to system service per the DSP resulting in a variance in each category. Also noted above, ORPC commenced a voltage conversion for Pembroke MS#1 and Pembroke MS#3. The voltage conversion proceeded in order to replace distribution transformers to enable the utility to remove 2 4.16 kV substations out of service and transfer the load onto the 12.4KV system. With the aging of these 2 substations and the lack of availability of certain replacement materials, ORPC found it was inefficient to replace and renew station assets and opted to proceed with the voltage conversion. The voltage conversion was classified as system renewal rather than system service resulting in opposing variances between the two categories.

General Plant - $64,730 Decrease

The DSP included a planned $60,000 in 2018 for the fleet vehicle replacement program and $26,000 for IT hardware. The remainder of $30,200 was composed of miscellaneous small capital projects per the DSP which would capture office equipment and furniture, computer hardware, computer software, small tools, measurement and testing equipment and leasehold improvements. ORPC actually incurred $51,470 in general plant expenditures which represented a decrease of $64,730 from the DSP. Actual capital vehicle expenditures included $30,997 for significant exhaust replacements/repairs on 2 large vehicles resulting in a variance of $29,003 from the DSP. Additionally, ORPC performed $16,920 in actual IT expenditures resulting in a variance of $9,080 from the DSP. Remaining general plant expenditures only totaled $3,553 compared to $30,200 in the DSP.

VARIANCE ANALYSIS FROM PREVIOUS DSP: 2019 CAPEX PLAN VERSUS ACTUAL – SYSTEM ACCESS:

Table 34 - Variance Analysis: 2019

	2019			
	Plan	Actual	Var	
	$ '000		$	%
System Access	392,700	468,091	75,391	19.2%
System Renewal	193,200	328,749	135,549	70.2%
System Service	293,200	47,622	-245,578	-83.8%
General Plant	134,200	427,097	292,897	218.3%
TOTAL EXPENDITURE	1,013,300	1,271,558	258,258	25.5%

System Access - $75,391 Increase

The 2019 DSP plan assumed a total of $392,700, excluding capital contributions, for system access compared to actual incurred expenditures of $468,091. The actual incurred expenditures include $183,075 in contributions received from customers which would adjust the actual comparative, excluding capital contributions, to $651,166 resulting in an adjusted variance of $258,466 from the plan. The budget included $290,700 for scattered residential and subdivisions and $91,500 for commercial system access. In 2019, the actual incurred costs included a material project of $172,940 for Riverfront Phase 5 in Almonte. Riverfront Phase 5 was an externally initiated housing development in Almonte which saw 141 customers added to the ORPC customer base. The remaining variance was as a result of higher than anticipated minor capital system access projects as this category captures externally initiated development projects that can vary significantly year to year.

System Renewal - $135,549 Increase

Regarding system renewal, the plan included $64,500 for the fully dressed wood pole replacement program, $103,000 for the transformer replacement program and other minor projects composed the remainder of the $25,700. Actual pole replacements came in at $81,848 for 2019 which was $17,348 over budget while overhead conductor replacement came in at $185,041 which was not accounted for in the 2019 DSP amounts. The majority of the conductor replacement pertained to Pembroke MS#1 and Pembroke MS#3 which contributed capital costs of $159,040 to system renewal. The voltage conversion continued in order to replace distribution transformers to enable the utility to remove 2 4.16 kV substations out of service and transfer the load onto the 12.4KV system. With the aging of these 2 substations and the lack of availability of certain replacement materials, ORPC found it was inefficient to replace and renew station assets and opted to proceed with the voltage conversion. The remaining material project was the Beachburg Road pole replacement project which consisted of the replacement of rotten poles along Beachburg road to bring them to standard.

System Service - $245,578 Decrease

The system service category assumed a budget of $293,200 for 2019 compared to $47,622 actually incurred for a variance of $245,578.

Planned material projects for system service included $108,000 for breaker replacements, $45,000 for Scada upgrades and $115,000 for substation design. Excluding work on Almonte MS#4 which is included in the ICM accounts and will be transferred to the rate base on May 1st, 2022, the only system service project that occurred in 2019 was a feeder relocation in Almonte. A substation distribution feeder in Almonte was attached to a private building. As a result of health and safety issues, the feeder was relocated. The project required a new pole line, a river crossing and external engineering to complete. ORPC continued a voltage conversion for Pembroke MS#1 and Pembroke MS#3 resulting in capital costs of $159,040. The voltage conversion continued in order to replace distribution transformers to enable the utility to remove 2 4.16 kV substations out of service and transfer the load onto the 12.4KV system. With the aging of these 2 substations and the lack of availability of certain replacement materials, ORPC found it was inefficient to replace and renew station assets and opted to proceed with the voltage conversion. The voltage conversion was classified as system renewal rather than system service resulting in offsetting variances between the two categories.

General Plant - $292,897 Increase

The DSP included a planned $47,000 for IT software and hardware. The remaining plan per the DSP included $87,200 which was composed of miscellaneous small capital projects per the DSP which would capture office equipment and furniture, computer hardware, computer software, small tools, measurement and testing equipment and leasehold improvements. The actual incurred expenditures included $364,485 for the purchase of a 2018 International RBD to replace a non-functional and unsafe 2010 international RBD which did not reach its intended useful life.

2.2.2 ACCUMULATED DEPRECIATION

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

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

The rates have remain unchanged since the 2016 Cost of Service filing.

The rates used are presented below, and the Continuity Schedules of the Accumulated Depreciation are presented in the table below. ORPC's capitalization policy and methodology are provided on the next page. The depreciation expenses continuity schedules are presented in Exhibit 4.

2.3 DEPRECIATION, AMORTIZATION, AND DEPLETION

2.3.1 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.

Continuity Statements of the historical and forecasted depreciation expenses are presented on the next page and are filed in Excel format along with this application.

Table 35 - Depreciation Schedule 2016

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2016	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2016 Depreciation Expense	2016 Depreciation Expense per Appendix 2-B Fixed Assets,	Variance ²
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) ¹	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$202,931.53	$96,678.82	$106,252.71	$21,070.00	$116,787.71	3	33.33%	$38,929.24	$31,159.24	$7,770.00
1612	Land Rights (Formally known as Account 1906)	$2,747.84		$2,747.84		$2,747.84	8	12.50%	$343.48	$335.00	$8.48
1805	Land	$130,499.26		$130,499.26		$130,499.26	0		$0.00	$0.00	$0.00
1808	Buildings	-$11,864.69	-$11,864.69	$0.00		$0.00	25	4.00%	$0.00	$0.00	
1808	Buildings	$7,846.00		$7,846.00		$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$91,038.35		$91,038.35		$91,038.35	50	2.00%	$1,820.77	$1,820.94	-$0.17
1808	Buildings	$83,618.96		$83,618.96		$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$228,040.00	-$104,655.61	$332,695.61	$54,222.45	$359,806.84	25	4.00%	$14,392.27	$14,391.56	$0.72
1820	Distribution Station Equipment <50 kV	$31,185.00		$31,185.00		$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$922,753.51	-$763,675.16	$1,686,428.67		$1,686,428.67	30	3.33%	$56,214.29	$56,205.38	$8.91
1820	Distribution Station Equipment <50 kV	-$65,477.28	-$94,553.20	$29,075.92		$29,075.92	34	2.94%	$855.17	$855.00	$0.17
1820	Distribution Station Equipment <50 kV	$123,386.89		$123,386.89	$121,525.29	$184,149.54	40	2.50%	$4,603.74	$4,603.74	$0.00
1820	Distribution Station Equipment <50 kV	$163,045.50		$163,045.50	$94,060.22	$210,075.61	45	2.22%	$4,668.35	$4,833.15	-$164.80
1820	Distribution Station Equipment <50 kV	$27,437.89		$27,437.89		$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$2,341,214.02	$3,844,591.50		$3,844,591.50	25	4.00%	$153,783.66	$143,860.90	$9,922.76
1830	Poles, Towers & Fixtures	$509,760.78		$509,760.78	$269,378.29	$644,449.93	45	2.22%	$14,321.11	$14,321.10	$0.01
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36		$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.21
1835	Overhead Conductors & Devices	$9,059.05		$9,059.05	$1,702.17	$9,910.14	40	2.50%	$247.75	$247.75	$0.00
1835	Overhead Conductors & Devices	$92,543.06		$92,543.06	$16,291.18	$100,688.65	45	2.22%	$2,237.53	$2,237.54	-$0.01
1835	Overhead Conductors & Devices	$1,024,535.09		$1,024,535.09	$171,656.28	$1,110,363.23	60	1.67%	$18,506.05	$18,506.05	$0.00
1840	Underground Conduit	$1,694,521.98	$227,255.55	$1,467,266.43		$1,467,266.43	25	4.00%	$58,690.66	$61,218.38	-$2,527.72
1840	Underground Conduit	-$1,174,814.95	-$1,630,734.40	$455,919.45		$455,919.45	35	2.86%	$13,026.27	$13,031.19	-$4.92
1840	Underground Conduit	$54,124.86	$0.00	$54,124.86		$54,124.86	40	2.50%	$1,353.12	$1,353.00	$0.12
1840	Underground Conduit	$111,044.64		$111,044.64	$10,252.68	$116,170.98	50	2.00%	$2,323.42	$2,323.43	-$0.01
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57		$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$517,564.95		$517,564.95	$25,027.79	$530,078.85	40	2.50%	$13,251.97	$13,251.98	-$0.01
1850	Line Transformers	$866,182.05	-$743,946.35	$1,610,128.40		$1,610,128.40	25	4.00%	$64,405.14	$71,693.84	-$7,288.71
1850	Line Transformers	$634,168.81		$634,168.81	$127,653.03	$697,995.33	40	2.50%	$17,449.88	$17,449.88	$0.00
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58		$981,475.58	25	4.00%	$39,259.02	$39,259.02	$0.00
1855	Services (Overhead & Underground)	$351,785.49		$351,785.49	$53,057.99	$378,314.49	40	2.50%	$9,457.86	$9,457.86	$0.00
1855	Services (Overhead & Underground)	$112,090.77		$112,090.77	$40,573.50	$132,377.52	60	1.67%	$2,206.29	$2,206.29	$0.00
1860	Meters	$98,768.36	-$5,814.43	$104,582.79	$0.00	$104,582.79	25	4.00%	$4,183.31	$4,315.69	-$132.38
1860	Meters	$2,025.96	-$1,453.93	$3,479.89	$36,172.07	$21,565.93	15	6.67%	$1,437.73	$1,478.20	-$40.47
1860	Meters (Smart Meters)	$1,645,231.00		$1,645,231.00		$1,645,231.00	15	6.67%	$109,682.07	$109,682.00	$0.07
1915	Office Furniture & Equipment (10 years)	$13,903.30	-$2,771.64	$16,674.94	$27,072.09	$30,210.99	10	10.00%	$3,021.10	$3,021.10	-$0.01
1920	Computer Equipment - Hardware	$84,929.63	$52,975.82	$31,953.81	$1,668.77	$32,788.20	3	33.33%	$10,929.40	$16,507.25	-$5,577.85
1930	Transportation Equipment - automobiles	$77,377.31	$49,141.31	$28,236.00	$0.00	$28,236.00	4	25.00%	$7,059.00	$7,059.00	$0.00
1930	Transportation Equipment - under 3 Tons	$129,889.71	$22,318.60	$107,571.11	$0.00	$107,571.11	5	20.00%	$21,514.22	$18,705.42	$2,808.80
1930	Transportation Equipment - 3 Tons & Over	$664,486.39	-$216,228.42	$880,714.81	$116,565.00	$938,997.31	8	12.50%	$117,374.66	$110,279.37	$7,095.29
1940	Tools, Shop & Garage Equipment	$74,405.91	-$1,434.03	$75,839.94	$14,006.95	$82,843.42	10	10.00%	$8,284.34	$8,284.33	$0.01
1945	Measurement & Testing Equipment	$23,637.80	-$904.50	$24,542.30		$24,542.30	10	10.00%	$2,454.23	$2,454.23	$0.00
1955	Communication Equipment 5 yrs	$26,170.96	$1,225.12	$24,945.84		$24,945.84	5	20.00%	$4,989.17	$4,989.17	$0.00
1955	Communication Equipment 10 yrs			$0.00		$0.00			$0.00	$0.00	$0.00
1960	Miscellaneous Equipment	$11,498.80	-$605.20	$12,104.00		$12,104.00	10	10.00%	$1,210.40	$1,210.40	$0.00
1980	System Supervisor Equipment	$74,735.46	$73,620.86	$1,114.60		$1,114.60	3	33.33%	$371.53	$287.65	$83.88
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00		$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$50,708.16	$50,708.16	$0.00		$0.00	10	10.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00		$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00		-$34,000.00		-$34,000.00	3	33.33%	-$11,333.33	-$11,333.33	$0.00
2040	Contributions & Grants	-$294,404.66		-$294,404.66	-$96,899.30	-$342,854.31	40	2.50%	-$8,571.36	-$8,571.36	$0.00
				$0.00		$0.00			$0.00		$0.00

Table 36 - Depreciation Schedule 2017

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2017	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2017 Depreciation Expense	2017 Depreciation Expense per Appendix 2-B Fixed Assets,	Variance ²
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) ¹	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$224,001.53	$143,298.82	$80,702.71	$33,880.61	$97,643.02	3	33.33%	$32,547.67	$25,719.89	$6,827.78
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$0.00	$2,747.84	$0.00	$2,747.84	8	12.50%	$343.48	$335.00	$8.48
1805	Land	$130,499.26	$0.00	$130,499.26	$39,130.00	$150,064.26	0		$0.00	$0.00	$0.00
1808	Buildings	-$11,864.69	-$11,864.69	$0.00	$0.00	$0.00	25	4.00%	$0.00	$0.00	$0.00
1808	Buildings	$7,846.00		$7,846.00	$0.00	$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$0.00	$0.00	$0.00	$731.25	$365.63	45	2.22%	$8.13	$8.13	-$0.01
1808	Buildings	$91,038.35	$0.00	$91,038.35	$0.00	$91,038.35	50	2.00%	$1,820.77	$1,820.94	-$0.17
1808	Buildings	$83,618.96	$0.00	$83,618.96	$0.00	$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$282,262.45	-$104,655.61	$386,918.06	$3,278.27	$388,557.20	25	4.00%	$15,542.29	$15,541.58	$0.71
1820	Distribution Station Equipment <50 kV	$31,185.00	$0.00	$31,185.00	$0.00	$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$922,753.51	-$750,348.01	$1,673,101.52	$8,487.00	$1,677,345.02	30	3.33%	$55,911.50	$55,899.68	$11.82
1820	Distribution Station Equipment <50 kV	-$65,477.28	-$94,553.20	$29,075.92	$0.00	$29,075.92	34	2.94%	$855.17	$871.08	-$15.91
1820	Distribution Station Equipment <50 kV	$244,912.18	$0.00	$244,912.18	$12,316.20	$251,070.28	40	2.50%	$6,276.76	$6,276.74	$0.01
1820	Distribution Station Equipment <50 kV	$257,105.72	$696.27	$256,409.45	$27,656.51	$270,237.71	45	2.22%	$6,005.28	$6,005.29	$0.00
1820	Distribution Station Equipment <50 kV	$27,437.89	$0.00	$27,437.89	$0.00	$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$2,149,743.53	$3,653,121.01	$0.00	$3,653,121.01	25	4.00%	$146,124.84	$134,564.64	$11,560.20
1830	Poles, Towers & Fixtures	$779,139.07	$0.00	$779,139.07	$162,879.07	$860,578.61	45	2.22%	$19,123.97	$19,123.95	$0.01
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36	$0.00	$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.21
1835	Overhead Conductors & Devices	$10,761.22	$0.00	$10,761.22	$2,487.20	$12,004.82	40	2.50%	$300.12	$300.12	$0.00
1835	Overhead Conductors & Devices	$108,834.24	$0.00	$108,834.24	$24,539.10	$121,103.79	45	2.22%	$2,691.20	$2,691.20	-$0.01
1835	Overhead Conductors & Devices	$1,196,191.37	$0.00	$1,196,191.37	$264,779.97	$1,328,581.36	60	1.67%	$22,143.02	$22,143.02	$0.00
1840	Underground Conduit	$1,694,521.98	$336,655.28	$1,357,866.70	$0.00	$1,357,866.70	25	4.00%	$54,314.67	$53,852.11	$462.56
1840	Underground Conduit	-$1,174,814.95	-$1,528,249.21	$353,434.26	$0.00	$353,434.26	35	2.86%	$10,098.12	$10,112.58	-$14.46
1840	Underground Conduit	$54,124.86	$0.00	$54,124.86	$0.00	$54,124.86	40	2.50%	$1,353.12	$1,353.00	$0.12
1840	Underground Conduit	$121,297.32	$0.00	$121,297.32	$31,940.21	$137,267.43	50	2.00%	$2,745.35	$2,745.35	-$0.01
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57	$0.00	$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$542,592.74	$0.00	$542,592.74	$140,969.86	$613,077.67	40	2.50%	$15,326.94	$15,326.94	$0.00
1850	Line Transformers	$866,182.05	-$743,946.35	$1,610,128.40	$0.00	$1,610,128.40	25	4.00%	$64,405.14	$68,429.54	-$4,024.41
1850	Line Transformers	$761,821.84	$0.00	$761,821.84	$140,853.33	$832,248.51	40	2.50%	$20,806.21	$20,806.22	$0.00
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58	$0.00	$981,475.58	25	4.00%	$39,259.02	$39,259.02	$0.00
1855	Services (Overhead & Underground)	$404,843.48	$0.00	$404,843.48	$79,089.27	$444,388.12	40	2.50%	$11,109.70	$11,109.71	-$0.01
1855	Services (Overhead & Underground)	$152,664.27	$0.00	$152,664.27	$47,364.34	$176,346.44	60	1.67%	$2,939.11	$2,939.11	$0.00
1860	Meters	$98,768.36	-$5,814.43	$104,582.79	$0.00	$104,582.79	25	4.00%	$4,183.31	$4,292.26	-$108.94
1860	Meters	$38,198.03	-$1,453.93	$39,651.96	$35,397.20	$57,350.56	15	6.67%	$3,823.37	$3,843.66	-$20.29
1860	Meters (Smart Meters)	$1,645,231.00	$0.00	$1,645,231.00	$0.00	$1,645,231.00	15	6.67%	$109,682.07	$109,682.00	$0.07
1915	Office Furniture & Equipment (10 years)	$40,975.39	-$2,771.64	$43,747.03	$4,397.75	$45,945.91	10	10.00%	$4,594.59	$4,594.60	-$0.01
1920	Computer Equipment - Hardware	$86,598.40	$52,975.84	$33,622.56	$6,396.67	$36,820.90	3	33.33%	$12,273.63	$10,514.15	$1,759.48
1930	Transportation Equipment - Automobiles	$77,377.31	$49,141.31	$28,236.00	$0.00	$28,236.00	4	25.00%	$7,059.00	$7,059.00	$0.00
1930	Transportation Equipment - under 3 Tons	$129,889.71	$50,406.61	$79,483.10	$0.00	$79,483.10	5	20.00%	$15,896.62	$15,896.62	$0.00
1930	Transportation Equipment - 3 Tons & Over	$781,051.39	-$201,988.78	$983,040.17	$322,428.24	$1,144,254.29	8	12.50%	$143,031.79	$135,936.46	$7,095.33
1940	Tools, Shop & Garage Equipment	$88,412.86	$659.86	$87,753.00	$3,354.45	$89,430.23	10	10.00%	$8,943.02	$8,943.02	$0.00
1945	Measurement & Testing Equipment	$23,637.80	-$904.50	$24,542.30	$999.00	$25,041.80	10	10.00%	$2,504.18	$2,504.18	$0.00
1955	Communications Equipment	$26,170.96	$1,225.12	$24,945.84	$0.00	$24,945.84	5	20.00%	$4,989.17	$4,831.72	$157.45
1960	Miscellaneous Equipment	$11,498.80	-$605.20	$12,104.00	$0.00	$12,104.00	10	10.00%	$1,210.40	$1,210.40	$0.00
1980	System Supervisor Equipment	$74,735.46	$74,124.13	$611.33	$35,234.31	$18,228.49	3	33.33%	$6,076.16	$5,974.28	$101.88
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$50,708.16	$50,708.16	$0.00	$0.00	$0.00	10	10.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00	$0.00	$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00		-$34,000.00		-$34,000.00	3	33.33%	-$11,333.33	-$11,333.33	$0.00
2040	Contributions & Grants	-$391,303.96		-$391,303.96	-$263,532.76	-$523,070.34	40	2.50%	-$13,076.76	-$13,076.76	$0.00
				$0.00		$0.00			$0.00		$0.00
	Total	$12,907,439.01	-$5,896,318.32	$18,803,757.33	$1,165,057.05	$19,386,285.86			$885,213.11	$861,334.43	$23,878.68

Table 37 - Depreciation Schedule 2018

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2018	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2018 Depreciation Expense	2018 Depreciation Expense per Appendix 2-B Fixed Assets,	Variance ²
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) ¹	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$257,882.14	$184,265.53	$73,616.61	$11,474.01	$79,353.62	3	33.33%	$26,451.21	$23,340.22	$3,110.99
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$0.00	$2,747.84	$0.00	$2,747.84	8	12.50%	$343.48	$335.00	$8.48
1805	Land	$169,629.26	$0.00	$169,629.26	$88,721.06	$213,989.79	0		$0.00	$0.00	$0.00
1808	Buildings	-$11,864.69	-$11,864.69	$0.00	$0.00	$0.00	25	4.00%	$0.00	$0.00	$0.00
1808	Buildings	$7,846.00	$0.00	$7,846.00	$0.00	$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$731.25		$731.25	$0.00	$731.25	45	2.22%	$16.25	$16.25	$0.00
1808	Buildings	$91,038.35	$0.00	$91,038.35	$0.00	$91,038.35	50	2.00%	$1,820.77	$1,820.94	-$0.17
1808	Buildings	$83,618.96	$0.00	$83,618.96	$0.00	$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$285,540.72	-$104,655.61	$390,196.33	$1,572.78	$390,982.72	25	4.00%	$15,639.31	$15,638.60	$0.71
1820	Distribution Station Equipment <50 kV	$31,185.00	$0.00	$31,185.00	$0.00	$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$931,240.51	-$750,348.01	$1,681,588.52	$0.00	$1,681,588.52	30	3.33%	$56,052.95	$56,030.37	$22.58
1820	Distribution Station Equipment <50 kV	-$65,477.28	-$80,937.12	$15,459.84	$0.00	$15,459.84	34	2.94%	$454.70	$453.35	$1.35
1820	Distribution Station Equipment <50 kV	$257,228.38	$0.00	$257,228.38	$35,767.68	$275,112.22	40	2.50%	$6,877.81	$6,877.79	$0.02
1820	Distribution Station Equipment <50 kV	$284,762.23	$696.27	$284,065.96	$0.00	$284,065.96	45	2.22%	$6,312.58	$6,312.59	-$0.01
1820	Distribution Station Equipment <50 kV	$27,437.89	$0.00	$27,437.89	$0.00	$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1825	Storage Battery Equipment	$0.00	$0.00	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$1,929,603.28	$3,432,980.76	$0.00	$3,432,980.76	25	4.00%	$137,319.23	$125,042.18	$12,277.05
1830	Poles, Towers & Fixtures	$942,018.14	$0.00	$942,018.14	$169,618.68	$1,026,827.48	45	2.22%	$22,818.39	$22,818.37	$0.02
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36	$0.00	$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.21
1835	Overhead Conductors & Devices	$13,248.42	$0.00	$13,248.42	$3,030.51	$14,763.68	40	2.50%	$369.09	$369.09	$0.00
1835	Overhead Conductors & Devices	$133,373.34	$0.00	$133,373.34	$27,657.51	$147,202.10	45	2.22%	$3,271.16	$3,271.15	$0.01
1835	Overhead Conductors & Devices	$1,460,971.34	$0.00	$1,460,971.34	$280,021.36	$1,600,982.02	60	1.67%	$26,683.03	$26,683.03	$0.00
1840	Underground Conduit	$1,694,521.98	$393,689.63	$1,300,832.35	$0.00	$1,300,832.35	25	4.00%	$52,033.29	$48,680.27	$3,353.02
1840	Underground Conduit	-$1,174,814.95	-$1,471,954.63	$297,139.68	$0.00	$297,139.68	35	2.86%	$8,489.71	$8,490.07	-$0.36
1840	Underground Conduit	$54,124.86	$0.00	$54,124.86	$0.00	$54,124.86	40	2.50%	$1,353.12	$1,353.00	$0.12
1840	Underground Conduit	$153,237.53	$0.00	$153,237.53	$42,831.57	$174,653.32	50	2.00%	$3,493.07	$3,493.07	$0.00
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57	$0.00	$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$683,562.60	$0.00	$683,562.60	$115,159.44	$741,142.32	40	2.50%	$18,528.56	$18,528.56	$0.00
1850	Line Transformers	$866,182.05	-$743,946.35	$1,610,128.40	$0.00	$1,610,128.40	25	4.00%	$64,405.14	$23,382.92	$41,022.21
1850	Line Transformers	$902,675.17	$0.00	$902,675.17	$521,399.67	$1,163,375.01	40	2.50%	$29,084.38	$29,084.45	-$0.07
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58	$0.00	$981,475.58	25	4.00%	$39,259.02	$39,259.02	$0.00
1855	Services (Overhead & Underground)	$483,932.75	$0.00	$483,932.75	$49,426.35	$508,645.93	40	2.50%	$12,716.15	$12,716.15	$0.00
1855	Services (Overhead & Underground)	$200,028.61	$0.00	$200,028.61	$16,508.75	$208,282.99	60	1.67%	$3,471.38	$3,471.39	-$0.01
1860	Meters	$98,768.36	-$5,814.43	$104,582.79	$0.00	$104,582.79	25	4.00%	$4,183.31	$4,269.38	-$86.07
1860	Meters	$73,595.23	-$1,453.93	$75,049.16	$107,964.17	$129,031.25	15	6.67%	$8,602.08	$8,598.61	$3.47
1860	Meters (Smart Meters)	$1,645,231.00	$0.00	$1,645,231.00	$0.00	$1,645,231.00	15	6.67%	$109,682.07	$109,682.00	$0.07
1915	Office Furniture & Equipment (10 years)	$45,373.14	-$2,771.64	$48,144.78	$4.58	$48,147.07	10	10.00%	$4,814.71	$4,814.72	-$0.01
1920	Computer Equipment - Hardware	$92,995.07	$63,532.70	$29,462.37	$5,446.05	$32,185.40	3	33.33%	$10,728.47	$7,162.32	$3,566.15
1930	Transportation Equipment	$77,377.31	$49,141.31	$28,236.00	$0.00	$28,236.00	4	25.00%	$7,059.00	$3,529.50	$3,529.50
1930	Transportation Equipment	$129,889.71	$50,406.61	$79,483.10	$0.00	$79,483.10	5	20.00%	$15,896.62	$10,305.01	$5,591.61
1930	Transportation Equipment	$1,103,479.63	-$201,988.78	$1,305,468.41	$30,997.23	$1,320,967.03	8	12.50%	$165,120.88	$147,764.98	$17,355.90
1940	Tools, Shop & Garage Equipment	$91,767.31	$659.86	$91,107.45	$368.11	$91,291.51	10	10.00%	$9,129.15	$9,129.18	-$0.03
1945	Measurement & Testing Equipment	$24,636.80	-$904.50	$25,541.30	$3,180.25	$27,131.43	10	10.00%	$2,713.14	$2,713.14	$0.00
1955	Communications Equipment	$26,170.96	$2,799.45	$23,371.51	$0.00	$23,371.51	5	20.00%	$4,674.30	$4,674.30	$0.00
1960	Miscellaneous Equipment	$11,498.80	-$605.20	$12,104.00	$0.00	$12,104.00	10	10.00%	$1,210.40	$1,210.40	$0.00
1980	System Supervisor Equipment	$109,969.77	$74,735.46	$35,234.31	$12,648.09	$41,558.36	3	33.33%	$13,852.79	$13,852.79	-$0.01
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$50,708.16	$50,708.16	$0.00	$0.00	$0.00	10	10.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00	$0.00	$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00		-$34,000.00		-$34,000.00	3	33.33%	-$11,333.33	-$5,666.67	-$5,666.66
2040	Contributions & Grants	-$654,836.72		-$654,836.72	-$136,450.00	-$723,061.72	40	2.50%	-$18,076.54	-$18,076.55	$0.01
				$0.00		$0.00			$0.00	$0.00	$0.00
	Total	$14,072,496.06	-$5,495,523.83	$19,568,019.89	$1,387,347.85	$20,261,693.82			$918,825.11	$834,658.25	$84,166.85

Table 38 - Depreciation Schedule 2019

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2019	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2019 Depreciation Expense	2019 Depreciation Expense per Appendix 2-B Fixed Assets,	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$269,356.15	$202,931.52	$66,424.63	$16,660.16	$74,754.71	3	33.33%	$24,918.24	$21,406.57	$3,511.67
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$0.00	$2,747.84	$0.00	$2,747.84	8	12.50%	$343.48	$335.00	$8.48
1805	Land	$258,350.32	$0.00	$258,350.32	$0.00	$258,350.32	0		$0.00	$0.00	$0.00
1808	Buildings	-$11,864.69	-$11,864.69	$0.00	$0.00	$0.00	25	4.00%	$0.00	$0.00	$0.00
1808	Buildings	$7,846.00	$0.00	$7,846.00	$0.00	$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$731.25	$0.00	$731.25	$0.00	$731.25	45	2.22%	$16.25	$16.25	$0.00
1808	Buildings	$91,038.35	$0.00	$91,038.35	$0.00	$91,038.35	50	2.00%	$1,820.77	$1,820.94	-$0.17
1808	Buildings	$83,618.96		$83,618.96	$0.00	$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$287,113.50	-$104,655.61	$391,769.11	$4,189.19	$393,863.71	25	4.00%	$15,754.55	$15,753.83	$0.72
1820	Distribution Station Equipment <50 kV	$31,185.00	$0.00	$31,185.00	$0.00	$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$931,240.51	-$745,828.77	$1,677,069.28	$0.00	$1,677,069.28	30	3.33%	$55,902.31	$56,226.71	-$324.40
1820	Distribution Station Equipment <50 kV	-$65,477.28	-$79,204.77	$13,727.49	$0.00	$13,727.49	34	2.94%	$403.75	$395.49	$8.26
1820	Distribution Station Equipment <50 kV	$292,996.06	$0.00	$292,996.06	$0.00	$292,996.06	40	2.50%	$7,324.90	$7,324.89	$0.01
1820	Distribution Station Equipment <50 kV	$284,762.23	$696.27	$284,065.96	$0.00	$284,065.96	45	2.22%	$6,312.58	$6,312.59	-$0.01
1820	Distribution Station Equipment <50 kV	$27,437.89	$0.00	$27,437.89	$0.00	$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$1,718,053.06	$3,221,430.54	$0.00	$3,221,430.54	25	4.00%	$128,857.22	$113,821.95	$15,035.27
1830	Poles, Towers & Fixtures	$1,111,636.82	$0.00	$1,111,636.82	$147,244.97	$1,185,259.31	45	2.22%	$26,339.10	$26,339.08	$0.02
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36	$0.00	$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.21
1835	Overhead Conductors & Devices	$16,278.93	$0.00	$16,278.93	$2,190.91	$17,374.39	40	2.50%	$434.36	$434.36	$0.00
1835	Overhead Conductors & Devices	$161,030.85	$0.00	$161,030.85	$19,718.17	$170,889.94	45	2.22%	$3,797.55	$3,797.55	$0.00
1835	Overhead Conductors & Devices	$1,740,992.70	$0.00	$1,740,992.70	$197,181.68	$1,839,583.54	60	1.67%	$30,659.73	$30,659.73	$0.00
1840	Underground Conduit	$1,686,496.97	$438,089.65	$1,248,407.32	$0.00	$1,248,407.32	25	4.00%	$49,936.29	$43,941.08	$5,995.21
1840	Underground Conduit	-$1,166,789.94	-$1,422,629.55	$255,839.61	$0.00	$255,839.61	35	2.86%	$7,309.70	$7,299.61	$10.09
1840	Underground Conduit	$54,124.86		$54,124.86	$0.00	$54,124.86	40	2.50%	$1,353.12	$1,353.00	$0.12
1840	Underground Conduit	$196,069.10	$0.00	$196,069.10	$22,971.79	$207,555.00	50	2.00%	$4,151.10	$4,151.10	$0.00
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57	$0.00	$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$798,722.04	$0.00	$798,722.04	$131,837.42	$864,640.75	40	2.50%	$21,616.02	$21,616.03	-$0.01
1850	Line Transformers	$866,182.05	-$743,946.35	$1,610,128.40	$0.00	$1,610,128.40	25	4.00%	$64,405.14	$103,764.72	-$39,359.59
1850	Line Transformers	$1,424,074.84	$0.00	$1,424,074.84	$153,676.63	$1,500,913.16	40	2.50%	$37,522.83	$37,522.91	-$0.08
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58	$0.00	$981,475.58	25	4.00%	$39,259.02	$39,259.03	-$0.01
1855	Services (Overhead & Underground)	$533,359.10	$0.00	$533,359.10	$139,843.98	$603,281.09	40	2.50%	$15,082.03	$15,082.03	$0.00
1855	Services (Overhead & Underground)	$216,537.36	$0.00	$216,537.36	$27,802.63	$230,438.68	60	1.67%	$3,840.64	$3,840.66	-$0.02
1860	Meters	$98,768.36	-$5,814.43	$104,582.79	$0.00	$104,582.79	25	4.00%	$4,183.31	$4,241.59	-$58.28
1860	Meters	$181,559.40	-$1,453.93	$183,013.33	$66,700.65	$216,363.66	15	6.67%	$14,424.24	$14,363.31	$60.93
1860	Meters (Smart Meters)	$1,645,231.00	$0.00	$1,645,231.00	$0.00	$1,645,231.00	15	6.67%	$109,682.07	$109,682.00	$0.07
1915	Office Furniture & Equipment (10 years)	$45,377.72	-$2,771.64	$48,149.36	$0.00	$48,149.36	10	10.00%	$4,814.94	$4,814.95	-$0.01
1920	Computer Equipment - Hardware	$98,441.12	$84,929.62	$13,511.50	$13,428.49	$20,225.75	3	33.33%	$6,741.92	$7,162.33	-$420.41
1930	Transportation Equipment	$77,377.31	$77,377.31	$0.00	$0.00	$0.00	4	25.00%	$0.00	$0.00	$0.00
1930	Transportation Equipment	$129,889.71	$106,322.71	$23,567.00	$0.00	$23,567.00	5	20.00%	$4,713.40	$4,713.40	$0.00
1930	Transportation Equipment	$1,134,476.86	$75,706.06	$1,058,770.80	$390,985.00	$1,254,263.30	8	12.50%	$156,782.91	$156,554.75	$228.16
1940	Tools, Shop & Garage Equipment	$92,135.42	$659.86	$91,475.56	$1,834.00	$92,392.56	10	10.00%	$9,239.26	$9,239.26	$0.00
1945	Measurement & Testing Equipment	$27,817.05	-$904.50	$28,721.55	$0.00	$28,721.55	10	10.00%	$2,872.16	$2,872.16	-$0.01
1955	Communications Equipment	$26,170.96	$4,947.04	$21,223.92	$0.00	$21,223.92	5	20.00%	$4,244.78	$4,459.54	-$214.76
1960	Miscellaneous Equipment	$11,498.80	-$605.20	$12,104.00	$0.00	$12,104.00	10	10.00%	$1,210.40	$1,210.40	$0.00
1980	System Supervisor Equipment	$122,617.86	$74,735.46	$47,882.40	$0.00	$47,882.40	3	33.33%	$15,960.80	$15,960.80	$0.00
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$50,708.16	$50,708.16	$0.00	$0.00	$0.00	10	10.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00	$0.00	$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00	-$34,000.00	$0.00		$0.00	3	33.33%	$0.00	$0.00	$0.00
2040	Contributions & Grants	-$791,286.72		-$791,286.72	-$312,299.72	-$947,436.58	40	2.50%	-$23,685.91	-$23,685.92	$0.01
				$0.00		$0.00			$0.00		$0.00
	Total	$15,459,843.91	-$4,813,939.48	$20,273,783.39	$1,023,965.95	$20,785,766.37			$911,849.26	$927,291.00	-$15,441.75

Table 39 - Depreciation Schedule 2020

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2020	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2020 Depreciation Expense	2020 Depreciation Expense per Appendix 2-B Fixed Assets,	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$286,016.31	$224,001.53	$62,014.78	$5,473.34	$64,751.45	3	33.33%	$21,583.82	$15,937.04	$5,646.78
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$0.00	$2,747.84	$0.00	$2,747.84	8	12.50%	$343.48	$335.00	$8.48
1805	Land	$258,350.32	$0.00	$258,350.32	$0.00	$258,350.32	0		$0.00	$0.00	$0.00
1808	Buildings	-$16,471.20	-$69,919.21	$53,448.01	$0.00	$53,448.01	25	4.00%	$2,137.92	$2,137.92	$0.00
1808	Buildings	$1,899.41	-$5,946.59	$7,846.00	$0.00	$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$731.25		$731.25	$0.00	$731.25	45	2.22%	$16.25	$16.25	$0.00
1808	Buildings	$101,591.45	$10,553.10	$91,038.35	$0.00	$91,038.35	50	2.00%	$1,820.77	$9,768.38	-$7,947.61
1808	Buildings	$83,618.96		$83,618.96	$0.00	$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$291,302.69	-$43,260.05	$334,562.74	$50,191.89	$359,658.69	25	4.00%	$14,386.35	$14,396.47	-$10.12
1820	Distribution Station Equipment <50 kV	$31,185.00		$31,185.00	$0.00	$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$1,071,682.53	-$385,110.50	$1,456,793.03	$0.00	$1,456,793.03	30	3.33%	$48,559.77	$48,560.50	-$0.73
1820	Distribution Station Equipment <50 kV	-$205,919.30	-$205,919.30	$0.00	$0.00	$0.00	34	2.94%	$0.00	$0.00	$0.00
1820	Distribution Station Equipment <50 kV	$293,692.33	$696.27	$292,996.06	$15,684.12	$300,838.12	40	2.50%	$7,520.95	$7,520.94	$0.01
1820	Distribution Station Equipment <50 kV	$284,065.96		$284,065.96	$0.00	$284,065.96	45	2.22%	$6,312.58	$6,312.59	-$0.01
1820	Distribution Station Equipment <50 kV	$27,437.89		$27,437.89	$0.00	$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$1,502,956.82	$3,006,334.30	$0.00	$3,006,334.30	25	4.00%	$120,253.37	$105,638.25	$14,615.12
1830	Poles, Towers & Fixtures	$1,258,881.79		$1,258,881.79	$59,280.98	$1,288,522.28	45	2.22%	$28,633.83	$28,633.81	$0.02
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36	$0.00	$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.22
1835	Overhead Conductors & Devices	$18,469.84		$18,469.84	$1,162.96	$19,051.32	40	2.50%	$476.28	$476.28	$0.00
1835	Overhead Conductors & Devices	$180,749.02		$180,749.02	$11,058.35	$186,278.20	45	2.22%	$4,139.52	$4,139.51	$0.01
1835	Overhead Conductors & Devices	$1,938,174.38		$1,938,174.38	$115,908.54	$1,996,128.65	60	1.67%	$33,268.81	$33,268.81	$0.00
1840	Underground Conduit	$1,694,521.98	$728,156.79	$966,365.19	$0.00	$966,365.19	25	4.00%	$38,654.61	$31,329.53	$7,325.08
1840	Underground Conduit	-$1,174,814.95	-$1,174,814.95	$0.00	$0.00	$0.00	35	2.86%	$0.00	$0.00	$0.00
1840	Underground Conduit	$54,124.86	$54,124.86	$0.00	$0.00	$0.00	40	2.50%	$0.00	$0.00	$0.00
1840	Underground Conduit	$219,040.89		$219,040.89	$15,277.66	$226,679.72	50	2.00%	$4,533.59	$4,533.60	-$0.01
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57	$0.00	$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$930,559.46	$0.00	$930,559.46	$23,419.10	$942,269.01	40	2.50%	$23,556.73	$23,556.74	-$0.01
1850	Line Transformers	$866,182.06	-$724,351.62	$1,590,533.68	$0.00	$1,590,533.68	25	4.00%	$63,621.35	$58,741.84	$4,879.51
1850	Line Transformers	$1,577,751.47	$0.00	$1,577,751.47	$206,692.18	$1,681,097.56	40	2.50%	$42,027.44	$42,027.52	-$0.08
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58	$0.00	$981,475.58	25	4.00%	$39,259.02	$39,259.02	$0.00
1855	Services (Overhead & Underground)	$673,203.08	$0.00	$673,203.08	$48,988.23	$697,697.20	40	2.50%	$17,442.43	$17,442.43	$0.00
1855	Services (Overhead & Underground)	$244,339.99	$0.00	$244,339.99	$21,163.44	$254,921.71	60	1.67%	$4,248.70	$4,248.71	-$0.01
1860	Meters	$100,794.32	-$7,268.36	$108,062.68	$0.00	$108,062.68	25	4.00%	$4,322.51	$4,353.88	-$31.37
1860	Meters	$246,234.09	$0.00	$246,234.09	$89,486.12	$290,977.15	15	6.67%	$19,398.48	$19,398.48	$0.00
1860	Meters (Smart Meters)	$1,645,231.00	$0.00	$1,645,231.00	$0.00	$1,645,231.00	15	6.67%	$109,682.07	$109,682.00	$0.07
1915	Office Furniture & Equipment (10 years)	$45,377.72	-$2,771.64	$48,149.36	$5,574.39	$50,936.56	10	10.00%	$5,093.66	$4,799.48	$294.18
1920	Computer Equipment - Hardware	$111,869.61	$86,598.40	$25,271.21	$32,756.85	$41,649.64	3	33.33%	$13,883.21	$12,817.11	$1,066.10
1930	Transportation Equipment	$77,377.31	$77,377.31	$0.00	$0.00	$0.00	4	25.00%	$0.00	$0.00	$0.00
1930	Transportation Equipment	$129,889.71	$106,322.71	$23,567.00	$0.00	$23,567.00	5	20.00%	$4,713.40	$2,356.70	$2,356.70
1930	Transportation Equipment	$1,525,461.86	$75,706.06	$1,449,755.80	$53,553.90	$1,476,532.75	8	12.50%	$184,566.59	$175,464.61	$9,101.98
1935	Stores Equipment	$0.00	$0.00	$0.00	$3,472.21	$1,736.11	10	10.00%	$173.61	$173.64	-$0.03
1940	Tools, Shop & Garage Equipment	$93,969.42	$659.86	$93,309.56	$0.00	$93,309.56	10	10.00%	$9,330.96	$9,214.22	$116.74
1945	Measurement & Testing Equipment	$27,817.05	-$904.50	$28,721.55	$4,971.36	$31,207.23	10	10.00%	$3,120.72	$3,120.73	-$0.01
1955	Communications Equipment	$26,170.96	$4,947.04	$21,223.92	$0.00	$21,223.92	5	20.00%	$4,244.78	$2,122.39	$2,122.39
1960	Miscellaneous Equipment	$11,498.80	-$605.20	$12,104.00	$2,499.00	$13,353.50	10	10.00%	$1,335.35	$1,335.35	$0.00
1980	System Supervisor Equipment	$122,617.86	$74,735.46	$47,882.40	$3,247.00	$49,505.90	3	33.33%	$16,501.97	$10,629.58	$5,872.39
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$50,708.16	$50,708.16	$0.00	$0.00	$0.00	10	10.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00	$0.00	$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00	-$34,000.00	$0.00		$0.00	3	33.33%	$0.00	$0.00	$0.00
2040	Contributions & Grants	-$1,103,586.44		-$1,103,586.44	-$101,292.73	-$1,154,232.81	40	2.50%	-$28,855.82	-$28,855.82	$0.00
				$0.00		$0.00			$0.00		$0.00
	Total	$16,483,809.87	-$3,722,551.83	$20,206,361.70	$668,568.89	$20,540,646.14			$923,613.35	$878,120.81	$45,492.54

Table 40 - Depreciation Schedule 2021

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2021	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2021 Depreciation Expense	2021 Depreciation Expense per Appendix 2-B Fixed Assets.	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$188,482.18	$154,874.67	$33,607.51	$194,419.95	$130,817.49	3	33.33%	$43,605.83	$41,693.49	$1,912.34
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$0.00	$2,747.84	$0.00	$2,747.84	8	12.50%	$343.48	$335.00	$8.48
1805	Land	$0.00	$0.00	$0.00	$0.00	$0.00	0		$0.00	$0.00	$0.00
1808	Buildings	-$16,471.20	-$69,919.21	$53,448.01	$0.00	$53,448.01	25	4.00%	$2,137.92	$2,137.92	$0.00
1808	Buildings	$1,899.41	-$5,946.59	$7,846.00	$0.00	$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$731.25		$731.25	$0.00	$731.25	45	2.22%	$16.25	$16.25	$0.00
1808	Buildings	$101,591.45	$10,553.10	$91,038.35	$0.00	$91,038.35	50	2.00%	$1,820.77	$1,820.94	-$0.17
1808	Buildings	$83,618.96		$83,618.96	$0.00	$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$341,494.58	-$35,099.22	$376,593.80	$10,343.36	$381,765.48	25	4.00%	$15,270.62	$15,278.05	-$7.43
1820	Distribution Station Equipment <50 kV	$31,185.00		$31,185.00	$0.00	$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$1,071,682.53	-$40,217.13	$1,111,899.66	$0.00	$1,111,899.66	30	3.33%	$37,063.32	$37,057.41	$5.91
1820	Distribution Station Equipment <50 kV	-$205,919.30	-$205,919.30	$0.00	$0.00	$0.00	34	2.94%	$0.00	$0.00	$0.00
1820	Distribution Station Equipment <50 kV	$309,376.45	$696.27	$308,680.18	$1,134.00	$309,247.18	40	2.50%	$7,731.18	$7,731.17	$0.01
1820	Distribution Station Equipment <50 kV	$284,065.96		$284,065.96	$0.00	$284,065.96	45	2.22%	$6,312.58	$6,312.59	-$0.01
1820	Distribution Station Equipment <50 kV	$27,437.89		$27,437.89	$0.00	$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$1,290,560.60	$2,793,938.08	$0.00	$2,793,938.08	25	4.00%	$111,757.52	$95,784.73	$15,972.79
1830	Poles, Towers & Fixtures	$1,318,162.77	$0.00	$1,318,162.77	$228,352.03	$1,432,338.79	45	2.22%	$31,829.75	$31,829.73	$0.02
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36	$0.00	$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.22
1835	Overhead Conductors & Devices	$19,632.80	$0.00	$19,632.80	$1,791.06	$20,528.33	40	2.50%	$513.21	$513.20	$0.01
1835	Overhead Conductors & Devices	$191,807.37	$0.00	$191,807.37	$16,119.53	$199,867.14	45	2.22%	$4,441.49	$4,441.49	$0.00
1835	Overhead Conductors & Devices	$2,054,082.92	$0.00	$2,054,082.92	$161,195.28	$2,134,680.56	60	1.67%	$35,578.01	$35,578.01	$0.00
1840	Underground Conduit	$1,686,496.97	$805,840.86	$880,656.11	$0.00	$880,656.11	25	4.00%	$35,226.24	$27,448.96	$7,777.28
1840	Underground Conduit	-$1,174,814.95	-$1,174,814.95	$0.00	$0.00	$0.00	35	2.86%	$0.00	$0.00	$0.00
1840	Underground Conduit	$54,124.86	$54,124.86	$0.00	$0.00	$0.00	40	2.50%	$0.00	$0.00	$0.00
1840	Underground Conduit	$234,318.55	$0.00	$234,318.55	$5,973.83	$237,305.47	50	2.00%	$4,746.11	$4,746.11	$0.00
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57	$0.00	$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$953,978.56	$0.00	$953,978.56	$55,439.44	$981,698.28	40	2.50%	$24,542.46	$24,542.47	-$0.01
1850	Line Transformers	$861,512.34	-$687,304.71	$1,548,817.05	$0.00	$1,548,817.05	25	4.00%	$61,952.68	$55,814.38	$6,138.30
1850	Line Transformers	$1,784,443.65	$0.00	$1,784,443.65	$192,990.27	$1,880,938.79	40	2.50%	$47,023.47	$47,023.55	-$0.08
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58	$0.00	$981,475.58	25	4.00%	$39,259.02	$39,259.02	$0.00
1855	Services (Overhead & Underground)	$722,191.31	$0.00	$722,191.31	$0.00	$722,191.31	40	2.50%	$18,054.78	$18,054.79	-$0.01
1855	Services (Overhead & Underground)	$265,503.43	$0.00	$265,503.43	$78,455.81	$304,731.34	60	1.67%	$5,078.86	$5,078.87	-$0.01
1860	Meters	$100,794.32	-$7,268.36	$108,062.68	$0.00	$108,062.68	25	4.00%	$4,322.51	$4,319.93	$2.58
1860	Meters	$335,720.21	$0.00	$335,720.21	$115,736.50	$393,588.46	15	6.67%	$26,239.23	$26,239.23	$0.00
1860	Meters (Smart Meters)	$1,645,231.00	$0.00	$1,645,231.00	$0.00	$1,645,231.00	15	6.67%	$109,682.07	$109,681.98	$0.09
1915	Office Furniture & Equipment (10 years)	$50,952.11	$3,111.74	$47,840.37	$36,560.70	$66,120.72	10	10.00%	$6,612.07	$6,483.48	$128.59
1920	Computer Equipment - Hardware	$119,133.24	$67,501.85	$51,631.39	$141,853.26	$122,558.02	3	33.33%	$40,852.67	$39,944.99	$907.68
1930	Transportation Equipment	$77,377.71	$77,377.71	$0.00	$0.00	$0.00	4	25.00%	$0.00	$0.00	$0.00
1930	Transportation Equipment	$129,889.71	$129,889.71	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1930	Transportation Equipment	$1,301,320.52	-$56,357.53	$1,357,678.05	$13,602.08	$1,364,479.09	8	12.50%	$170,559.89	$145,477.16	$25,082.73
1935	Stores Equipment	$3,472.71	$0.00	$3,472.71	$0.00	$3,472.71	10	10.00%	$347.27	$347.27	$0.00
1940	Tools, Shop & Garage Equipment	$92,080.48	$1,105.82	$90,974.66	$2,000.00	$91,974.66	10	10.00%	$9,197.47	$8,941.81	$255.66
1945	Measurement & Testing Equipment	$32,788.41	-$904.50	$33,692.91	$0.00	$33,692.91	10	10.00%	$3,369.29	$3,369.30	-$0.01
1955	Communications Equipment	$26,170.96	$26,170.96	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1960	Miscellaneous Equipment	$13,997.80	-$605.20	$14,603.00	$0.00	$14,603.00	10	10.00%	$1,460.30	$1,460.30	$0.00
1980	System Supervisor Equipment	$125,864.86	$109,969.77	$15,895.09	$0.00	$15,895.09	3	33.33%	$5,298.36	$3,190.34	$2,108.02
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00	$0.00	$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$50,708.16	$50,708.16	$0.00	$0.00	$0.00	10	10.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00	$0.00	$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00	-$34,000.00	$0.00		$0.00	3	33.33%	$0.00	$0.00	$0.00
2040	Contributions & Grants	-$1,204,879.17		-$1,204,879.17	-$194,750.00	-$1,302,254.17	40	2.50%	-$32,556.35	-$32,556.36	$0.01
				$0.00	$0.00	$0.00			$0.00	$0.00	$0.00
	Total	$16,473,249.74	-$3,176,302.46	$19,649,552.20	$1,061,217.10	$20,180,160.75			$932,994.64	$872,624.88	$60,369.76

Table 41 - Depreciation Schedule 2022

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2021	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2022 Depreciation Expense	2022 Depreciation Expense per Appendix 2-B Fixed Assets,	Variance [2]
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d) [1]	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$382,902.13	$166,348.68	$216,553.45	$55,000.00	$244,053.45	3	33.33%	$81,351.15	$78,574.46	$2,776.69
1612	Land Rights (Formally known as Account 1906)	$2,747.84	$0.00	$2,747.84		$2,747.84	8	12.50%	$343.48	$67.84	$275.64
1805	Land	$0.00	$0.00	$0.00		$0.00	0		$0.00	$0.00	$0.00
1808	Buildings	-$16,471.20	-$69,919.21	$53,448.01		$53,448.01	25	4.00%	$2,137.92	$2,137.92	$0.00
1808	Buildings	$1,899.41	-$5,946.59	$7,846.00		$7,846.00	30	3.33%	$261.53	$245.00	$16.53
1808	Buildings	$731.25		$731.25		$731.25	45	2.22%	$16.25	$16.25	$0.00
1808	Buildings	$101,591.45	$10,553.10	$91,038.35		$91,038.35	50	2.00%	$1,820.77	$1,820.94	-$0.17
1808	Buildings	$83,618.96		$83,618.96		$83,618.96	60	1.67%	$1,393.65	$1,392.00	$1.65
1810	Leasehold Improvements	$351,837.94	-$35,099.22	$386,937.16	$42,000.00	$407,937.16	25	4.00%	$16,317.49	$16,306.60	$10.89
1820	Distribution Station Equipment <50 kV	$31,185.00		$31,185.00		$31,185.00	15	6.67%	$2,079.00	$2,078.99	$0.01
1820	Distribution Station Equipment <50 kV	$1,071,682.53	$207,709.15	$863,973.38		$863,973.38	30	3.33%	$28,799.11	$28,795.85	$3.26
1820	Distribution Station Equipment <50 kV	-$205,919.30	-$205,919.30	$0.00		$0.00	34	2.94%	$0.00	$0.00	$0.00
1820	Distribution Station Equipment <50 kV	$2,229,057.17	$696.27	$2,228,360.90	$810,000.00	$2,633,360.90	40	2.50%	$65,834.02	$65,834.01	$0.01
1820	Distribution Station Equipment <50 kV	$284,065.96		$284,065.96		$284,065.96	45	2.22%	$6,312.58	$6,312.59	-$0.01
1820	Distribution Station Equipment <50 kV	$27,437.89		$27,437.89		$27,437.89	50	2.00%	$548.76	$548.76	$0.00
1830	Poles, Towers & Fixtures	$1,503,377.48	-$965,722.21	$2,469,099.69		$2,469,099.69	25	4.00%	$98,763.99	$80,979.44	$17,784.55
1830	Poles, Towers & Fixtures	$1,559,134.15	$0.00	$1,559,134.15	$370,975.75	$1,744,622.03	45	2.22%	$38,769.38	$38,769.36	$0.02
1830	Poles, Towers & Fixtures	$34,959.29	$0.00	$34,959.29		$34,959.29	50	2.00%	$699.19	$699.19	$0.00
1835	Overhead Conductors & Devices	$1,624,906.73	-$972,605.63	$2,597,512.36		$2,597,512.36	25	4.00%	$103,900.49	$103,900.71	-$0.22
1835	Overhead Conductors & Devices	$21,888.40	$0.00	$21,888.40	$2,396.92	$23,086.86	40	2.50%	$577.17	$577.16	$0.01
1835	Overhead Conductors & Devices	$212,881.19	$0.00	$212,881.19	$21,572.24	$223,667.31	45	2.22%	$4,970.38	$4,970.38	$0.00
1835	Overhead Conductors & Devices	$2,271,782.05	$0.00	$2,271,782.05	$215,722.35	$2,379,643.23	60	1.67%	$39,660.72	$39,660.73	-$0.01
1840	Underground Conduit	$1,686,496.97	$877,152.30	$809,344.67		$809,344.67	25	4.00%	$32,373.79	$24,137.06	$8,236.73
1840	Underground Conduit	-$1,174,814.95	-$1,174,814.95	$0.00		$0.00	35	2.86%	$0.00	$0.00	$0.00
1840	Underground Conduit	$54,124.86	$54,124.86	$0.00		$0.00	40	2.50%	$0.00	$0.00	$0.00
1840	Underground Conduit	$250,601.02	$0.00	$250,601.02	$59,970.29	$280,586.17	50	2.00%	$5,611.72	$5,611.72	$0.00
1845	Underground Conductors & Devices	$276,675.21	-$129,412.36	$406,087.57		$406,087.57	25	4.00%	$16,243.50	$16,243.53	-$0.03
1845	Underground Conductors & Devices	$1,010,178.14	$0.00	$1,010,178.14	$154,432.64	$1,087,394.46	40	2.50%	$27,184.86	$27,165.88	$18.98
1850	Line Transformers	$861,512.34	-$603,854.35	$1,465,366.69		$1,465,366.69	25	4.00%	$58,614.67	$51,326.19	$7,288.48
1850	Line Transformers	$1,986,862.92	$0.00	$1,986,862.92	$311,611.99	$2,142,668.92	40	2.50%	$53,566.72	$53,566.81	-$0.09
1855	Services (Overhead & Underground)	$657,447.41	-$324,028.17	$981,475.58		$981,475.58	25	4.00%	$39,259.02	$39,259.02	$0.00
1855	Services (Overhead & Underground)	$722,191.31	$0.00	$722,191.31		$722,191.31	40	2.50%	$18,054.78	$18,054.79	-$0.01
1855	Services (Overhead & Underground)	$343,959.24	$0.00	$343,959.24	$80,918.15	$384,418.32	60	1.67%	$6,406.97	$6,406.99	-$0.02
1860	Meters	$100,794.32	-$7,268.36	$108,062.68		$108,062.68	25	4.00%	$4,322.51	$4,264.33	$58.18
1860	Meters	$451,456.71	$0.00	$451,456.71	$113,530.89	$508,222.16	15	6.67%	$33,881.48	$33,881.48	$0.00
1860	Meters (Smart Meters)	$1,645,231.00	$56,147.84	$1,589,083.16		$1,589,083.16	15	6.67%	$105,938.88	$105,938.87	$0.01
1915	Office Furniture & Equipment (10 years)	$87,512.81	$5,683.94	$81,828.87	$5,000.00	$84,328.87	10	10.00%	$8,432.89	$8,432.90	-$0.01
1920	Computer Equipment - Hardware	$260,986.50	$72,947.90	$188,038.60	$11,000.00	$193,538.60	3	33.33%	$64,512.87	$62,274.79	$2,238.08
1930	Transportation Equipment	$77,377.71	$77,377.71	$0.00		$0.00	4	25.00%	$0.00	$0.00	$0.00
1930	Transportation Equipment	$129,889.71	$129,889.71	$0.00		$0.00	5	20.00%	$0.00	$0.00	$0.00
1930	Transportation Equipment	$1,314,922.60	$344,968.66	$969,953.94	$5,000.00	$972,453.94	8	12.50%	$121,556.74	$119,641.57	$1,915.17
1935	Stores Equipment	$3,472.71	$0.00	$3,472.71		$3,472.71	10	10.00%	$347.27	$347.27	$0.00
1940	Tools, Shop & Garage Equipment	$94,080.48	$6,219.43	$87,861.05	$2,000.00	$88,861.05	10	10.00%	$8,886.11	$8,266.20	$619.90
1945	Measurement & Testing Equipment	$32,788.41	-$904.50	$33,692.91	$19,210.00	$43,297.91	10	10.00%	$4,329.79	$4,329.80	-$0.01
1955	Communications Equipment	$26,170.96	$26,170.96	$0.00		$0.00	5	20.00%	$0.00	$0.00	$0.00
1960	Miscellaneous Equipment	$13,997.80	-$605.20	$14,603.00		$14,603.00	10	10.00%	$1,460.30	$1,460.30	$0.00
1980	System Supervisor Equipment	$125,864.86	$122,617.86	$3,247.00		$3,247.00	3	33.33%	$1,082.33	$1,082.33	$0.00
1980	System Supervisor Equipment	$8,100.00	$8,100.00	$0.00		$0.00	5	20.00%	$0.00	$0.00	$0.00
1980	System Supervisor Equipment	$61,915.89	$50,708.16	$11,207.73	$45,000.00	$33,707.73	10	10.00%	$3,370.77	$3,370.77	$0.00
1980	System Supervisor Equipment	-$130,454.90	-$130,454.90	$0.00		$0.00	15	6.67%	$0.00	$0.00	$0.00
1995	Contributions & Grants	-$892,619.01	$489,090.42	-$1,381,709.43		-$1,381,709.43	25	4.00%	-$55,268.38	-$55,268.36	-$0.02
1995	Contributions & Grants	-$634,169.79		-$634,169.79		-$634,169.79	40	2.50%	-$15,854.24	-$15,913.31	$59.07
2040	Contributions & Grants	-$34,000.00	-$34,000.00	$0.00		$0.00	3	33.33%	$0.00	$0.00	$0.00
2040	Contributions & Grants	-$1,399,629.17		-$1,399,629.17	-$423,652.00	-$1,611,455.17	40	2.50%	-$40,286.38	-$40,286.38	$0.00
				$0.00		$0.00			$0.00		$0.00
	Total	$19,594,220.39	-$1,954,048.00	$21,548,268.39	$1,901,689.22	$22,499,113.00			$998,586.00	$957,282.73	$41,303.27

2.3.2 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.

2.3.3 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.

2.3.4 DEPRECIATION AND CAPITALIZATION POLICY

ORPC's Depreciation rates and Capitalization Policy is presented below.

CAPITALIZATION POLICY

ORPC's capitalization policy has not changed since its last Cost of Service in 2016. 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 debts used for construction while the construction is in progress.

ORPC's adherence to the capitalization policy can be described 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 cost of acquisition or construction 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.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

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 asset 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 follow:

Table 42 – Service Life Policy

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

In addition to the direct cost, ORPC applies a labour and vehicle burdens for these direct costs. These burden costs are described further below. ORPC typically doesn't capitalize items below $500. It is implied that a number of expenditures can be grouped together under a specified capital project in order to reach the minimum threshold and be recorded as capital asset.

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

The capitalized expenditures for these accounts include:

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

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 as well of their 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 44.23% 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

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

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 possible if the asset is no longer in service or if the asset is fully depreciated. When an item is disposed, any remaining contributions are 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

2.4 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 on June 03, 2015 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 attests 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 table below shows ORPC's calculations in determining its Allowance for Working Capital.

Table 45 - Allowance for Working Capital

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particulars	Last Board Approved	2016	2017	2018	2019	2020	2021	2022
Net Capital Assets in Service:								
Average Gross Assets	$30,265,128	$12,684,917	$13,833,139	$15,197,310	$16,364,217	$16,989,599	$17,724,210	$19,205,663
Average Accumulated Depreciation	-$20,539,657	-$2,746,384	-$3,600,161	-$4,448,158	-$5,190,285	-$5,882,601	-$6,686,437	-$7,678,773
Average Balance	$9,725,471	$9,938,532	$10,232,978	$10,749,152	$11,173,932	$11,106,997	$11,037,773	$11,526,890
Working Capital Allowance	$2,076,814	$2,073,726	$1,932,615	$1,828,968	$1,825,450	$2,183,328	$1,779,541	$1,755,507
Total Rate Base	**$11,802,285**	**$12,012,259**	**$12,165,593**	**$12,578,120**	**$12,999,383**	**$13,290,325**	**$12,817,314**	**$13,282,397**

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**Last Board Approved**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Eligible Distribution Expenses:								
3500-Distribution Expenses - Operation	$572,467	$630,729	$565,513	$484,252	$513,327	$785,741	$815,322	$901,091
3550-Distribution Expenses - Maintenance	$728,123	$613,081	$692,292	$500,384	$645,567	$501,236	$562,975	$576,747
3650-Billing and Collecting	$733,000	$747,071	$804,067	$668,041	$748,224	$837,380	$951,322	$962,860
3700-Community Relations	$67,000	$55,936	$79,674	$71,838	$64,147	$30,338	$41,362	$42,318
3800-Administrative and General Expenses	$964,375	$886,993	$1,121,542	$1,076,915	$1,235,810	$1,203,797	$1,158,155	$1,225,378
Total Eligible Distribution Expenses	$3,064,965	$2,933,810	$3,263,088	$2,801,430	$3,207,076	$3,358,492	$3,529,137	$3,708,394
3350-Power Supply Expenses	$24,625,882	$24,715,874	$22,505,110	$21,584,813	$21,132,260	$25,752,551	$20,198,073	$19,698,362
Total Expenses for Working Capital	$27,690,847	$27,649,684	$25,768,198	$24,386,243	$24,339,335	$29,111,042	$23,727,210	$23,406,757
Working Capital factor	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**$2,076,814**	**$2,073,726**	**$1,932,615**	**$1,828,968**	**$1,825,450**	**$2,183,328**	**$1,779,541**	**$1,755,507**

2.4.2 LEAD LAG STUDY

ORPC is not proposing to use a lead lag study in order 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 2021Bridge Year and the 2022 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, 2019 to October 31, 2020" . 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 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 46 - Summary of Cost of Power 2022

2022 Test Year - Cop	**Cop**
4705 -Power Purchased	$15,463,943
4707- Global Adjustment	$4,557,894
4708-Charges-WMS	$465,359
4714-Charges-NW	$1,126,347
4716-Charges-CN	$966,176
4730-RRRP	$68,435
4750-Charges-LV	$500,392
4751-IESO SME	$18,506
Misc A/R or A/P	-$3,473,641
TOTAL	**$19,693,411**

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 May 21, 2021, to April 30, 2022".

Table 47 - Calculation of Commodity

Commodity **Prices:**

Electricity Commodity	Units	2022 Test Year Volume	RPP Rate	$	2022 Test Year Volume	non-RPP Rate	$	Total $
Class per Load Forecast				-				
Residential	kWh	83,632,401		8,667,662	-		-	8,667,662
GS<50 kW	kWh	30,853,774		3,197,685	-		-	3,197,685
GS 50 to 4999 kW	kWh	20,424,299		3,145,959	50,320,586		249,232	3,395,191
Sentinel Lighting	kWh	202,761		21,014	-		-	21,014
Street Lighting	kWh	1,125,146		116,610	-		-	116,610
Unmetered Scattered Load	kWh	631,786		65,478	-		303	65,781
other		-		-	-		-	-
other		-		-	-		-	-
other		-		-	-		-	-
SUB-TOTAL		136,870,168		15,214,409	50,320,586		249,534	$ 15,463,943

Global Adjustment non-RPP	Units	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh			0				
GS<50 kW	kWh			0				
GS 50 to 4999 kW	kWh			0			4,557,894	
Sentinel Lighting	kWh			0			-	
Street Lighting	kWh			0				
Unmetered Scattered Load	kWh			0				
other				0				
other				0				
other				0				
SUB-TOTAL		0		0			4,557,894	$ 4,557,894

Table 48 - 2022 Forecasted Commodity Prices

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$19.25	$19.25
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$85.18	$85.18
Adjustments ($/MWh)				($0.79)
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$103.64**

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 2022 Load Forecast to determine the commodity to be included in the Cost of Power. The commodity cost for 2022 is projected at $15,463,943.

Transmission Network:

The Transmission Network charges are calculated in the OEB's RTSR model. The rates are applied to the 2022 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 2022 is projected at $1,126,347.

Table 49 - Transmission Network

Transmission - Network	**Units**	Volume	Rate	$
Class per Load Forecast				
Residential	kWh	83,632,401	0.0058	486,831
GS<50 kW	kWh	30,853,774	0.0051	158,649
GS 50 to 4999 kW	kW	219,749	2.1475	471,911
Sentinel Lighting	kW	495	1.6276	805
Street Lighting	kW	3,027	1.6195	4,902
Unmetered Scattered Load	kW	631,786	0.0051	3,249
other				-
other				-
other				-
				-
SUB-TOTAL				1,126,347

Transmission Connection:

The Transmission Connection charges are also calculated in the OEB's RTSR model. The rates are applied to the 2022 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 2022 is projected at $966,176.

Table 50 - Transmission Connection

Transmission - Connection	Units	Volume	Rate	$
Class per Load Forecast				
Residential	kWh	83,632,401	0.0051	424,815
GS<50 kW	kWh	30,853,774	0.0045	137,916
GS 50 to 4999 kW	kW	219,749	1.8007	395,703
Sentinel Lighting	kW	495	1.4216	704
Street Lighting	kW	3,027	1.3922	4,214
Unmetered Scattered Load	kW	631,786	0.0045	2,824
other				-
other				-
other				-
SUB-TOTAL				966,176

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

On December 17, 2019, the OEB released Decision and Order (EB-2019-0278) for the Wholesale Market Service (WMS) and Capacity Based Recovery (CBR) effective January 1, 2020. The Board's decision is summarized as follows:

- The WMS rate used by rate-regulated distributors to bill their customers shall be $0.0030 per kilowatt-hour, effective January 1, 2020. For Class B customers, a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0034 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 $0.0034/kWh to its 2022 Load Forecast to include $465,359 in its Cost of Power.

Table 51 - Wholesale Market

Wholesale Market Service Class per Load Forecast	Units	Volume	Rate	$
Residential	kWh	83,632,401	0.0030	250,897
GS<50 kW	kWh	30,853,774	0.0030	92,561
GS 50 to 4999 kW	kWh	20,424,299	0.0030	61,273
Sentinel Lighting	kWh	202,761	0.0030	608
Street Lighting	kWh	1,125,146	0.0030	3,375
Unmetered Scattered Load	kWh	631,786	0.0030	1,895
other				-
other				-
other				-
SUB-TOTAL				410,611

Class B CBR Class per Load Forecast	Units	Volume	Rate	$
Residential	kWh	83,632,401	0.0004	33,453
GS<50 kW	kWh	30,853,774	0.0004	12,342
GS 50 to 4999 kW	kWh	20,424,299	0.0004	8,170
Sentinel Lighting	kWh	202,761	0.0004	81
Street Lighting	kWh	1,125,146	0.0004	450
Unmetered Scattered Load	kWh	631,786	0.0004	253
other				-
other				-
other				-
SUB-TOTAL				54,748

Rural or Remote Electricity Rate Protection:

On December 17, 2019, the OEB released EB-2019-0278 Decision and Order for the Rural or Remote Electricity Rate Protection (RRRP) effective January 1, 2020. The Board's decision is summarized as follows:

- The IESO's RRRP charge to rate-regulated distributors shall be $0.0005 per kilowatt-hour for electricity consumed on or after January 1, 2020

In compliance with this order, ORPC has applied the Board Approved $0.0005/kWh to its 2022 Load Forecast to include $68,435 in its Cost of Power.

Table 52 - Rural or Remote Electricity Rate Protection

RRRP	Units	Volume	Rate	$
Class per Load Forecast				
Residential	kWh	83,632,401	0.0005	41,816
GS<50 kW	kWh	30,853,774	0.0005	15,427
GS 50 to 4999 kW	kWh	20,424,299	0.0005	10,212
Sentinel Lighting	kWh	202,761	0.0005	101
Street Lighting	kWh	1,125,146	0.0005	563
Unmetered Scattered Load	kWh	631,786	0.0005	316
other				-
other				-
other				-
SUB-TOTAL				68,435

Smart Meter Entity Charge:

On March 1, 2018, 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 2018-2022 period, for a new SMC of $0.57 per smart meter (Residential and General Service <50 kW) per month. The proposed rate remains at $0.57 in accordance with the OEB guidance provided on March 23, 2018. .

In compliance with this order, ORPC has applied the Board Approved rate of $0.57 per month for the forecasted Residential and General Service<50kW customers for Test Year 2021 and included the projected amount of $18,506 in its' Cost of Power as illustrated below:

Table 53 - Smart Meter Entity

Smart Meter Entity Charge		Customers	Rate	$
Class per Load Forecast				
Residential		2,248	0.57	15,375
GS<50 kW		458	0.57	3,130
				-
SUB-TOTAL				18,506

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 2020 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. 2022 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 2022 is projected at $487,559.

Table 54 - Low Voltage Charges

Low Voltage Charges - Historical and Proposed LV Charges

				2016	2017	2018	2019	2020	5 year avg	4 year avg
4075-Billed - LV				$177,328	$139,973	$153,746	$150,400	$147,607	$153,811	$147,932
4750-Charges - LV				$497,045	$397,335	$543,550	$506,992	$492,873	$487,559	$485,188
1551 LV Charges				$525,307	$870,539	$1,283,487	$769,606	$1,129,850		

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues
(volumes are not loss adjusted)

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Uplifted Volumes**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0051**	83,632,401	$424,815	43.97%
GS<50 kW	kWh	**$0.0045**	30,853,774	$137,916	14.27%
GS 50 to 4999 kW	kW	**$1.8007**	219,749	$395,703	40.96%
Sentinel Lighting	kW	**$1.4216**	495	$704	0.07%
Street Lighting	kW	**$1.3922**	3,027	$4,214	0.44%
Unmetered Scattered Load	kW	**$0.0045**	631,786	$2,824	0.29%
other	0	**$0.0000**	0	$0	0.00%
other	0	**$0.0000**	0	$0	0.00%
other	0	**$0.0000**	0	$0	0.00%
TOTAL			**115,341,233**	**$966,176**	**100.00%**

Low Voltage Charges Rate Rider Calculations
(volumes are not loss adjusted)

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	43.97%	214,373	80,335,302	$0.0027	kWh
GS<50 kW	14.27%	69,596	29,637,405	$0.0023	kWh
GS 50 to 4999 kW	40.96%	199,683	219,749	$0.9087	kW
Sentinel Lighting	0.07%	355	495	$0.7174	kW
Street Lighting	0.44%	2,127	3,027	$0.7025	kW
Unmetered Scattered Load	0.29%	1,425	606,879	$0.0023	kWh
other	0.00%	0		#DIV/0!	0
other	0.00%	0		#DIV/0!	0
other	0.00%	0		#DIV/0!	0
TOTAL	**100.00%**	**487,559**	**110,802,857**		

2.6 CAPITAL EXPENDITURES

2.6.1 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 this Distribution System Plan provides the rationale for the capital expenditures and supporting activities planned for the investment period of 2022-2026.

In advance of the Cost of Service application, ORPC retained the services of Metsco Energy Solutions Inc., an independent power sector consulting firm, to perform an Asset Condition Assessment (ACA) of the fixed assets employed on ORPC's distribution system. This study has assisted the LDC in reaffirming its asset replacement methodology and processes as well as identifying data gaps.

The ACA report evaluates the risk of an assets' failure in service by taking into account 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 report is included within ORPC's 2022 Distribution System Plan which has been filed at Appendix 2A.

ORPC has relied on Metsco Energy Solutions Inc. who in turn used the OEB's filing requirements Chapter 5 to guide its presentation of its policies, practices, and decision-making processes.

METSCO's 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 METSCO assessed and calculated Health Index ("HI") values for the following asset classes:

- Poles
- Distribution Overhead Conductors

- Distribution Underground Cables
- Distribution Transformers
- Distribution Overhead Switches
- Station Power Transformers
- Station Circuit Breakers
- Station Protection Relays
- Station Overhead Switches
- Station Battery Banks

All asset condition data used in the study are maintained by ORPC as part of its regular asset management practices. The ACA results are based on condition data recorded by ORPC, its contractors and METSCO up to the end of December 2019. METSCO received ORPC's data between August of 2019 and March of 2020. In July 2021, ORPC began further pole inspection in the Pembroke area. The ACA for poles was updated with the updated pole data supplied as of July 30.

2.6.2 DISTRIBUTION SYSTEM PLAN

ORPC has filed its' 2022 Distribution System Plan as a separate document as Appendix 2A.

2.6.4 CAPITALIZATION OF OVERHEAD

Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not, nor have they ever been capitalized and therefore, Appendix 2-D is not applicable in this application.

2.6.5 COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

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.

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 in order 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. Lastly, ORPC is not considered a generation facility.

2.6.6 NEW 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.

2.6.7 ADDITION OF ICM ASSETS TO RATE BASE

In its' 2019 IRM Application (EB-2018-0063), ORPC requested and received approval for an Incremental Capital Module (ICM) for capital funding of $1,603,409 to build a new 5 MVA substation (MS-4) in the Almonte Ward in the Town of Mississippi Mills. The MS-4 substation is a necessary and prudent expenditure to meet system and reliability needs.

ORPC completed the construction work and energized the new 5 MVA substation in 2020.

The actual cost for the project was 28.46% higher than the amount approved in the ICM application. This was a result of additional expenses for rock drilling and disturbing a confined aquifer which resulted in flooding of the property and flood mitigation measures. The original estimate provided by ORPC in the ICM calculation excluded labour costs as these costs were not considered incremental to the utility. The following table itemizes the difference between budgeted and actual values for costs and ICM calculations.

Table 55 – 5 MVA Substation ICM vs Actual

	ICM	Project Actual Values
Project Cost	$1,603,409	$2,059,754
Annual Amortization	$38,421	$51,588
Incremental Revenue Requirement	$129,085	$162,663

The incremental revenue requirement is $33,578 higher than approved in the ICM. ORPC is not proposing to recover the difference from the ICM rate implementation date of May 1, 2019 to the Cost of Service rate implementation date of May 1, 2022.

As would be expected, the revenue generated from the rate rider is very close to the approved ICM Incremental Revenue Requirement:

Table 56 – ICM Rev. Requirement vs Actual

	Incr. Rev. Requirement	RR Actual Revenue	Difference
2019 (May 1 – Dec 31)	$86,646	-$84,776	$1,870
2020	$129,805	-$127,107	$2,698
2021	$129,805		
2022 (Jan 1 to Apr 30)	$42,676		

Given the small annual debit balances of this difference, ORPC proposes that no action be taken in disposing of this variance and the ICM assets and amortization be added to the rate base balances as of May 1st, 2022. Once this is complete and the new rates are implemented May 1st, 2022, this will terminate the collection of the ICM rate riders.

At the time of preparing this Application, ORPC is not forecasting the need for a new Incremental Capital Module or Advanced Capital Module.

2.6.8 SERVICE QUALITY AND RELIABILITY PERFORMANCE

ORPC records and reports annually the following Service Reliability Indices:

- SAIDI = Total Customer-Hours of Interruptions/Total Customers Served
- SAIFI = Total Customer Interruptions/Total Customers Served

These indices provide ORPC with annual measures of its service performance that are used for internal benchmarking purposes when making comparisons with other distribution companies (e.g., to better understand the rankings that will support the OEB's Incentive Rate Making Mechanism and Performance Based Regulation). They are reported in accordance with Section 7.3.2 of the OEB's Electricity Distribution Rate Handbook.

ORPC's performance metrics are discussed in detail in Exhibit 1, and the Applicant's 2022 Distribution System Plan.

ORPC is not proposing any additional benchmarking metrics that are not already in place.

Table 57 – OEB App 2-G ESQR Results

Measures	Sub-Measures	2015 (%)	2016 (%)	2017 (%)	2018 (%)	2019 (%)	2020 (%)	OEB Minimum Standard
New Residential / Small Business Services Connected on Time	Low Voltage Connections	100	100	98.57	100	100	100	≥90%
	High Voltage Connections	N/A	N/A	100	100	N/A	N/A	≥90%
	Reconnection Performance Standard	100	100	100	100	100		>85%
Telephone Calls Answered on Time	Telephone Accessibility	99.90	99.90	99.87	99.92	99.95	97.63	≥65%
	Telephone Call Abandon Rate	0.10	N/A	N/A	N/A	0.05	2.37	≤10%
Scheduled Appointments Met on Time	Appointments Met	100	100	99.14	98.64	98.15	98.29	≥90%
	Appointment Scheduling	100	99.60	99.85	99.81	97.94	98.04	≥90%
	Rescheduling Missed Appointments	N/A	N/A	100	100	100	100	>100%
Written Response to Enquiries		98.8	100	100	100	100	96.63	≥80%
Emergency Response	Urban	98.4	100	100	100	100	100	≥80%
	Rural	N/A	100	100	100	N/A	N/A	≥80%

** ORPC is an urban distributor and does not respond to rural emergencies.

No explanations are required as all Service Quality Indicators have been met or exceeded by ORPC over the 5-year period of 2015 to 2020 inclusive.

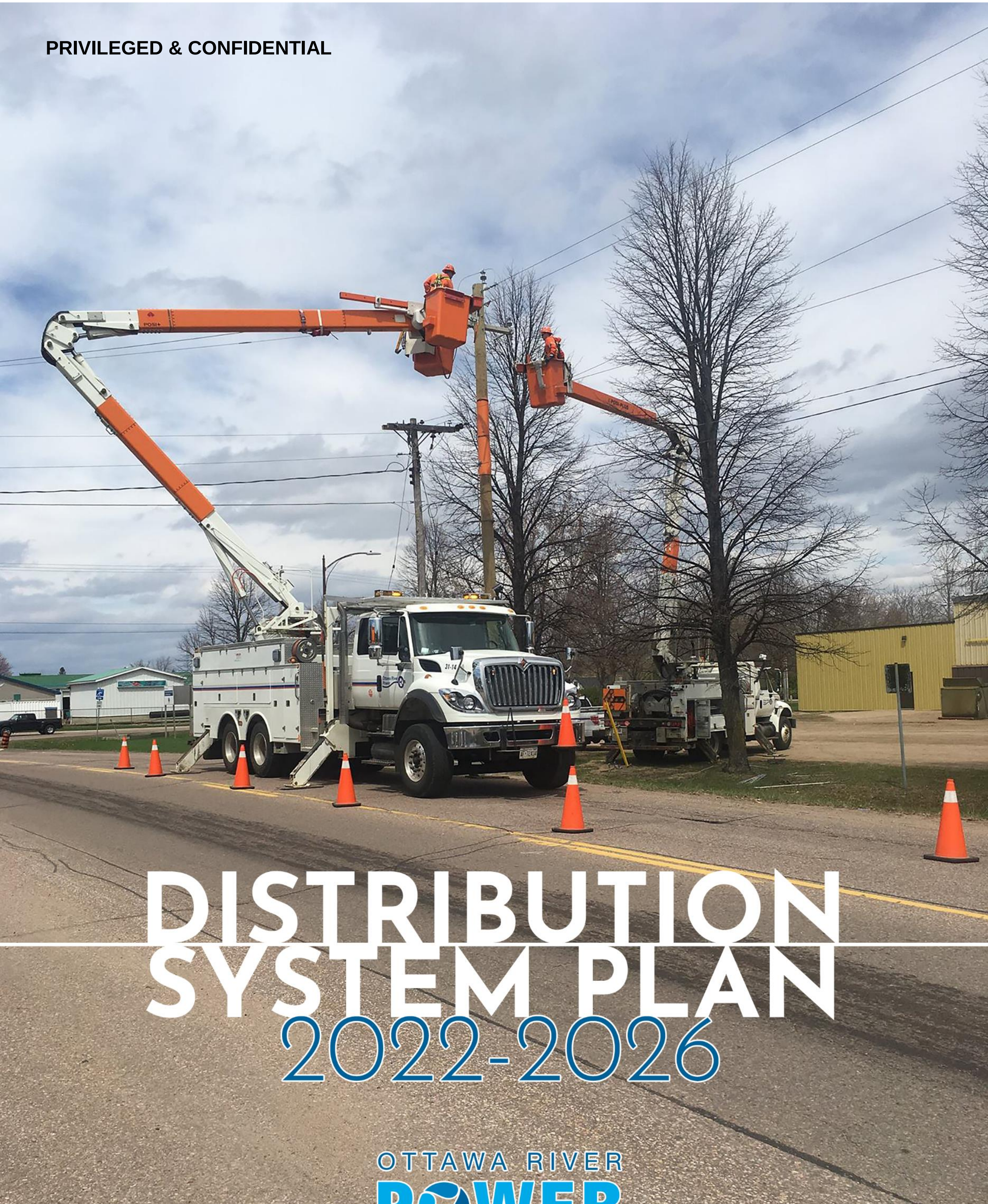
The Applicant confirms that the data represented above is consistent with RRR filings and ORPC's annual Scorecard.

APPENDIX

LIST OF APPENDICES

Appendix 2A – 2022 Distribution System Plan

PRIVILEGED & CONFIDENTIAL



DISTRIBUTION SYSTEM PLAN 2022-2026

OTTAWA RIVER POWER

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LIST OF ACRONYMS

Acronym	Meaning
ACA	Asset Condition Assessment
AM	Asset Management
APUL	Assets Past Useful Life
CHI	Customer Hours Interrupted
CI	Customers Interrupted
COS	Cost of Service
DSP	Distribution System Plan
ESA	Electrical Safety Authority
Filing Requirement	Chapter 5 Consolidated Distribution System Plan Filing Requirements
GS	General Service
HI	Health Index
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRM	Incentive Rate-Setting Mechanism
LDC	Local Distribution Company
LOS	Loss of Supply
MED	Major Event Day
METSCO	METSCO Energy Solutions Inc.
OEB	Ontario Energy Board
OH	Overhead
ORPC	Ottawa River Power Corporation
REG	Renewable Energy Generation
RRF	Renewed Regulatory Framework
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UG	Underground
TUL	Typical Useful Life
O&M	Operations and Maintenance
COVID-19	Coronavirus disease

1 INTRODUCTION

Ottawa River Power Corporation ("ORPC") has prepared this Distribution System Plan ("DSP") as part of its 2022 Cost of Service ("COS") Application. The DSP is prepared by following Ontario Energy Board's ("OEB's") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated June 24, 2021 ("Filing Requirements"). ORPC retained METSCO Energy Solutions Inc. ("METSCO") to advise on and assist with the preparation of this DSP.

1.1. EXECUTIVE SUMMARY

ORPC is the Local Distribution Company ("LDC") for the City of Pembroke, the Township of Whitewater (Beachburg only), the Town of Mississippi Mills (Almonte Ward Only), and the Township of Killaloe, Hagarty & Richards (Killaloe only). This DSP is the second five-year plan submitted to OEB and has been prepared in line with the Filing Requirements. The DSP is designed to provide detailed information on different aspects of system planning such as asset management planning, performance monitoring, coordinated planning with 3rd parties, and capital expenditure planning including business case development for program material investments. It also demonstrates major initiatives ORPC plans to undertake over the forecast period from 2022 to 2026 to modernize its grid and improve its reliability, safety, and security of supply.

ORPC's DSP has been prepared in consultation with customers and stakeholders such as municipalities, townships, and ORPC's residential and commercial customers, with an objective to produce outcomes that meet or exceed their expectations. The information retrieved from such 3rd party resources was integrated with ORPC's internal knowledge about their distribution network and expert resources from external consultants to develop a plan that serves the system's short- and long-term needs. As with the previous DSP submission for the period from 2015-2019, the 2022-2026 plan continues to reflect the incentive rate-setting mechanism ("IRM") methodology that is aligned with OEB policy guidelines.

The DSP describes the rigorous investment strategy developed by ORPC that targets all four OEB defined investment categories: System Access, System Renewal, System Service, and General Plant. ORPC is continuing with the commitments made in its previous DSP of maintaining consistent performance across its service quality, safety, and other performance metrics. To continue the attainment of these performance targets, investments to renew deteriorating or aging assets, and to meet the obligation of providing network access to customers remain the highest priority. To achieve this goal, ORPC has also made significant improvements in its asset management planning that will enhance the short- and long-term management of its assets. The new plan proposed in this DSP has been strategically adopted to produce an investment strategy of programs and projects that will be executed during the 2022-2026 period. This strategy includes a robust program evaluation process that has informed the prioritization and pacing of programs and projects throughout the forecast period. To enhance its management of delivering projects within its budget and manage any significant variance, ORPC has developed a new asset management metric. The objective of this proposed metric development is to ensure ORPC's overall spending profile remains within a defined variance of 10% each year and across the five-year period.

The 2022-2026 DSP that has been prepared balances the need to manage aging and degrading assets that allow ORPC to maintain its performance targets, meeting system needs, addressing customer satisfaction, and ensuring electricity rates are as digestible as possible for its customers. Historical information, inspection and testing data and forecast information have been used to develop the proposed expenditure. ORPC plans to invest a total of $6.7million across all four investment categories during the forecast period from 2022 to 2026. Figure 1-1 illustrates the five-year forecast of net capital expenditures, while Tables 1-1 and 1-2 detail the historical capital expenditures from 2015-2019, with 2020 & 2021 as bridge years, and the forecasted capital expenditures from 2022-2026 respectively.

Figure 1-1: Forecasted Capital Expenditures – 2022-2026 ($K)

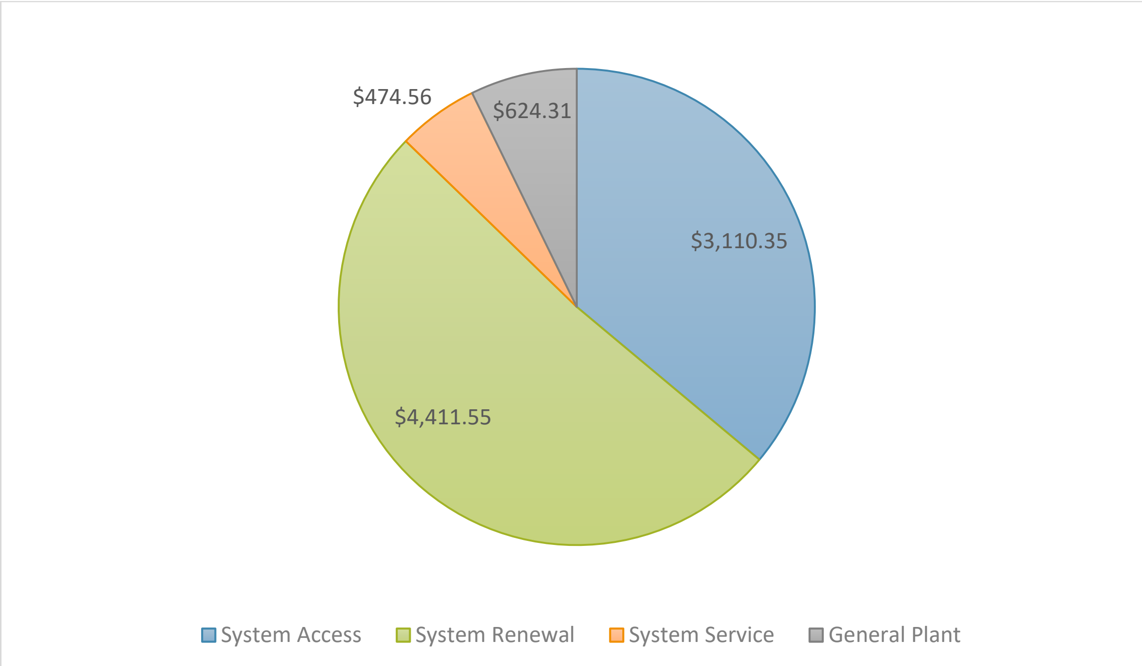


Table 1-1: Historical (Actuals) and Bridge Year (Estimated) Capital Expenditures and System O&M

Category	Historical Period ($K)						Bridge ($K)
	2015	2016	2017	2018	2019	2020	2021
System Access (Gross)	$311.94	$172.79	$363.64	$493.50	$651.17	$193.08	$381.41
System Renewal (Gross)	$351.26	$580.78	$605.97	$860.66	$328.75	$221.40	$474.65
System Service (Gross)	$161.16	$167.88	$156.47	$221.88	$106.48	$44.23	$1.13
General Plant (Gross)	$113.13	$234.61	$374.73	$51.47	$427.10	$161.74	$398.78
Gross Capital Expenses	**$937.91**	**$1,127.15**	**$1,496.80**	**$1,503.62**	**$1,642.71**	**$652.38**	**$1,196.67**
Contributed Capital	$(194.39)	$(96.90)	$(263.53)	$(136.45)	$(312.30)	$(101.29)	$(194.75)
Net Capital Expenses after Contributions	**$743.10**	**$1,059.16**	**$1,237.28**	**$1,491.06**	**$1,271.561**	**$551.09**	**$1,061.22**
System O&M	$1,207.30	$1,243.81	$1,257.81	$984.64	$1,158.90	$1,286.98	$1,378.30

Table 1-2: Forecasted Capital Expenditures and System O&M

Category	Forecast Period ($K)				
	2022	2023	2024	2025	2026
System Access (Gross)	$833.35	$546.77	$661.50	$542.30	$526.43
System Renewal (Gross)	$1,247.78	$738.61	$770.79	$861.31	$793.06
System Service (Gross)	$105.00	$161.91	$62.30	$70.08	$75.27
General Plant (Gross)	$139.21	$19.40	$29.90	$7.40	$428.40
Gross Capital Expenses	**$2,319.11**	**$1,466.70**	**$1,524.49**	**$1,481.09**	**$1,823.16**
Contributed Capital	$(423.65)	$(334.23)	$(426.15)	$(336.50)	$(347.01)
Net Capital Expenses after Contributions	**$1,901.69**	**$1,132.47**	**$1,098.34**	**$1,144.59**	**$1,476.16**
System O&M	$1,477.84	$1,507.40	$1,537.54	$1,568.30	$1,599.66

1.1.1. System Access

System Access investments are triggered by externally driven requirements such as customer connections, installation, and replacement of revenue meters, and/or relocating existing infrastructure due to 3rd party requests. Investments within this category are all non-discretionary and are mandated obligations as defined in the Distribution System Code ("DSC"). ORPC plans to invest $1.25 million within the System Access category during the forecast period, which represents approximately 18% of the total capital expenditure. ORPC maintains strong relationships with municipalities and townships to understand the population growth and economic activities within its service areas. Based on this coordination, ORPC has developed a forecast of the number of potential new connections in its service area and has integrated the results of this in its capital expenditure plan. A large contribution from the System Access expenditure will be made towards relocating ORPC infrastructure on Pembroke Street West due to the installation of three sets of traffic lights to comply with the Accessibility for Ontarians with Disabilities Act, 2005. The remaining investment is related to ORPC's obligation in regard to reverifying, sampling and replacing revenue meters across its service areas.

1.1.2. System Renewal

Expenditures within the System Renewal category are primarily driven by the condition and/or age of the distribution system assets. These investments are crucial for sustaining the overall reliability, maintainability, and safety of the distribution system. As part of developing its plans, ORPC performed Asset Condition Assessments ("ACA") of its distribution system to identify assets that are in poor or very poor condition, leveraged the results of an Assets Past Useful Life ("APUL") study, and conducted further planning to identify the most critical projects required to be undertaken in the forecast period. The distribution asset renewal investment contains a variety of projects such as replacing aging wood poles, replacing both overhead and underground transformers containing PCB, and replacing underground cables with newer cables. The station asset renewal investment involves the replacement of aging and poor condition assets, such as switchgear, power transformers that are critical for maintaining the operation of these stations. Additionally, ORPC will replace in 2022 a power transformer that unexpectedly failed in late July 2021. This has meant that ORPC spend in 2022 has increased significantly due to the need to carry out this urgent work which accounts for $750K of spend for 2022. ORPC will also continue its voltage conversion plan from 4.16 kV to 12.47 kV, which will allow ORPC to decommission some stations in the future and the network to be managed more efficiently with a reduction in line losses. ORPC plans to invest $4.36 million within the System Renewal category during the forecast period, which represents approximately 65% of the total capital expenditure.

1.1.3. System Service

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 within this category is the upgrade of the SCADA system, which has become obsolete and has recurring failures. As part of the project, different key components within the SCADA system will be upgraded such as electromechanical relays and remote terminal units in Pembroke MS4 and MS8. Another initiative is to upgrade the overhead infrastructure that supplies the double-circuit 44kV main feed to the City of Pembroke. The 44kV feed is critical for maintaining the security of supply and ensuring that customers continue to receive a reliable supply of electricity. ORPC has used APUL, ACA, historical SCADA failure information and other SCADA inspection reports to develop its capital expenditure plans. ORPC plans to invest $0.52 million within the System Service category during the forecast period, which represents approximately 8% of the total capital expenditure.

1.1.4. General Plant

The General Plant category expenditure is driven by the need to modify, upgrade, and/or replace facilities, information systems, and operational technology that are vital to ORPC's 24/7 operations. There is the need to invest in the information technology program. This program is focused on upgrading an unreliable and failing e-billing system that without being replaced will continue to impact customers and how they receive their bills. ORPC is also required to invest in its facilities to ensure these remain functional and safe, for both employees and the general public who use them. In addition, ORPC will need to replace a vehicle that has reached its end of life and has increasing maintenance costs, as well as having extended periods of downtime. ORPC plans to invest $0.62 million within the General Plant category during the forecast period which represents approximately 9% of the total capital expenditure.

Overall, ORPC believes that the proposed capital expenditures address the need to invest in projects that renew and upgrade both distribution and station assets as well as non-distribution assets, that are either past their typical useful life or are in poor and/or very poor condition. At the same time, ORPC capital expenditures across the 2022-2026 period also ensure that they meet the customer needs of keeping electricity rates as digestible as possible. ORPC will continually review its capital expenditure plan to ensure it is up to date and continues to deliver on ORPC's asset management objectives and customer needs.

1.2. Objectives & Scope of Work

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 2022 onwards to 2026. 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.*

1.3. Outline of Report

This is ORPC's second DSP prepared in alignment with the Filing Requirements. This DSP describes how ORPC has developed, managed, and maintained its distribution system equipment to provide a safe, secure, reliable, efficient, and cost-effective service to its customers. The DSP identifies major initiatives and projects to be undertaken over the filed planning period. The DSP provides the capital investment plan from 2022 onwards to 2026 (with 2022 being the Test Year), as well as information regarding the historical period of investments from 2015 to 2021 (with 2020 and 2021 being the Bridge Years).

The report contains four sections, including this introductory Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of ORPC's asset management practices, a description of assets management, asset life cycle optimization policies, and an assessment of the system capability for Renewable Energy Generation ("REG"). Section 4 provides a summary of ORPC's capital expenditure plan, including an overview of the capital expenditure planning process, and an explanation of historical expenditure for the 2015-2019 period. Section 5, 6, 7, and 8 provide the material program justifications for System Access, System Renewal, System Service and General Plant categories. The DSP is organized using the same section headings indicated in the Filing Requirements. Other relevant information is included in separately identified sections.

1.4. Description of the Utility Company

ORPC is an electricity distributor licensed by the OEB. Under its electricity distribution license # ED-2003-0033, 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 over 11,442 customers. ORPC is incorporated under the Ontario Business Corporations Act. ORPC is 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.

ORPC receives power from the Hydro One Networks Inc. ("HONI") transmission system and delivers electricity to its customers within the Almonte, Beachburg, Killaloe and Pembroke service areas. ORPC is responsible for maintaining distribution and infrastructure assets deployed over 35 square kilometers (including 10 municipal substations, 510 kilometers of overhead and underground lines) within its service areas. The ORPC's service areas for Almonte, Beachburg, Killaloe and Pembroke is represented by Figure 1-2, Figure 1-3, Figure 1-4, and Figure 1-5 respectively.

Figure 1-2: Almonte Service Area

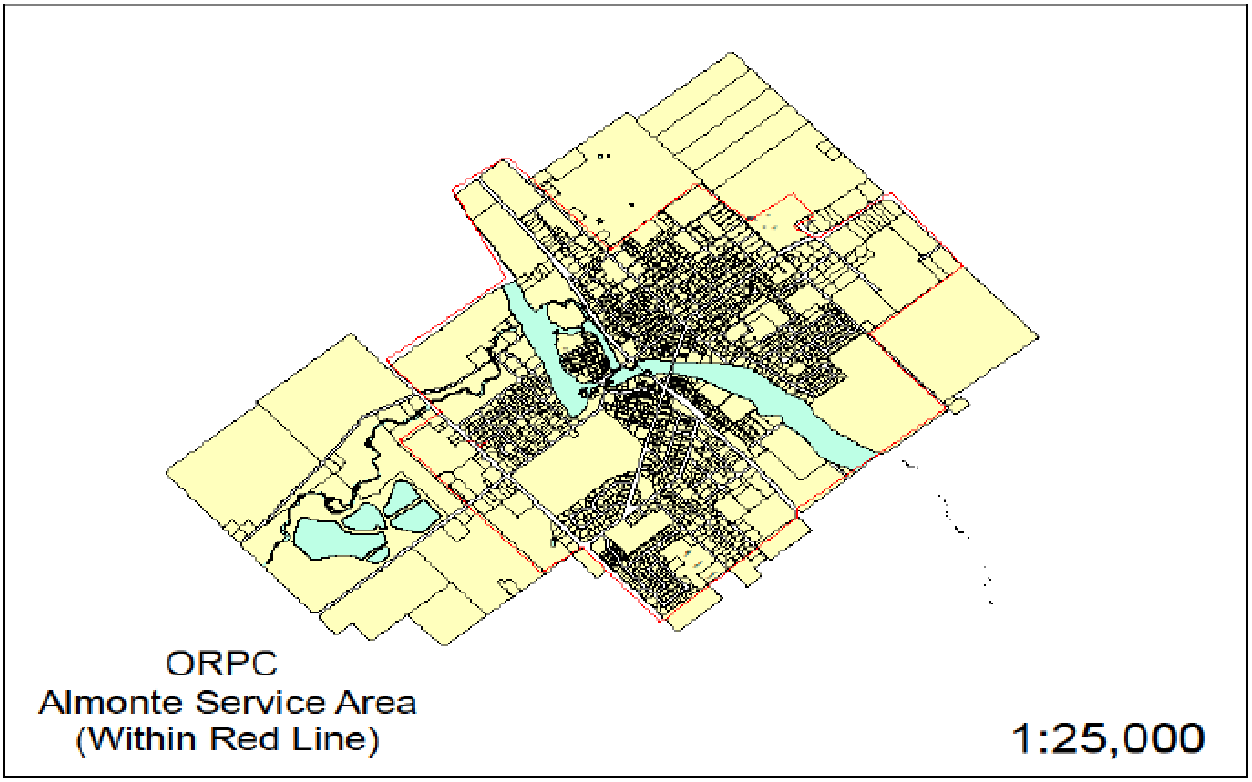


Figure 1-3: Beachburg Service Area

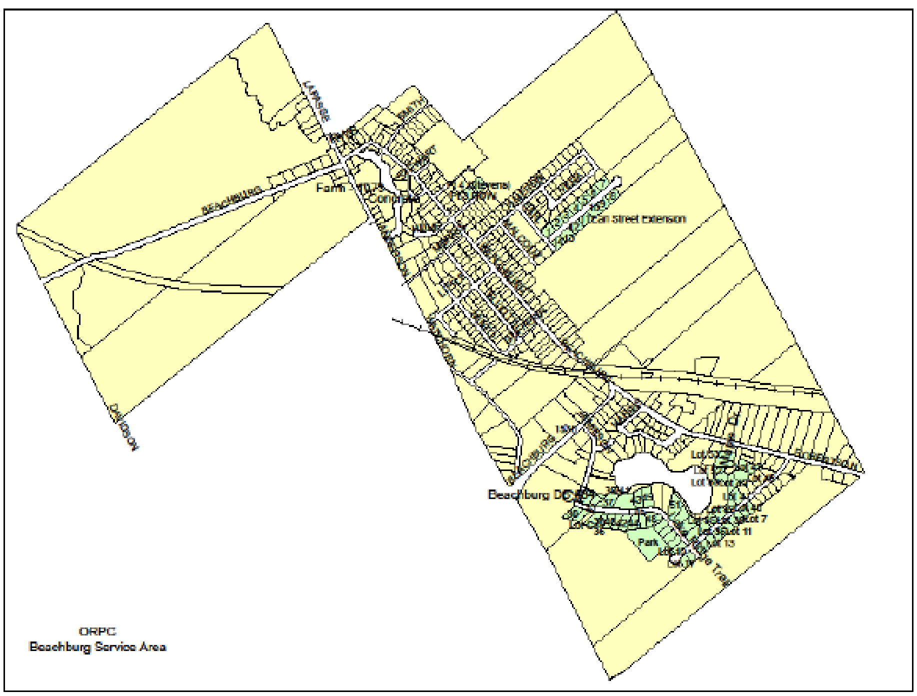


Figure 1-4: Killaloe Service Area

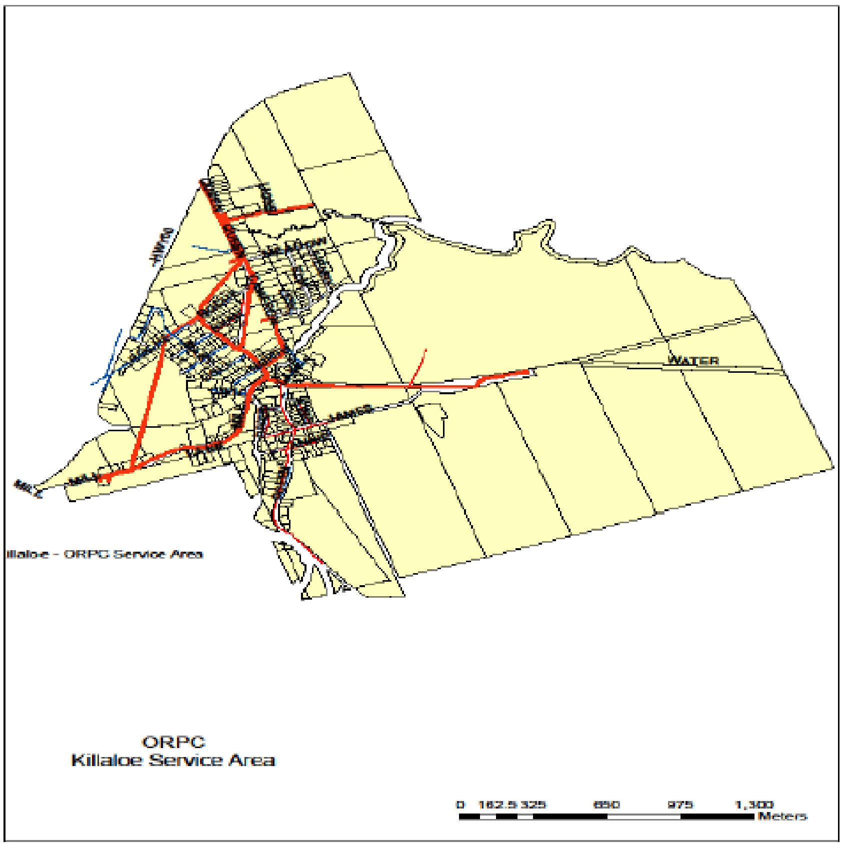
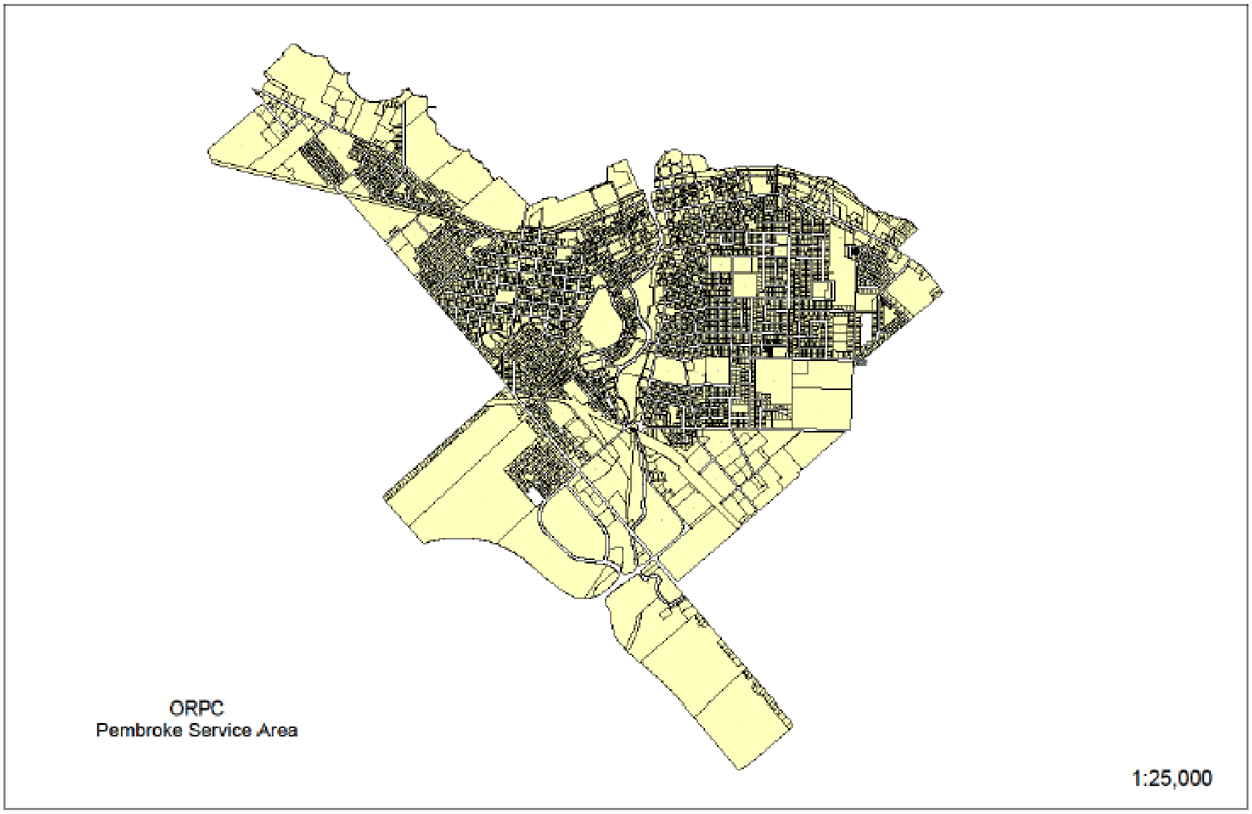


Figure 1-5: Pembroke Service Area



1.4.1. Mission and Core Values Statement

1.4.1.1. 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.”

1.4.1.2. Core Values

- *To be a responsible corporate leader in the community*
- *To be part of a productive and effective workforce 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*

1.4.2. Customers Served

In 2020, ORPC served 11,442 electricity distribution customers across its service area. The four communities ORPC serves have diverse characteristics. Section 3.2.1 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.

Table 1-3 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 1-3 ORPC's 2015-2020 actual customer base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Large Use > 5MW	Total
2015 Actual	9,441	1,301	150	-	10,892
2016 Actual	9,550	1,294	150	-	10,994
2017 Actual	9,676	1,283	150	-	11,109
2018 Actual	9,809	1,289	149	-	11,247
2019 Actual	9,888	1,283	149	-	11,344
2020 Actual	10,019	1,273	150	-	11,442

1.4.3. System Demand and Efficiency

Table 1-4 illustrates the annual peak demand (kW) for ORPC distribution system.

Table 1-4: Peak system demand statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2015 Actual	34,706	31,003	28,383
2016 Actual	37,047	35,163	30,177
2017 Actual	34,903	31,424	26,943
2018 Actual	40,812	42,344	31,702
2019 Actual	41,522	40,578	32,293
2020 Actual	34,936	36,163	31,338

ORPC experiences its peak demand mostly during winter months. Variances in seasonal peaks are attributable to annual changes in summer weather conditions and loading impacts associated with the number of degree days. Table 1-5 indicates the efficiency of the kilowatt-hour purchased by ORPC.

Table 1-5: Efficiency of kWh purchased by ORPC

Annual kWh Purchased	Total kWh Delivered (excluding losses)	Total Distribution Losses (kWh)	Total kWh Purchased	Losses as % of Purchased
2015 Actual	184,785,032	7,318,901	192,118,367	3.8%
2016 Actual	183,317,003	7,413,149	190,743,906	3.9%
2017 Actual	177,934,181	7,732,667	185,695,254	4.2%
2018 Actual	185,198,705	8,428,768	193,629,869	4.4%
2019 Actual	183,512,928	8,749,211	192,262,140	4.6%
2020 Actual	186,712,632	8,359,394	178,353,238	4.5%

1.5. BACKGROUND & DRIVERS

The Filing Requirements outline four categories of investments ("DSP Investment Categories") into which investment programs and discrete projects must be grouped. Each program is assigned a primary (trigger) and secondary driver. The subsections below serve to further define each of the DSP Investment Categories, as well as the drivers as defined by the Filing Requirements.

1.5.1. System Access

These non-discretionary investments represent modifications (including asset relocations) made to the distribution system that ORPC is obligated to perform in order to provide a customer (including a generator customer) or group of customers with access to electricity services via ORPC's distribution system.

1.5.2. System Renewal

These investments involve the replacement of ORPC's distribution system assets that are found to be either at, exceeding or approaching their Typical Useful Life ("TUL") within the DSP planning period or have been found to be in Poor or Very Poor condition, such that ORPC can mitigate the failure risks and reliability impacts within the system.

1.5.3. System Service

These investments involve modifications to the system in order to address system-wide critical issues such that ORPC's operational objectives continue to be achieved while addressing anticipated future customer electricity service requirements.

1.5.4. General Plant

These investments represent modifications, replacements or installation of new assets that are not part of the distribution system but ultimately serve to provide the backbone of ORPC's 24/7 operations. This includes land and buildings, tools, and equipment, fleet as well as Information Technology ("IT") hardware and software – all of which contribute towards the day-to-day operations and management of the distribution system.

1.5.5. ORPC Category Drivers

All of ORPC's investment programs possess a primary (trigger) and secondary driver as specified by the Filing Requirements. The primary driver corresponds to the DSP investment category that the program has been positioned within, while secondary drivers may belong to other investment categories.

Table 1-6 defines each of the drivers associated with the DSP investment categories.

Table 1-6: 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 on customers as well as potential safety risks to crew workers or 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 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	Management of system-wide reliability concerns such that system reliability is either maintained or improved.
	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 operations and maintenance. E.g., land, building, office supplies
	Business Operations Efficiency	The ability to mitigate and recover from disruptions to core business functions. E.g., information technologies such as computers, workstations, etc.
	Non-System Physical Assets	Rolling stock vehicles, tools, and equipment

2. DISTRIBUTION SYSTEM PLAN (5.2)

ORPC produced this Distribution System Plan in accordance with OEB's Filing Requirements. This document is designed to provide the OEB and customers with an accessible and transparent view of ORPC's distribution investment plans over the planning period from 2022 onwards to 2026. Key elements within this section of the document include the following:

Section 2.1 provides a high-level overview of the DSP, including the key elements, capital, and system O&M expenditures within the 2015-2019 historical period, the 2020 and 2021 bridge years as well as the 2022-2026 forecast period, as well as the DSP investment categories, underlying investment programs and associated expenditures. This section also provides insights into how ORPC addresses customer needs & preferences and anticipated sources of cost savings.

Section 2.2 summarizes ORPC's coordinating planning activities with third parties, including their interactions on the Regional Planning Process, the Independent Electricity System Operator ("IESO"), and municipalities.

Section 2.3 summarizes ORPC's performance measures that will be utilized for continuous improvements within the organization, including customer-oriented performance measures, cost efficiency and effectiveness measures and asset/system performance measures.

Finally, Section 2.4 summarizes ORPC's realized efficiencies due to smart meters.

2.1. DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

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.

2.1.1. Key Elements of the DSP (5.2.1.a)

This DSP has been developed to address the short-term needs as well as ensuring that the system continues to achieve safe and reliable distribution in the long term in conjunction with effective asset management planning. This DSP is a product of multiple inputs from initiatives, processes, and documents involving several stakeholders including the municipalities, customers, the IESO, and transmission utility, HONI. These input sources include the following:

- Customer Engagements
- Asset Management Process
- Regulatory Obligations
- Municipality Growth Plans

Electricity Regional Planning Studies (obtained from HONI website)

Table 2-1 and Table 2-2 presents the capital expenditures by investment category and the system operations and maintenance ("O&M") expenditures for the historical period (2015-2019), bridge years (2020 & 2021) and forecast period (2022-2026) respectively. Actual expenditures are presented in the historical period, which represent in-service additions to the system, whereas estimated expenditures have been presented for both the bridge years (2020 & 2021) as well as the forecast period (2022-2026).

Table 2-1: Historical (Actuals) and Bridge Year (Estimated) Capital Expenditures and System O&M

Category	Historical Period ($K)					Bridge ($K)	
	2015	2016	2017	2018	2019	2020	2021
System Access (Gross)	$311.94	$172.79	$363.64	$493.50	$651.17	$193.08	$381.41
System Renewal (Gross)	$351.26	$580.78	$605.97	$860.66	$328.75	$221.40	$474.65
System Service (Gross)	$161.16	$167.88	$156.47	$221.88	$106.48	$44.23	$1.13
General Plant (Gross)	$113.13	$234.61	$374.73	$51.47	$427.10	$161.74	$398.78
Gross Capital Expenses	**$937.91**	**$1,127.15**	**$1,496.80**	**$1,503.62**	**$1,642.71**	**$652.38**	**$1,196.67**
Contributed Capital	$(194.39)	$(96.90)	$(263.53)	$(136.45)	$(312.30)	$(101.29)	$(194.75)
Net Capital Expenses after Contributions	**$743.10**	**$1,059.16**	**$1,237.28**	**$1,491.06**	**$1,271.561**	**$551.09**	**$1,061.22**
System O&M	$1,207.30	$1,243.81	$1,257.81	$984.64	$1,158.90	$1,286.98	$1,378.30

Table 2-2: Forecasted Capital Expenditures and System O&M

Category	Forecast Period ($K)				
	2022	2023	2024	2025	2026
System Access (Gross)	$833.35	$546.77	$661.50	$542.30	$526.43
System Renewal (Gross)	$1,247.78	$738.61	$770.79	$861.31	$793.06
System Service (Gross)	$105.00	$161.91	$62.30	$70.08	$75.27
General Plant (Gross)	$139.21	$19.40	$29.90	$7.40	$428.40
Gross Capital Expenses	**$2,319.11**	**$1,466.70**	**$1,524.49**	**$1,481.09**	**$1,823.16**
Contributed Capital	$(423.65)	$(334.23)	$(426.15)	$(336.50)	$(347.01)
Net Capital Expenses after Contributions	**$1,901.69**	**$1,132.47**	**$1,098.34**	**$1,144.59**	**$1,476.16**
System O&M	$1,477.84	$1,507.40	$1,537.54	$1,568.30	$1,599.66

Based upon the execution of ORPC's AM Process (further described in Section 3.1), ORPC has identified investments across the four DSP investment categories and developed a total of 11 underlying investment programs as detailed in Table 2-3.

Table 2-3: ORPC **2022-2026** *Investment Programs*

OEB Category	Program	Definition
System Access	**Customer Connections**	The connection of minor (residential) and major (condos, commercial properties, and other large developments) customers to the distribution system.
	Metering	Investments related to the ORPC's metering technologies to ensure reliable measurement of electricity acquired by the utility.
	Externally Initiated Plant Relocation	Replacement and/or relocation of asset infrastructure due to third-party (customer) needs (e.g., city-related or transportation-related initiatives)
System Renewal	**Underground Renewal**	Replacement of underground distribution infrastructure, including underground transformers and cables that are past their TUL and/or in Poor or Very Poor condition, along with transformers containing PCB's.
	Overhead Renewal	Replacement of overhead distribution infrastructure, including overhead pole-mount transformers, poles and conductor that are past TUL and/or in Poor or Very Poor condition, as well as conversion of 4.16kV overhead infrastructure and replacement of transformers containing PCB's.
	Stations Renewal	Replacement of substation infrastructure, including power transformers, circuit breakers, protection relays, station switches and battery banks that are past TUL and/or in Poor or Very Poor condition.
System Service	**System Enhancement**	Modifications to the system to address system-wide critical issues, including the mitigation of operational constraints as well as security of supply issues within the system.
	Station Expansion	Modifications to the substation assets to address critical station-level issues, including communication & controls.
General Plant	**Information Technology**	Upgrades to critical IT infrastructure providing support to the 24/7 operations of the utility.
	Operational Technology	Upgrades to critical tools and testing technologies leveraged by field personnel.
	Facilities	Management of the utilities' facilities infrastructure, including ORPC's office buildings and substation properties.
	Fleet	Replacement of Vehicles to support the 24/7 operations of the utility: Maintenance, support capital projects, respond to emergency outages.

Figure 2-1 illustrates the forecasted capital expenditures from 2022-2026 for each of the four DSP investment categories. As further explained in Section 4.2, these capital expenditures reflect a balance between the needs of the system as identified by ORPC's decision-making analytics as well as their long-term and short-term planning sub-processes (further discussed in Section 3.1), as well as the need to keep rates as digestible as possible for customers and account for available resources and system constraints. The largest form of spending can be seen in the System Renewal category, which will continue to manage aging, deteriorating and functionally obsolete infrastructure, along with assets introducing possible environmental and safety risks within the system. Its also includes significant increase in spend in 2022 due to the unexpected failure of a power transformer in late June 2021.

These capital expenditures from 2022-2026 closely align with the historical capital expenditures from 2015-2019, with only inflationary increases occurring within the forecast period. However, due to the unexpected failure of a power transformer in late June 2021 spend in 2022 has been increased to be able to replace the transformer.

Figure 2-1: Forecasted Capital Expenditures (2022 - 2026)

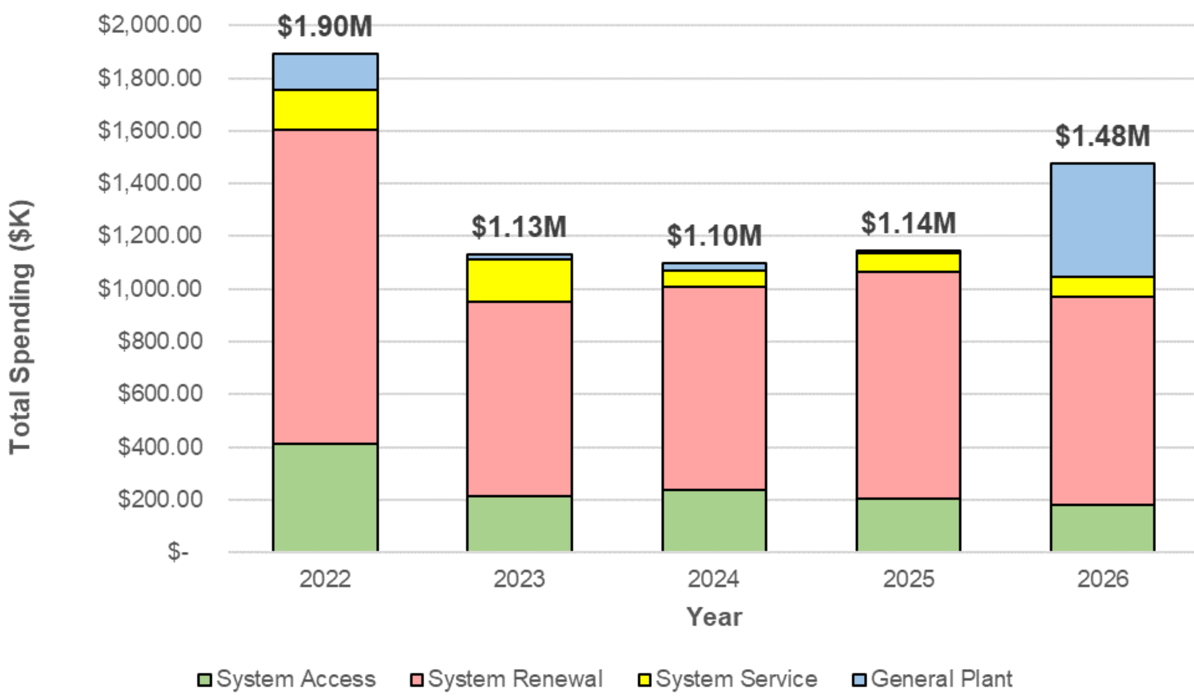
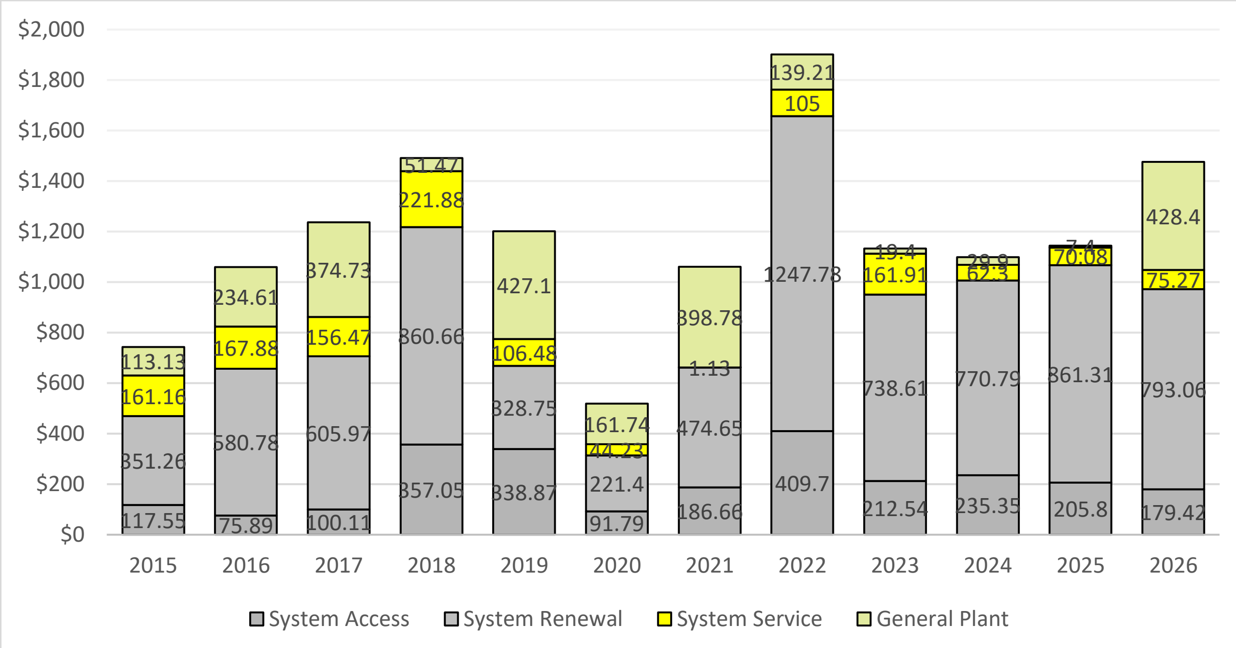


Figure 2-2 illustrates all historical and forecasted capital expenditures from 2015-2026. The lowest capital expenditures have been incurred in the 2020, mostly due to emerging constraints due to the COVID-19 pandemic.

Figure 2-2: Historical & Forecasted Capital Expenditures (2015 - 2026)



2.1.2. Addressing Customer Needs & Preferences (5.2.1.b)

ORPC's efforts into the development of short-term and long-term investment plans have always been closely aligned to the preferences as captured by their customer base. ORPC engages their customers on an annual basis through a series of initiatives, including a survey that is conducted during the DSP bridge year, as well as customer satisfaction and public awareness safety surveys that third-party firms working on behalf of the utility will execute during the DSP planning period. These surveys are deployed both in online as well as phone formats.

Table 2-4 illustrates the breakdown of ORPC customers that have been surveyed over the past 3-year period, including the most recent online survey conducted as part of the DSP development process ("DSP Survey"):

Table 2-4: ORPC Customer Engagement Activities: 2017-2020

Customer Engagement Activity	Methodology	Number of Customers Engaged (2017 – 2020)
2017 Customer Satisfaction Survey	**Phone Calls / Interviews**	400
2018 Electrical Safety Authority Public Awareness Survey	**Phone Calls / Interviews**	400
2019 Customer Satisfaction Survey	**Phone Calls / Interviews**	400
2020 Electrical Safety Authority Public Awareness Survey	**Phone Calls / Interviews**	400
2020 ORPC Distribution System Plan Survey	**Online**	106
2021 Customer Satisfaction Survey	**Phone Calls / Interviews**	402

Total Customers Engaged (2015 – 2020)	Phone Calls / Interviews / Online	1,706

The following subsections provide more details for each of these survey deployments:

2.1.2.1. Public Awareness of Electrical Safety Survey

The "Public Awareness of Electrical Safety" is defined under the OEB Electricity Reporting and Record Keeping Requirements ("RRR") as *"the level of public awareness within the electricity distributor's service territory about electrical safety information and precautions related to distribution network assets"*[1]. The OEB requires LDCs to conduct Public Awareness of Electrical Safety surveys as part of meeting the performance scorecard requirements. To enable comparability of results year-over-year and among LDCs, it is crucial that survey methodology is consistent among distributors. To enable consistency, the Electrical Safety Authority ("ESA") tasked Innovative Research Group Inc. to develop a standardized and methodical approach to questionnaires and implementing this survey.

ORPC tasked Redhead Media Solutions Inc. ("Redhead Media Solutions") to deploy the survey on behalf of the utility via phone interviews. The objective of the survey is to produce a Public Safety Awareness ("PSA") score that can be assigned to the LDC. The score is calculated by aggregating responses from individuals related to six core measures of the survey instrument, including:

- Call for Locates
- The Danger of Touching Powerlines
- Safe Distance from Powerlines
- Opening Electrical Equipment
- Proximity to Downed Powerlines
- Vehicles Touching Powerlines

ORPC has executed the Public Awareness of Electrical Safety survey in 2018 and as recently as 2020, respectively.

2.1.2.2. Customer Satisfaction Survey

Engaging customers in a constantly changing energy environment is increasingly important. ORPC undertakes customer satisfaction surveys every two years to receive feedback from its customers regarding the overall value of services delivered by the utility. The objective of the survey is to provide an Overall Customer Satisfaction Index ("CSI") score for ORPC to be integrated into their performance scorecard. This score is calculated by aggregating values based on the responses received from ORPC's low volume customer base such as Residential and General Service customers less than 50kW. The core measures of this survey instrument include:

- Power Quality & Reliability (Satisfaction related to voltage fluctuations, the flickering of lights, and reliability of service such as the number of outages and time to restore power when an outage occurs)
- Billing & Payment (Billing accuracy and convenience of receiving bills)
- Customer Service Experience
- Quality of Communication
- Customer Satisfaction towards the Portion of the Electricity Bill that goes to ORPC

[1] "Electricity Reporting and Record Keeping Requirements", Section 2.1.19, p. 26, Ontario Energy Board, March 31, 2020. URL: https://www.oeb.ca/sites/default/files/RRR-Electricity-20200331.pdf

Redhead Media Solutions was also tasked to develop and deploy this survey via phone interviews, in 2017, 2019 and most recently in 2021.

2.1.2.3. DSP Survey

Most recently, as part of developing the 2022-2026 DSP (contained within this application), and ensuring that the proposed 2022-2026 capital investments are aligned to customer preferences, ORPC engaged METSCO in the preparation and development of a DSP Survey deployed across their entire customer base to capture information relating to the following categories:

- Customer Details (service area, customer type, dwelling type, age range, role in paying electricity bill, etc.)
- Overall Performance of ORPC (services provided by ORPC, customer satisfaction with system reliability, power restoration, planned outages, customer response times, bill accuracy, overall customer service, etc.)
- ORPC Capital Investments (customer preferences on System Renewal, Service, Access, and General Plant investments as well as System O&M investments)
- Communication Preferences with ORPC in Future

Due to the COVID-19 pandemic, this survey was deployed using an online platform, with invitations to the platform being distributed via customer billing inserts. In addition, ORPC also advertised the survey link through their social media channels. Complete results from the DSP Survey are further provided in Exhibit 1, Appendix E. Based upon the results, it is clear that customers are deeply interested in ORPC addressing day-to-day reliability, helping customers reduce and manage their electricity consumption, and ensuring that electricity rates are maintained to reasonable levels. The majority of ORPC customers were found to be either very satisfied or somewhat satisfied with respect to customer service, inquiry response time and outage response time, respectively.

With respect to the pacing and execution of ORPC's investments as designated within this DSP, the majority of ORPC's customers were found to be either satisfied with the pace of investments as described within the plan or preferred for the utility to increase the pace of investments. Similarly, with respect to system performance, the majority of ORPC's customers were found to be either satisfied with the utility continuing to deliver the same level of system performance as seen over the past 5-year period or would like to see an improvement in system performance which would require an increase in investment levels from what has been described in the plan.

In general, the selected investments and pacing of the investments have been driven based upon the needs of the system, available resources to execute the work, as well as the feedback as captured by customers through the engagements described in Table 5.2-3 conducted from 2015 through to 2021.

2.1.3. Anticipated Sources of Cost Savings (5.2.1.c)

Cost savings within ORPC are integrated within the day-to-day planning and investment processes communicated through this DSP, as well as through continuous improvements introduced across the introduction.

ORPC adheres to OEB's Distribution System Code ("DSC"), which defines good utility practices, minimum performance standards, and minimum inspection requirements to be applied by distribution utilities within Ontario. Consistent with good utility practices, ORPC continues to execute maintenance activities that allow for the reliable and safe operation of their assets and replaced or repaired equipment that is either at or exceeding their typical useful life or has reached a poor or very poor condition as per asset condition assessment results.

Most of the cost savings that will be achieved during the forecast period (2022-2026) will be based upon the following practices presently executed by ORPC:

- Continuous improvements to maintenance procedures, including the introduction of infrared thermography equipment that will allow for the detection of hotspots on overhead and underground distribution plant. This technology will ultimately allow for more information to be embedded within ORPC's asset condition assessment ("ACA") framework. Outputs from this framework, including the health index ("HI") results, will allow OPRC to proactively take necessary actions to repair or replace equipment and avoid potential outages to the customer. In addition, ORPC continues to rollout improvements to in-field data entry, such as the introduction of embedded tools within their GIS system and the rollout of iPads, thereby allowing in-field inspectors to enter visual inspection results directly in electronic format. These improvements will reduce the reliance on paper records which are complex and time-consuming to digitize into electronic format. These improvements are further discussed in Section 3.1.2.1.

- Upgrades to Supervisory Control and Data Acquisition ("SCADA") systems at Pembroke substations MS4 and MS8 respectively as part of the Station Expansion program that will allow for ORPC to better detect major feeder-level outages at the control room and respond to these outages in a timelier manner, thereby introducing operational efficiencies and cost savings to the organization. This work is further described in Section 7.2.

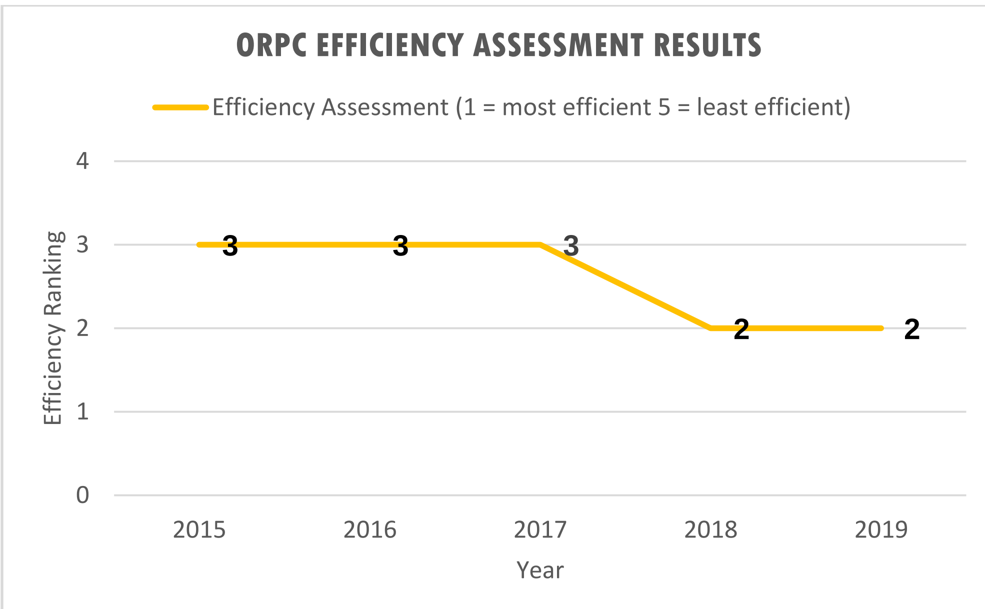
- Replacement of assets as part of the rebuilding of Pembroke Street West will be coordinated with the City of Pembroke, who will be sharing the rebuilding costs for the project. Therefore, ORPC is able to replace these assets at an overall reduced cost and these cost savings have been integrated into the forecasted expenditures within the Externally Initiated Plant Relocation program as described in Section 5.2.

- ORPC continues to enhance its asset management process, which allows for enhanced decision making and prioritization of assets to be replaced within the capital expenditure plan. For example, the introduction of new technologies such as the infrared thermography technology (as described within the Operational Technologies program detailed in Section 8.3) will result in enhanced ACA and HI results to be produced, which will ultimately provide more awareness of assets in poor and/or very poor condition that must be proactively replaced. Thus, outages can be avoided, along with the associated emergency repair and restoration costs. Cost savings introduced through the AM process and enhanced decision-making are embedded within the forecasted capital expenditure plan.
- The capital expenditure plan within this DSP has been designed to smooth out the financial rate impacts to the customer such that disruptive "spikes" in electricity rates are avoided when addressing the volume of assets reaching the end of their typical useful life and/or assets reaching poor and very poor condition criteria, respectively. Savings are embedded within the forecasted capital expenditure plan.
- Voltage conversion activities to be executed within the capital expenditure plan are expected to ensure that reliability can be maintained at current levels, by replacing assets at or past their typical useful life and/or assets in poor or very poor conditions, respectively. The eventual elimination of the assets associated with the 4.16kV system connected to the Pembroke MS1 and MS3 substations will allow for these substations to eventually be converted, thereby eliminating the future maintenance costs to be executed for these assets. In addition, the removal of this 4.16kV plant will also reduce the need to stock parts and equipment associated with this voltage class, which will introduce efficiencies to ORPC's supply chain and inventory. Voltage conversion investments are embedded as part of the Overhead Renewal program as

described in Section 6.2 and savings are embedded within the forecasted capital expenditure plan.

It should also be noted that each year, a total cost benchmarking evaluation is performed by Pacific Economics Group ("PEG") on behalf of the OEB in order to establish an efficiency ranking for all local distribution companies across the Province of Ontario. These rankings are then segmented into five groups based upon the size of the difference between the distributors' actual costs and their predicted costs as estimated via the benchmarking evaluation. As per ORPC's 2019 utility scorecard results, as published on September 1, 2020, the utility remains in Group 2 efficiency ranking, meaning that ORPC's actual costs are 10-25% below the predicted costs. ORPC has remained within the Group 2 ranking since 2018 as shown in Figure 2-3. As per the results, ORPC is an above-average cost performer[2].

Figure 2-3: Historical Efficiency Assessment Results for ORPC (2015 – 2019)



2.1.4. Period Covered by DSP (5.2.1.d)

This DSP covers a planning period over an eleven-year period, which includes the historical period from 2015 onwards to 2019, the 2020 & 2021 bridge years, as well as the forecast period from 2022 onwards to 2026, with 2022 being the Test year.

2.1.5. Vintage of the Information (5.2.1.e)

Unless otherwise noted, all information contained in the DSP is current as of June 30, 2021.

2.1.6. Important Changes to Asset Management Processes (5.2.1.f)

Section 3.1 provides an overview of ORPC's AM process, including the major stages in the process, as well as key inputs, outputs and underlying components associated with each stage. This process represents an evolution of the process that was presented in ORPC's 2015-2019 DSP, with continuous improvements implemented to allow for enhanced decision-making and overall assessment of their asset base.

2.1.7. DSP Contingencies (5.2.1.g)

There are certain investments proposed within this DSP that are contingent upon the outcome of ongoing activities or future events that are beyond ORPC's control. Such projects can influence capital project prioritization or overall spending profile outlined in this DSP. Associated projects and contingencies include the following:

2.1.7.1. New Customer Connections within Pembroke, Almonte & Beachburg Service Areas

New customer connections are forecasted based on the information received from municipalities and cities, including planning reports, developer submissions, and historical customer inquiries. As such, total spending associated with each customer connection initiative as outlined within Section 5.1 within ORPC's capital expenditure plan may be subject to change, depending on the capabilities of the developers to execute their work (i.e., develop the associated residential communities).

2.1.7.2. Externally Initiated Plant Relocation along Pembroke Street West

Work relating to the replacement of infrastructure along Pembroke Street West will be driven by the City of Pembroke, who will be executing and driving the reconfiguration work along this street. This work may be subject to changes to the plan as introduced by the City of Pembroke.

2.1.7.3. Ongoing COVID-19 Pandemic

The ongoing COVID-19 pandemic has resulted in construction delays to work to executed in the 2020. However, this is now no longer a major problem for 2021 onwards for ORPC. ORPC have introduced procedures to ensure staff and contractors are safe. This will ensure that there will be minimal impact to construction work due to the pandemic.

2.1.8. Grid Modernization, Energy Resource, and Climate Change Adaptation (5.2.1h)

As part of the Stations Expansion program as described within Section 7.2 of the DSP, upgrades to the existing SCADA systems will be introduced at Pembroke substations MS4 and MS8, respectively. These upgrades will allow for ORPC to better detect major feeder-level outages at the control room and respond to these outages in a timelier manner, thereby introducing operational efficiencies and cost savings to the organization.

In addition, as part of the Overhead Renewal program as described within Section 6.2 of the DSP, voltage conversion activities will be executed to convert existing 4.16 kV feeders connected to the Pembroke MS1 and MS3 substations to the 12.47 kV voltage level. These conversions will allow for the eventual decommissioning of these substations as part of ORPC's broader grid modernization efforts.

Obsolete and end-of-life assets, including distribution transformers containing Polychlorinated biphenyls ("PCBs") will also be replaced as part of the Overhead and Underground Renewal programs, respectively.

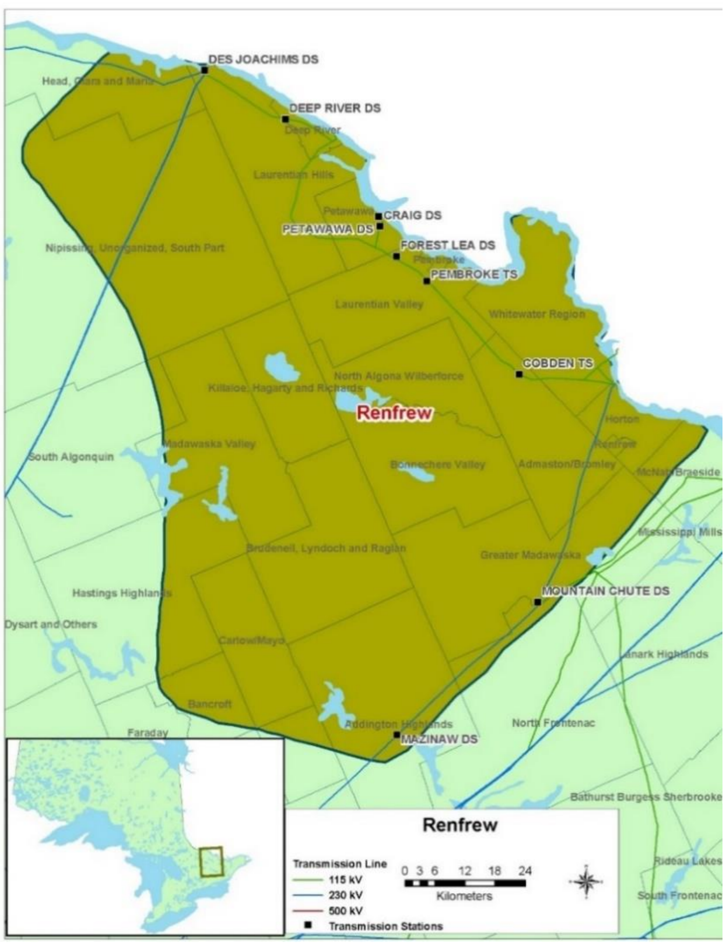
2.2. COORDINATED PLANNING WITH THIRD PARTIES (5.2.2)

2.2.1. 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. The 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 2-4, the boundaries of the Renfrew Region include the Ottawa River in the Northeast, Algonquin Provincial Park in the West, and Route 508 in the South.

Figure 2-4: Renfrew Region - Regional Planning Group 3

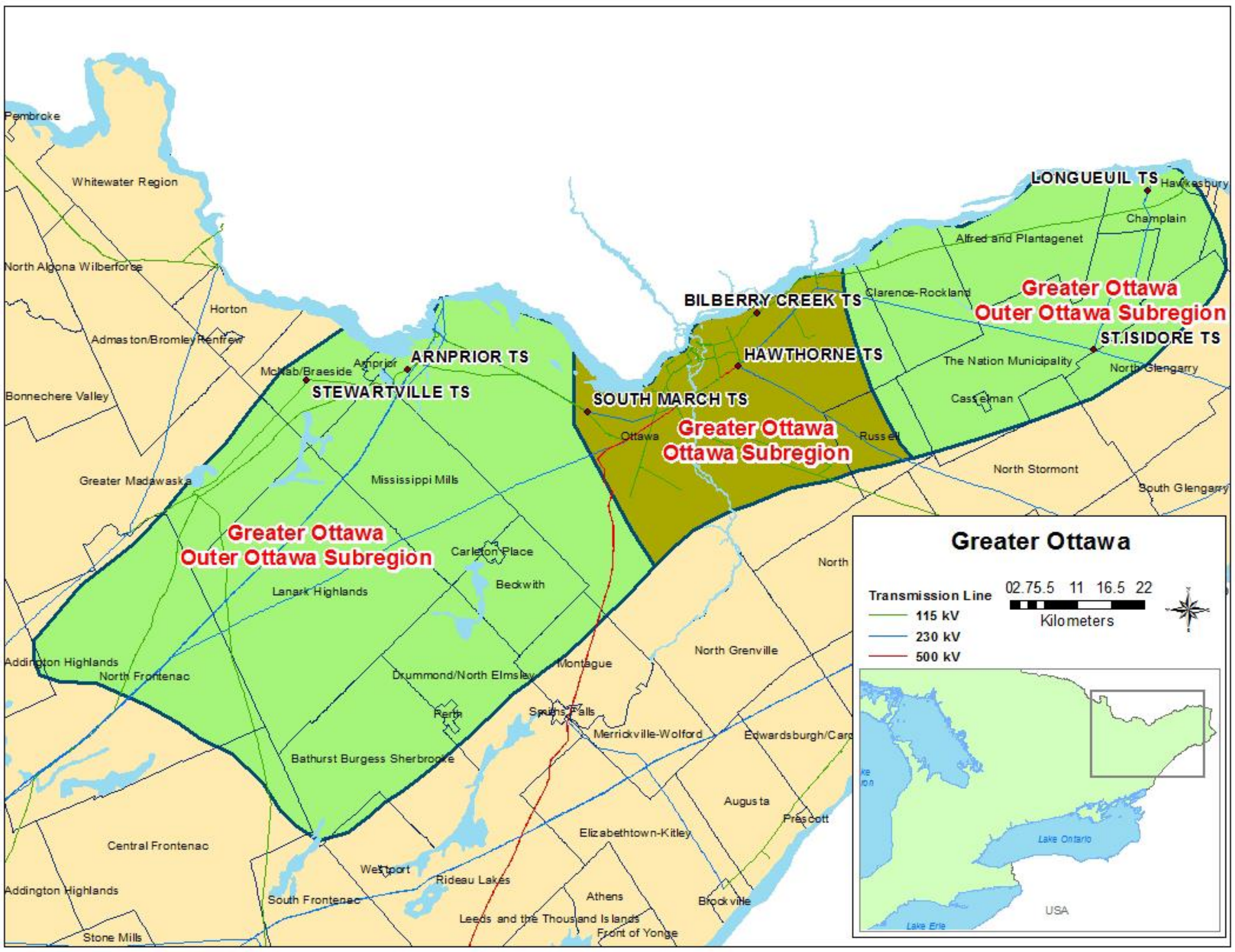


ORPC is also part of the Greater Ottawa region which belongs to Group 1 of the prioritization region. The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Stewartville in the West to Hawkesbury in the East and North of Highway 43 as illustrated in Figure 2-5. At the center 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. As a result, ORPC did not directly participate in the planning process.

Figure 2-5: Greater Ottawa - Regional Planning Group 1



2.2.1.1. Summary of Consultation (5.2.2.a)

Purpose of the 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 also 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.

Other participants in the consultation process:

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.

Effect on the DSP

Renfrew Regional Planning: Since the conclusion of the first cycle of the RIP, no further coordinated regional planning was required, and no explicit investment is planned over the next five years.

Greater Ottawa Regional Planning: The needs identified in the Ontario Power Authority ("OPA")-led Integrated Regional Resource Plan ("IRRP") process or Need Screening ("NS") led by HONI have not identified any significant need that may impact ORPC or result in any cost implications for ORPC[3].

2.2.1.2. Summary of Final Deliverables for the Consultation (5.2.2.b)

Renfrew Region

The RIP report[4] for the Renfrew region was published in July 2016. The report was designed to assess:

- Adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and,

- Adequacy of the transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

The Needs Assessment and RIP Report for the Renfrew Region is attached as Appendix A and B, respectively. From the planning and consultation efforts that were undertaken through this process, it was determined that all stations within this region have sufficient capacity to supply the loads within the studied period under normal and single contingency conditions. Moreover, all transmission circuits also have sufficient capacity under normal and single contingency conditions. It was also determined

[3] "Regional Planning Status Letter – ORPC", Hydro One Networks Inc., November 03, 2014, URL: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Ottawa%20River%20Power%20Corporation%20-%20Planning%20Status%20Letter.pdf

[4] "Renfrew Region – Regional Infrastructure Plan", Hydro One Networks Inc, July 22, 2016, URL: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/renfrew/Documents/RIP%20Report%20-%20Renfrew.pdf

that there are no transmission system reliability issues and no operating issues identified for any one element such as transformers or stations out of service in this region. Based upon the gross coincident demand forecast, the loss of one element will not result in load interruption for more than 150MW based upon the configuration. All of the load within the region can typically be restored within eight hours as per the Ontario Resource and Transmission Assessment Criteria ("ORTAC") requirement for loads under 150 MW.

The first cycle of the Regional Planning Process was completed, and the RIP was published in July 2016. The second cycle of the planning process is currently anticipated to commence in 2021[5].

Greater Ottawa – Ottawa Area Sub-region

In the first cycle of the Regional Planning Process, the RIP identified that the on-going installation of a 230 kV circuit breaker circuit M29C at Almonte TS would improve the reliability of the corresponding section of the circuit. This project was solely initiated and capitalized by HONI. The circuit breaker has been in-service since 2015. The second cycle of the Regional Planning Process has not yet been completed. 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. As a result, ORPC did not directly participate in the planning process.

During the NA for the second cycle of the Regional Planning Process, a potential voltage regulation risk was identified for Almonte TS and Terry Fox MTS. As per the configuration, Almonte TS is required to be radially supplied by Clarington TS in case of opening of Circuit E34M, which is a 290 km line between Clarington TS in Oshawa and Merivale TS in Ottawa. However, studies have shown that Clarington TS will not be able to provide adequate support for Almonte TS and Terry Fox MTS during the peak loading period, which would in turn result in voltages below the minimum allowable levels[6]. The 1st cycle of RIP recommended that Hydro Ottawa to install 20 MVARs of capacitor banks at Terry Fox MTS as it was decided to be adequate for the near term[7]. The 2nd cycle of NA concluded that further assessment of this need would be conducted during the IRRP phase once the load forecast in the Ottawa Area Sub-region has been updated.

The first cycle of the Regional Planning Process was completed, and the RIP was published in December 2015. The second cycle of the planning process has been initiated and the NA have been completed and published in June 2018.

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[5] "EB-2011-0043 –Regional Planning Status Report", Hydro One Networks Inc., 2019 URL: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/Documents/HONI_RegionalPlanningStatusReport_20191101.pdf

[6] "Needs Assessment Report – Greater Ottawa Region", Section 7.3, p.19, Hydro One Networks Inc., June 15, 2018, URL: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Greater%20Ottawa%20Needs%20Assessment%202018.pdf

[7] "Regional Infrastructure Plan – Greater Ottawa Region", Section 7.13.2, p.45, Hydro One Networks Inc., December 02, 2015, URL: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/RIP%20Report%20Greater%20Ottawa.pdf

Role of ORPC in Greater Ottawa Regional Planning
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. As a result, ORPC did not directly participate in the planning process.

Relevant Documents in the Process (5.2.2.c)

Renfrew Region
Study team participants, including representatives from ORPC, the IESO, and HONI provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation, and demand management ("CDM") and distributed generation ("DG") information, load restoration data, and performance information including major equipment approaching end-of-life. During the NA started in 2015, ORPC provided 2012-2014 net loads and gross load forecasts for 2015-2024 for each station. Planned distribution investments (forecast period in the last DSP) were also provided to the study team.

Greater Ottawa Region
ORPC did not directly participate in the planning process.

2.2.2. IESO Comment Letter (5.2.2d)

ORPC has requested and received a comment letter from the IESO regarding:

- Status update on regional planning actions
- ORPC REG investment plans.

ORPC's report on REG Investments and the Comment Letter from the IESO is attached in Appendix C. As discussed in the REG investment report, due to upstream capacity constraints at HONI-owned stations, ORPC is unable to accommodate new REG connections beyond 10 kW. Moreover, ORPC does not currently have any FIT or net metering connections installed within its service territories. As applications are no longer being accepted for new microFIT connections, ORPC does not anticipate any new REG connections over the next five-year (2022 to 2026) DSP planning period and does not propose any REG-related investments during this period.

2.2.3. Coordination with 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 of 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.

2.2.3.1. Coordination with Corporation of the Municipality of Mississippi Mills

The Municipality is anticipating estimated population growth in the Almonte Ward to reach to 2,785 residents. The majority of growth is expected to occur within the Urban boundary where several vacant residential sites have existed. These sites are indicated as Parcel A, B, C, and D in the official plan illustrated in Figure 2-6. There will also be the continued development of employment land within the urban boundary that will be used by a mix of institutional, commercial, or industrial activities. However, from the context of Mississippi Mills, the employment land is anticipated to operate within a light use framework.

2.2.3.2. Coordination with Township of Killaloe, Hagarty, and Richards

The township currently has one project in the Village of Killaloe for an addition to the Killaloe library to increase the area by 1,125 sq. ft. The only other development that the township is anticipating is the building of a new Fire Hall which will not be located directly within the Village of Killaloe.

2.2.3.3. Coordination with Township of Whitewater Region

The population of the Whitewater region grew steadily by 1.3% between 2011 and 2016, from 6,921 to 7,009, or by 88 customers, and it grew by 7.5% or 489 customers between 2001 and 2016. The overall growth potential of any area is generally defined by the availability of economic or export-based jobs. As of 2016, 39% of the total jobs available within the Township of Whitewater Region is economic-based agriculture and manufacturing jobs. The township has seen a gradual decline in these economic-based jobs and is anticipated to decline further in the future.

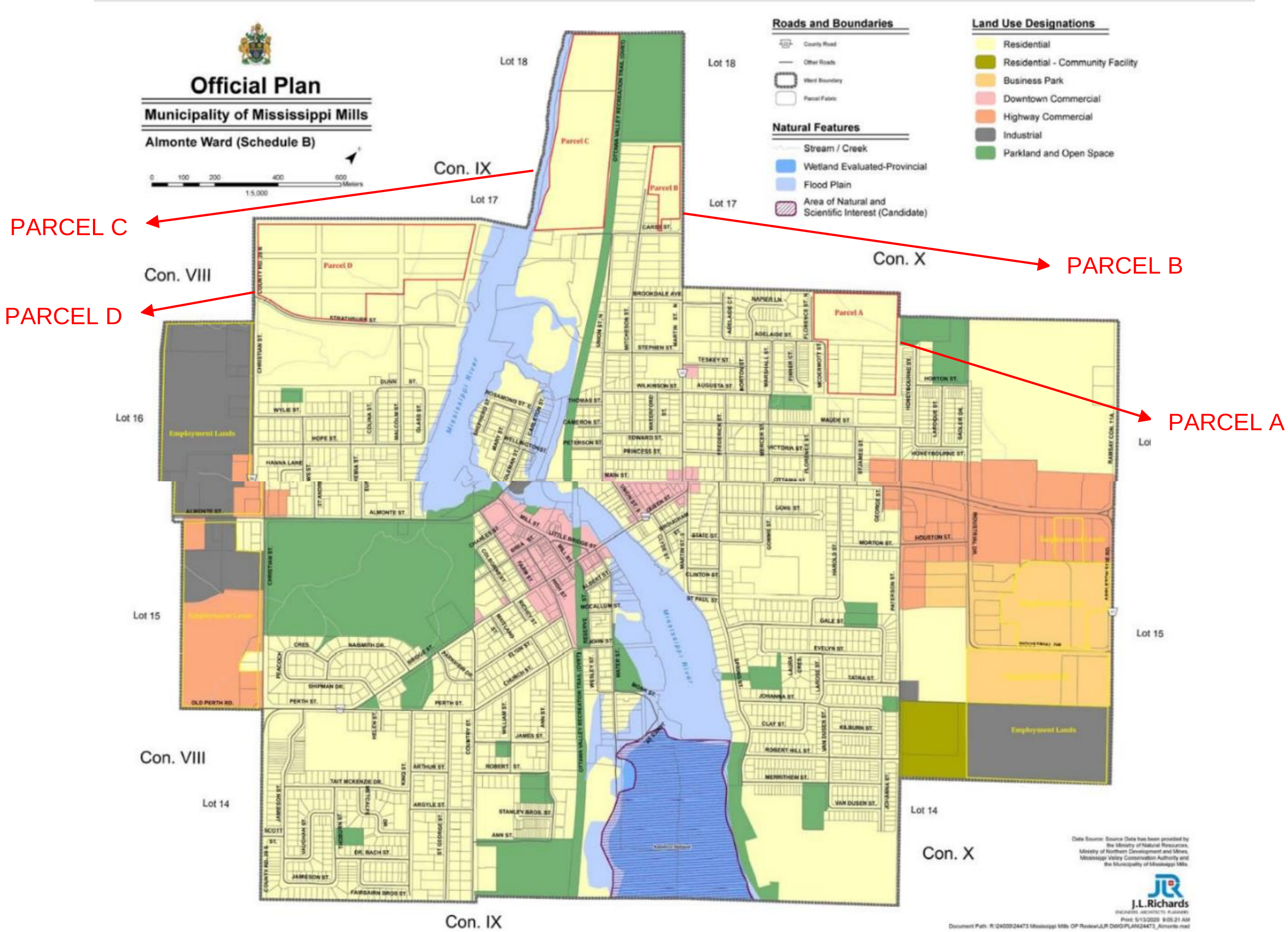
2.2.3.4. Coordination with the City of Pembroke

ORPC held consultations with the City of Pembroke concerning its planning works on Pembroke Street West that require the relocation of poles owned by ORPC. ORPC actively participated in this consultation to understand the scope of work and its implication to the ORPC distribution system. As part of the engagement, ORPC also provided cost estimates to the City of Pembroke such that the required relocation to be completed in a safe, environmentally friendly, reliably, timely, and cost-effective manner. The project scope involves the upgrade of traffic signals, widening of boulevards, installation of AODA lights, and others. Overall, the project will be carried out in the following four phases:

- Phase 1 – City Limits to Crandall Street (carried out in 2020 & 2021)
- Phase 2 – Crandall Street to Reynolds Ave (carried out in 2020 & 2021)
- Phase 3 – Reynold’s Ave to Miramichi
- Phase 4 – Miramichi to Christie Street

This consultations from the city eventually directed the ORPC’s capital expenditure planning for system access investments in the forecast period (2022 to 2026). As part of ORPC’s investment strategy, the information derived from this engagement has been used to pace and prioritize a program called Externally Initiated Plant Relocation which is specifically aimed towards accommodating 3rd-party infrastructure development requirements.

Figure 2-6: Official Growth Plan for the Municipality of Mississippi Hills



2.3. Performance Measurement for Continuous Improvement (5.2.3)

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 2-5 provides the desired outcomes for measures associated with each of the three groups. The purpose of this section is to address performance measures as 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 2-5: DSP Performance Measures

Performance Outcome	Measure	Driver	Metric	Desired Outcome
Customer-Oriented Performance	System Reliability	Regulatory/ Customer	SAIDI	<1.92
			SAIFI	<1.22
	Customer Satisfaction	Customer	Customer Satisfaction Survey Results	75%
	Service Quality	Regulatory/ Customer	New Residential / Small Business Services Connected on Time	≥90%
			Telephone Calls Answered on Time	≥65%
			Scheduled Appointments Met on Time	≥90%
Cost Efficiency and Effectiveness	DSP Implementation Progress	Regulatory/ Corporate	DSP Progress Variance	±10%
	Cost Control	Regulatory/ Customer	Total Cost per Customer	≤ 10%
			Total Cost per Km of Line	≤ 10%
			O&M Cost per Customer	≤ 20%
			O&M Cost per Km of Line	≤ 20%
			O&M Cost of KW	≤ 35%
Asset/System Operations Performance	Safety	Regulatory/ Corporate	Level of Compliance with Ontario Regulation 22/04	0 NC; 0 NI
			Serious Electrical Incident Index	0
	System Performance	Corporate	System losses	5% or less

2.3.1. Customer-Oriented Performance

ORPC monitors customer-oriented performance in terms of service quality, system reliability, and customer satisfaction.

2.3.1.1. Service Quality

2.3.1.1.1. Methods and Measures

ORPC on an annual basis reports service quality requirements as stated within Section 7 of the DSC[8]. 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 in order 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.

2.3.1.1.2. Historical Performance

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 2-6 represents the focus areas and their measures and for tracking ORPC's performance in the service quality category.

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[8] "Distribution System Code", Section 7, p. 128, Ontario Energy Board, March 1, 2020 , URL: https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2020-03/Distribution-System-Code-20200301-02.pdf

Table 2-6: Historical Service Quality Performance

Measures	Sub-Measures	2015 (%)	2016 (%)	2017 (%)	2018 (%)	2019 (%)	2020 (%)	OEB Minimum Standard
New Residential / Small Business Services Connected on Time	Low Voltage Connections	100	100	98.57	100	100	100	**≥90%**
	High Voltage Connections	N/A	N/A	100	100	N/A	N/A	**≥90%**
	Reconnection Performance Standard	100	100	100	100	100		**>85%**
Telephone Calls Answered on Time	Telephone Accessibility	99.90	99.90	99.87	99.92	99.95	97.63	**≥65%**
	Telephone Call Abandon Rate	0.10	N/A	N/A	N/A	0.05	2.37	**≤10%**
Scheduled Appointments Met on Time	Appointments Met	100	100	99.14	98.64	98.15	98.29	**≥90%**
	Appointment Scheduling	100	99.60	99.85	99.81	97.94	98.04	**≥90%**
	Rescheduling Missed Appointments	N/A	N/A	100	100	100	100	**>100%**
Written Response to Enquiries		98.8	100	100	100	100	96.63	**≥80%**
Emergency Response	Urban	98.4	100	100	100	100	100	**≥80%**
	Rural	N/A	100	100	100	N/A	N/A	**≥80%**

2.3.1.1.3. Effect on the DSP

ORPC has exceeded the industry targets for each service quality measure. ORPC's performance on these measures indicates that no substantial additional material projects are required for investments in this area. ORPC continues to strive for continuous improvements and to serve the customer with the highest excellence. ORPC intended action for these measures is to maintain the performance.

2.3.1.2. Customer Satisfaction

2.3.1.2.1. Methods and Measures

ORPC measures and reports on customer satisfaction measures which include:

- First Contact Resolution;
- Billing Accuracy; and
- Customer Satisfaction Survey Results.

First Contact Resolution:

The OEB requires LDCs to report on their success at meeting customers' needs the first time the LDC is contacted. This metric is known as the First Contact Resolution. For ORPC, First Contact Resolution has measured the number of customer inquiries that are resolved by the first contact at the utility, and therefore not resulting in the inquiry being escalated to an alternate contact from ORPC, which would typically be a supervisor or a manager.

Billing Accuracy:

The OEB prescribes a measurement of Billing Accuracy which must be used by all LDCs. The measure has been defined as the number of accurate bills issued which is expressed as a percentage of total bills issued.

Customer Satisfaction Survey:

Engaging customers in a constantly changing energy environment is increasingly important. ORPC undertakes surveys to receive feedback from its customer regarding the overall value of services delivered by ORPC. ORPC retained consultant Redhead Media Solutions Inc. to conduct its most recent customer satisfaction survey in 2021.

The objective of the survey is to provide an Overall Customer Satisfaction Index ("CSI") score for ORPC. The score was calculated by aggregating values based on the responses received from its low volume customer base such as residential and GS < 50 KW customers.

2.3.1.2.2. Historical Performance

The historical performance of the Customer Satisfaction measure is represented in Table 2-7. The results indicate that ORPC has consistently exceeded the Billing Accuracy industry target of 98% with an average Billing Accuracy of 99.97% over the past six years (2015-2020). ORPC's average performance for First Contact Resolution was 98.43% over the historical period, while Customer Satisfaction Survey Results were 79.30% on average as shown in Table 2-8. Based upon the historical performance as captured by the survey results, ORPC will be using the target of 75% for Customer Satisfaction Survey Results as it is indicative of realistic target for ORPC during its upcoming rate filing applications.

Table 2-7: Performance Measures – Customer Satisfaction

Measure	2015	2016	2017	2018	2019	2020
First Contact Resolution	97.5%	98.2%	98.8%	98.5%	98.60%	99.0%
Billing Accuracy	100.00%	99.99%	99.98%	99.90%	99.96%	99.97%
Customer Satisfaction Survey Results	Satisfied	78.8%	78.8%	80.3%	80.3%	81.0%

Table 2-8: Customer Satisfaction Survey Results

Target Low Volume Customer Base	2017		2019		2021	
	Customers	CSI Score	Customers	CSI Score	Customers	CSI Score
Residential customers	370	78.70%	364	80.20%	362	81.00%
GS < 50 KW customers	30	80.60%	36	80.70%	40	79.00%
Total	**400**	**78.80%**	**400**	**80.30%**	**402**	**81.00%**

2.3.1.2.3. Effect on DSP

ORPC's 2021 Customer Satisfaction Index Score is 81.0%, This is a 1.5% increase over the 2017 results (78.8%) and just under 1% increase from 2019 results. The survey results indicated that ORPC's customers have an increasing level of satisfaction with the quality of service that they are receiving from the utility. As part of continuous improvements, ORPC reviews the results from their customer satisfaction surveys in order to determine the extent of corporate programs, projects, and strategies that may require adjustment. The overall score is an indication of ORPC's performance in meeting customer expectations related to safety, reliability, and ORPC response time for connections, appointments, and inquiries.

2.3.1.3. System Reliability

2.3.1.3.1. Methods and Measures

The reliability of supply is primarily measured by the internationally accepted indices System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") as defined within the OEB's Electricity Reporting & Record-Keeping Requirements dated March 31, 2020[9]. SAIDI represents the length of outage customers experience in the year on average, expressed as hours per customer as shown in Equation 2-1, and is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI represents the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer as shown in Equation 2-2. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered a sustained interruption if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served} \qquad (EQ\ 2\text{-}1)$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served} \qquad (EQ\ 2\text{-}2)$$

To meet the reporting requirements, ORPC also considers the impacts of other defined parameters such as Loss of Supply ("LOS") and Major Event Days ("MED") to calculated adjusted values of reliability indices. LOS is defined as an interruption that is caused due to a problem and/or failure of assets owned and/or operated by another party, and/or in the bulk electricity supply system. Similarly, MED is defined as an event that is beyond the control of ORPC and is unforeseeable, unpredictable, unpreventable, and unavoidable. MEDs are calculated using the IEEE STD 1366-2012 methodology.

2.3.1.3.2. Historical Performance

ORPC's 2015 to 2020 reliability indices due to all causes, excluding LOS, and excluding LOS and MEDs are presented in Figure 2-7 and Figure 2-8 respectively.

The operational effectiveness section of the OEB Scorecard shows ORPC's continuous improvement in productivity and cost performance, along with reliability and quality objectives. ORPC's reliability indices, excluding LOS and MEDs, over the historical period are presented in *Table 2-9*. For comparison purposes, this table also includes the average for each reliability metric both with and without MEDs and LOS.

Excluding LOS events and MEDs, ORPC's reliability performance in recent years demonstrates an improvement trend. On average, an ORPC customer experiences one outage per annum and without power for 1.55 hours. In the summer of 2015, a significant storm resulted in widespread damages within the Pembroke service area, resulting in longer than average interruptions for large sections of the city. Assets in the sub transmission system were initially affected by foreign interference, later resulted in unplanned and scheduled outages due to defective components. Both causes contributed to 2015 SAIFI & SAIDI performance being worse than their targets. However, since this time, the

[9] "Electricity Reporting and Record Keeping Requirements", Section 2.1.4.2, p. 9, Ontario Energy Board, March 31, 2020. URL: https://www.oeb.ca/sites/default/files/RRR-Electricity-20200331.pdf

reliability of ORPC's system had greatly improved. Both SAIDI and SAIFI for the remaining historical period were favourable with respect to its target with respect to excluding LOS and MED.

Figure 2-7: Historical SAIDI Performance

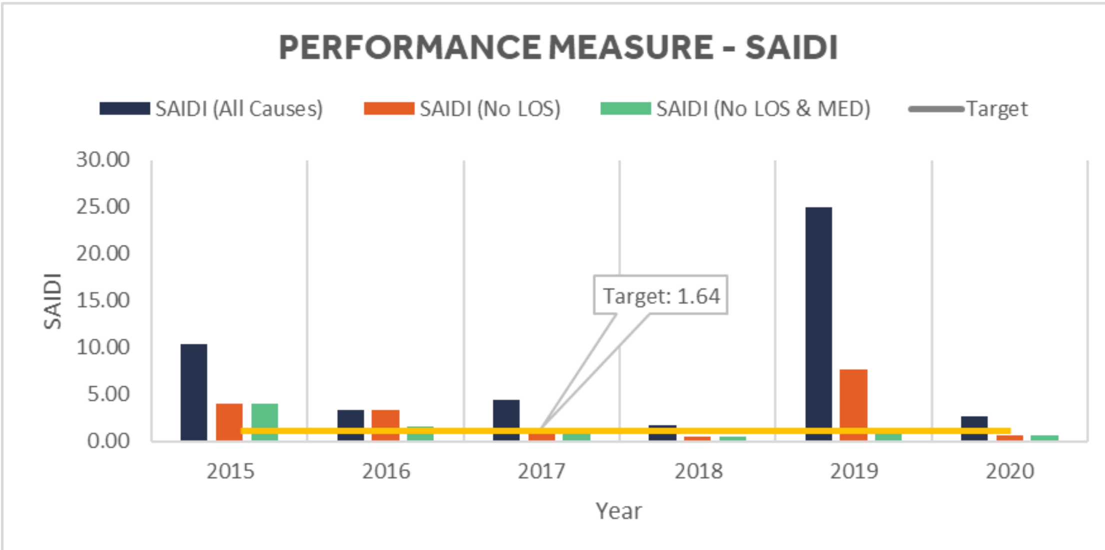


Figure 2-8: Historical SAIFI Performance

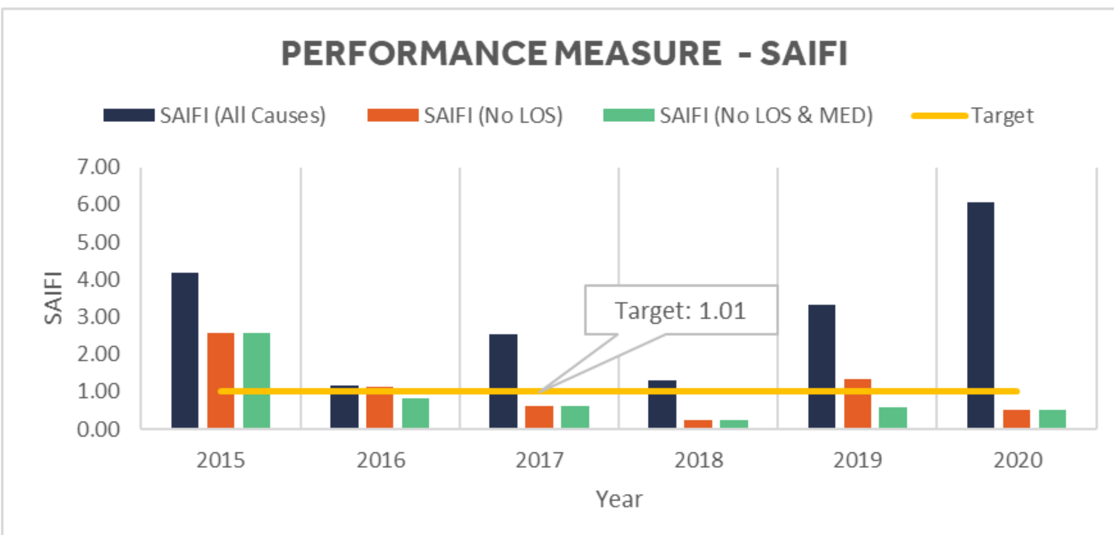


Table 2-10 summarises the number of outages that have occurred within ORPC's service territory. Notwithstanding the positive results from the comparative perspective discussed above, the table highlights an increasing trend of outages experienced within ORPC's service territory, excluding MED and LOS outages. Further breakdown of these outages is provided in the following sections.

Table 2-9: 2015 to 2020 Reliability Performance Metrics

Metric	Exclude MED & LOS								Include MED & LOS
	Target	2015	2016	2017	2018	2019	2020	Average	Average
SAIDI	1.64	3.95	1.55	0.95	0.53	0.79	0.56	1.39	7.90
SAIFI	1.01	2.56	0.84	0.62	0.24	0.59	0.53	0.9	3.10

Table 2-10: Number of Outages (2015-2020)

Categorization	2015	2016	2017	2018	2019	2020
All interruptions	41	35	72	145	127	128
All interruptions excluding LOS	36	34	65	135	124	120
All interruption excluding MED and LOS	34	33	65	135	119	120

Description of MEDs

In addition, ORPC's system has experienced MEDs in 2015, 2016, and 2019 within the historical period from 2015 onwards to 2020. During this period, *Loss of Supply* introduced the majority of the MEDs – with interruptions exceeding 220,000 customer hours. *Table 2-11* summarizes the impact of MEDs in terms of number of interruptions, customer interruptions ("CI") and customer hours of interruptions ("CHI"). *Table 2-12* lists the details of each identified MED.

Table 2-11: MEDs by Cause Code (2015-2020)

Major Events Details	2015	2016	2017	2018	2019	2020
Number of Interruptions						
2 - Loss of Supply	1	-	-	-	3	-
6 - Adverse Weather	-	1	-	-	-	-
7 - Adverse Environment	-	-	-	-	1	-
8 - Human Element	-	-	-	-	1	-
Number of Customer Interruptions						
2 - Loss of Supply	7,140	-	-	-	22,510	-
6 - Adverse Weather	-	3,429	-	-	-	-
7 - Adverse Environment	-	-	-	-	7,372	-
8 - Human Element	-	-	-	-	1,215	-
Number of Customer Hours of Interruptions						
2 - Loss of Supply	30,955	-	-	-	196,786	-
6 - Adverse Weather	-	19,313	-	-	-	-
7 - Adverse Environment	-	-	-	-	77,406	-
8 - Human Element	-	-	-	-	809	-

Table 2-12: List of MEDs over the Historical Period

Date	Customer Interrupted	Description
27-Jul-15	7130	4.3hrs, Pembroke, 2-Loss of Supply
27-Jul-15	10	5.8hrs, Pembroke, 2-Loss of Supply
20-Jun-16	310	4.2hrs, Pembroke, 6-Adverse Weather
21-Jun-16	3119	17.8hrs, Pembroke, 6-Adverse Weather
2-Jan-19	7372	10.5hrs, Pembroke, 7-Adverse Environment
30-Jan-19	7372	7.3hrs, Pembroke, 2-Loss of Supply
13-Aug-19	8000	14.5hrs, Pembroke /Killaloe/Beachburg, 2-Loss of Supply
10-Oct-19	1215	0.7hrs, Pembroke, 8-Human Element
14-Dec-19	7138	3.8hrs, Pembroke, 2-Loss of Supply

Figure 2-9 presents the summation of outages experienced at ORPC. Table 2-13 presents the quantity of outages broken down by cause code. The top three cause codes ranked by percentage share over the historical period are *Scheduled Outage, Defective Equipment*, and *Foreign Interference*.

Figure 2-9: Historical Number of Outages at ORPC

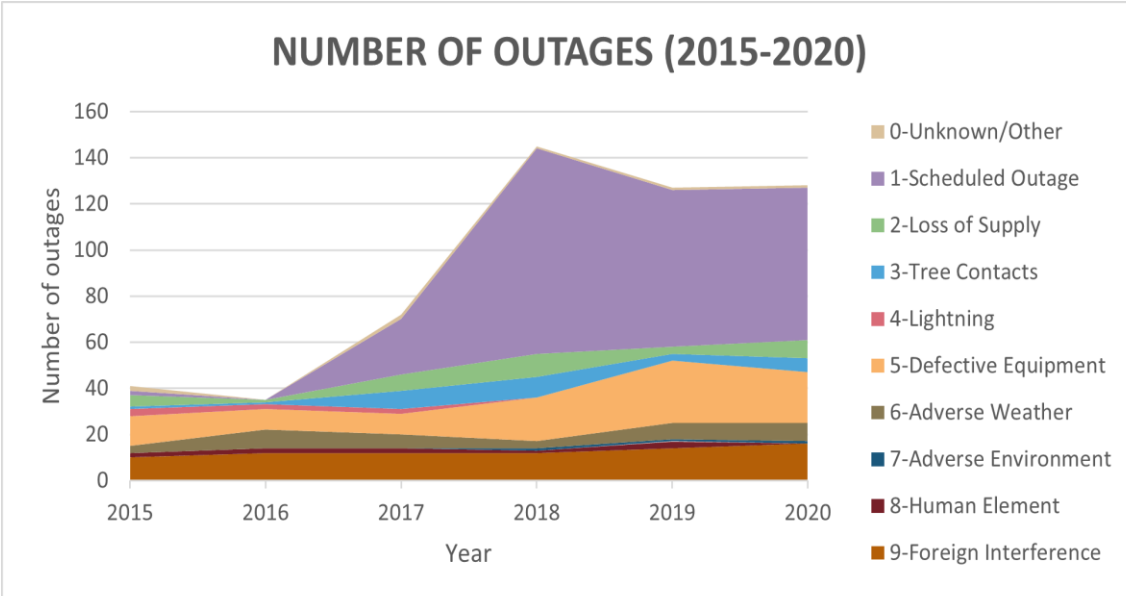


Table 2-13: Number of Outages by Cause Codes (2015-2020)

Cause Code	2015	2016	2017	2018	2019	2020	Total Outages	%
0-Unknown/Other	2	-	2	1	1	1	7	1%
1-Scheduled Outage	2	-	24	89	68	66	249	45%
2-Loss of Supply	5	1	7	10	3	8	34	6%
3-Tree Contacts	1	1	8	9	3	6	28	5%
4-Lightning	3	2	2	-	-	-	7	1%
5-Defective Equipment	13	9	9	19	27	22	99	18%
6-Adverse Weather	3	8	6	3	7	8	35	6%
7-Adverse Environment	-	-	-	1	1	1	3	1%
8-Human Element	2	2	2	1	3	-	10	2%
9-Foreign Interference	10	12	12	12	14	16	76	14%

Figure 2-10 illustrates the summation of CI within ORPC's system over the historical period from 2015 onwards to 2020. Table 2-14 further details the numbers of customers interrupted by cause code. The top three cause codes ranked by percentage share over the historical period include *Loss of Supply, Defective Equipment*, and *Foreign Interference*.

Figure 2-10: Historical ORPC Customers Interrupted

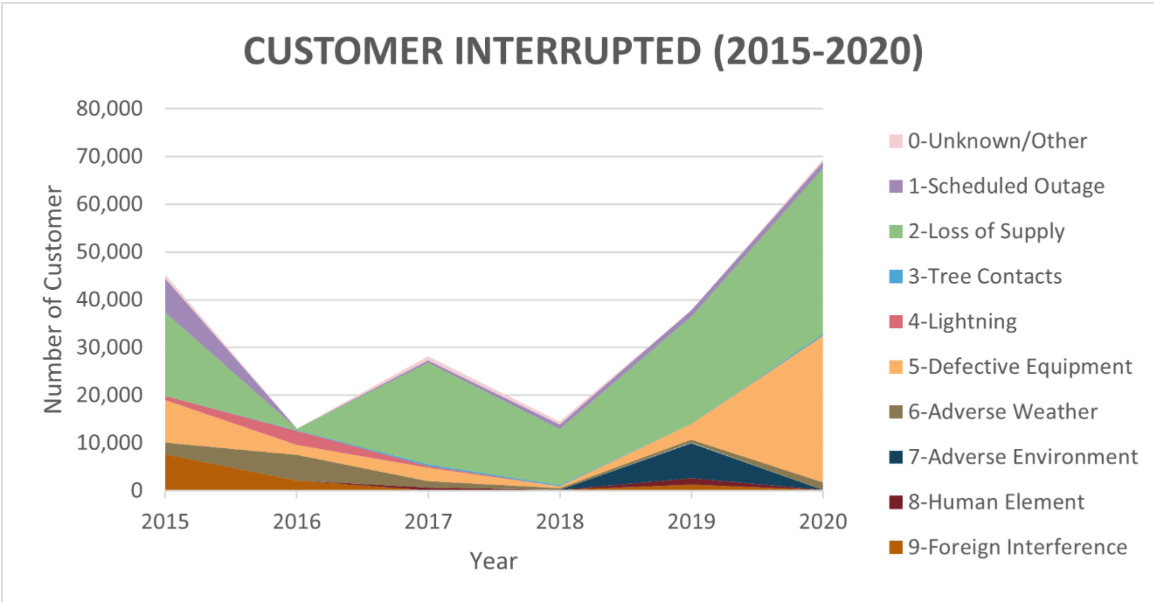


Table 2-14: Customers Interrupted by Cause Codes (2015-2020)

Cause Code	2015	2016	2017	2018	2019	2020	Total CI	%
0-Unknown/Other	875	-	850	650	45	523	2,943	1%
1-Scheduled Outage	7,150	-	456	913	1,244	1,283	11,046	5%
2-Loss of Supply	17,470	376	21,363	11,750	22,510	34,751	108,220	52%
3-Tree Contacts	6	14	283	203	60	364	930	0%
4-Lightning	827	3,009	425	-	-	-	4,261	2%
5-Defective Equipment	8,836	2,093	2,838	424	3,207	30,684	48,082	23%
6-Adverse Weather	2,513	5,294	1,276	305	728	1,548	11,664	6%
7-Adverse Environment	-	-	-	15	7,372	77	7,464	4%
8-Human Element	4	31	586	21	1,357	-	1,999	1%
9-Foreign Interference	7,616	2,144	100	196	1,286	154	11,496	6%

Figure 2-11 presents the summation of customer hours interrupted at ORPC. *Table 2-15* details the customer hours interrupted by cause code over the historical period. The top three cause codes ranked by percentage share over the historical period are *Loss of Supply, Adverse Environment*, and *Scheduled Outage*. There was a big increase in the number of hours customers were interrupted due to Loss of Supply in 2019 due to a major outage affecting multiple customers.

Figure 2-11: Historical ORPC Customer Hours Interrupted

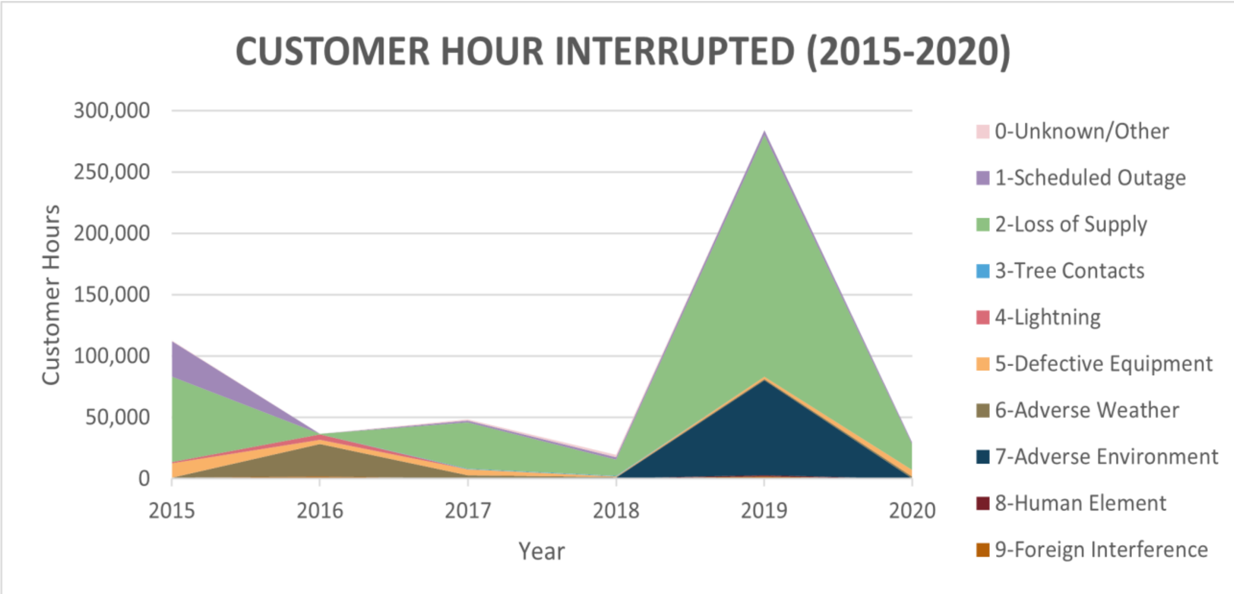


Table 2-15: Customer Hours Interrupted (rounded) by Cause Codes (2015-2020)

Cause Code	2015	2016	2017	2018	2019	2020	Total CHI	%
0-Unknown/Other	572	-	742	2,002	21	26	3,363	1%
1-Scheduled Outage	28,570	-	1,369	1,586	3,785	1,853	37,163	7%
2-Loss of Supply	69,604	496	37,715	13,474	196,786	20,871	338,946	64%
3-Tree Contacts	51	4	552	572	102	257	1,538	0%
4-Lightning	858	4,460	278	-	-	-	5,596	1%
5-Defective Equipment	11,775	3,375	4,903	268	1,962	5,077	27,360	5%
6-Adverse Weather	182	26,586	2,188	798	868	1,702	32,324	6%
7-Adverse Environment	-	-	-	124	77,406	151	77,681	15%
8-Human Element	16	66	246	68	1,081	-	1,477	0%
9-Foreign Interference	907	1,790	195	530	1,964	116	5,502	1%

2.3.1.3.3. Effect on DSP

The cause code that introduced the greatest contributions – 51% towards CI and 64% towards CHI respectively is Loss of Supply, which is out of ORPC's direct control. The System Enhancement program has been proposed to further reinforce the key supply points between HONI and ORPC's service areas, thereby managing the security of supply. Further details of this program are described in Section 7.1. A significant number of outages and CI can also be attributed to the Defective Equipment category. Investment programs within the System Renewal category, including Underground, Overhead, and Stations Renewal – further described in Sections 6.1, 6.2, and 6.3 respectively – have allocated a total of $3.61M over the DSP planning period to replace assets at, approaching or exceeding their TUL, and/or assets in Poor or Very Poor condition.

Although 15% towards CHI was attributed to the Adverse Environment cause code, this was mainly due to a rare incident that occurred in 2019 (a fire affecting sub-transmission lines). Such an event was unpredictable and out of ORPC's control.

Additional investments are planned over the next five years to address system reliability. SCADA is installed in the substation to support real-time control of the system from ORPC's control room. When a fault occurs, staff can quickly pinpoint the incident location and isolate the faulted circuit to reduce the impact on the system. Hence, ORPC has planned to refurbish the SCADA system due to obsolescence of system and reduction in number of available spare parts. Details of the SCADA system upgrades can be found in Section 7.2.

2.3.2. Cost Efficiency and Effectiveness

2.3.2.1. Cost Control

2.3.2.1.1. Methods and Measures

Total cost per customer is calculated as the sum of ORPC's capital and operating costs and dividing this cost figure by the total number of customers that the utility serves as shown in Equation 2-3.

$$\textbf{Total Cost per Customer} = \frac{\sum \textbf{Capital \& Operating costs}}{\textbf{Number of customer served}} \qquad \text{(EQ 2-3)}$$

ORPC collects the trend data on the cost per kilometer of line as well. The total cost per kilometer of line is calculated as the sum of ORPC's capital and operating costs divided by the total kilometers of line in service at ORPC as shown in Equation 2-4.

$$\textbf{Total Cost per Kilometer of Line} = \frac{\sum \textbf{Capital \& Operating costs}}{\textbf{Kilometers of line}} \qquad \text{(EQ 2-4)}$$

Additionally, ORPC has begun tracking additional metrics as recently introduced in OEB's Filing Requirements. This includes the O&M Cost Per Customer, O&M Cost per Kilometer of Line, and the O&M Cost per KW of Peak Capacity. The metrics are calculated with the total recoverable O&M costs divided by the respective number for each metric is defined in Equations 2-5, 2-6 and 2-7 respectively.

$$\textbf{O\&M / Customer} = \frac{\sum \textbf{O\&M Cost}}{\textbf{Number of customer served}} \qquad \text{(EQ 2-5)}$$

$$\textbf{O\&M Cost / Kilometer of Line} = \frac{\sum \textbf{O\&M Cost}}{\textbf{Kilometers of line}} \qquad \text{(EQ 2-6)} \text{ ed}$$

$$\textbf{O\&M Cost / Average Peal Capacity} = \frac{\sum \textbf{O\&M Cost}}{\textbf{Average Peak Capacity(KW)}} \qquad \text{(EQ 2-7)}$$

2.3.2.1.2. Historical Performance

Figure 2-12 presents the total cost per customer over the historical years while Figure 2-14 presents the O&M cost per customer. ORPC's total cost per customer and O&M cost per customer has shown steady trends until 2017. From 2017 to 2018, the O&M cost per customer showed a temporary decline of 23% which is a decrease in cost from $113.2 per customer to $87.5 per customer. This decline is attributed to multiple vacancies including two front office staff maternity leaves and a vacant engineering and management position. In 2019, O&M cost per customer increased and returned to its historical average as vacant positions started to fill.

Figure 2-13 presents the total cost per km of line over the historical years while Figure 2-15 presents the O&M cost per km of line. Both Total Cost per km as well as O&M per km of lines have seen steady trends from 2014 to 2016. After 2016, there has been a major reduction in both costs per km due to the reassessment of actual underground and overhead circuit length as part of continuous improvements to GIS data. These improvements have resulted in an updated combined underground and overhead circuit length from 178 km in 2016 to 490 km in 2017 and further refined to 510 km in 2019.

Figure 2-12: Performance Measure - Total Cost per Customer

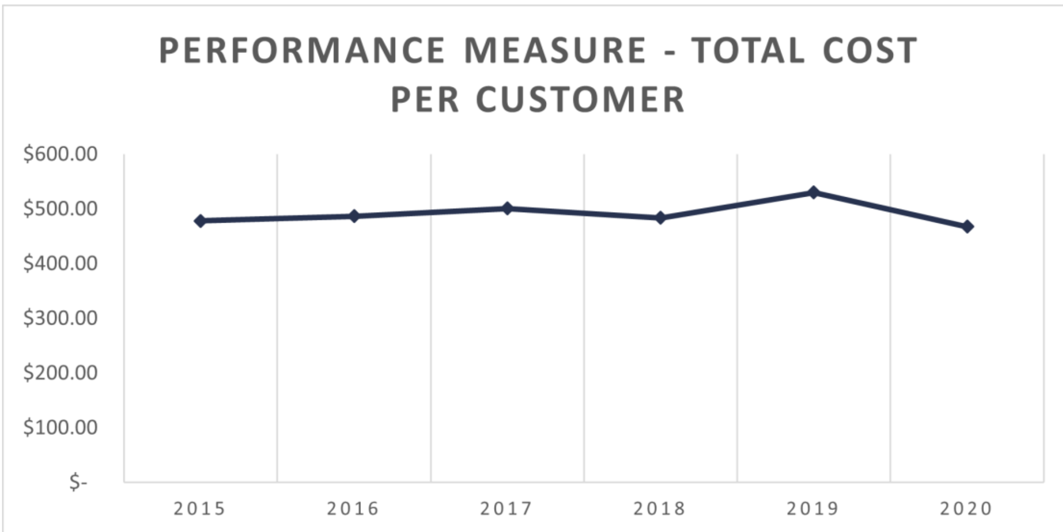


Figure 2-13: Performance Measure - Total Cost per Kilometer of Line

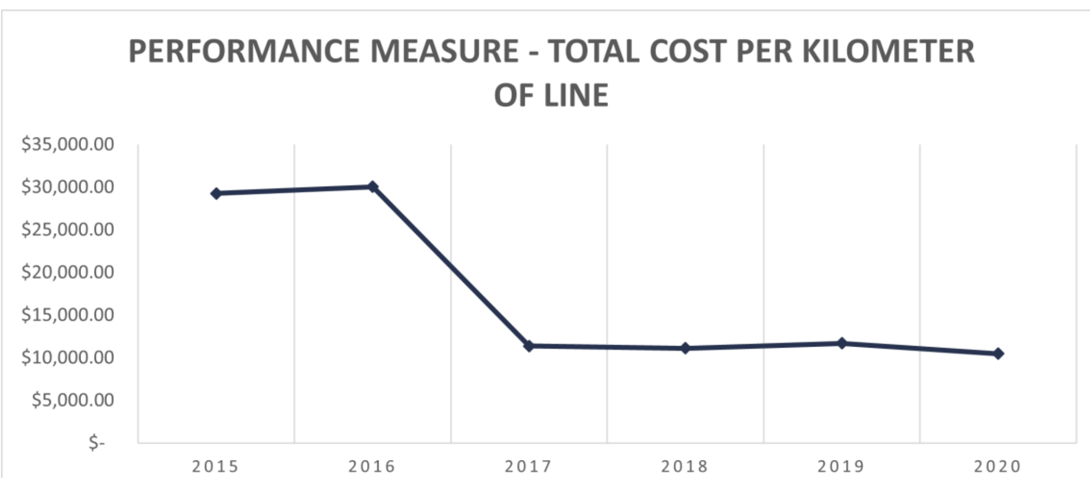


Figure 2-14: Performance Measure - O&M Cost per Customer

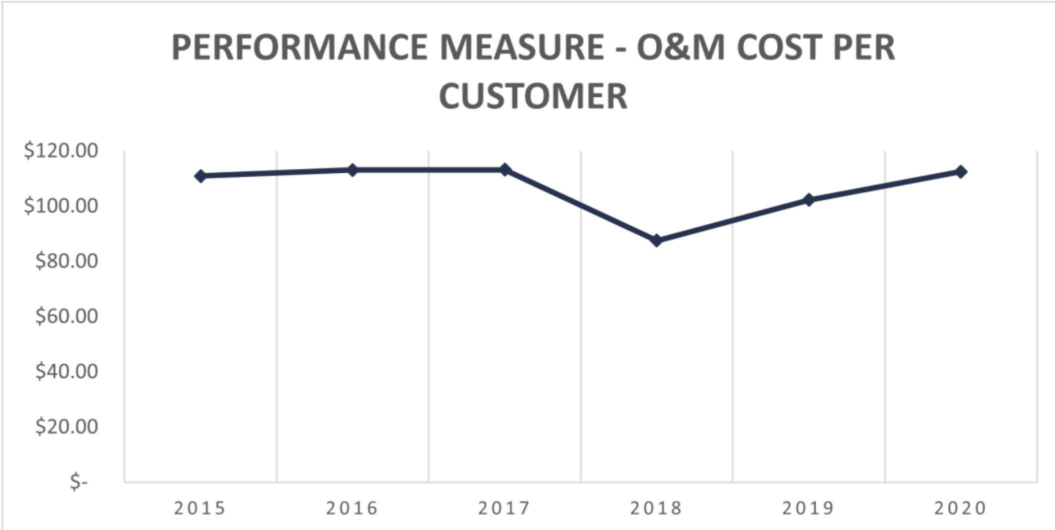


Figure 2-15: Performance Measure - O&M Cost per Kilometer of Line

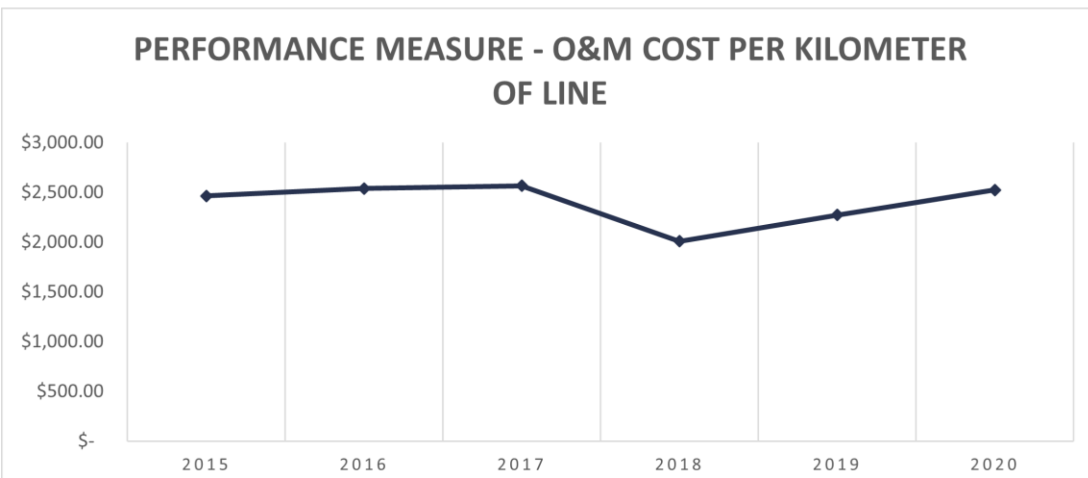
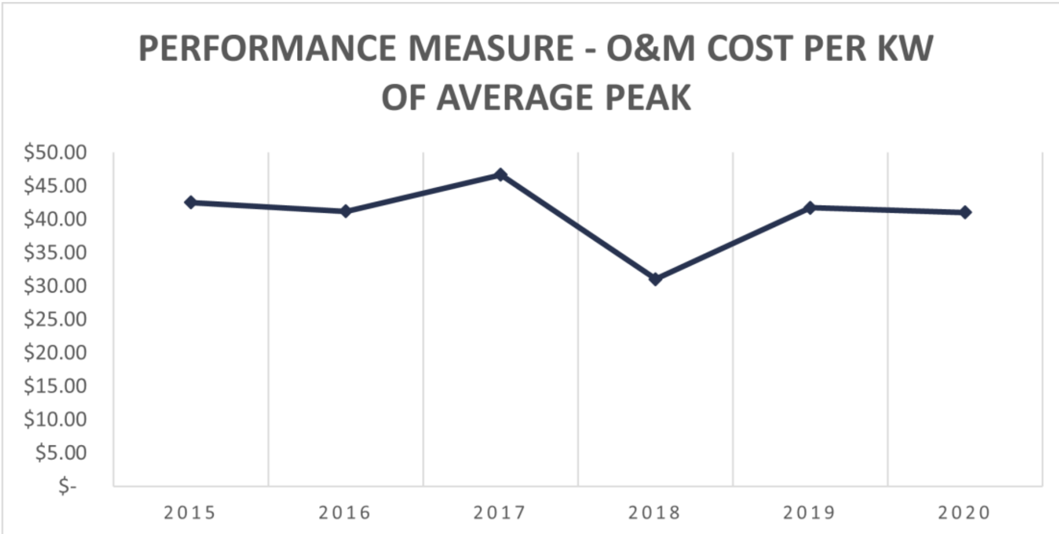


Figure 2-16: Performance Measure - O&M Cost per kW of Average Peak



2.3.2.1.3. Effect on the DSP

ORPC continues to seek ways to introduce cost savings and efficiencies within the organization. As discussed in Section 3.1, ORPC's asset management process is cyclical in nature, allowing for continuous improvements with respect to input data, decision-making, and ultimately improvements to the investments implemented within the system. By proactively replacing equipment prior to failure, ORPC is able to avoid the potential reactive costs and outage impacts to customers. As ORPC executes their capital investment plan, these performance measures will be continually monitored for capture a better understanding between these measures and their influence on capital and maintenance investments.

Total Cost per Customer

The target of ≤ 10% has been proposed. The target is proposed on the basis of the maximum of year-over-year variance observed within this metric during the historical period (2015 to 2019).

Total Cost per km of Line and O&M Cost per km of Line

Due to improvements with respect to GIS data, the circuit length data has been updated during the historical period. The circuit length data was updated from 178 km in 2016 to 490 km in 2017. Due to continuous data improvements, the circuit length was further revised from 490 km to 510 km in 2019. Since the change in circuit length was entirely due to improvements in data collection and within the GIS, the target has been selected by considering 510 km as the actual circuit length throughout the historical period (2015 to 2019) and recalculating the total and O&M costs per km of line. The target is then calculated based on the maximum of year over year variance observed during the historical period.

Based on the analysis carried out, ORPC will be using the target of ≤ 10% and ≤ 20% for total cost per km of line and O&M cost per km of line, respectively.

O&M Cost per Customer

The target of ≤ 20% has been proposed. The target is proposed on the basis of maximum of year over year variance observed in this metric during the historical period (2015 to 2019).

O&M Cost of KW

The target of ≤ 35% has been proposed. The target is proposed on the basis of maximum of the year over year variance observed in this metric during the historical period (2015 to 2019).

2.3.2.2. DSP Progress Variance

2.3.2.2.1. Methods and Measures

Going forward for the 2022-2026 DSP period, on a semi-annual basis, ORPC will review actual capital expenditures to date and will forecast total expenditures to year-end. When the year-end forecast is found to be materially higher in cost when compared to the budget, ORPC will review their projects to determine if certain projects can be deferred to a later year or if the scope of work within these projects can be reduced. Mandatory projects within a given year will not be subjected to this deferral procedure.

ORPC will calculate for each year, and on a cumulative basis for the five years of the DSP, its actual capital spending when compared to the approved capital budget. ORPC's target for this measure is for DSP actual spending to be within 10% of the approved DSP capital budget.

2.3.2.2.2. Historical Performance

As this is a newly introduced metric, there is no historical performance data for this metric.

2.3.2.2.3. Effects on the DSP

The DSP has been prepared, ensuring that program spending is achievable with the given available resources in a timely manner, including suppliers (material), design services, municipal approvals, contract labor, and vehicles. Programs are expected to be completed in the period(s) that they are budgeted within. Annual DSP spending exceeding a designated threshold of +/- 10% will require a detailed variance explanation. DSP investment planning has been set up to design, issue, and construct a reasonable amount of work that can be achieved within the forecast period. Section 4.3 provides further details of the variances encountered during the 2015-2019 historical period.

2.3.3. Asset/ System Operations Performance

2.3.3.1. Safety

2.3.3.1.1. Methods and Measures

Maintaining a high level of employee safety, health & wellness and public safety are key corporate objectives for ORPC. The safety measure is generated by the ESA and includes three components:

a) Component A – Public Awareness of Electrical Safety
b) Component B – Compliance with Ontario Regulation 22/04[10]
c) Component C – Serious Electrical Incident Index

Component A – Public Awareness of Electrical Safety

Public Awareness of Electrical Safety" is defined under RRR section 2.1.19 (d)[11] as the level of public awareness within the electricity distributor's service territory about electrical safety information and precautions related to distribution network assets. OEB requires LDCs to conduct Public Awareness of the Electrical Safety surveys as part of performance scorecard development. To enable comparability of results year over year and among distributors, it is crucial that the survey methodology is consistent among LDCs. To enable consistency, the ESA tasked Innovative Research Group Inc. to develop a standardized and methodical approach to questionnaires and implementing this survey. Further details on the survey components are described in Section 2.1.2.1.

Component B – Compliance with Ontario Regulation 22/04

The objective of Ontario Regulation 22/04 is to enhance public safety with regards to the power distribution system within the Province of Ontario. The regulation affects the safety requirements for the design, construction, and maintenance of power distribution network owned by licensed electricity distributors. Section 13 of the regulations stipulated requirements regarding the participation of distributors in annual compliance audits. The purpose of a compliance audit is to conduct a comprehensive review of guidelines, processes, and standards used by ORPC in their designs, construction, installations, use, maintenance and repairs, extensions, connections, and disconnections of electrical equipment forming the distribution system to avoid or reduce the possibility of electrical hazards. The audit is carried out every year which deems ORPC's performance in one of three below categories:

- In compliance;
- Needs Improvement; or
- Not in compliance.

To ensure compliance with Ontario Regulation 22/04, ESA performs Due Diligence Inspections ("DDI") of LDCs. The outcome of the DDI is the inspection report which could require LDCs to initiate corrective actions in case of significant findings public safety and safety of personnel. The following are definitions and instructions concerning responding DDI inspections observations:

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[10] "O. Reg. 22/04: Electrical Distribution Safety", Queen's Printer for Ontario, 2017.

[11] Electricity Reporting and Record Keeping Requirements", Section 2.1.19, p. 26, Ontario Energy Board, March 31, 2020. URL: https://www.oeb.ca/sites/default/files/RRR-Electricity-20200331.pdf

Imminent Fire/Shock/Explosion Hazard: This section details imminent fire/shock/explosion hazards. All items listed under this section need to be addressed immediately by the LDC and a formal, written response submitted to ESA.

Key Due Diligence Findings: Key Due Diligence Findings are items that ESA requires formal, written responses within 10 working days.

Observations: Observations are items that ESA does not require formal, written responses to, unless specifically requested.

Non-Compliances to Regulation 22/04: The section details non-compliances to Regulation 22/04. All items listed under this section need to be addressed by the LDC and a formal, written response submitted to ESA. For each non-compliance detailed, the LDC shall address an action plan/ response and timelines (when not detailed by ESA) for addressing each non-compliance.

Needs Improvement: This section details areas where improvements are required with respect to Regulation 22/04. All items listed under this section need to be addressed by the LDC and a formal, written response submitted to ESA. For each Needs Improvement point, the LDC shall address an action plan/ response and timelines (when not detailed by ESA) for addressing each non-compliance.

Safety Related Observations: The section details safety related observations discovered during the inspection. Items listed under this section do not require a response by the LDC, unless specifically requested by ESA. These observations affect the safety of the public or LDC personnel and may or may not fall under Regulation 22/04.

Component C – Serious Electrical Incident Index

ORPC tracks the safety of employees using the Safe Worked Hours measure. This measure is a summation of all employee hours worked, beginning at zero, ending in the event that an employee suffers a lost time injury. A lost time injury refers to accidents or injuries that force the employee to remain away from his or her work and receiving WSIB benefits, beyond the day of the accident or for the next shift. Similarly, ORPC also tracks the amount of time that has elapsed in the unit “Year” since the last occurrence of lost time injury.

2.3.3.1.2. Historical Performance

ORPC continues to strive in maintaining its employee safety, health & wellness, and public safety measures and in compliance with Ontario Regulation 22/04. Table 2-16 outlines the historical performance for each of the three components of the safety measure. Table 2-17 and Table 2-18 reveal results of the Ontario Regulation 22/04 compliance audits and ESA DDI, respectively.

Table 2-16 Performance Measure - Safety

Measure		Target	2015	2016	2017	2018	2019	2020
Level of Public Awareness			82.20%	82.20%	80.40%	80.40%	82.00%	82.00%
Level of Compliance with *O. Reg. 22/04**		C	C	C	C	C	C	C
Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	0	0
	Rate per 10, 100, 1000 km of line	0	0	0	0	0	0	0

**Compliance Assessment grades: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).*

Table 2-17: ORPC Ontario Regulation 22/04 Compliance Audit Results

Audit Year	2015	2016	2017	2018	2019	2020
Section 4 Safety Standards	C	C	C	C	C	C
Section 5 When Safety Standards Met		C	C	C	C	C
Section 6 Equipment Approval	C	C	C	C	C	C
Section 7 Approval of plans, drawings, and specifications for installation work	C	C	C	C	C	C
Section 8 Construction Approval and Inspections	NI	C	NI	NI	C	C

Table 2-18: ORPC ESA DDI Performance History

Inspection year	2015	2016	2017	2018	2019
Imminent Fire/Shock/Explosion Hazards	0	0	0	0	0
Non-Compliance (s) to O.Reg. 22/04	0	0	0	0	0
Needs Improvement	0	0	0	0	0
Safety Related Observations	0	0	0	0	0
Miscellaneous Observations	0	0	0	0	0

2.3.3.1.3. *Effect on the DSP*

Promoting awareness, training and education related to safety is among the top priorities for ORPC. ORPC's continued efforts to ensure public safety and enforcing safety work is also well demonstrated by its audit and inspection results over the last five years indicating continued compliance with Ontario. The historical results indicate that DDI performance is not identified as needing improvement or to be a driver requiring material investments over the planning period. ORPC's objective is to maintain the current performance levels.

2.3.3.2. System Performance

2.3.3.2.1. Methods and Measures

Within this DSP, ORPC is proposing a new performance metric called System Losses. As stated in the Ontario Electricity Distributor Practices Relating to Management of System Losses[12], the OEB allows electricity distributors to recover distribution system losses by approving a loss factor as a component of their rates. However, if a distributor's losses exceed 5%, it is required to provide an explanation and action plan as to how it intends to reduce its losses.

System losses are essentially the difference between the total amount of electricity accepted into the system (i.e., amount delivered from the transmission system, the production of distribution connected generation, plus the net import through interconnections with other distribution systems), and the total amount of electric energy delivered by the distribution system (i.e., load that is metered with interval recording meters, demand meters and energy meters, as well as load that is unmetered). System Losses are measured by calculating the efficiency of the kWh purchased by ORPC as shown in Equation 2-8. This calculation is performed as follows for a given year:

$$\textit{System Losses} = \frac{\textit{Total Distribution Losses}}{\textit{Total kWh purchased}} \qquad \textit{(EQ 2-8)}$$

This allows ORPC to analyze the system losses as a percentage of the total kWh purchased. ORPC has a performance target of 5% for the DSP, as required by the OEB.

2.3.3.2.2. Historical Performance

Table 2-19 presents ORPC's system losses over the same period. Distribution losses ranged from 3.8% to 4.5% over the historical period and have trended upwards. However, it can be seen that the losses are ranging in between 3.5 – 4.6% over the historical DSP period which is less than the 5% threshold set by OEB.

Table 2-19: ORPC System Losses

Year	2015	2016	2017	2018	2019	2020
System Losses	3.8%	3.9%	4.2%	4.4%	4.6%	4.5%

2.3.3.2.3. Effect on the DSP

Existing performance is within performance targets and as such, there is no specific impact on the DSP. For the period of the DSP, ORPC will continue to meet the threshold requirements as defined by OEB for system losses.

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[12] "Ontario Electricity Distributor Practices Relating to Management of System Losses", Ontario Energy Board – Regulatory Audit Office, June 23, 2008 URL: https://www.oeb.ca/oeb/_Documents/Audit/report_audit_system_losses_20080624.pdf

2.4. REALIZED EFFICIENCIES DUE TO SMART METERS (5.2.4)

The installation of smart meters has provided ORPC with a variety of operational advantages to deliver its service to its customers. The following is some of the key efficiencies that have been achieved had are contributing towards ORPC's performance outcome achievements as outlined in Table 2-5.

2.4.1. Billing Accuracy

ORPC's advanced metering infrastructure ("AMI") has improved the accuracy of billing charged to its customers. Historical performance of Billing Accuracy over the past five years (2015-2019) has indicated that ORPC has consistently exceeded the industry target of 98% with an average Billing Accuracy of 99.97%. From ORPC's DSP Survey (further discussed in Exhibit 1, Appendix E), 68% of surveyed customers were very satisfied with respect to ORPC's billing accuracy, with an additional 14% of surveyed customers being somewhat satisfied.

2.4.2. System Reliability

ORPC is currently planning to replace its Station SCADA system over the next ten years, with specific upgrades within this plan integrated within the Station Expansion program as described in Section 7.2. These upgrades will allow for ORPC to monitor the system and achieve enhanced integration with smart metering devices better remotely.

ORPC intends to explore the potential use of the communication capabilities from their AMI to further enhance customer outage response via advanced outage detection that can be achieved through the newest smart metering technology. For example, new smart meters possess "last gasp" capabilities which can detect when an outage has occurred. This means that outages can be reported and triangulated automatically without the need for customers to call-in to report the outage.

Currently, loading data from the AMI can be leveraged to monitor and identify distribution transformers that are nearing their capacity or have become overloaded, which will drive investment decisions to upgrade the transformer capacity. As it is known that loading is a major contributor to transformer degradation, the use of smart meter data has greatly influenced ORPC's capability of identifying overloaded transformers and making timely and efficient decisions to proactive replace these transformers before their overloading results in a failure.

2.4.3. Service Quality

ORPC's smart meters have also enabled ORPC to better achieve its service quality objectives. ORPC leverages improved quality of data from smart meters to inform system controllers who dispatch field crews more effectively thus contributing positively toward outage response and emergency response actions. ORPC's score of 100% in Emergency Response Planning measure is indicative of ORPC efforts in using all possible resources including smart meter technology towards improving its customer-oriented performances.

3. ASSET MANAGEMENT PROCESS (5.3)

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.

Section 3.1 provides an overview of ORPC's AM process, including the inputs, underlying process components and produced outputs.

Section 3.2 provides an overview of the assets managed, including at-a-glance system information, age and condition demographics results across the asset base, as well as information relating to system capacity and loading.

Section 3.3 outlines ORPC's asset lifecycle optimization policies and practices, including information regarding ORPC's replacement and refurbishment practices, analytical decision-support systems used to identify and justify investment opportunities, as well as information regarding ORPC's maintenance practices.

Section 3.4 outlines the system capability assessment for REG connections

3.1. ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

3.1.1. Overview of Asset Management Objectives (5.3.1a)

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 base at the best appropriate 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."[13]

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"[14]

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[13] "Ottawa River Power Corporation – The Corporation", Ottawa River Power Corporation, 2020. URL: https://www.orpowercorp.com/about-us/the-corporation/

[14] "Distribution System Code", Ontario Energy Board, Section 4.4.1, p. 82, 2020.

- "To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service."[15]

Table 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 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
Operational Effectiveness	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 such that ORPC can continue being a trusted energy advisor for our customers.	▪ SAIFI ▪ SAIDI	1. SAIDI within range of past 5-year performance 2. SAIFI within range of past 5-year performance
Financial Performance	Financial Management	Prudent and optimal invesmtnet planning to manage rate impacts while upholding corporate financial stability and long-term performance.	▪ Investment Spending ▪ DSP implementation	1.Material Capital Expenditure +/- 20% to Estimate 2.DSP Annual Investment Category Spending +/- 10% of Plan
Public Policy Responsiveness	Environmental Awareness	Ensure that environmental risks are appropiately 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 2022-2026 Capital Expenditure Plan, which is further detailed in Section 4. ORPC continuously refines and improves upon their asset management process and objectives in order to maintain alignment with changing regulatory and legislative requirements.

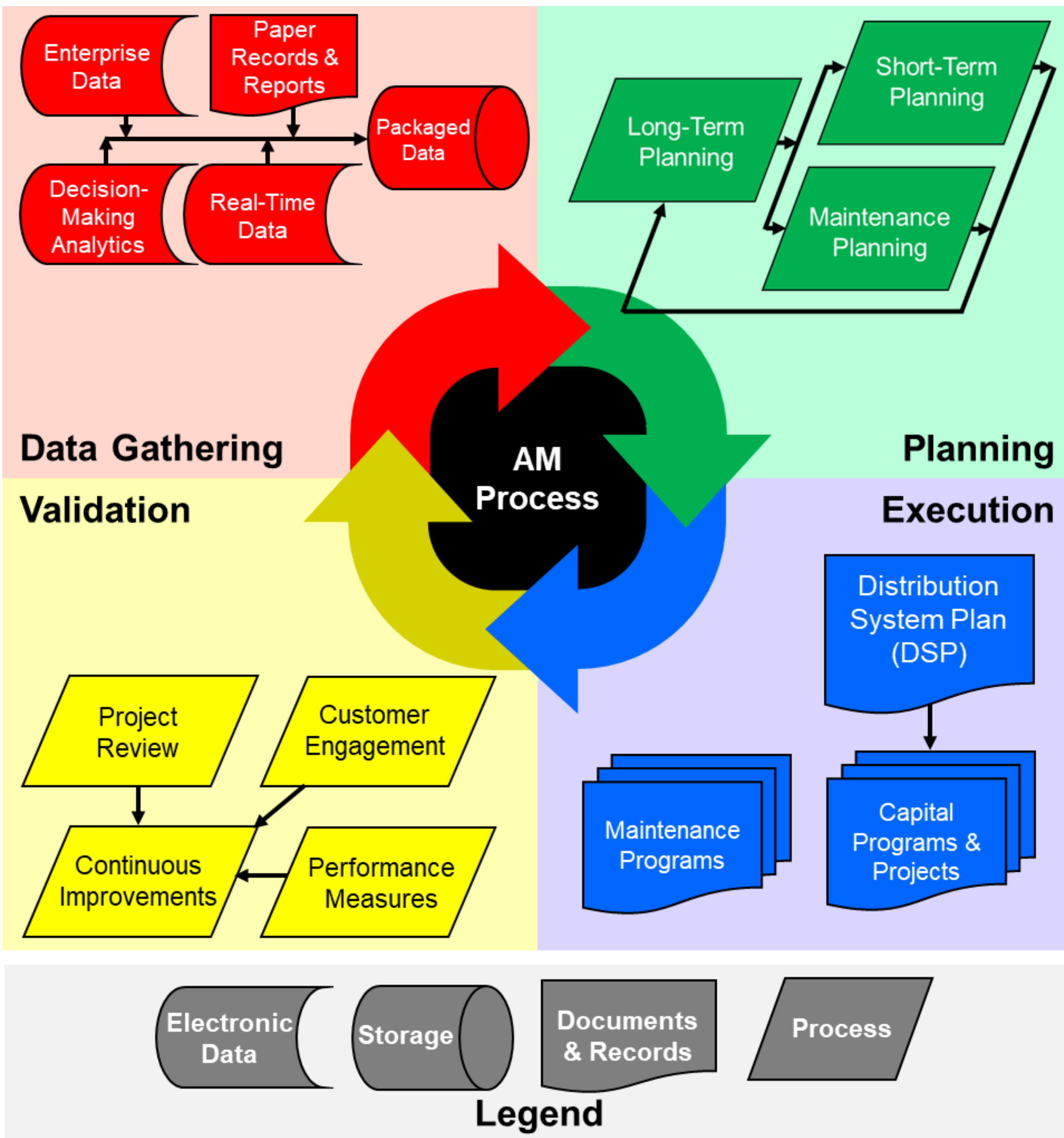
[15] "Ontario Energy Board Act, 1998", Ontario Energy Board, Part 1, Subsection 1, Paragraph 1, 2020.

3.1.2. Components of the Asset Management Process (5.3.1b)

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 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 3-1: ORPC's AM Process & Underlying Components

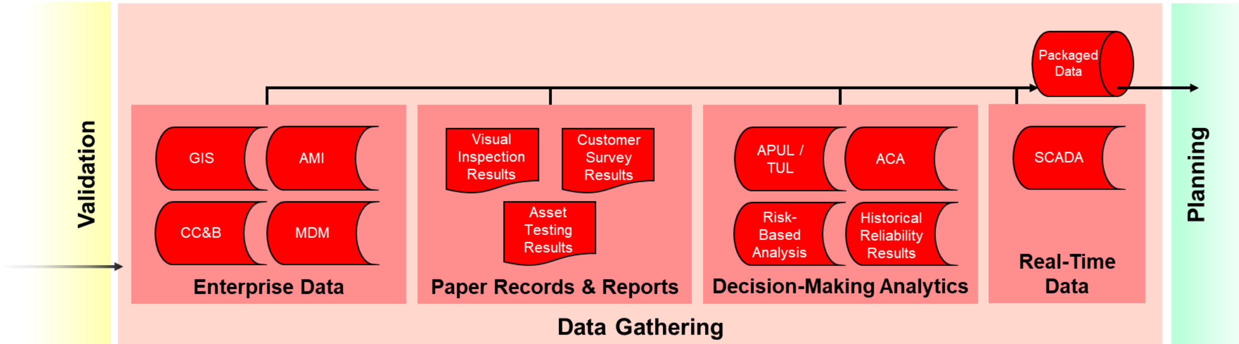


The following subsections further detail the four stages of ORPC's AM process:

3.1.2.1. Data Gathering

The first stage of ORPC's AM process is to gather data across all repositories within the utility in order 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 3-2.

Figure 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 procedures 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. These decision-support procedures are further discussed in Section 3.3.

- Real-Time Data: Real-time operational data captured from ORPC's SCADA system is used to support a number of planning processes, including load forecasting. This information is also 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.

ORPC continues to strive for improvements to their data. As an example, ORPC is rolling out new tools embedded within their GIS system to allow in-field inspectors to enter visual inspection results directly in electronic format. As part of planned IT investments (as discussed in Section 8.1), ORPC also plans to roll out mobile iPads to allow for electronic data entry to be performed directly from the field. Such initiatives allow for immediate cost and efficiency savings within the organization as data no longer needs to be converted into electronic format at a later time in the process.

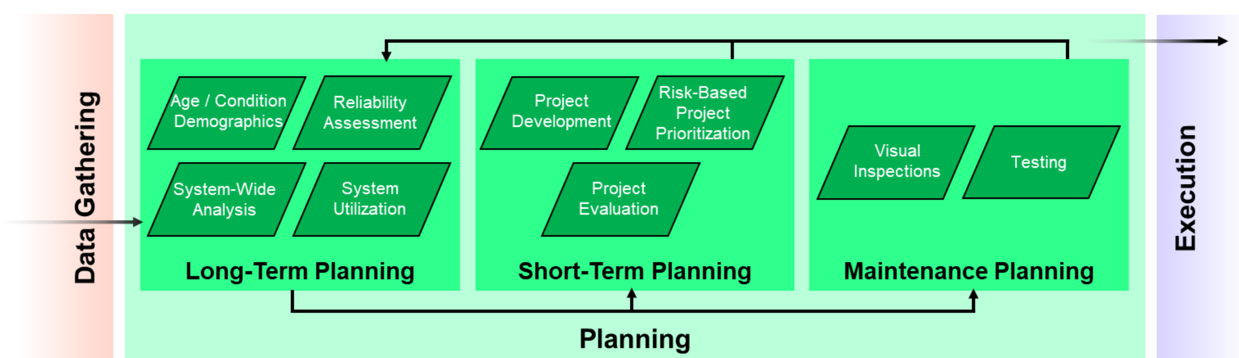
As noted previously, the AM process is cyclical in nature, meaning that any outputs that are derived from the "Validation" stage of the AM process are used to drive data quality and data accessibility improvements. As the foundational data is improved over time, these improvements are carried over proportionally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

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 includes long-term and short-term capital investment planning sub-processes, as well as maintenance planning sub-processes.

The Planning process is further illustrated in Figure 3-3.

Figure 3-3: ORPC's Planning Process



This stage of the AM process itself operates in a cyclical manner (much like the broader AM process), with outputs from Long-Term Planning feeding into Short-Term Planning and Maintenance Planning, and with outputs from Short-Term and Maintenance Planning feeding into the Long-Term Planning sub-process. These sub-processes are further explained below:

- Long-Term Planning: This sub-process provides a holistic evaluation of the system leveraging age, condition, historical reliability, and load forecasting data captured during the Data Gathering stage. Key elements within this sub-process include the following:

    - Reliability Assessment: Historical reliability data is leveraged in order to produce an overall reliability assessment across the system to identify major trends that need to be appropriately managed over the next 5-year period. This holistic assessment ultimately provides the groundwork for the more detailed asset-related and system-related assessments further described below.

    - Age/Condition Demographics: APUL results are leveraged to produce the age demographics results as presented in Section 3.2.3 to better identify those assets that are (a) already past their TUL, (b) approaching TUL within the next 5-year period, or (c) not approaching TUL within the next 5-year period. ACA results are leveraged to produce demographical results as presented in Section 3.2.4 to better identify those assets that are in Very Poor or Poor condition.

    - System Utilization: A system utilization analysis is performed in order to ascertain the overall capacity needs of the system and identify any possible capacity constraints. This analysis considers the results of capacity assessments performed at the substation and feeder levels, along with customer and economic growth trends, to identify potential risks over the DSP planning period.

The long-term planning sub-process concludes with the System-Wide Analysis, in which results from the elements described above are paired with information captured during the Data Gathering stage in order to develop and define the long-term investment programs within the DSP. Each program is assigned to one of the four DSP investment categories (i.e., System Renewal, Service, Access, and General Plant) and is assigned a primary (trigger) driver and secondary drivers based upon the parent DSP investment category.

Depending on the driver, different input information will be used to drive the development of the program. For example, in order to develop long-term System Renewal programs, individual asset APUL and ACA results are integrated with ORPC's GIS data in order to spatially identify problematic locations across the system. Risks pertaining to legacy infrastructure that no longer comply with ORPC's current standards (e.g., legacy infrastructure connected to the 4.16 kV system) and environmental risks (e.g., transformers with PCBs) will also be considered as part of the analysis.

For System Service programs that are managing system-wide critical issues such as capacity constraints, configuration-related issues and security of supply concerns, information from the Reliability Assessment and System Utilization analyses will be leveraged to identify crucial problems.

System Access programs will be driven by the needs of new customers and third-party requests as well as mandated service obligations, all of which is closely examined to ensure that a comprehensive plan is developed within the DSP planning period in order to meet the necessary requirements. The end-of-life considerations for metering infrastructure is also considered as part of this analysis.

Finally, General Plant programs will be driven by the need to improve operational efficiencies and replace end-of-life non-system physical assets. Age information coupled with outputs from the respective maintenance programs will be used to prioritize the long-term investment requirements for Fleet and Facilities infrastructure, respectively. For IT assets, age as well as functional obsolescence and cybersecurity risks will be considered in order to drive investment into hardware and software. Operational Technology investments will be identified based upon the need to introduce efficiency improvements with respect to ORPC's day-to-day operations.

- Short-Term Planning: The short-term planning sub-process is designed to populate each of the produced investment programs with targeted and discrete investment projects within the DSP planning period. Key elements within this sub-process include the following:

  - Project Development: Discrete projects are developed in alignment with the investment programs, drivers, and definitions. These programs 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: Projects are selected and prioritized within the system for the test year based upon both probability and impact-related results. For probability, parameters such as age and condition are leveraged. For impact, customer count estimates from ORPC's GIS system are taken into consideration to account for the potential reliability impacts should asset infrastructure fail. Consideration of both probability and impact-related results in an overall risk-based analysis that is performed by ORPC.

  - Project Evaluation: All material projects within the test year for a given program that are not driven by mandated service obligations, third-party or customer service requests are evaluated leveraging a Project Evaluation procedure, whereby different timing & pacing alternatives are economically evaluated leveraging a benefit-cost analysis. Costs will consider the total costs of the underlying projects within each program within the test year. Quantified benefits will vary depending on the drivers for the given program. Further details regarding the Project Evaluation procedure are further discussed in Section 3.3.2.2.2.

  As the parent 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.

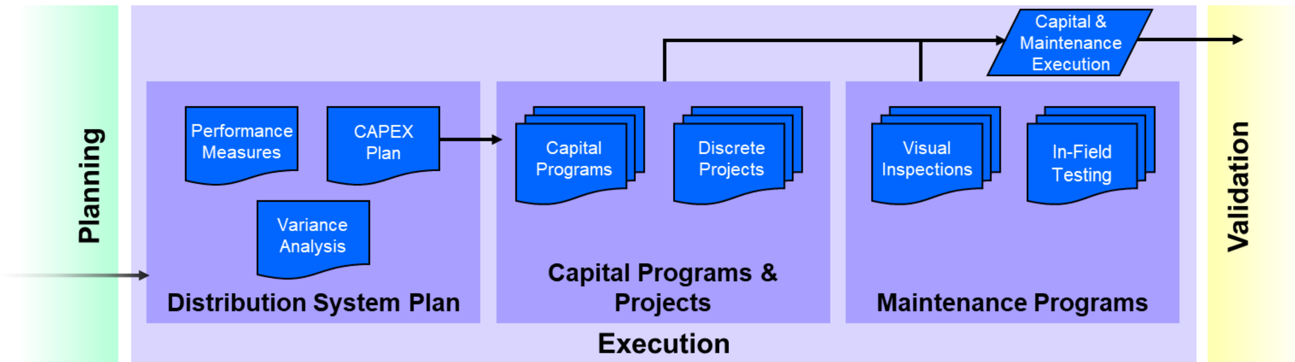
- Maintenance Planning: The maintenance planning sub-process is designed to support the continued reliable operation of their asset base over its TUL through the execution of visual inspection and testing programs. These programs result in the production of data that is mostly stored in paper records. However, ORPC continues to strive for continuous improvements in this regard, introducing new tools to manage the entry of data electronically, thus introducing efficiencies within the organization. Outputs from the maintenance planning sub-process will feed back into the long-term planning sub-process to influence the development of new programs based upon emerging issues that are identified from the in-field inspections and testing activities.

3.1.2.3. Execution

The third stage of ORPC's AM process involves the execution of the outputs produced from the Planning stage in order to deliver the Distribution System Plan and underlying capital & maintenance investment programs & projects and execute these programs and projects across the distribution system.

The Execution process is further illustrated in Figure 3-4.

Figure 3-4: ORPC's Execution Process



Key elements of the Execution process are further detailed below:

- Distribution System Plan: The DSP is designed to communicate the five-year capital investment plan ("CAPEX Plan") as well as communicate ORPC's third-party coordination activities and AM Process (as presented in this chapter), which provides the overall architecture and framework used to develop the CAPEX Plan. In addition to these outputs, the DSP is designed to communicate how ORPC has performed from the previous planning year 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 planning period. The Performance Measures presented in the DSP are designed to allow ORPC to communicate the overall effectiveness of the capital and maintenance investments over the planning period.

- 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 (2022-2026) are presented in Section 4.3 .

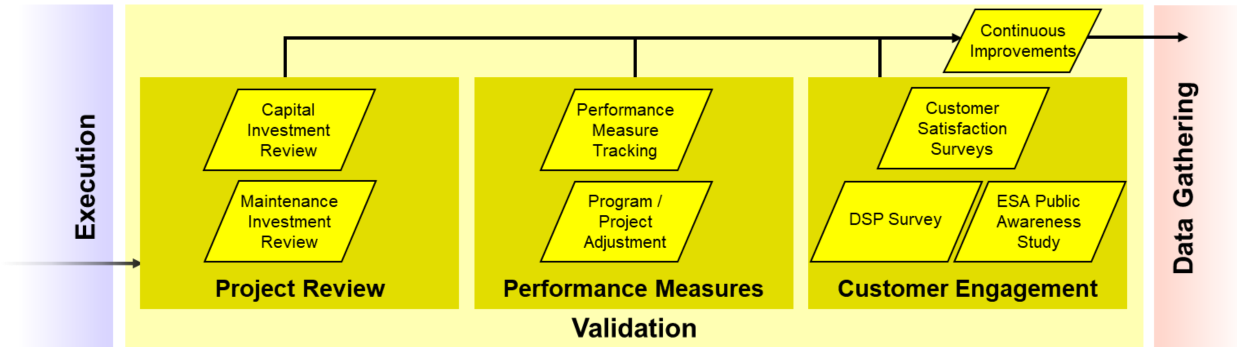
- Maintenance Programs: In-field maintenance which consists of visual inspections and in-field testing of asset infrastructure is performed across the distribution system. Different asset classes will have different maintenance cycles, depending on the complexity of the asset and components that must be inspected or tested. Further details on ORPC's current maintenance programs are described in Section 3.3.1.3.

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

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, the tracking of performance measures as well as execution of customer engagements throughout the DSP planning period. The Validation process is further illustrated in Figure 3-5.

Figure 3-5: ORPC's Validation Process



Key elements of the Validation process are further detailed below:

- 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.

- 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 in order to meet their desired targets. The performance measures for this DSP planning period (2022-2026) have been fully described in Section 2.3.

- 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 (Exhibit 1, Appendix E), customer satisfaction surveys as well as ESA public awareness surveys. These surveys are further described in Section 2.1.2.

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.

3.2. OVERVIEW OF ASSETS MANAGED (5.3.2)

3.2.1. Description of the Service Area (5.3.2a)

OPRC is a local distribution company serving approximately 11,442 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. OPRC maintains 11 municipal substations (“MS”) and almost 500 kilometers of distribution lines throughout its service area. 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.

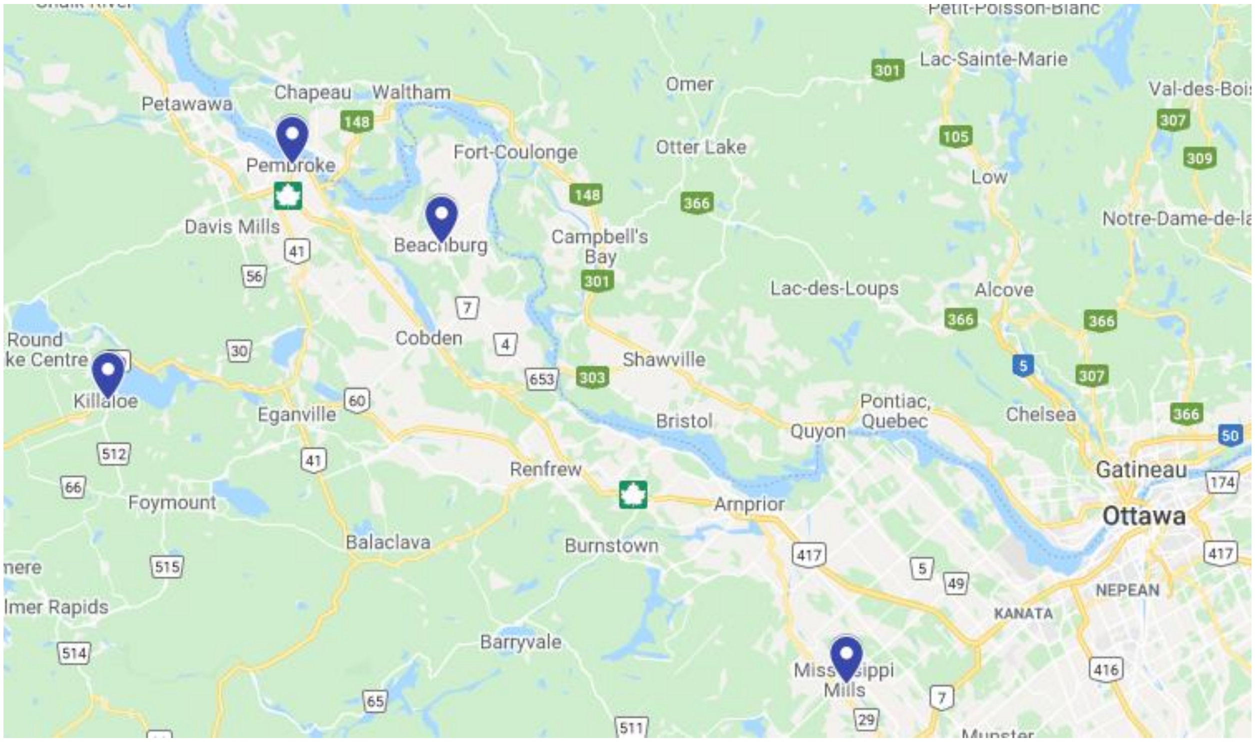
The economic growth has been slow within ORPC’s service area. The population in Almonte and Beachburg increased between 2011 and 2016, whereas the population in Killaloe and Pembroke decreased over the same period. The total change in population within the service area is -1.2% based on the 2016 Census.

Pembroke, known as “the heart of the Ottawa Valley”, experiences a warm humid continental climate with a significant amount of rain throughout the year. The average annual temperature is 5°C with 821 millimeters of rainfall per year. The summer-like condition usually spans from June to mid-September with July being the warmest month. Temperature generally drops below 0°C between November to March. Located 20 kilometers and 40 kilometers away from Pembroke, respectively, Beachburg and Killaloe share similar climate characteristics with Pembroke.

Almonte, located about 45 kilometers from Ottawa, has the same type of climate. The annual amount of rainfall exceeds 800 millimeters. Most of the rain falls in July, which is also the warmest month of the year with a high of 26°C. Winter-like conditions take place from mid-September to May, when the temperature typically drops below 0°C.

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 further illustrated in Figure 3-6.

Figure 3-6: ORPC Service Area



3.2.2. Summary of System Configuration (5.3.2b)

ORPC does not own any TS and instead receives power at the 44kV system voltage from four HONI TS/DS as listed in Table 3-2

Table 3-2: 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 system consists of approximately 364 km of overhead conductor and 126 km of underground cables. ORPC owns 11 MS which contains, in aggregate, 14 power transformers. Out of the 14 power transformers, 10 are rated for the 4.16 kV voltage on the secondary side supplying 30 feeders, and 4 are rated for the 12.47 kV voltage on the secondary side supplying 12 feeders. Table 3-3 illustrates the number of feeders and length at each voltage class. Table 3-4 shows the list of power transformers owned by ORPC and their rated capacity.

Table 3-3: Number and Length of lines based on the voltage class

Voltage (kV)	Feeder Count	Feeder Length (km)
4.16	30	92.4
12.47	12	92.0

Table 3-4: Station Transformers and Capacity (MVA)

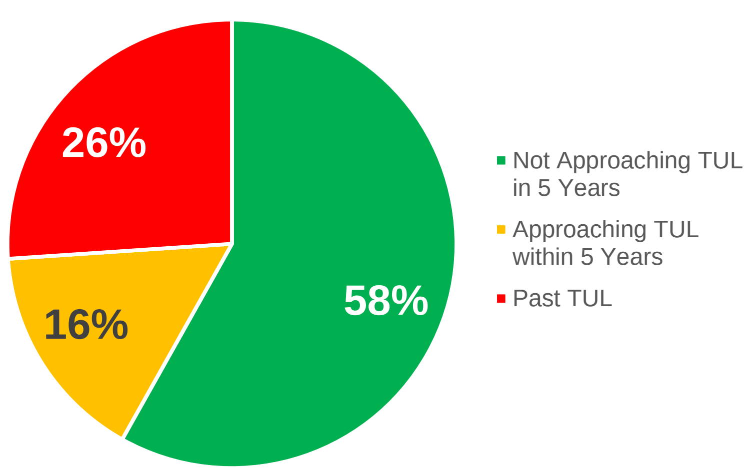
Service Area	MS #	Transformer Bank	Capacity (MVA)	Secondary Voltage (kV)
Pembroke	MS1	T1 (single phase)	2.5	4.16
		T2 (single phase)	2.5	4.16
		T3 (single phase)	2.5	4.16
	MS2	T1	6	4.16
	MS3	T1	5	4.16
	MS4	T1	5	4.16
	MS5	T1	3	4.16
	MS6	T1	10	12.47
		T2	10	12.47
	MS7	T1	10	12.47
	MS8	T1	10	12.47
Almonte	MS1	T2	5	4.16
	MS2	T1	5	4.16
	MS3	T1	3	4.16
	MS4	T1	5	4.16

3.2.3. Results of Assets Past Useful Life (APUL)

As part of the Data Gathering stage of the AM Process – first explained in Section 3.1.2.1 – ORPC produces a series of decision-support analytics in order to support the subsequent Planning and Execution stages of the AM Process. The APUL analysis represents a key element of the AM Process that provides a holistic view of all assets in the system, by comparing the current age of the assets to their TUL value. The underlying methodology supporting the APUL analysis is further detailed in in Section 3.3.2.1.2.

Figure 3-7 illustrates the APUL results at a system level, providing the percentage quantity of assets (out of the total asset population) that are (a) past TUL, (b) will be approaching their TUL within the 5-year DSP planning period, and (c) not approaching their TUL within this 5-year period. These results indicate that approximately 26% of ORPC's assets are currently past TUL, with another 20% that will be approaching their TUL within the 5-year period. It should be noted that 20% of assets within ORPC's system do not have an asset age available and are therefore excluded from these results.

Figure 3-7: ORPC's APUL Results



In total, 42% of ORPC's assets – nearly half of ORPC's total asset population – will be approaching or has already exceeded their respective TUL values. However, at the same time, it is important to note that very few of these assets have been found to be in Very Poor or Poor condition, respectively. The differences between the APUL and ACA results can be explained in two ways.

For one thing, the ACA results are available for only 71% of the assets in ORPC's system, while APUL results are available for 80% of the assets within the system. In addition, despite many of ORPC's assets being heavily aged (as per the APUL results), these assets do not show signs of accelerated aging due to advanced degradation processes (as per the ACA results). The differences between the APUL and ACA results are further explained in Section 3.2.4.

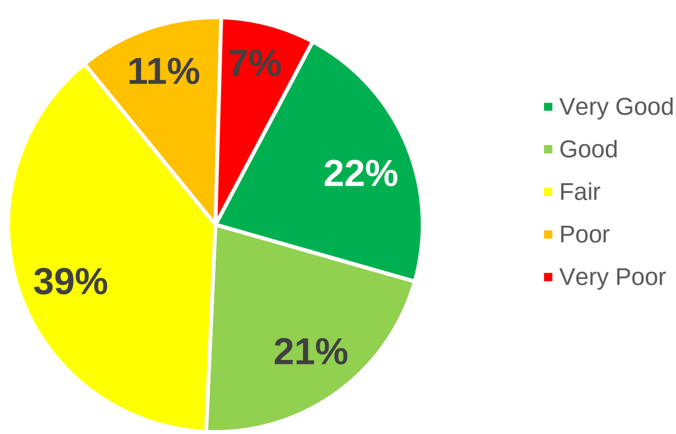
Ultimately, the combination of APUL and ACA results are used to provide foundational and holistic insight to ORPC regarding asset performance and have informed the development of the CAPEX Plan and its underlying programs and projects across the four DSP investment categories (System Renewal, Service, Access and General Plant).

3.2.4. Results of Asset Condition Assessment (ACA) (5.3.2c)

The ACA study was carried out by METSCO for ORPC with the objective of producing HI results for ORPC's in-service station and distribution asset infrastructure. These ACA results are derived based upon ORPC's visual inspection and testing program results, which were captured in paper format and digitized into electronic format. These results were compiled up to the end of March 2020, and the ACA analysis was completed in May 2020 and documented within the Ottawa River Power Asset Condition Assessment Report 2020 ("ACA Report") which is further detailed in Appendix D. In August 2021, the ACA report was updated with new pole analysis results using 2021 pole inspection data as of July 30, 2021.

Figure 3-8 illustrates the system-wide condition demographics results across all assets, showing the percentage quantity of assets (out of the total population) that are in Very Good, Good, Fair, Poor, or Very Poor condition, respectively.

Figure 3-8: ORPC's ACA Results



These results indicate that approximately 18% of ORPC's asset population are found to be in Very Poor or Poor condition, respectively. These results vary from the APUL results presented in Section 3.2.3 in which 42% of ORPC's asset base are already past TUL or will be approaching TUL over the 5-year DSP planning period. This deviation in results show that while ORPC's asset base is heavily aged – based upon the APUL results, the assets do not reveal signs of accelerated degradation – as evidenced by the ACA results. ORPC's maintenance program has certainly had an impact in managing the continued operation of the asset base in order to minimize any form of accelerated degradation.

At the same time, there are other factors that may be contributing to this deviation between the APUL and ACA analyses. For one thing, results from the ACA and APUL analyses only cover a subset of the asset population. As noted in Section 3.2.3, 20% of assets within ORPC's system do not have an asset age available and are therefore excluded from the APUL results. At least 70% of input data needed to support the HI calculation must be available to produce accurate results. A total of 29% of ORPC's assets do not meet this 70% threshold and have therefore been excluded from the ACA results as illustrated in Figure 3-8.

In addition, as explained in the ACA report, *"while ORPC's existing framework provides a significant volume of data, certain procedural and technological enhancements could further enhance the granularity of this data as well as the asset condition results and facilitate calculation of a greater proportion of numerical degradation scores."*[16] As ORPC continues to improve and enhance their maintenance activities, there will be an opportunity to further enhance the ACA results as part of future iterations of the AM Process. Finally, in both the ACA and APUL results, certain ages for assets were estimated using the average ages of adjacent asset infrastructure on the same street. A total of 24% of assets received estimated ages in this manner. As further explained in Section 3.3, due to the current-state data limitations, ORPC has leveraged results from across multiple decision-support analyses rather than relying on any one single analysis in order to develop the CAPEX Plan.

Figure 3-9 and Table 3-5 present the detailed condition demographics results across each of ORPC's evaluated asset classes. As Figure 3-9: indicates, the majority of ORPC's distribution system falls into the condition category of Fair or better condition, with several specific asset classes containing units found to be in Poor and Very Poor condition – most notably underground cables and pole-mount transformers.

[16] "Ottawa River Power Corporation Asset Condition Assessment Report 2020", p.10, METSCO, 2020.

Figure 3-9: Health Index Distribution for Each Asset Class

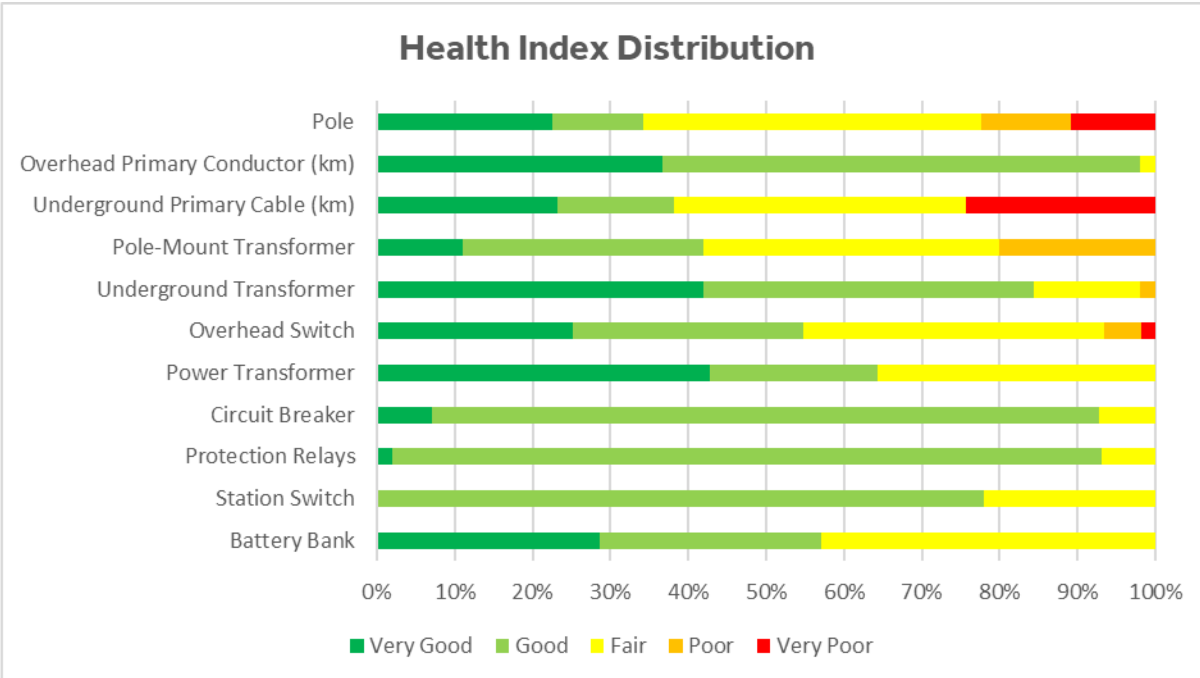


Table 3-5: Health Index Distribution Count Results

Asset Class	Population	HI Distribution (%)					Average Health HI	Average DAI
		Very Good	Good	Fair	Poor	Very Poor		
Distribution Assets								
Pole	4084	22.57%	11.73%	43.33%	11.58%	10.80%	62.52%	85.43%
Overhead Primary Conductor	150.0 km	36.67%	61.33%	2.00%	0.00%	0.00%	57.21%	86.03%
Underground Primary Cable	41.4 km	19.56%	15.01%	37.54%	0.00%	27.89%	55.76%	84.24%
Pole-Mount Transformer	1060	11.04%	30.85%	38.11%	20.00%	0.00%	62.23%	82.79%
Underground Transformer	367	41.96%	42.51%	13.62%	1.91%	0.00%	80.65%	58.68%
Overhead Switch	334	25.15%	29.64%	38.62%	4.79%	1.80%	69.65%	91.17%
Station Assets								
Power Transformer	14	42.86%	21.43%	35.71%	0.00%	0.00%	76.09%	100.00%
Circuit Breaker	42	7.14%	85.71%	7.14%	0.00%	0.00%	75.35%	78.23%
Protection Relay	101	1.98%	91.09%	6.93%	0.00%	0.00%	77.60%	100.00%
Station Switch	50	0.00%	78.00%	22.00%	0.00%	0.00%	73.65%	77.45%
Battery	7	28.57%	28.57%	42.86%	0.00%	0.00%	71.73%	96.43%

Table 3-6 consolidates the known and the estimated age demographics of in-service assets.

Table 3-6: Age Distribution Count Results

Asset Category	Population	Health Index Distribution (%)						
		0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years	No Data
Distribution Assets								
Pole	4084	338	345	405	907	665	770	654
Overhead Primary Conductor	150.0 km	0.7	7.0	32.0	39.6	26.4	2.3	41.9
Underground Primary Cable	41.4 km	4.2	2.6	3.2	2.0	10.2	12.7	6.5
Pole-Mount Transformer	1060	22	73	264	327	141	30	203
Underground Transformer	367	58	86	78	78	40	3	24
Overhead Switch	334	26	51	96	78	38	8	37
Station Assets								
Power Transformer	14	0	1	2	0	3	8	0
Circuit Breaker	42	0	3	2	0	20	17	0
Protection Relays	101	0	0	2	0	69	30	0
Station Switch	50	0	7	6	1	13	23	0
Battery Bank	7	3	2	2	0	0	0	0

3.2.4.1. Station Transformers

Housed within an MS, Power Transformers are used to step down the voltage from the sub-transmission system to distribution levels. ORPC has 14 in-service power transformers. Figure 3-10 presents the age profile of power transformers in-service. Majority of the power transformers have been in-service for more than 50 years. Figure 3-11 presents the HI results, which reveal that 35% of these assets are in Fair condition and the remaining 65% are in Good or Very Good condition.

Figure 3-10: Power Transformer Age Demographics

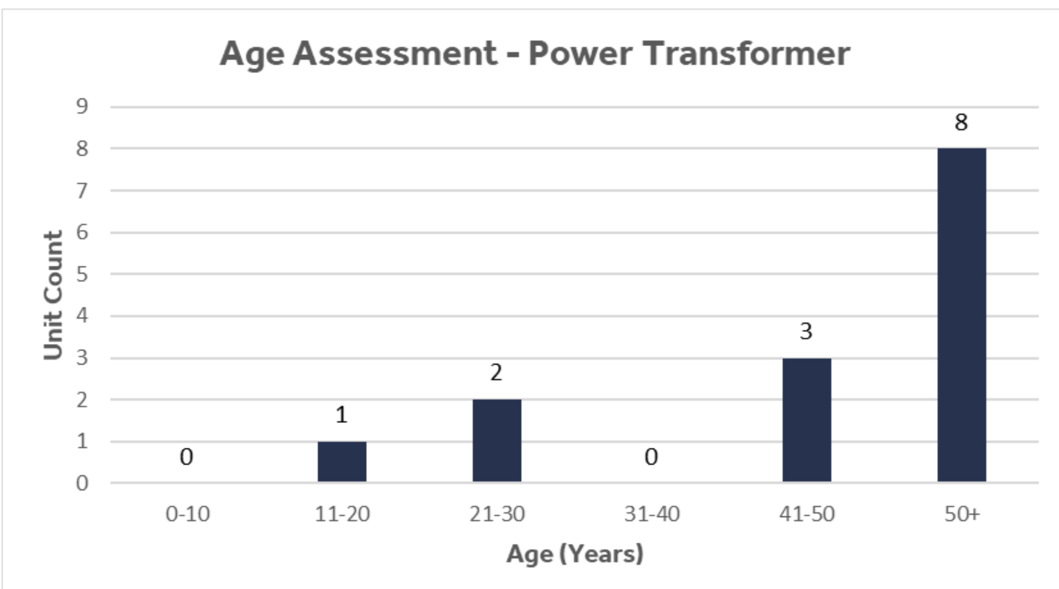
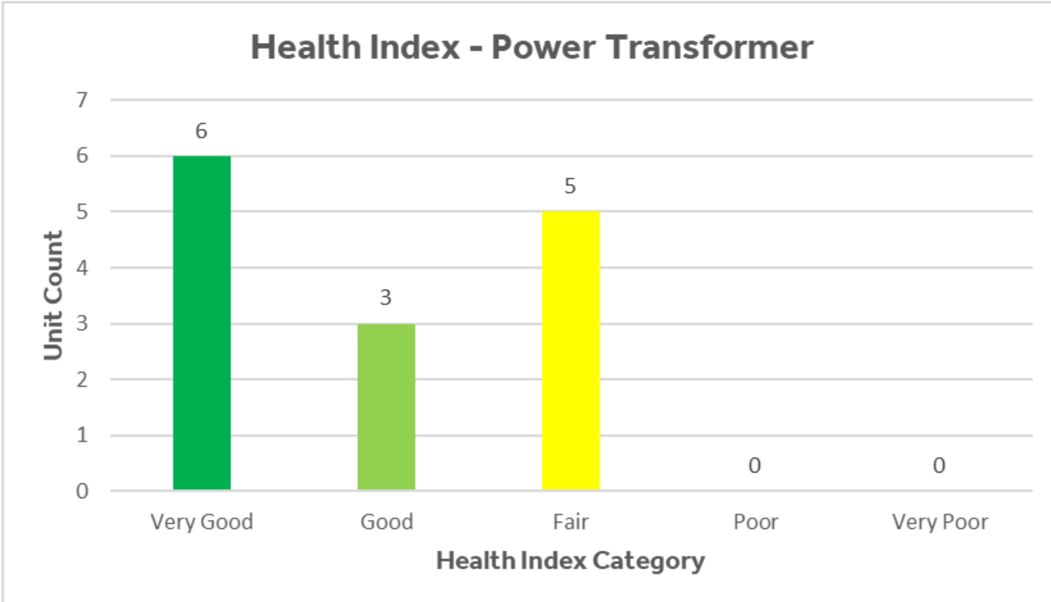


Figure 3-11: Power Transformers HI Results



3.2.4.2. Circuit Breakers

Located outdoors or in station switchgears, circuit breakers are electrical devices that operate automatically during a fault. ORPC owns 42 circuit breakers within its service territory. Age distribution of these circuit breakers are presented in Figure 3-12. The majority of the circuit breakers possess an age between 41 to 60 years. As shown in Figure 3-13, 7% of these assets are in Fair or better condition and the remaining 93% are in Good or Very Good condition.

Figure 3-12: Circuit Breaker Age Demographics

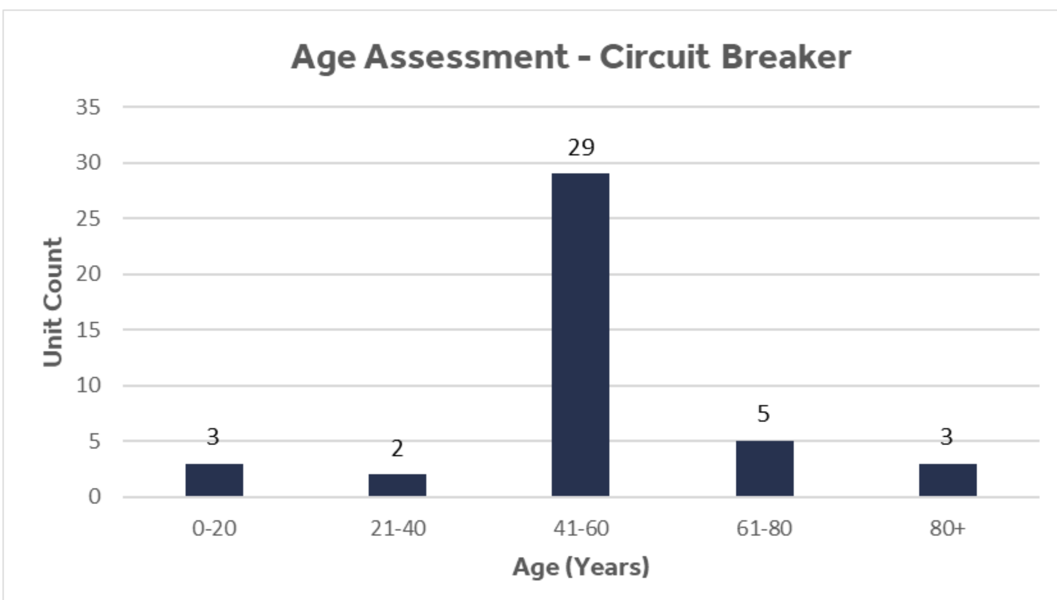
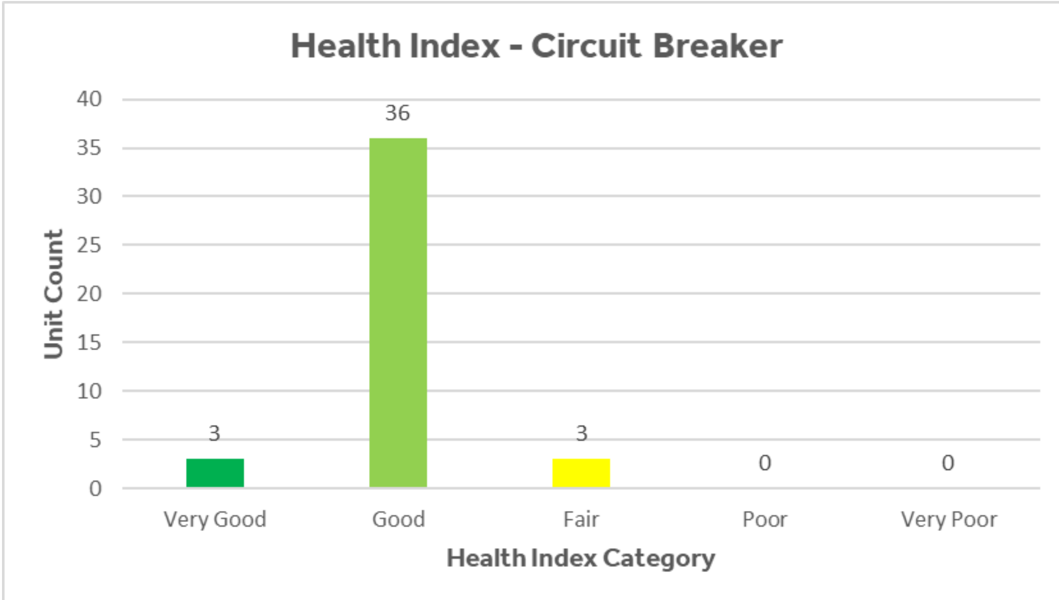


Figure 3-13: Circuit Breaker HI Results



3.2.4.3. Protection Relays

Projection relays detect abnormal operating conditions and initiate a trip in circuit breakers to isolate faulty circuits from healthy circuits. ORPC employs 101 protection relays, all of which have been in-service for less than 60 years as shown in Figure 3-14. Approximately 7% are in Fair condition and the remaining 93% are in Good or Very Good condition as shown in Figure 3-15.

Figure 3-14: Protection Relays Age Demographics

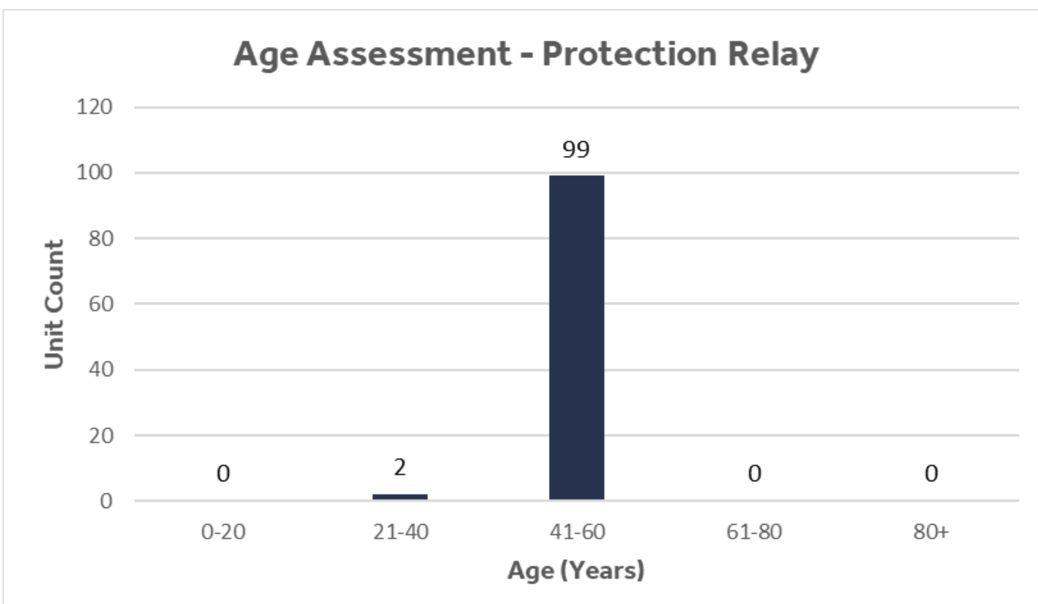
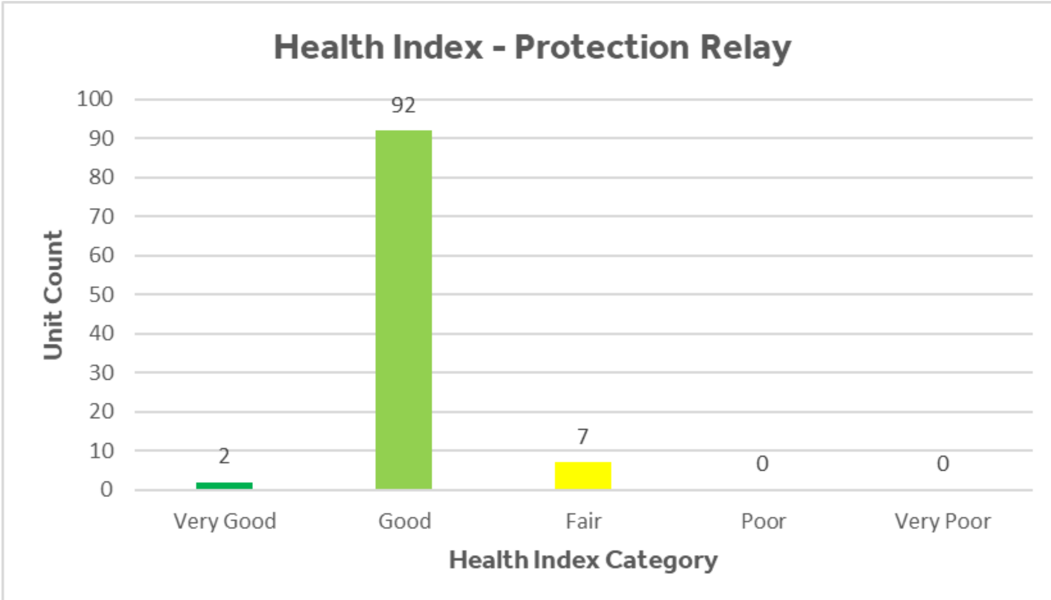


Figure 3-15: Protection Relays HI Results



3.2.4.4. Station Switches

Station switches provide isolation and can make or break load. ORPC has 50 in-service station switches. Figure 3-16 presents the age profile of the station switches. The majority of the station switches are aged between 41 to 60 years. As illustrated in Figure 3-17, 22% are in Fair condition and the remaining 78% are in Good condition.

Figure 3-16: Station Switch Age Demographics

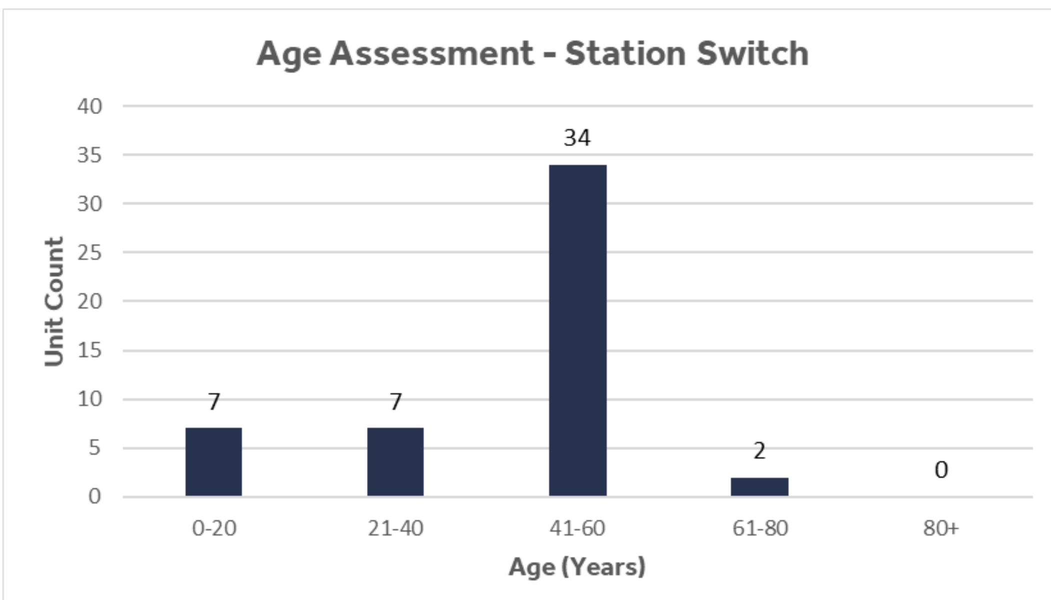
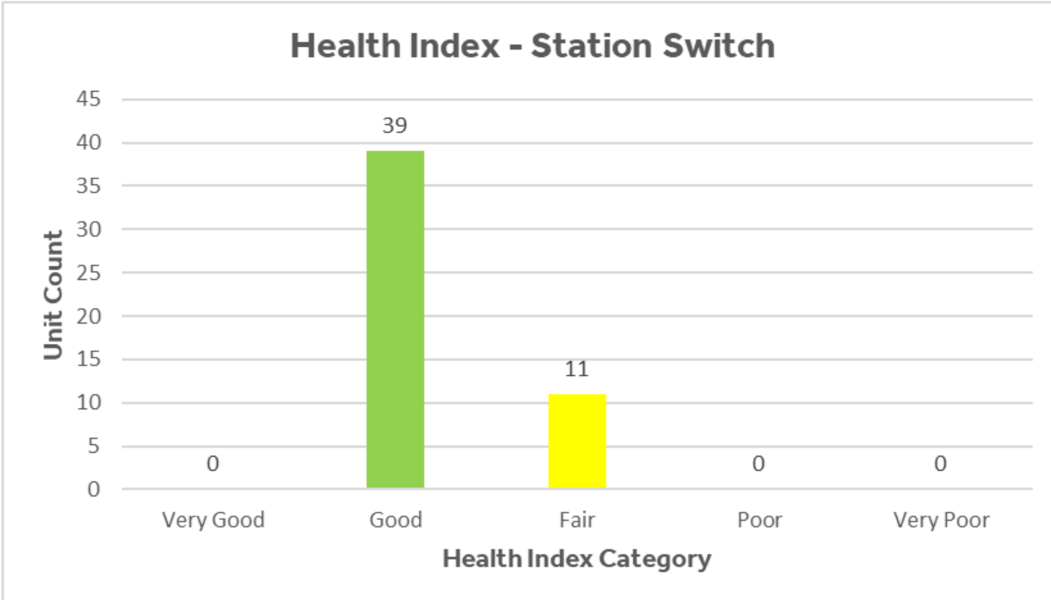


Figure 3-17: Station Switch HI Results



3.2.4.5. Battery Banks

The battery system provides backup power to essential station functionalities such as lighting, communication, and protection & control ("P&C") equipment in the event of a loss of supply to the station. The main components of the battery system are the charger and the battery bank which is comprised of several battery cells in series. ORPC employs 7 battery banks in its system. Figure 3-18 presents the age distribution for station battery banks, all of which have been in-service for less than 30 years. As shown in Figure 3-19, 43% are in Fair condition and the remaining are in 57% are in Good or Very Good condition.

Figure 3-18: Station Battery Banks Age Demographics

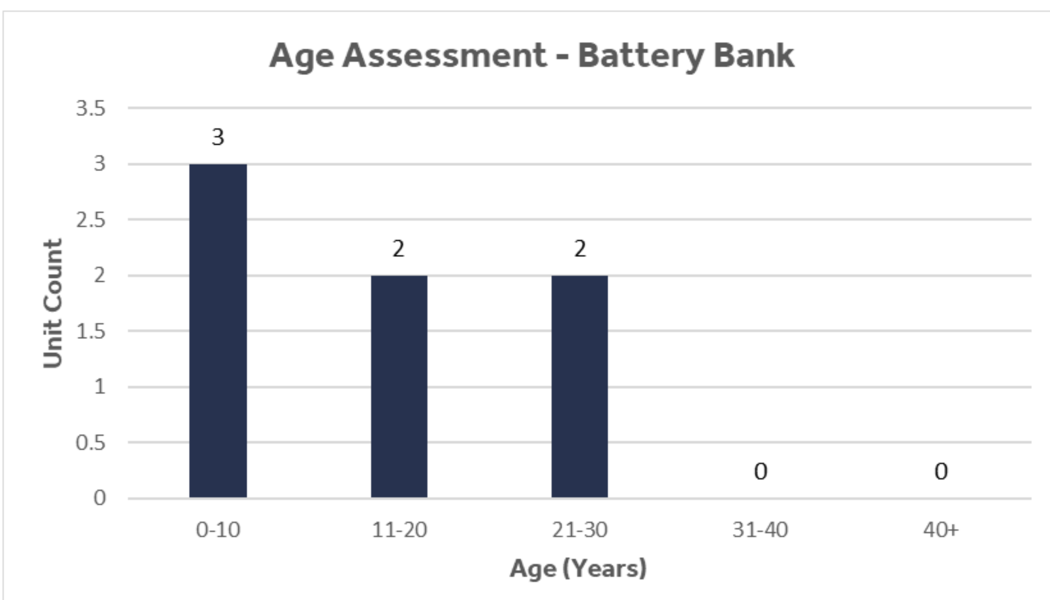
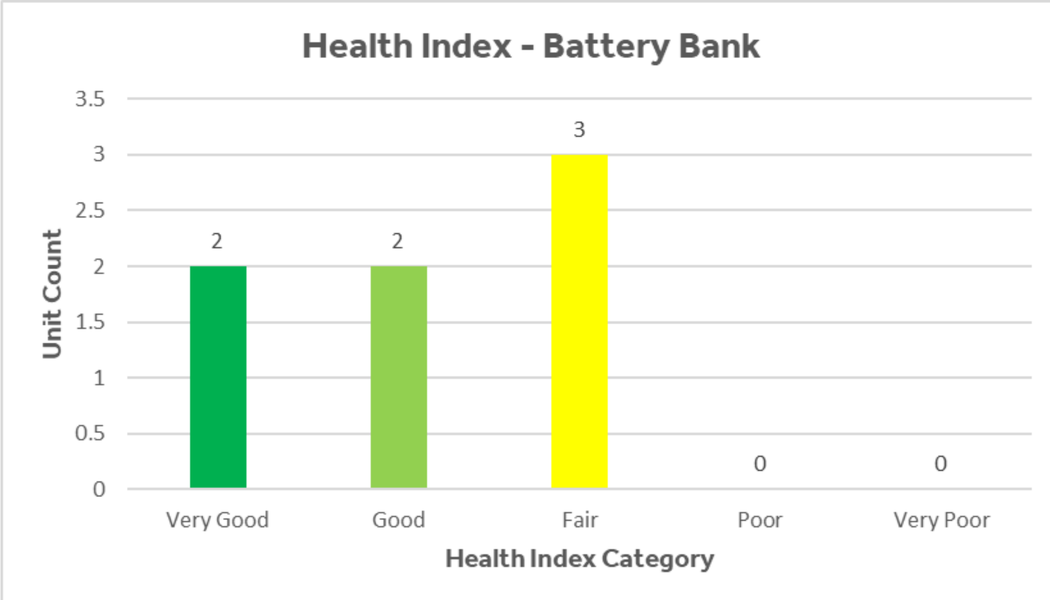


Figure 3-19: Station Battery Banks HI Results



3.2.4.6. Poles

Poles support the structures for overhead distribution system. They are often found with installed assets such as overhead pole-mount transformers, switches, reclosers, and streetlights. ORPC owns 4,084 poles within its service territory. Figure 3-20 presents the age distribution for in-service poles. Approximately 19% of poles older than 50 years of age; 39% are between 31 to 50 years; and 27% are in-service for less than or equal to 30 years, respectively. However, the installation year was not available for 16% of the population. As illustrated in Figure 3-21, approximately 22% of the poles are found to be in Poor or Very Poor condition; 43% are in Fair condition; and the remaining ~34% are in Good or Very Good condition, respectively.

Figure 3-20: Poles Age Demographics

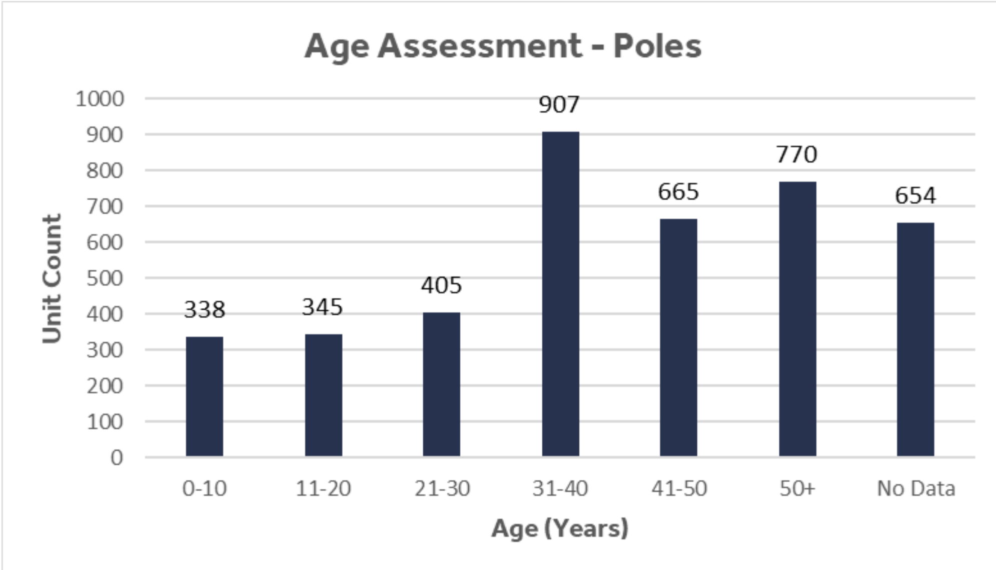
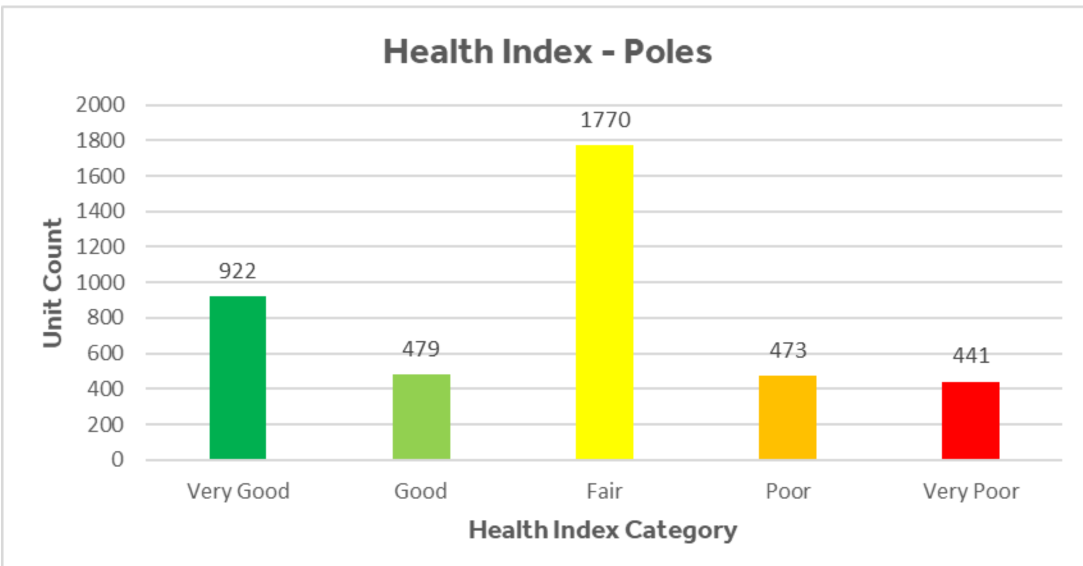


Figure 3-21: Pole HI Results



3.2.4.7. Overhead Primary Conductors

Overhead conductors distribute electricity from substations to customer premises and are supported by poles. Overhead conductor length is measured in kilometres of circuit, where a 1-km run of three-phase conductor is measured as 1 km rather than 3 km. ORPC employs 150 km of overhead primary conductor within its service territory. As the installation date was not known for the entire population of overhead conductor, ages for these assets were estimated by leveraging the average age of the adjacent assets located on the same street as the conductor spans with missing ages. These estimated age values were leveraged within the HI calculation.

Figure 3-22 presents the age distribution for in-service poles. Approximately 1.5% of conductor are above 50 years old; 44% are between 31 to 50 years; and 26.5% are in-service for less than 30 years, respectively. However, the installation year is still unknown for 28% of the population. Figure 3-23 shows that 2% are in Fair condition and the remaining 98% are in Good or Very Good condition.

Figure 3-22: Overhead Primary Conductor Age Demographic

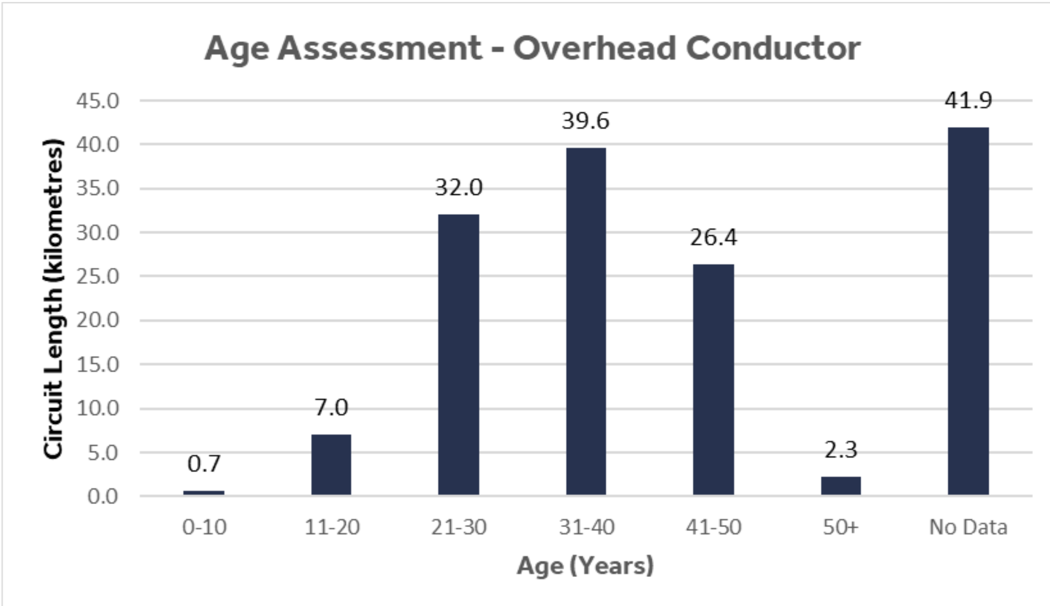
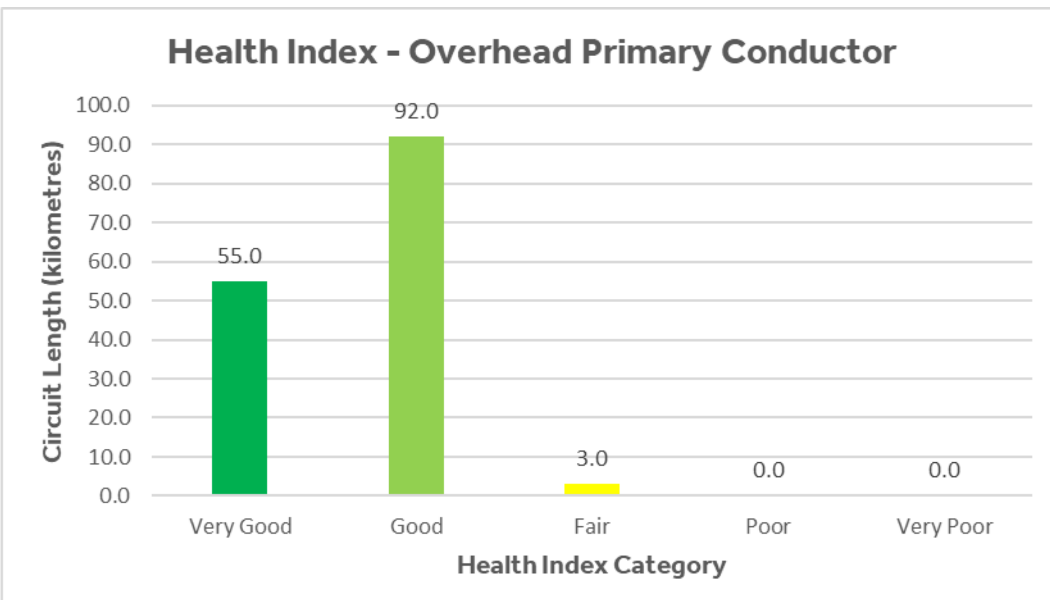


Figure 3-23: Overhead Primary Conductor Health Index Demographic



3.2.4.8. Underground Primary Cables

Like overhead conductors, underground cables also distribute electricity within the electrical distribution system. However, these assets are located below ground. Underground cable length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. ORPC owns approximately 41 km of underground primary cable within its service territory. As the installation date was not known for the entire population of underground cables, ages for these assets were estimated by leveraging the average age of the adjacent assets located on the same street as the underground cable segments with missing ages. These estimated age values were leveraged within the HI calculation.

Figure 3-24 presents the underground primary cable age profile. Approximately 31% of the cable population were installed more than 50 years ago, while 30% are found to be between 31 to 50 years of age and 27% of cables are less than 30 years of age. However, the installation date was still unknown for 16% of the in-service population. Figure 3-25 presents the HI results across the underground primary cable population. Approximately 28% of the in-service population are in Very Poor condition, which were mainly driven by the service age.

Figure 3-24: Underground Primary Cable Age Demographic

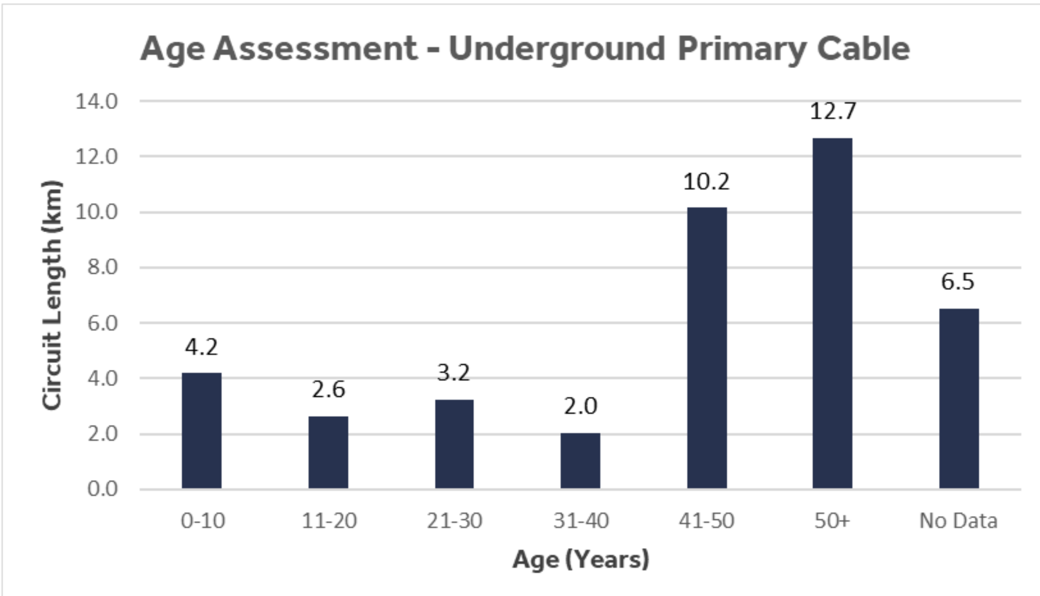
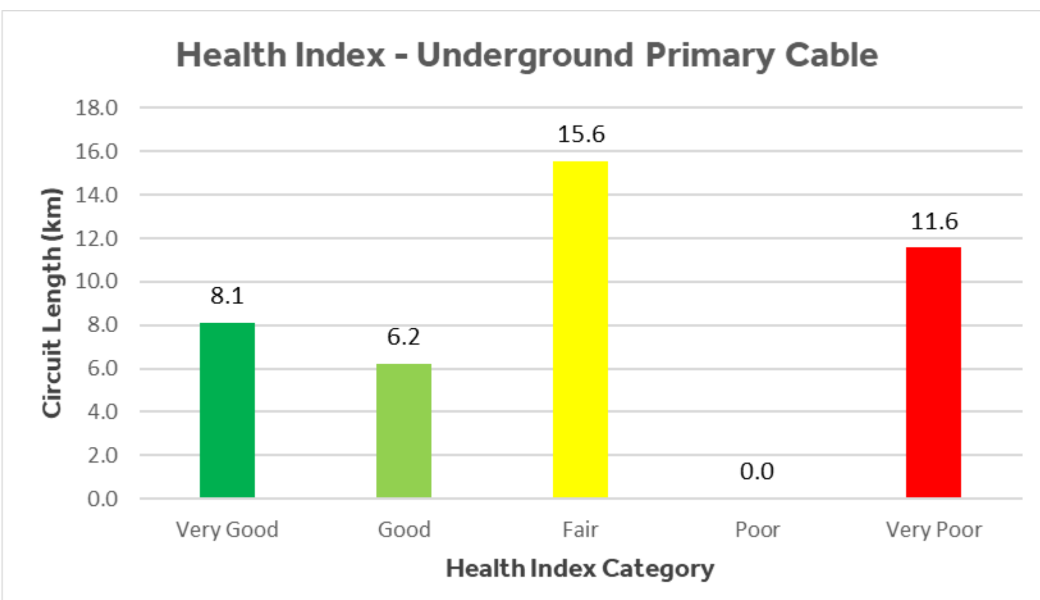


Figure 3-25: Underground Primary Cable Health Index Demographic



3.2.4.9. Overhead (Pole-Mount) Transformers

Overhead (pole-mount) transformers are installed on poles above ground with the primary function to step down power from the medium voltage distribution system to the voltage rating for customer use. ORPC has 1,060 in-service pole-mount transformers in service. As the installation date was not known for the 92% population of overhead transformers, ages for these assets were estimated by leveraging the average age of the adjacent assets located on the same street as the transformers with missing ages. These estimated age values were leveraged within the HI calculation.

Figure 3-26 presents the age distribution for pole-mount transformers. Approximately 3% of transformers are aged more than 50 years; 44% are aged between 31 to 50 years; and 34% are aged less than 30 years. However, it should be noted that the installation year could not be estimated for 19% of the in-service population. Figure 3-27 illustrates the HI condition for pole-mount transformers. Approximately 20% of these assets are in Poor condition; 38% are in Fair condition; and 42% are in Good or Very Good condition.

Figure 3-26: Pole-Mount Transformer Age Demographics

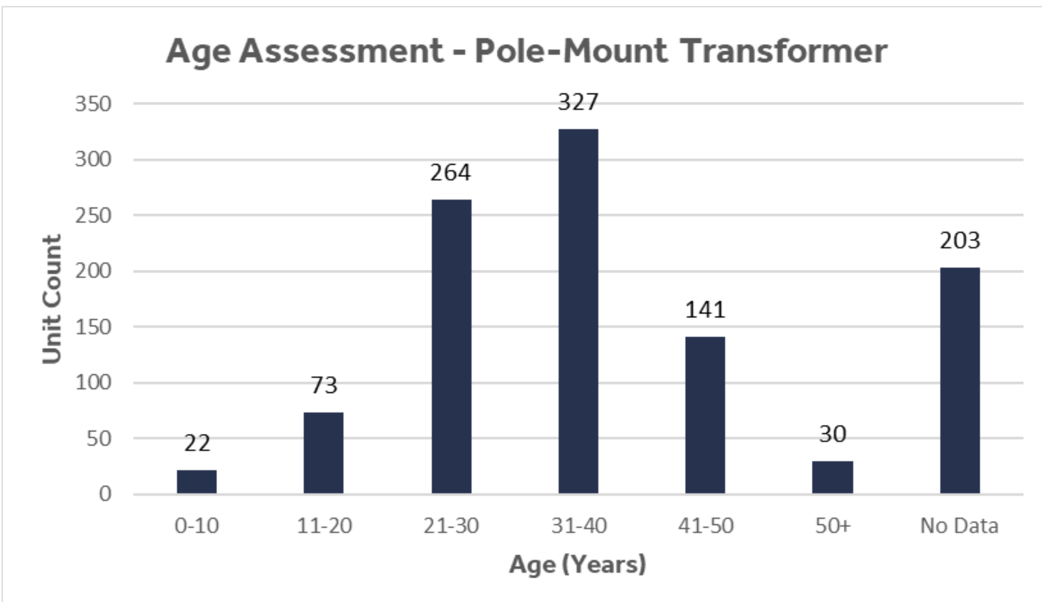
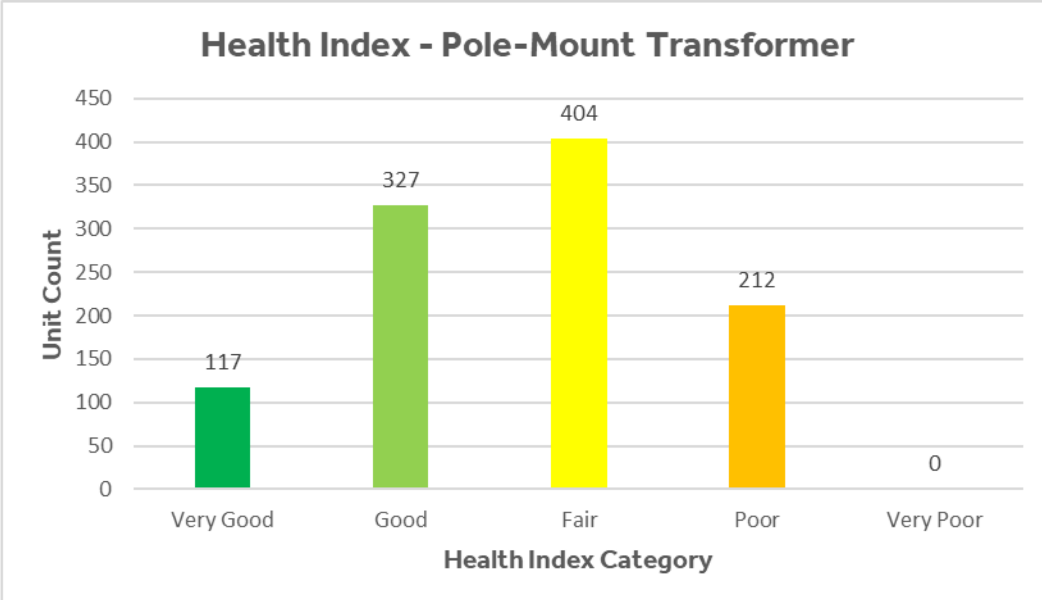


Figure 3-27: Pole-Mount Transformers HI Results



3.2.4.10. Underground Transformers

Distribution underground transformers, including pad-mount and vault transformers, are utilized for similar functionalities as pole-mount transformers. ORPC owns 367 underground transformers within its service territory. The installation date was unknown for 69% of the in-service underground transformers. Ages for these assets were estimated by leveraging the average age of the adjacent assets located on the same street as the transformers with missing ages. These estimated age values were leveraged within the HI calculation.

Figure 3-28 presents the age distribution for underground transformers. Less than 1% have been in-service for more than 50 years. Approximately 32% are aged between 31 to 50 years and 61% are aged less than 30 years. However, it should be noted that the installation year could not be estimated for 7% of the in-service population. As shown in Figure 3-29, the majority of the population are in Fair or better condition, with less than 2% found to be in Poor condition.

Figure 3-28: Underground Transformers Age Demographics

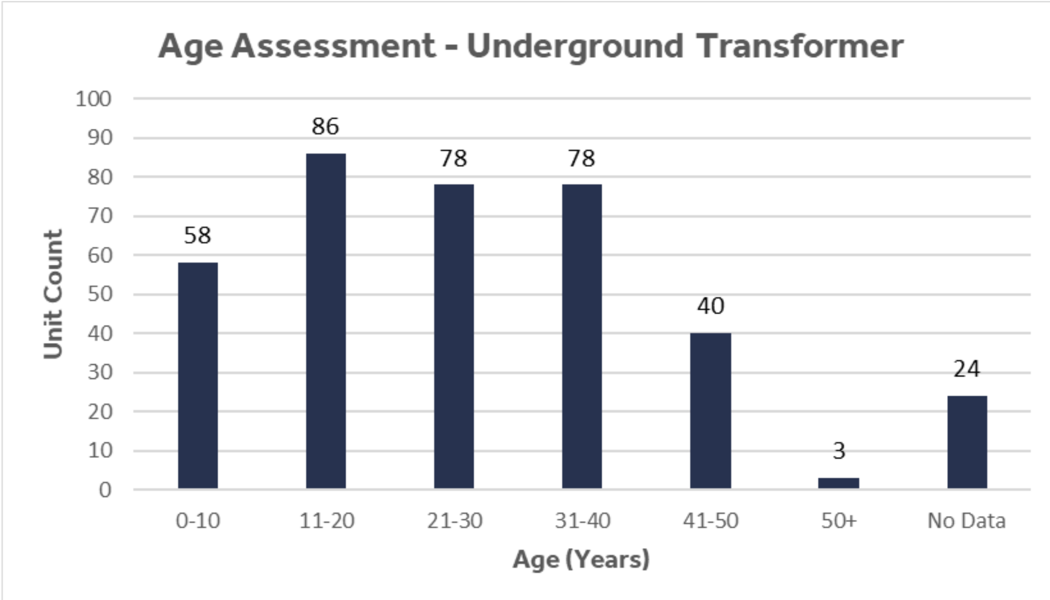
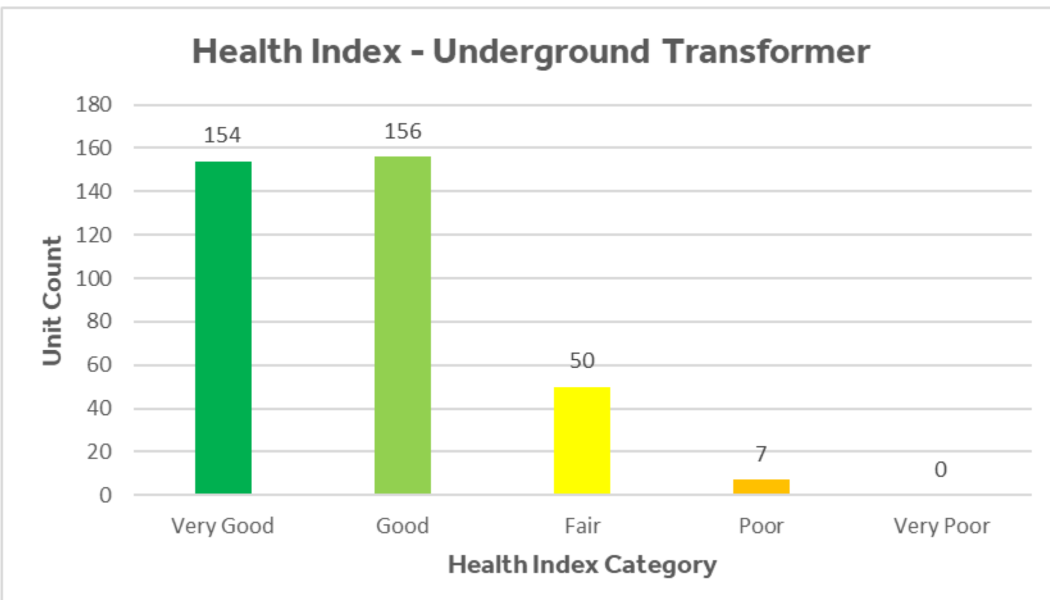


Figure 3-29: Underground Transformers HI Results



3.2.4.11. Overhead Switches

ORPC's overhead switch types include manual gang-operated sectionalizing switches, inline switches, and inline fused switches and are installed on wood poles. Overhead switches provide isolation of line sections or equipment when necessary. ORPC employs 334 overhead switches within its service territory. The installation date was known for 88% of the in-service overhead switches. Ages for these assets were estimated by leveraging the average age of the adjacent assets located on the same street as the switches with missing ages. These estimated age values were leveraged within the HI calculation. Figure 3-30 presents the age distribution for overhead switches. The majority of the population have been in-service for less than 30 years. Approximately 35% are aged between 31 to

50 years and 2% are aged over 50 years. However, it should be noted that the installation year could not be estimated for 11% of the in-service population. As illustrated in Figure 3-31, 6% are in Very Poor or Poor condition; 39% are in Fair condition; and 55% are in Good or Very Good condition.

Figure 3-30: Distribution Overhead Switch Age Demographic

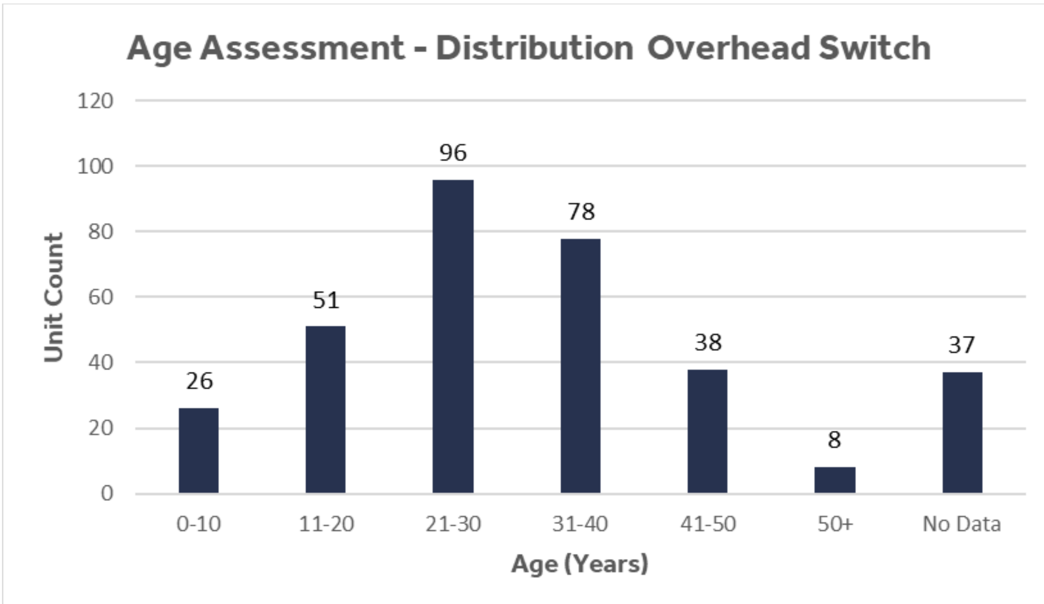
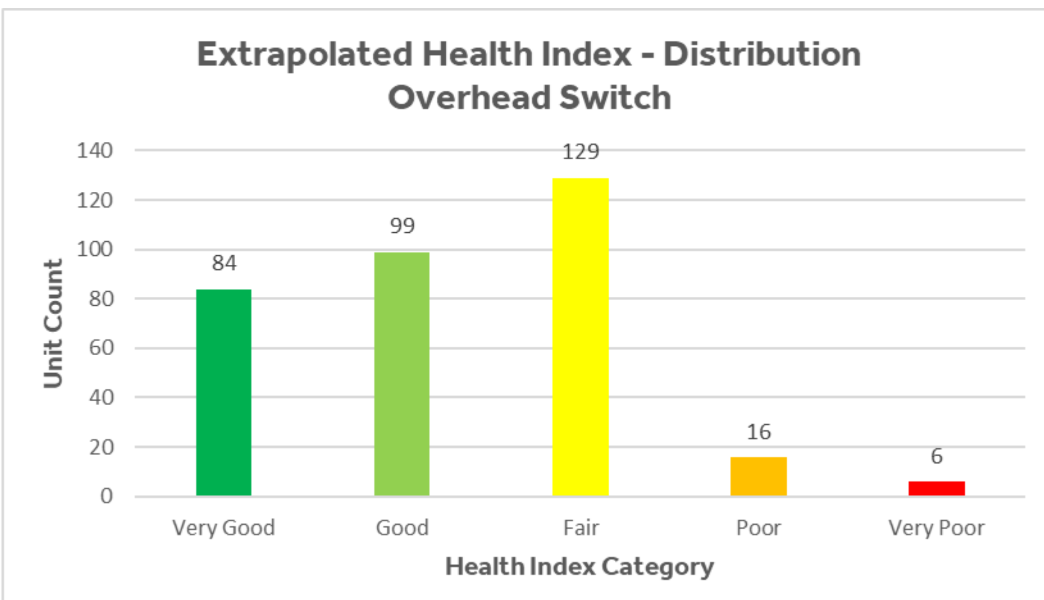


Figure 3-31: Distribution Overhead Switch Health Index Demographic



3.2.5. System Utilization (5.3.2d)

As previously noted in Section 3.1.2, ORPC performs a load forecasting and system utilization analysis as part of the Planning stage of the AM Process in order to identify potential capacity constraints across the system. System utilization is assessed based upon the peak load of each feeder and station transformer relative to their respective ratings. Feeders are typically rated at the calculated ampacity.

Station transformers are typically rated based on their rated nameplate capacity. Station capacity and feeder capacity results are further presented in the sub-sections below.

3.2.5.1. Station Capacity

Table 3-7 illustrates the transformer peak loading and utilization values across all of ORPC's MS in 2020. These results can ultimately be utilized to identify capacity constraints at the substation level. These results do not reveal any major capacity issues that would require capacity upgrades at any given substation.

With the recent introduction of the Almonte MS4 substation, ORPC is expected to see further capacity relief within the Almonte service area moving into the DSP planning period. With respect to Pembroke service area, while we do see higher utilization levels at the Pembroke MS1 substation, these current levels are not expected to pose any risk over the 5-year planning period when taking into consideration the slow economic growth and decreasing population within Pembroke between 2011 and 2016 (as explained in Section 3.2.1

Table 3-7: ORPC 2019 Station Transformer Utilization

Municipal Station	Transformer	Nominal Capacity (kVA)	2020 Peak Loading (kVA)	2020 % Utilization
Almonte				
MS1	T2	5,000	2,241	45%
MS2	T1	5,000	4,004	80%
MS3	T1	3,000	1,873	62%
MS4	T1	5,000	2,774	55%
Pembroke				
MS1	T1	2,500	2,810	112%
	T2		1,909	76%
	T3		2,017	81%
MS2	T1	6,000	2,390	40%
MS3	T1	5,000	1,158	23%
MS4	T1	5,000	2,138	43%
MS5	T1	3,000	841	28%
MS6	T1	10,000	2,628	26%
	T2	10,000	3,960	40%
MS7	T1	10,000	5,256	53%
MS8	T1	10,000	6,595	66%

3.2.5.2. Feeder Capacity

Table 3-8 illustrates the feeder utilization statistics across ORPC's distribution system in 2019. These results can ultimately be utilized to identify capacity constraints at the feeder level and determine if feeder upgrades or further load distribution is required.

Results within the Almonte service area do not reveal any major capacity issues that would require feeder upgrades. For the Pembroke service area, we do see Feeders 1-2 and 2-1 both with utilization levels at 80%. However, given the slow economic growth and decreasing population within Pembroke between 2011 and 2016 (as explained in 3.2.1), these results are not expected to introduce any feeder-level constraints over the 5-year planning period.

Table 3-8: ORPC Feeder utilization

Feeder	Planning Capacity (Amps)	2020 Peak Load (Amps)	2020 % Utilization
Almonte			
1-1	400	115	29%
1-2	400	132	33%
1-3	400	160	40%
2-1	400	226	57%
2-2	400	247	62%
2-3	400	191	48%
3-1	400	135	34%
3-2	400	160	40%
4-1	400	299	75%
4-2	400	299	75%
Pembroke			
1-1	300	100	33%
1-2	300	165	55%
1-3	300	150	50%
1-4	300	170	57%
2-1	300	185	62%
2-2	300	175	58%
2-3	300	80	27%
2-4	300	75	25%
2-5	300	50	17%
3-1	300	70	23%
3-2	300	100	33%
3-3	300	50	17%
3-4	300	110	37%
4-1	300	140	47%
4-2	300	100	33%
4-4	300	90	30%
4-5	300	80	27%
5-1	300	90	30%
5-4	300	120	40%
6-1	300	40	13%
6-2	300	110	37%
6-3	300	90	30%
6-4	300	126	42%
7-1	300	130	43%
7-2	300	175	58%
8-1	300	130	43%
8-2	300	187	62%

3.3. 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 first discussed in Section 3.1 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.

3.3.1. Asset Lifecycle Optimization Practices (5.3.3a)

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.

3.3.1.1. Long-Term Lifecycle Optimization Practices

As noted in Section 3.1.2.2, ORPC's long-term planning sub-process results in the development and definition of the investment programs within the DSP. Each program is designed to mitigate specific risks within 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 to that program.

System Renewal programs are largely driven by Failure Risk of assets exceeding their TUL and/or assets in Very Poor or Poor condition, assets that are Functionally Obsolete and no longer align to ORPC's current standards, and/or assets that are introducing environmental risks into the system. The typical lifecycle optimization practice undertaken by ORPC is to replace these assets when identified via the long-term planning sub-process. Table 3-9 provides further insight into the practices being undertaken within each of ORPC's System Renewal programs.

Table 3-9: 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

Program	Asset Lifecycle Optimization Practice
	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 conductor will be reused and reinstalled 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 3-10 provides further insight into the lifecycle optimization practices being undertaken within each of ORPC's System Service programs.

Table 3-10: 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 appropriately mitigated. • System Constraints: As discussed in Section 3.2.5, 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 to be 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 3-11 provides further insight into the lifecycle optimization practices being undertaken within ORPC's System Access programs.

Table 3-11: 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.
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.

Finally, 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 3-12 provides further insight into the lifecycle optimization practices being undertaken within ORPC's General Plant programs.

Table 3-12: 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 centres 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 purposes 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 in order 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

	day operations. This will include ensuring ORPC can carry out maintenance activities, support capital projects, and respond to emergency outages. The replacement of the vehicle will also reduce the ongoing maintenance cost of this vehicle.

3.3.1.2. 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.

As first explained in Section 3.1.2.2, 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 3.3.2.

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 3.3.1.1 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 3.3.2.2.2.

3.3.1.3. Maintenance Lifecycle Optimization Practices

ORPC's maintenance program is designed to support the continued reliable operation of their asset base over its TUL, through the execution of visual inspection and testing programs. ORPC's maintenance activities implement the Minimum Inspection Requirements as required by the OEB Distribution System Code – Appendix C[17] as well as Electrical Distribution Safety requirements as specified by Ontario Regulation 22/04[18].

All of ORPC's substation infrastructure, including power transformers, circuit breakers, protection relays, station switches and batteries are inspected on a monthly basis. Overhead and underground distribution assets receive visual inspections on a three-year rotational 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.

[17] "Appendix C – Minimum Inspection Requirements", Distribution System Code, Ontario Energy Board, 2020.
[18] "O. Reg. 22/04: Electrical Distribution Safety", Queen's Printer for Ontario, 2017.

- 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 3.1.2.1, 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 8.1), 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 3-13.

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 3-13: Summary of Maintenance Practices for ORPC's System Assets

Assets	Description of Maintenance Activities
Overhead Assets	• Transformers – Visual inspections performed to check for leaks, nomenclature, damaged bushings, lighting arrestor connections and proper grounding. • Poles – Visual inspections performed to assess overall shape of pole, woodpecker holes, access to pole and posters attached. • Overhead Conductors – Visual inspections performed to assess insulation condition, sag, and overall appearance. • Guys – Visual inspections performed to look for missing or damaged guards, loose guys, broken insulators, pulling anchors. • Vegetation – Visual inspections performed to assess close proximity of trees, back lot access.
Underground Assets	• Cabinet Damage – Visual inspections performed to check for loose or broke hinges, corrosion and rust, dents, graffiti, or vandalism. • Cabinet Access – Visual inspections of locks and penta-bolts in place, vegetation blocking access, landscape issues, drainage from ground water. • Cable terminations – Visual inspections performed to examine evidence of flashover, cable distortion, missing test points, discoloration of neutrals, tracking • Nomenclature – Visual inspections performed to examine proper labeling installed and legible, missing, or damaged I.D. tags.

Assets	Description of Maintenance Activities
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 • 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 build up, vandalism, paint, leaking roof.

3.3.2. Asset Lifecycle Risk Management Policies and Practices

In order to determine the asset lifecycle risk within ORPC's system, it is necessary to determine both the probability and impact of asset failure. Probabilistic and impact-related elements are determined within several stages of ORPC's AM Process, including the Data Gathering and Planning stages of the process. This section serves to provide further details into these elements, and how they ultimately form the complete asset lifecycle risk management policies and practices for the utility.

3.3.2.1. Asset Probability of Failure

The probability or likelihood of failure plays an important role into 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. Key decision-making analytics captured during the Data Gathering stage of the AM Process are used to determine the probabilistic trends and identify emerging asset-related issues within the system, including:

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

Each of these analytics are further discussed within the following subsections.

3.3.2.1.1. Reliability Assessment

The 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 – particularly within the System Renewal and System Service categories – in order to continue to manage system performance and mitigate the impacts associated with rare events such as Loss of Supply.

3.3.2.1.2. Assets Past Useful Life

The APUL analysis allows for ORPC to assess the age demographics at both an asset level as well as at the system level. APUL provides an indication where an asset has already exceeded or will be approaching its TUL value within the 5-year DSP planning period. The TUL values for ORPC were derived based upon the *Asset Depreciation Study for the Ontario Energy Board* report produced in 2010[19]. This report provided ranges of useful lives for distribution asset classes, as well as a TUL value. Results in the report were derived based upon a composite of industry values known to Kinectrics Inc., who developed the report on behalf of the OEB.

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 exceeding 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 end-of-life and require replacement and/or repair within the DSP planning period.

Table 3-14 provides the specific TUL values that ORPC has applied to its asset classes in order to perform the APUL analysis. Figure 3-32 illustrates the percentage quantities of overhead, underground and stations assets that are already exceeding, approaching, or not approaching their TUL values respectively over the DSP planning period from 2022 onwards to 2026.

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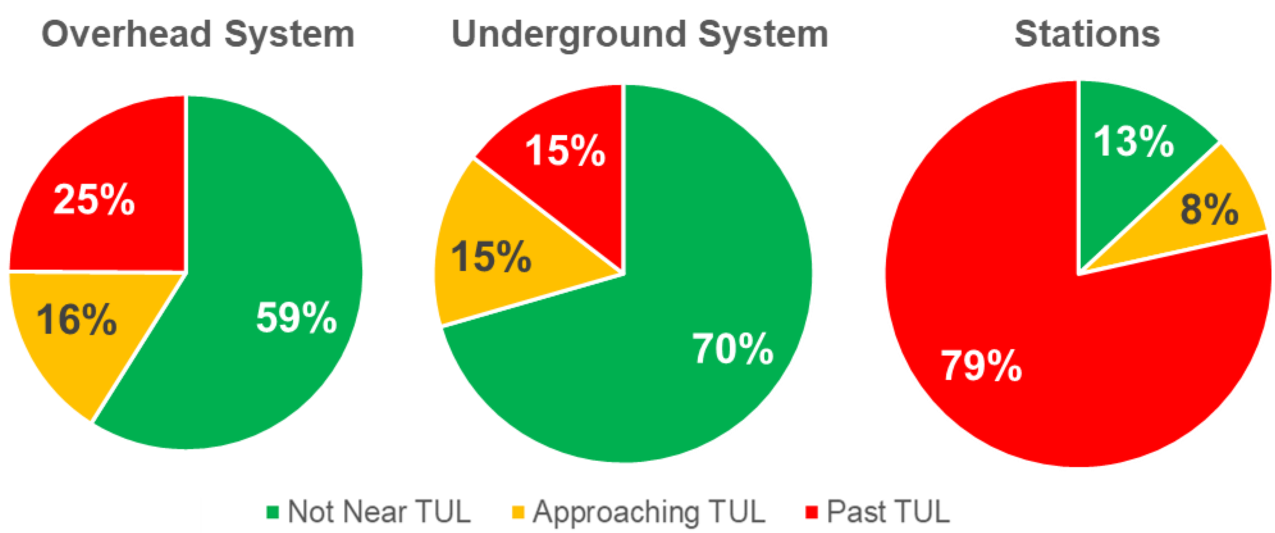
[19] "Asset Depreciation Study for the Ontario Energy Board", Kinectrics, 2010.

Table 3-14: Summary of Maintenance Practices for ORPC's System 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

Figure 3-32: APUL Results for Overhead, Underground & Stations Assets

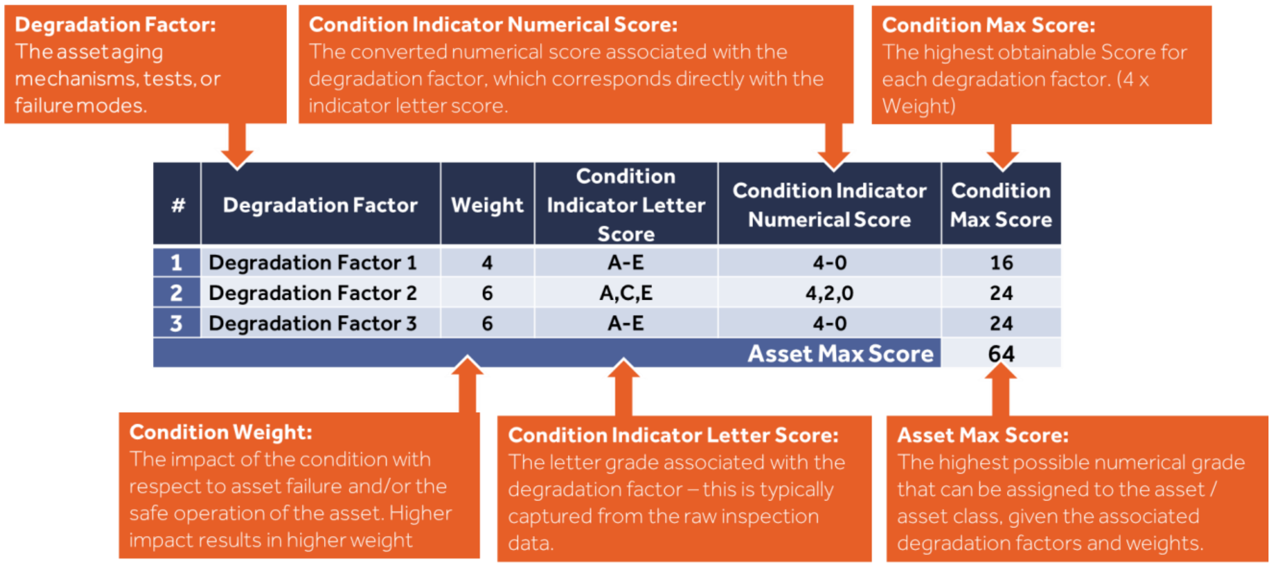


3.3.2.1.3. Asset Condition Assessment

The ACA analysis is designed to leverage in-field data, including visual inspection and testing information collected for individual assets, in order 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 3-33 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 3-33: Breakdown of ACA 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).

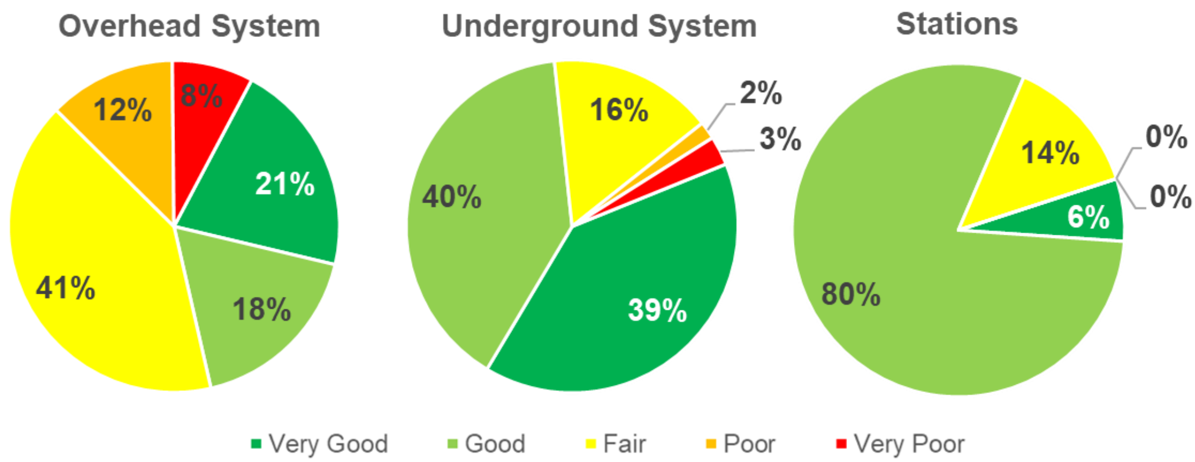
$$HI = \left(\frac{\sum_{i=1} Weight_i \ x \ Numerical\ Score_i}{Asset\ Max\ Score}\right) x\ 100 \qquad (EQ\ 3\text{-}1)$$

Where:

i	corresponds to each individual degradation factor
Weight	corresponds to the weight associated with each degradation factor
Numerical Score	corresponds to the condition indicator score for the degradation factor
Asset Max Score	corresponds to the maximum score that the asset can receive
HI	corresponds to the Health Index for the asset.

HI results can be leveraged at both the system level as well as the individual asset level, in order to develop the long-term investment program and create the short-term discrete projects. Figure 3-34 illustrates the percentage quantities of overhead, underground and stations assets that are in Very Poor, Poor, Fair, Good and Very Good conditions, respectively. Further results from the ACA analysis are presented in Section 3.2.4 and in the ACA Report which is further detailed in Appendix D.

Figure 3-34: ACA Results for Overhead, Underground & Stations Assets



3.3.2.2. Asset Impact and Risk of Failure

The impact or consequences of failure plays an important role into determining the possible impacts that an asset failure will have within the distribution system. By leveraging the impact-based results in conjunction with probability-based results, ORPC is able to apply a risk-based approach when managing their asset base.

As noted in Section 3.1.2.2, ORPC applies two forms of analytics as part of their short-term planning sub-process which considers both asset impacts as well as the risk of asset failure as part of the overall decision-making process:

- Risk-Based Project Prioritization
- Project Evaluation

Each of these analytics are further discussed within the following subsections.

3.3.2.2.1. Risk-Based Project Prioritization

Risk-Based Project Prioritization involves the selection and prioritization of projects within the test year of the 5-year DSP plan, based upon both probability and impact-based results.

For probability, both APUL and ACA results are leveraged in order to assess if the asset requires immediate replacement within the plan. These results are used in conjunction with customer count data for each project, where customer counts are estimated based upon an assessment of distribution transformers within the project location and their connections to commercial properties or residential homes. From this analysis, the localized customer outages in the area can be estimated should a given asset fail.

Where expanded information about the network configuration/topology is known, such as the upstream fuse or breaker that may trip should an outage occur, this information will also be leveraged as part of the analysis. This analysis is performed as part of a manual process by ORPC's asset planners when determining what projects should be executed within the test year.

3.3.2.2.2. Project Evaluation

All material projects within the test year for a given program that are not driven by mandated service obligations, third-party or customer service requests are evaluated leveraging a project evaluation procedure. Different timing & pacing alternatives are economically evaluated for the aggregate set of projects within the test year for a given program by leveraging a benefit-cost analysis.

For each alternative, the individual impacts and benefits are assessed, where each alternative's outcomes may yield similar or improved benefits to one another. However, each alternative assessed is a trade-off between project costs, benefits, and timing. Benefits vary depending on the type of investment, but typically include reduced reactive replacements, reduced customer load at risk, reduced environmental risk (e.g., oil spills, PCBs), and managed safety risks.

The benefits of each project alternative are considered to be the increase in productivity resulting from the implementation of the alternative. The costs of each program alternative are considered to be the increase in risk resulting from the implementation of the alternative. The risk resulting from the implementation of the alternative is a monetary value that is estimated using assumptions based upon subject matter expertise and available data. Historical data and industry research are used to estimate the monetary value of the program benefits and costs, within the scope of ORPC's objectives and their customer preferences.

For System Renewal projects, the costs associated with projects and considered in the project evaluation process are the capital cost, the 5-year expected asset failure cost, the environmental cost of potential transformer oil leaks, the cost of planned construction outages, and the cost of unplanned outages within the project scope. The 5-year expected asset failure cost is determined using the probability of failure of the project asset scope, based on ACA results. The environmental cost of potential transformer oil leaks is estimated as the standard volume of oil within the transformers being replaced. The cost of planned construction outages is estimated using current job time estimates and historical construction outage times per asset renewal, and the average cost per customer outage which is determined using the Interruption Cost Estimate ("ICE") calculator[20]. The cost of unplanned outages within the project scope is estimated using the expected number of unplanned outages for relevant system feeders, and the average cost per customer outage which is determined using the ICE calculator.

To calculate the expected number of unplanned outages for relevant system feeders, the number of outages for the relevant feeder is first recorded for a 10-year historical period. Then, an initial estimation of the 5-year annual feeder outages is made using a linear forecast model. An asset reaching end-of-life ("EOL") analysis is performed, utilizing system ACA and TUL results. This produces a forecast of the number of system assets that will reach the end of their useful life within a specified time period. The initial estimation of the 5-year annual feeder outages is plotted against the forecast number of assets reaching EOL in the same 5-year time period, which produces a linear relationship. This linear model is used to estimate the number of outages expected to occur for a given feeder, in the timeframe associated with the different alternative project pacing.

For General Plant projects, the costs associated with projects and considered in the project evaluation process are the capital cost, the 5-year expected asset failure cost, the system maintenance costs, and the system breach risk cost. The 5-year expected asset failure cost is determined using the probability of failure of the project asset scope and the expected immediate costs of failure. System maintenance costs are estimated based on historical data. System breach risk cost is estimated using assumptions based on subject matter expertise. The benefit associated with projects and considered in the project evaluation process is the productivity gain. Productivity gain is estimated using subject

[20] "Interruption Cost Estimate (ICE) Calculator", Nexant Inc., Lawrence Berkeley National Laboratory, 2020. URL: https://icecalculator.com/

matter expertise assumptions of employee time saved with system upgrades, historical data, and current employee rates.

For System Service projects within the Station Expansion program, the costs associated with projects and considered in the project evaluation process are the capital cost, the cost of unplanned outages within the project scope, and the risk cost of system breach. For System Service projects within the System Enhancement program, the costs associated with projects and considered in the project evaluation process are the capital cost and the cost of unplanned outages within the project scope. The cost of unplanned outages within the project scope is estimated using the expected number of unplanned outages for relevant system feeders which is calculated using the method outlined above for System Renewal projects, and the average cost per customer outage which is determined using the ICE calculator. The risk cost of system breach is estimated using assumptions based on subject matter expertise.

The project evaluation process produces a total cost of ownership (“TCO”) for the residual risk value of each alternative based on the projected benefit and cost streams over the life cycle of the assets. The alternative with the lowest TCO for residual risk is considered to be the most beneficial alternative. The results of the project evaluation process inform the decision-making process in selecting a recommended alternative.

3.4. System Capability Assessment for REG (5.3.4)

3.4.1. Applications for Renewable Generators over 10 kW (5.3.4a)

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 3-15. Moreover, there are an additional 40 microFIT (<10KW) projects listed within IESO records with a combined capacity of 354.1 kW. The details of these microFIT connections are presented in

Table 3-16. ORPC does not have any FIT or net metering connections within any of ORPC’s service territories.

Table 3-15: Description 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 3-16: Details on microFIT Connections

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

3.4.2. Forecast of REG Connections (5.3.4b)

Due to the upstream constraints at the HONI-owned stations (details are provided in Section 3.4.4) and the current state of REG connections, ORPC does not forecast any new REG connections over the five-year DSP planning period from 2022 to 2026. Currently, only one customer has requested an AC load displacement system of 40 kW and this project remains in the preliminary stages with no Connection Impact Assessment ("CIA") requested as of yet. Based on the assessment of available information, ORPC does not propose any investments over the DSP planning period to facilitate new REG connections.

3.4.3. Capacity Available (5.3.4c)

ORPC performs the analysis of its system utilization as part of planning stage of its AM process. The utilization is assessed based on peak load of each feeder and station transformer relative to their respective ratings. Sections 3.2.5.1 and 3.2.5.2 provide the details of available capacity for ORPC stations and feeders, respectively. The results as outlined in these sections do not identify any major capacity issues that would require capacity upgrades at any given substation. Currently, with the introduction of new Almonte MS4 station, ORPC is also expecting additional capacity within the Almonte service area to support growth and relief capacity.

3.4.4. Constraints Related to REG Connections (5.3.4d and 5.4.3e)

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.

ORPC is currently having discussions with one customer interested in a 40kW AC load displacement system. The discussions remain at a preliminary phase and have not yet reached the point where the CIA has been requested. It is not known at this time if the customer will move forward with this project. Should the project go ahead, ORPC will perform the detailed capacity assessment of its distribution system in order to safely accommodate the necessary connections for this load displacement generator.

4. CAPITAL EXPENDITURE PLAN (5.4)

This section details ORPC's five-year capital expenditure plan within the DSP planning period from 2022 onwards to 2026. This includes the following sections:

- Section 4.1 – Capital Expenditure Plan Summary: Provides an overall summary of the capital expenditure plan, including details on the investment categories, the 11 underlying investment programs, related drivers and associated expenditures.

- Section 4.2 – Capital Expenditure Planning Process: Provides details on how ORPC developed their CAPEX Plan via execution of the AM Process for the purposes of this application and the 2022-2026 DSP.

- Section 4.3 – Capital Expenditure Summary: Provides a full view of expenditures across the four DSP investment categories (i.e., System Renewal, Service, Access, General Plant) from the historical period (2015-2019), the bridge years (2020 & 2021) as well as the planning period (2022-2026), with explanatory notes on material variances.

- Sections 5 – Section 8 – Capital Investment Programs: Provides the full details on all capital investment programs across the four DSP investment categories, including Program Description, Project Need & Drivers, Timing & Pacing and Options Analysis results. Key sections include:
    - Section 5 – System Access Investments
    - Section 6 – System Renewal Investments
    - Section 7 – System Service Investments
    - Section 8 – General Plant Investments

4.1. SUMMARY

ORPC's DSP, and the integrated CAPEX Plan as presented within this chapter, have been developed as key outputs of the AM Process as described in Section 3.1. Capital investments over the DSP planning period from 2022 onwards to 2026 have been organized within the four DSP investment categories and further integrated into 12 investment programs, each with their own primary (trigger) and secondary drivers (where applicable) which correspond to the parent investment category.

The following subsections serve to provide a summary view of ORPC's expenditures across the four DSP investment categories, while also introducing the 12 investment programs and their associated drivers.

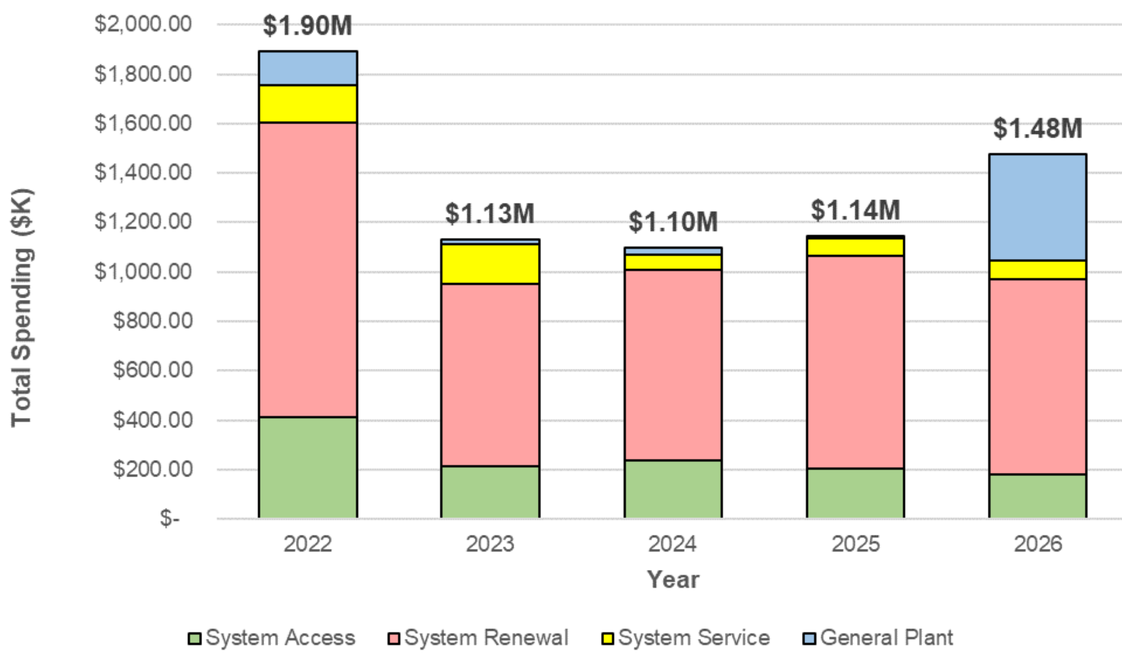
4.1.1. Summary of Capital Expenditures (2022-2026)

Table 4-1 presents the net capital expenditures for ORPC occurring within the DSP planning period from 2022 onwards to 2026. In 2022 there is significant increase in expenditure in due to the need to replace a power transformer that unexpectedly failed in late June 2021 just before the filing of this DSP. The cost of this accounts for around 40% of the expenditure in 2022. Figure 4-1 presents these same capital expenditures graphically.

Table 4-1: ORPC's Planned Net Capital Investment by Category ($K)

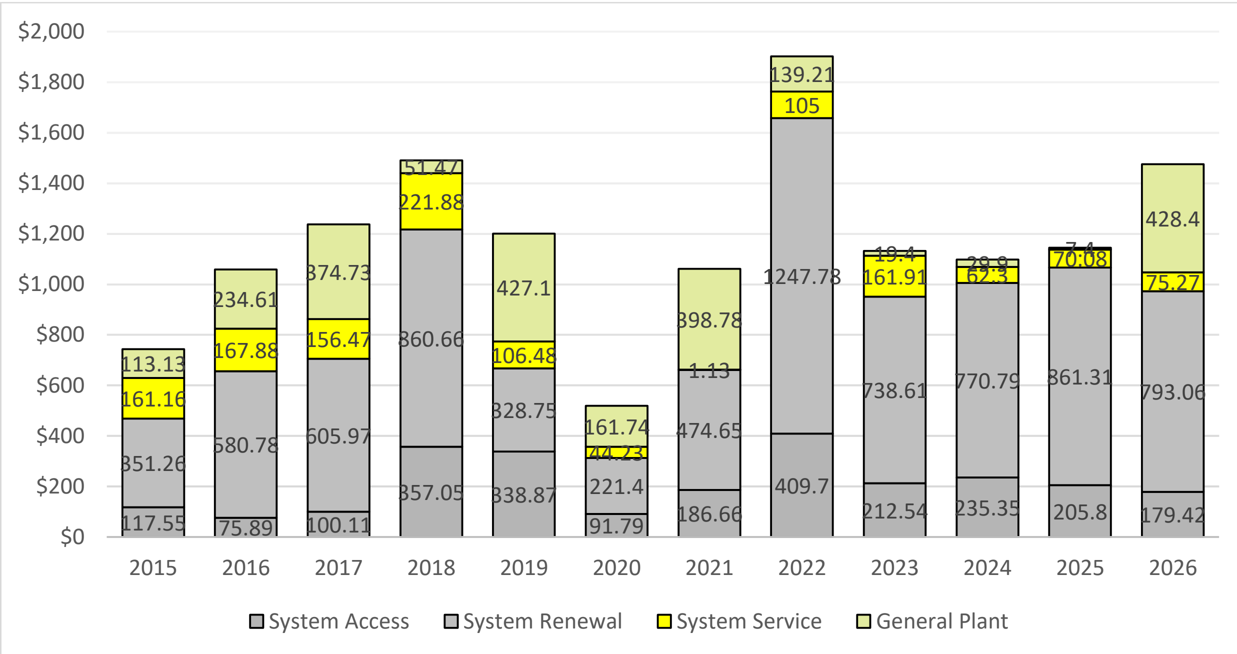
Category	Avg.	2022	2023	2024	2025	2026	Total
System Access	$ 248.56	$ 409.70	$ 212.54	$ 235.35	$ 205.80	$ 179.42	$ 1,242.82
System Renewal	$ 882.31	$ 1,247.78	$ 738.61	$ 770.79	$ 861.31	$ 793.06	$ 4,411.56
System Service	$ 94.91	$ 105.00	$ 161.91	$ 62.30	$ 70.08	$ 75.27	$ 474.56
General Plant	$ 124.86	$ 139.21	$ 19.40	$ 29.90	$ 7.40	$ 428.40	$ 624.31
TOTAL	**$ 1,350.65**	**$ 1,901.69**	**$ 1,132.47**	**$ 1,098.34**	**$ 1,144.59**	**$ 1,476.16**	**$ 6,753.25**

Figure 4-1: ORPC's Net Planned Capital Investment by Category



In total, ORPC plans to spend $6.75M over the next five-year period. This expenditure plan considers investment decisions based upon the AM and capital expenditure planning process, the project evaluation process, and customer preferences. Figure 4-2 illustrates all historical and forecasted capital expenditures from 2015 onwards to 2026, including the 2020 and 2021 bridge years and 2022 test year. The lowest capital expenditures have been incurred in the 2020 bridge year, mostly due to COVID-19 pandemic. It is not expected that the COVID-19 pandemic will have any major impact on what ORPC are able to deliver in the 2022-2026 period.

Figure 4-2: Historical & Forecasted Capital Expenditures (2015 - 2026)



4.1.2. Summary of Capital Investment Program Primary Drivers

All of ORPC's investment programs possess a primary (trigger) and secondary driver as specified by the Filing Requirements. Table 4-2 provides the listing and descriptions of primary drivers that were applied within ORPC's capital investment plan. Each primary driver corresponds to the DSP investment category that the investment program has been positioned within. On the other hand, secondary drivers may belong to any of the other DSP investment categories.

Table 4-2: ORPC Primary Drivers applied to DSP Investment Programs

OEB Category	Primary 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.
	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 on customers as well as potential safety risks to crew workers or the public.
System Service	**Reliability**	Management of system-wide reliability concerns such that system reliability is either maintained or improved.
General Plant	**System Maintenance Support**	To support day to day business operations and maintenance. E.g., land, building, office supplies
	Business Operations Efficiency	The ability to mitigate and recover from disruptions to core business functions. E.g., information technologies such as computers, workstations, etc.
	Non-System Physical Assets	Rolling stock vehicles, tools, and equipment

4.2. Capital Expenditure Planning Process Overview (5.4.1)

In order to develop the capital expenditure plan as integrated within this DSP, ORPC executed the AM Process as described in Section 3.1, which included the Data Gathering, Planning, Execution and Validation stages of the process. The following subsections further serve to detail the results from key driving elements of the AM Process as further described below:

- Section 4.2.1 provides key results from DSP Survey, which along with other customer engagements served to capture the define the customer preferences heading into the development of the DSP.

- Section 4.2.2 provides results from the decision-making analytics, including historical reliability results, APUL and ACA results that served to highlight the key needs from the system.

- Section 4.2.3 provides results from the System-Wide Analysis, which was applied to develop the capital investment programs, designed to balance the needs of ORPC's system with customer preferences, available resources and system constraints.

4.2.1. Results from the Customer Survey

As first described in Section 2.1.2, ORPC has executed a series of customer engagement surveys in order to capture overall customer preferences and satisfaction with respect to ORPC services and system reliability. As part of developing the DSP, ORPC also conducted a DSP Survey in 2020 to capture specific customer preferences with respect to ORPC's investment plan. Complete results from the DSP Survey are further provided in Exhibit 1, Appendix E. Key observations from the survey are noted below:

- Customers were asked to provide their top three priorities that they felt ORPC should be addressing. Figure 4-3 reveals that “Reasonable Distribution Rates” remains a top priority for ORPC customers, with just under 70% of customers selecting this option out of three options total. “Day-to-Day Reliability” was the second-highest priority, with just under 55% of customers selecting this option out of their three options. Finally, “Helping customers reduce and manage their electricity consumption” rounded out the top three priorities at just under 50% of customers.

- Figure 4-4, Figure 4-5, and Figure 4-6 present the results of investment preferences with respect to asset replacements, System Service and General Plant investments, respectively. Within the survey materials, customers were educated on the DSP investment categories, and were asked their preference with respect to ORPC’s plan for these investments respectively – should these be decreased, increased, or kept the same as documented in the plan? It was noted that the plan as documented generally aligned with the historical investments from 2015-2019:

    - For asset replacements (as presented in the System Renewal category), 41.6% of customers preferred that ORPC increase the pace of investment, while a proportional 40.6% of customers stated that they are satisfied with the rate of replacement as presented within the DSP. Less than 1% of customers wanted to see ORPC reduce investments.

    - For System Service investments, 43.4% of customers preferred that ORPC increase the investment plan, while a proportional 40.4% of customers stated that they would prefer ORPC to increase the investment plan. In this case, no customers wish to see the investments reduced.

    - For General Plant investments, more than 50% of customers stated that they are satisfied with the plan, while only 36.4% of customers preferring to see an increase in investment, and no customers wanting to see investments reduced.

- Finally, with respect to the overall DSP, more than 51% of customers felt that ORPC’s plan was the right approach to manage the system, while 42% of customers did not know if it was the right approach, but they trusted ORPC to make the right decisions. These results are illustrated in Figure 4-7.

In general, these results point to two conclusions. The first being that rate digestibility remains a top priority for ORPC’s customer base. The second being that customers are generally satisfied with ORPC’s plan or would prefer an increase to the plan that would result in further reliability improvements.

Figure 4-3: Top Three Customer Priorities that ORPC Should Address

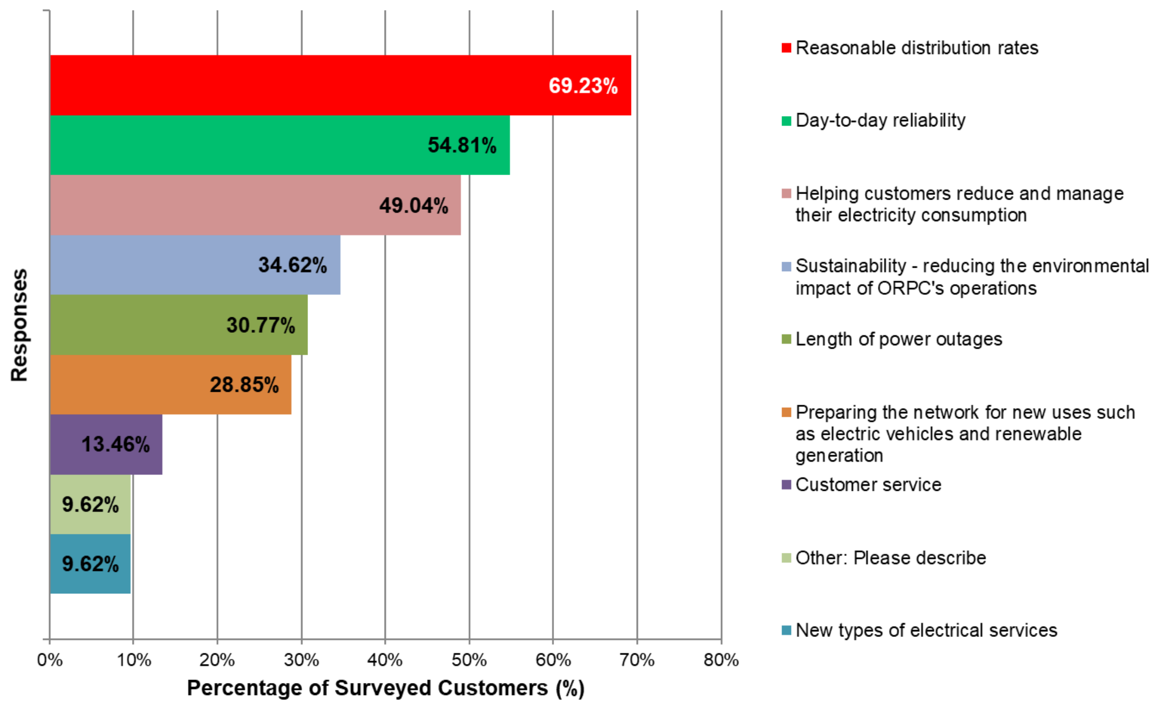


Figure 4-4: Customer Preferences towards Pacing of Asset Replacements (System Renewal)

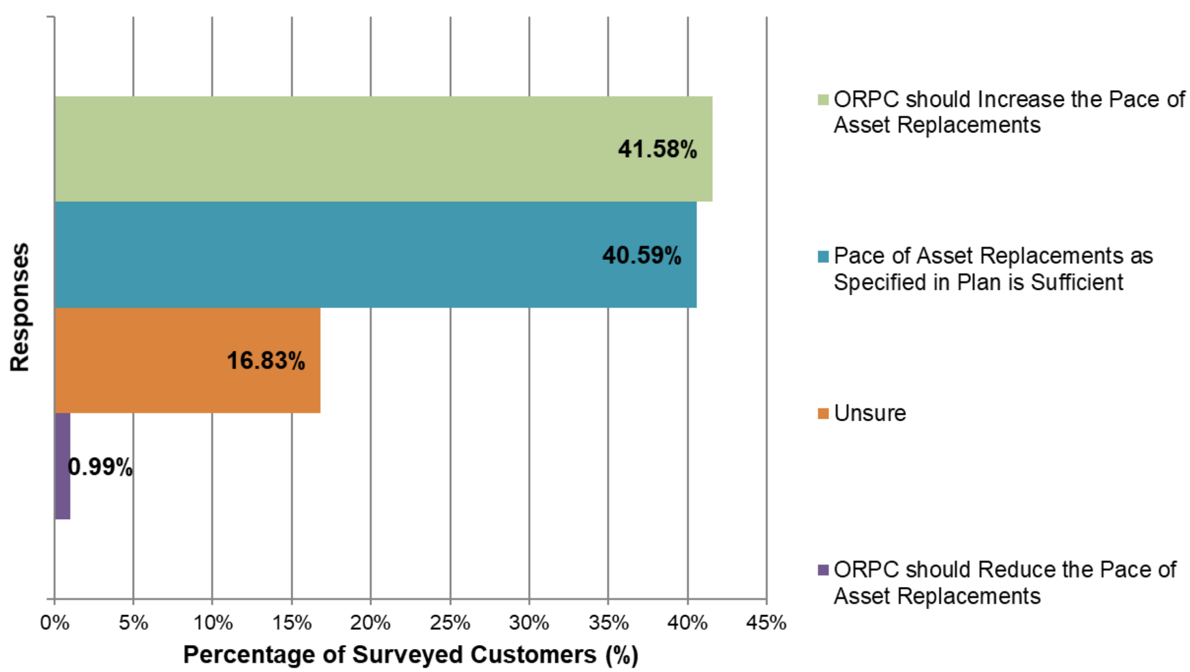


Figure 4-5: Customer Preferences towards Pacing of System Service Investments

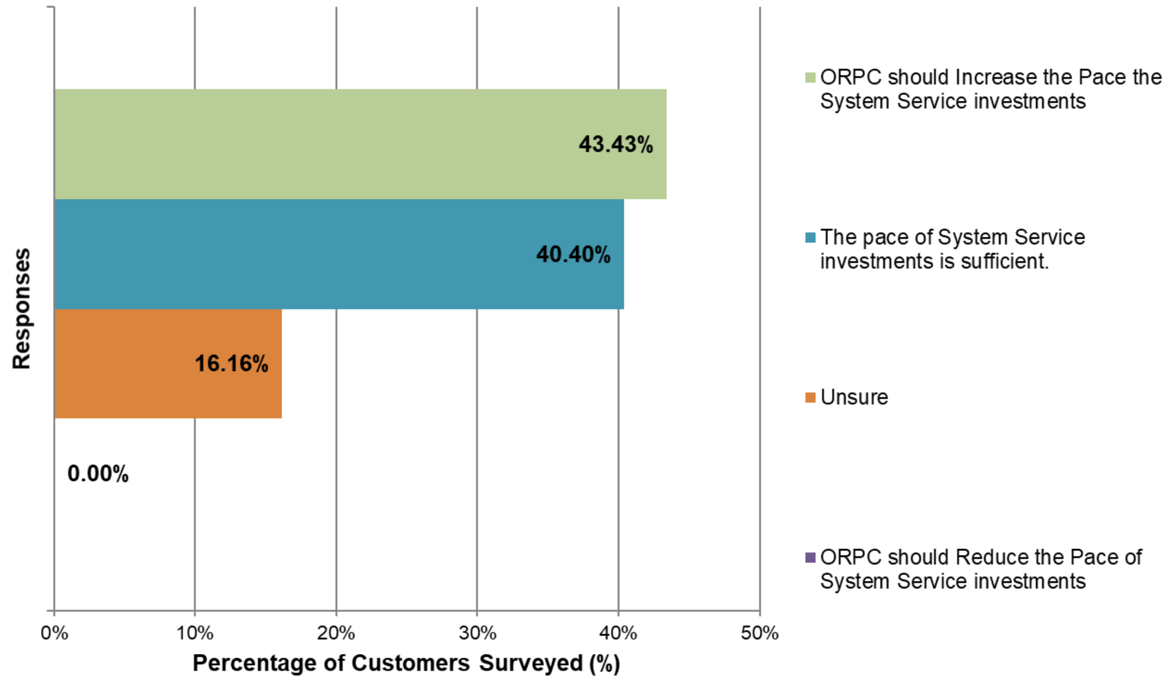


Figure 4-6: Customer Preferences towards Pacing of General Plant Investments

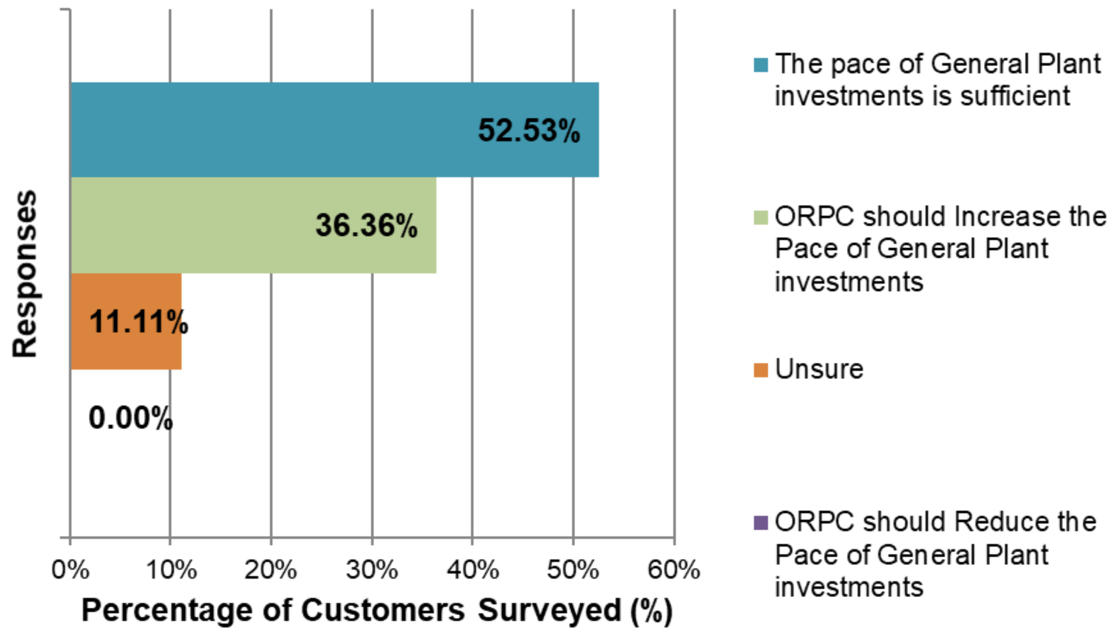
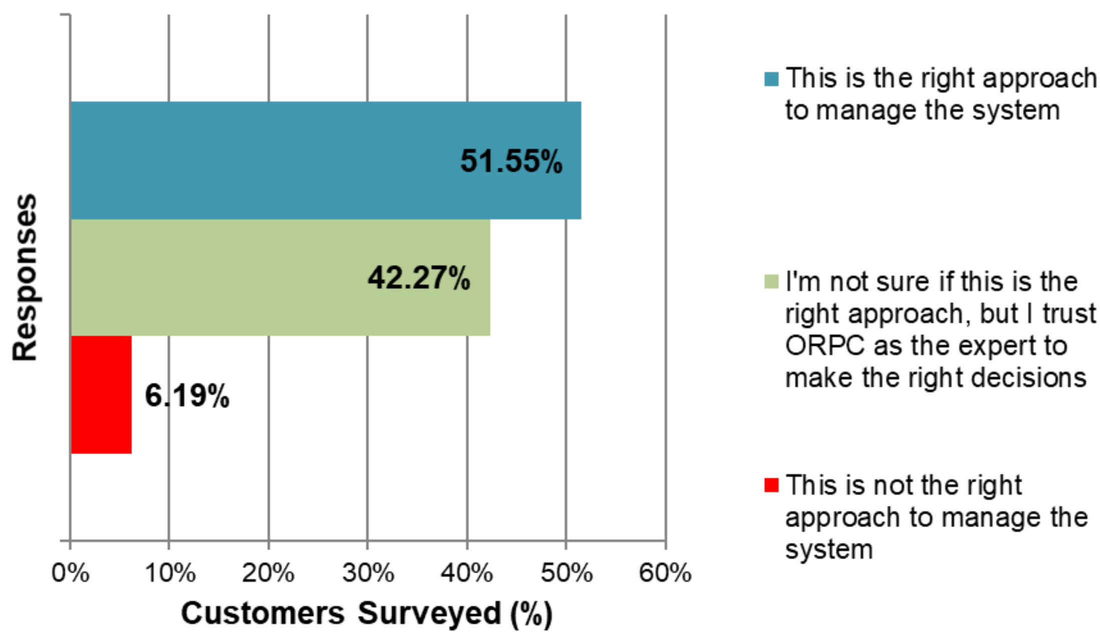


Figure 4-7: Overall Customer Preferences on DSP Approach



4.2.2. Results from Decision-Making Analytics

Data Gathering represents the first stage of the AM Process as noted in Section 3.1.2.1, where data is gathered, consolidated and digitized for the purposes of supporting the Planning stage of the process in order to produce long-term, short-term and maintenance planning outputs, respectively. Decision-making analytics represent a key form of information that is gathered within this stage, in order to support the subsequent Planning stage of the AM Process, and in particular, the Long-Term Planning sub-process. It is from this sub-process, and in particular, the System-Wide Analysis, that the Long-Term Capital Expenditure Plan as presented within this DSP was produced.

A key component in producing this long-term plan is the Reliability Assessment, which leverages the Historical Reliability Results as captured from the Data Gathering stage. As explained in Section 3.1.2.2, the Reliability Assessment allows for major trends to be identified that must be managed within the course of the DSP planning period. When examining the total number of outages (excluding MED and LOS events) as illustrated in Figure 4-8, we see an increasing trend of reliability impacts within the system. Figure 4-9 further filters down these reliability results to just the Defective Equipment cause code, which solely relates to assets that have failed within the system. From these results, we are starting to see a growing frequency of outages year-over-year from 2017 onwards to 2020, although in 2020 there was slight decrease compared to the previous year.

Figure 4-8: Total Number of Outages within ORPC's System

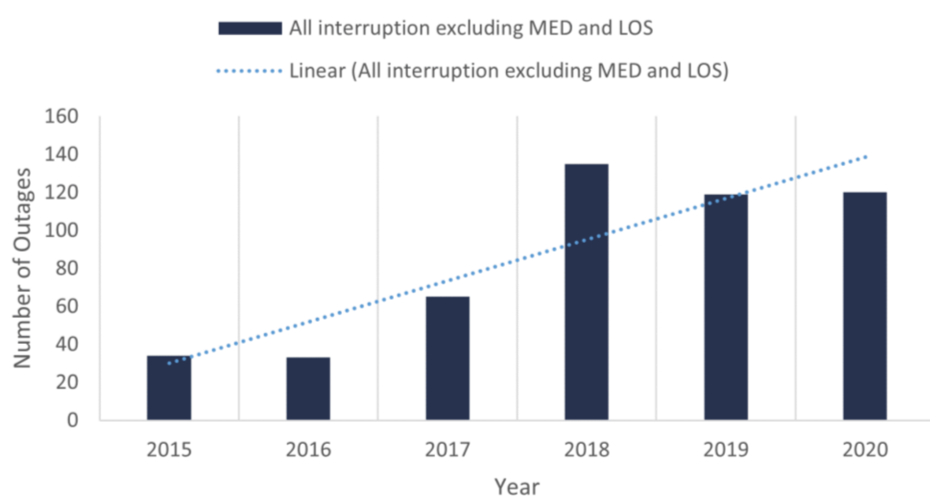
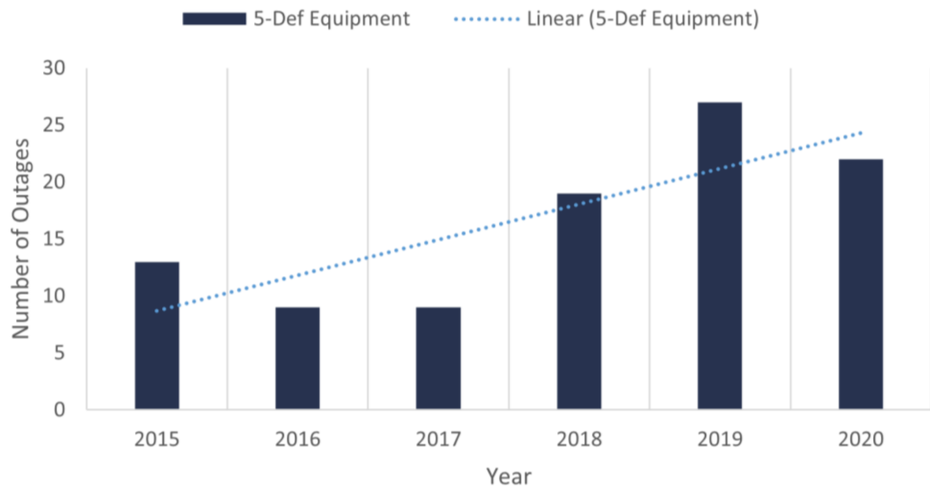


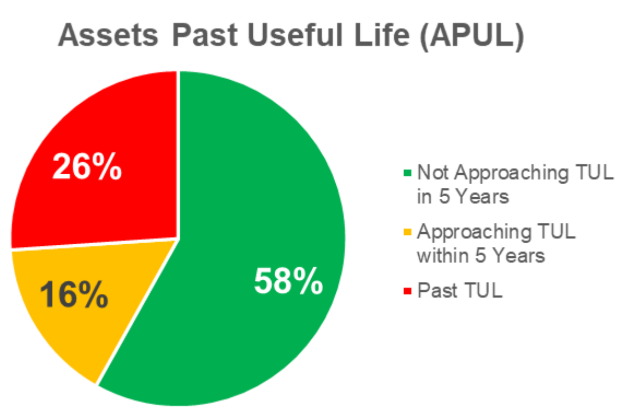
Figure 4-9: Total Number of Outages within ORPC's System

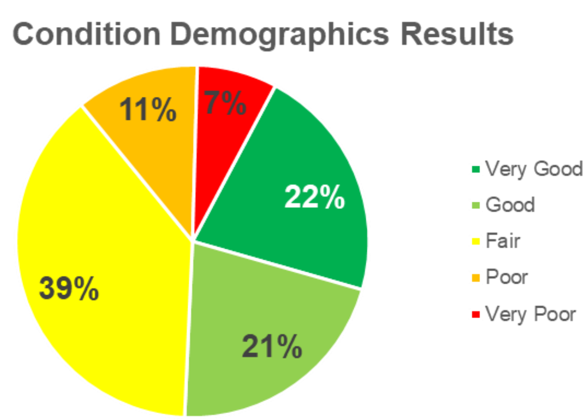


These results do indicate that there is a growing reliability concern within ORPC's system. To better understand the source of this concern, we must turn to the APUL, and ACA results as illustrated in Figure 4-10, in which individual distribution and stations assets within ORPC's system are evaluated based upon their age and condition, respectively. These results show a significant portion of the system – 26% that is already past TUL and therefore heavily aged. However, by the end of the DSP period, this number is expected to grow up to 42% – nearly half of ORPC's asset population.

From an ACA perspective on the other hand, we see that only 18% of ORPC's asset base is either in Poor or Very Poor condition. This suggests that while ORPC's asset base is heavily aged and contributing to reliability issues as illustrated by the APUL results, the assets are not degrading in an accelerated manner as illustrated by the ACA results, largely due to ORPC's maintenance program which continues to support the continued reliable operation of the asset base over its TUL through the execution of visual inspection and testing programs.

Figure 4-10: System-Level APUL & ACA Results





In general, however, these results collectively demonstrate a need for ORPC to manage its asset base such that reliability can be appropriately managed within the system. These results were ultimately used as key inputs into the System-Wide Analysis as discussed in the subsequent section.

4.2.3. System-Wide Analysis & Development of Capital Investment Programs

As first discussed in Section 3.1.2.2, the System-Wide Analysis represents a critical component of the AM Process, whereby results from the Data Gathering, coupled with System Reliability and Asset Analytics results, are brought together in order to develop the Long-Term Capital Investment Plan as presented in this DSP. The following key elements and conclusions needed to be appropriately balanced as part of the System-Wide Analysis in order to develop an optimal Capital Expenditure Plan for the system:

- System Needs: It is clear that there is a growing need within the system to sufficiently manage and replace aging and degrading equipment in order to better manage system reliability and reduce the number of defective equipment events.

- Customer Preferences: When examining the results from the DSP Survey, we also see a strong desire from ORPC customers to keep electricity rates as digestible as possible.

- Internal Resourcing: The capital expenditure plan must be executable within the DSP period such that variances can be minimized. Therefore, the plan must account for the available resources within ORPC to execute the work.

- System Constraints: Programs contained within the System Renewal and Service categories must take into consideration the constraints within the system, including capability to execute planned outages and to isolate portions of the system in order to execute the work program.

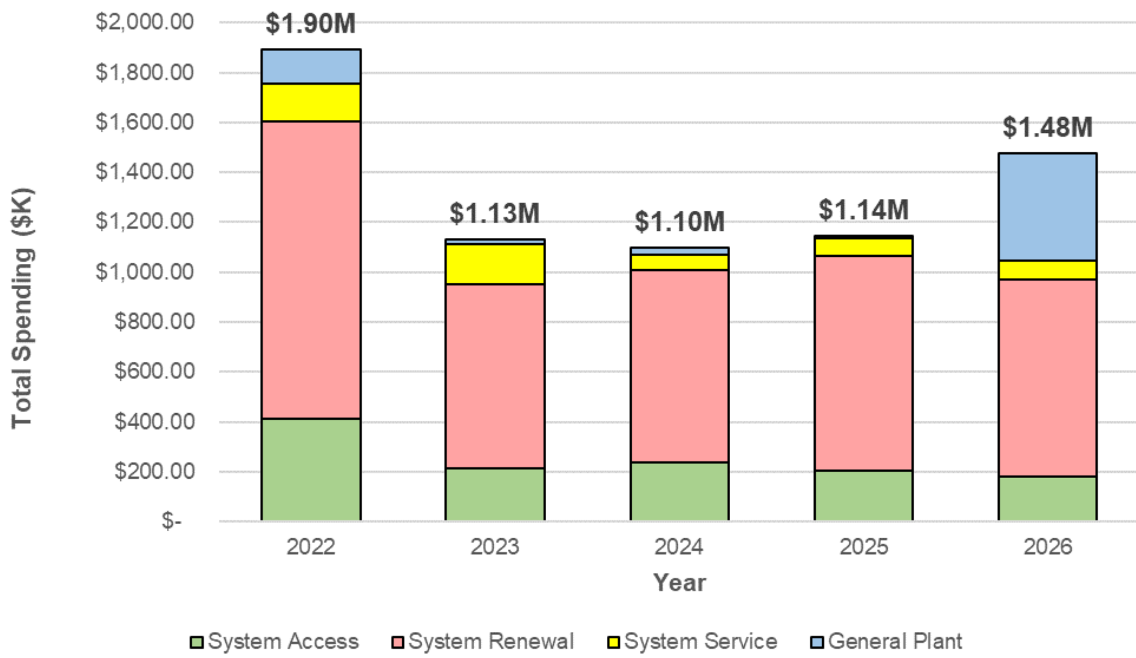
- External Constraints: The ongoing COVID-19 pandemic has already had a major impact in 2020 to ORPC's ability to execute capital investments within the system. However, it is currently not expected to impact on ORPC's ability to execute work in its forecast DSP period.

Through the execution of the System-Wide Analysis, a 2022-2026 Capital Expenditure Plan has been produced that optimally balances the five elements as noted above. In order to manage customer preferences and current resource and system constraints, it was necessary to produce a plan that closely aligned to the average expenditures from the previous 2015-2019 DSP, with only inflationary increases accounting for the differences in cost between the historical period and the forecast period. This has been achieved in the whole, expect in 2022 where due to the need to replace a power transformer that failed unexpectantly in late June 2021 just before filing.

At the same time, in order to combat the growing reliability and Defective Equipment trends, it was necessary to develop (a) targeted System Renewal programs to manage aging, deteriorating and legacy infrastructure that no longer aligns to ORPC's standards, as well as (b) broader System Service programs that go "beyond-the-asset" to manage system-wide issues, such as critical supply points that energize the Pembroke and Almonte service areas, and introducing new SCADA equipment at the Substations to better manage and respond to outages in a timely manner.

Figure 4-11 illustrates the resulting Capital Expenditure Plan for ORPC. Total costs over the five-year period will be $6.75M. It should be noted that these expenditures exclude the ICM spending that has taken place in this same time period.

Figure 4-11: 2022 – 2026 Capital Expenditure Plan by DSP Investment Category



Spending in 2022 is high due to the need to replace a power transformer that failed unexpectantly in late June 2021 just before the filing of the DSP accounting for around 40% of the expenditure in 2022. It then returns to level of spends that closely align with historical years for 2023-2025, with an increase in 2025 due to a significant expenditure on replacing a large new vehicle. Importantly, System Renewal remains a critical component of the plan, accounting for 65% of the total five-year spending, in order to manage and replace aging and deteriorating infrastructure. While System Service investments account for only 8% of the total five-year spending, these investments are more targeted, managing incoming supply points supporting the Pembroke and Almonte service areas, and upgrading SCADA systems in the first two years of the plan. General Plant and System Access investments round out the five-year plan, with General Plant investments focusing on critical upgrades, to better safeguard the utility and to ensure that the 24/7 operational backbone for the utility is well managed and maintained. Table 4-3 illustrates the capital expenditure plan totals (net costs) by investment program within each of the four DSP investment categories.

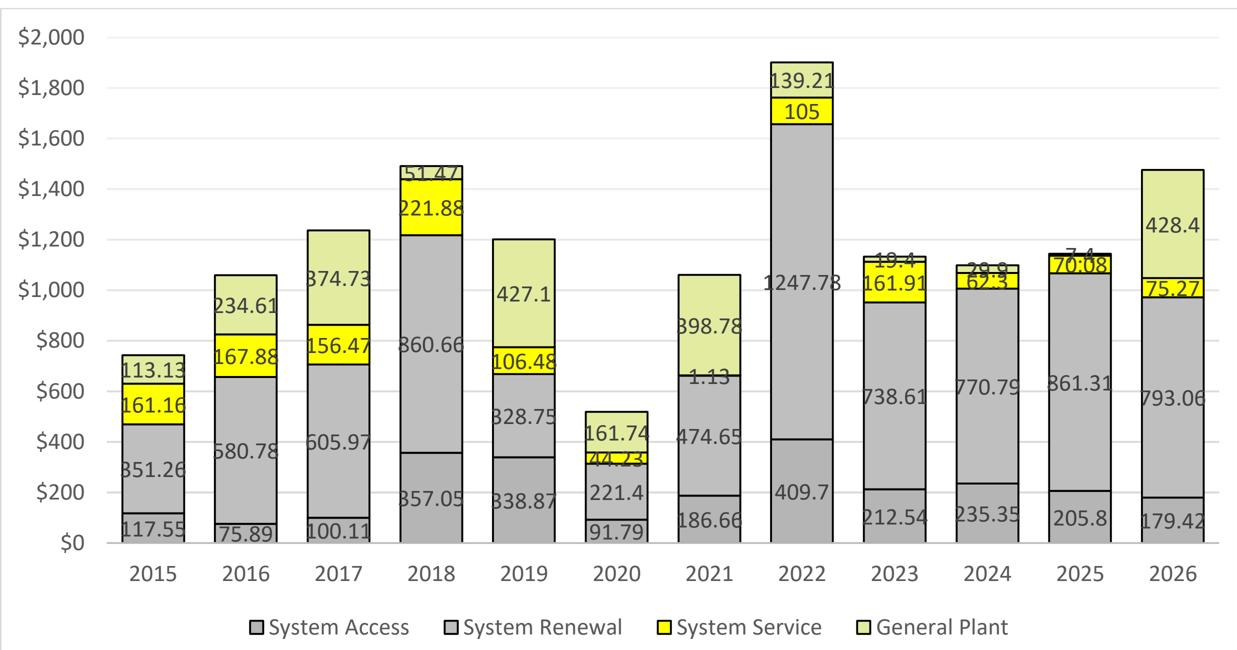
Table 4-3: 2022 – 2026 Capital Expenditure Plan by Investment Program (Net Costs - $K)

DSP Category	Proposed DSP Program	2022	2023	2024	2025	2026
System Access	Customer Connections	$ 120.70	$ 40.75	$ 67.91	$ 81.49	$ 81.49
	Metering	$ 95.40	$ 86.06	$ 68.80	$ 88.84	$ 56.55
	Externally Initiated Plant Relocation	$ 193.60	$ 85.73	$ 98.65	$ 35.47	$ 41.38
System Renewal	UG Renewal	$ 43.56	$ 48.11	$ 60.14	$ 64.95	$ 67.36
	OH Renewal	$ 454.22	$ 463.49	$ 483.64	$ 523.94	$ 544.09
	Stations	$ 750.00	$ 227.01	$ 227.01	$ 272.41	$ 181.61
System Service	System Enhancement	$ -	$ 51.91	$ 62.30	$ 70.08	$ 75.27
	Station Expansion	$ 105.00	$ 110.00	$ -	$ -	$ -
General Plant	Information Technology	$ 66.00	$ 1.40	$ 12.40	$ 1.40	$ 11.40
	Fleet	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 412.00
	Operational Technology	$ 19.21	0	$ -	$ -	$ -
	Facilities	$ 49.00	$ 13.00	$ 12.50	$ 1.00	$ 5.00
	Total	$ 1,901.69	$ 1,132.47	$ 1,098.34	$ 1,144.59	$ 1,476.16

4.3. Capital Expenditure Summary

The Capital Expenditure Summary provides a 'snapshot' of ORPC's capital expenditures over an 12-year period, which includes five historical years (2015-2019), excluding the historical ICM costs, and five forecast years (2022-2026), with 2020 and 2021 being the bridge years. The costs of individual projects or activities are allocated to one of four investment categories based on the primary (i.e., initial or 'trigger') driver of the investment: System Access, System Renewal, System Service, and General Plant. Figure 4-12 further illustrates total spending across the historical period, the bridge year, as well as the forecast period.

Figure 4-12: 2015 – 2026 Capital Expenditures by DSP Investment Category



4.3.1. 2015-2019 Capital Expenditures: Overall Variance Summary

As first discussed in Section 3.1.2.4, as part of the Validation stage of the AM Process, ORPC continually monitors planned versus actual expenditures during the execution of the capital expenditure plan. Where variances begin to materialize, ORPC will implement the necessary adjustments to either increase or decrease spending as needed, such that variances can be minimized as effectively as possible.

Table 4-4 further illustrates the results from this process, where the "planned" expenditures as published within the 2015-2019 DSP have been compared to the "actual" expenditures that took place during this same period. While material variances are revealed within the individual DSP investment categories, overall variances across the capital expenditure plan have been limited to just 2% of underspending, further demonstrating the robustness of ORPC's Validation stage from the AM Process, and the utilities' commitment to minimizing variances.

Ultimately, when balancing the needs of the system with the need to balance planned versus actual expenditures, some trade-offs must be made which may result in overspending for certain categories of investments. However, ORPC will ultimately deliver the necessary adjustments to the plan to ensure that overall variances are minimized.

Table 4-4: 2015 – 2019 Capital Expenditure Plan – Planned vs. Actuals

Category	2015-2019		
	Plan.	Act.	Var.
	$K		%
System Access	$ 2,239.3	$ 2,230.2	0%
System Renewal	$ 1,279.1	$ 2,571.2	101%
System Service	$ 1,958.3	$ 705.3	-64%
General Plant	$ 1,094.0	$ 1,201.0	10%
Total (Gross)	**$ 6,570.7**	**$ 6,707.8**	2%
Capital Contributions		$ 988.8	
Total (Net)		**$ 5,719.0**	
System O&M		**$ 5,852.4**	

From these results, capital expenditures in the System Access category reveal no overall difference in actual spending when compared to the plan.

System Renewal reveals a 101% increase in actual spending when compared to the plan. This is due to ORPC identifying new emerging issues within the system that needed to be resolved through the replacement of infrastructure. This level of overspending was necessary in order to appropriately manage reliability for customers.

System Service reveals a 64% decrease in actual spending when compared to the plan. This was mostly driven due to a significant reduction in Stations upgrades that were originally proposed within the plan. Certain stations that were originally scheduled for decommissioning were deferred, and in fact will be further deferred until after the conclusion of the 2022-2026 plan as documented here. Reductions in this category were also driven by the need to prioritize System Service investments against the more critical and emerging System Renewal investments, and therefore deprioritize the System Service investments in order to appropriately manage the variances.

Finally, General Plant reveals a 10% increase in actual spending when compared to the plan. This was primarily driven by the need to increase spending on critical software that, during the historical period, needed to be upgraded at an earlier time as the software had become unsupported from the supplier with respect to further upgrades and security fixes. In order to maintain the 24/7 backbone that support ORPC's AM and field services activities, and also to ensure that ORPC has begun the process to comply with emerging cybersecurity legislation as part of the OEB Cybersecurity Framework, it was necessary to perform software upgrades at an earlier point in the plan.

Table 4-5 further expands the variance results on a year-by-year basis, showing periods within the 2015-2019 historical period were ORPC underspent, to balance the overspending that took place in later years. The subsequent sections provide further insight into the specific variances that occurred on a DSP investment category basis. Finally, Figure 4-13 graphically illustrates the total planned versus actual expenditures for each DSP investment category. Sections 4.3.2 through to 4.3.6 provide the year-over-year spending comparisons from 2015 onwards to 2026, with further discussions on variances between planned and actual expenditures.

Table 4-5: 2016 – 2019 Capital Expenditure Plan – Planned vs. Actuals – Expanded Results

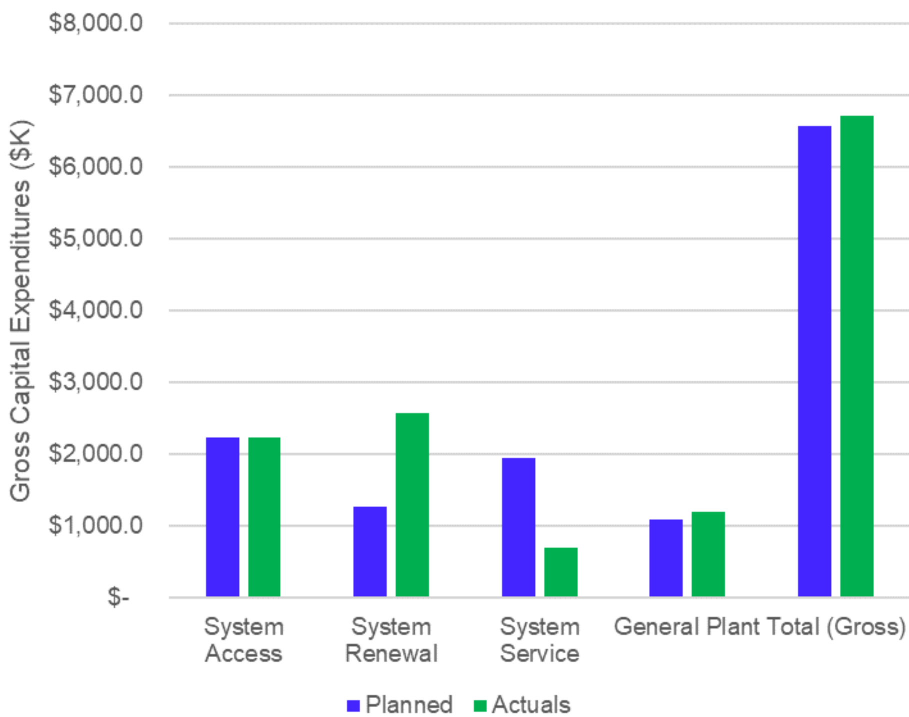
	2016			
	Plan	**Actual**	**Var**	
	$ '000		$	%
System Access	200,850	75,894	-124,956	-62.2%
System Renewal	194,100	580,784	386,684	199.2%
System Service	474,800	167,879	-306,921	-64.6%
General Plant	376,200	234,605	-141,595	-37.6%
TOTAL EXPENDITURE	1,245,950	1,059,161	-186,789	-15.0%

	2017			
	Plan	**Actual**	**Var**	
	$ '000		$	%
System Access	452,200	100,107	- 352,093	-77.9%
System Renewal	248,750	605,967	357,217	143.6%
System Service	345,849	156,475	- 189,374	-54.8%
General Plant	255,200	374,735	119,535	46.8%
TOTAL EXPENDITURE	1,301,999	1,237,284	- 64,715	-5.0%

	2018			
	Plan	**Actual**	**Var**	
	$ '000		$	%
System Access	392,700	357,050	- 35,650	-9.1%
System Renewal	193,200	860,657	667,457	345.5%
System Service	573,650	221,884	- 351,766	-61.3%
General Plant	116,200	51,470	- 64,730	-55.7%
TOTAL EXPENDITURE	1,275,750	1,491,061	215,311	16.9%

	2019			
	Plan	**Actual**	**Var**	
	$ '000		$	%
System Access	392,700	468,091	75,391	19.2%
System Renewal	193,200	328,749	135,549	70.2%
System Service	293,200	47,622	-245,578	-83.8%
General Plant	134,200	427,097	292,897	218.3%
TOTAL EXPENDITURE	1,013,300	1,271,558	258,258	25.5%

Figure 4-13: Comparison of Planned Expenditure vs Actual Expenditures for 2015-2019 Period

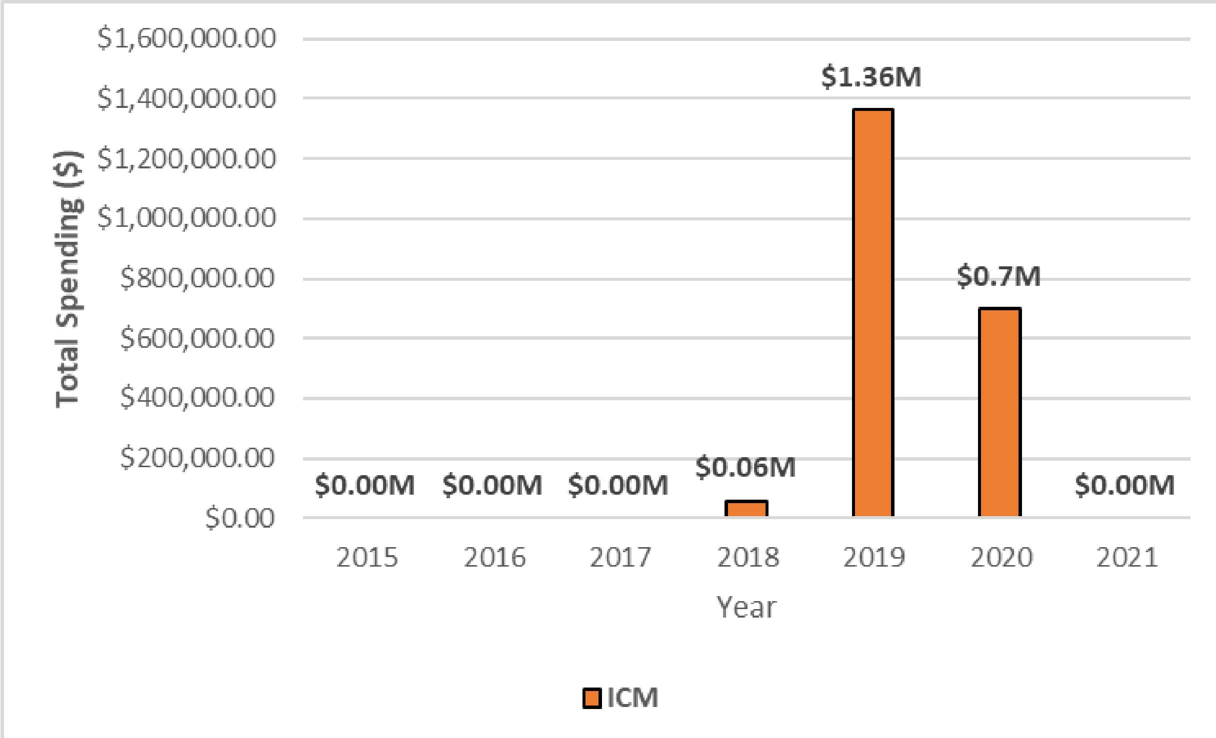


In addition to the capital expenditures as shown in Figure 4-12, ORPC applied for and gained approval in 2019 for construction of the Almonte MS4 substation. Total ICM expenditures were $1.9M from 2018 onwards to 2021 and have been presented separately and are further detailed in Table 4-6 and illustrated in Figure 4-14.

Table 4-6: ICM Expenditures – 2015 - 2021

Category	Historical Period Spending ($K)					Bridge	
	2015	2016	2017	2018	2019	2020	2021
ICM	$ -	$ -	$ -	$ 58.9	$ 1,363.9	$ 700.1	$ -

Figure 4-14: ICM Expenditures – 2015 - 2021



4.3.2. System Access Investments

System Access investments represent non-discretionary investments including modifications (including asset relocations) made to the distribution system that ORPC is obligated to perform in order to provide a customer (including a generator customer) or group of customers with access to electricity services via ORPC's distribution system. Key investments within this category include Customer Connections, Metering and Externally Initiated Plant Relocations. Table 4-7 summarizes total year-over-year expenditures from 2015 onwards to 2026.

Expenditures in the forecast period from 2022-2026 total $1.25M, which aligns with expenditures undertaken from 2015-2019 totalling $1.24M.

Table 4-7: System Access Expenditures – 2015 – 2026

DSP Category	Historical Period Spending ($K)					Bridge		Forecast Period Spending				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Access	$ 117.5	$ 75.9	$ 100.1	$ 357.0	$ 468.1	$ 193.1	$ 183.1	$ 409.7	$ 212.5	$ 235.4	$ 205.8	$ 179.4

As shown in Table 4-4, actual System Access expenditures across the 5-year period from 2015-2019 align with the original forecast as published within the 2015-2019 DSP. As shown in Table 4-5, System Access actual expenditures for 2015, 2016 and 2017 were all lower when compared to the plan, with 2018 and 2019 actual expenditures being higher when compared to the plan. Underspending from 2015 to 2017 was primarily driven by the following:

- The number of customer connections that was originally forecasted in the 2015-2019 DSP did not materialise. This resulted in ORPC not needing to spend additional money to connect new customers to the grid. In general, Customer Connection spending forecasts remain highly volatile, and driven by various external factors (e.g., size and location of connections, available capacity provisions, economic drivers, etc.).

- Following these reductions within the Customer Connection program, some expenditures were reallocated to support the unplanned Externally Initiated Plant Relocation at Martin Street, Upper Valley Drive and Boundary Road. These expenditures also remain very volatile and mostly driven by external factors.

Increased actual spending in 2018 and 2019 when compared to the plan was primarily driven by:

- An increase in metering expenditures, mainly due to new services being installed and significant service upgrades. Additionally, there were 1,000 meters that failed during the 2015-2019 period, with ORPC needing to replace these such that accurate measurement and billing of customers could continue.

- An unplanned Externally Initiated Plant Relocation in 2019 driven by Petro-Canada to upgrade service capacity. In addition, a new line was constructed to service new customers who were previously fed directly from the HONI system. There was also an installation and connection of a pad-mounted transformer in 2019 to allow for the removal of a transformer vault located within the basement of a school. In addition, there was a project in 2016 on Paul Martin Drive to relocate overhead poles due to the road being rebuilt, which was unknown at the beginning of the DSP period.

The above additional work had to be undertaken as ORPC is mandated through the DSC to deliver these services as requested by customers. As the majority of the work in this category is customer-driven, it can be challenging to predict the amount of the future work to occur as many customers are unable to provide long-term forecasts. Where possible, ORPC will attempt to get this information as early as possible to accommodate and adjust its work program accordingly. In particular, ORPC communicates regularly with the municipalities associated with their service areas.

4.3.3. System Renewal Investments

System Renewal investments involve the replacement of ORPC's distribution system assets that are found to be either at, exceeding or approaching their TUL or have been found to be in Poor or Very Poor condition, such that ORPC can mitigate the failure risks and reliability impacts within the system. Key investments within this category include Overhead Renewal, Underground Renewal and Stations Renewal. Table 4-8 summarizes total year-over-year expenditures from 2015 onwards to 2026.

Expenditures in the forecast period from 2022-2026 total $4.36M, which exceeds the amount of expenditures undertaken from 2015-2019 totalling $2.57M. This is primarily due to increases in the Stations Renewal program, where nearly 80% of stations assets are already past their TUL, with another 8% of stations assets to exceed their TUL during the forecast period. Therefore, necessary funding has been allocated to ensure that these critical assets are being proactively and appropriately managed within ORPCs system.

Table 4-8: System Renewal Expenditures – 2015 – 2026

DSP Category	Historical Period Spending ($K)					Bridge		Forecast Period Spending				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Renewal	$ 351.3	$ 580.8	$ 606.0	$ 860.7	$ 328.7	$ 221.4	$ 419.0	$ 1,247.8	$ 738.6	$ 770.8	$ 861.3	$ 793.1

As shown in Table 4-4, actual System Renewal expenditures across the 5-year period from 2015-2019 were 101% higher than the original forecast as published within the 2015-2019 DSP. When viewed in isolation, this represents a material overspend when compared to the planned amounts. However, at the same time, it is important to recognize the System Renewal activities are driven by the needs of the system and are ultimately critical in ensuring that assets continue to function as expected, and to maintain the security of supply and the reliability that customers expect. Overspending within this investment category was primarily driven by the following factors:

- An increase in failure-risk-driven investments within both the underground and overhead systems, respectively.

- The original 2015-2019 DSP featured plans to upgrade and replace infrastructure at the Pembroke MS1 substation. As stated in its previous DSP, ORPC considered voltage conversion as an alternative to full replacement. This resulted in ORPC deciding to convert all feeders connected to this substation. However, because the Pembroke MS3 substation represents a primary backup point for MS1, if MS1 were converted without converting MS3, the associated 4.16kV feeders and connected customers would not have any available backup supply. As a result, it was necessary to perform voltage conversion for all connected feeders to both of these substations simultaneously. These efforts will continue within the 2022-2026 capital expenditure plan. Ultimately, the Pembroke MS1 and MS3 substations will not be decommissioned until after 2025 or later.

- New copper grounding infrastructure had to be re-installed at Pembroke MS6 substation, due to the original copper being stolen. As the station grounding is critical to the safe and effective operation of this substation, it was necessary to allocate funding to execute this work.

- An increase in the number of additional single pole replacements that were undertaken due to the likelihood of these poles failing, based on inspection, ACA and APUL information, which would result in potential unexpected customer outages. Alongside these single pole replacements, the associated overhead conductor had to be transferred to the new poles, and in some cases the conductor had to be upgraded where it was deemed to not meet ORPC standards.

As a result of the increased spending associated with the System Renewal program, ORPC adjusted its spending in other investment categories (e.g., reduction in spending to System Service category over the 5-year period) in order to ensure that overall variances were minimized as much as was reasonably possible, down to 2%.

4.3.4. System Service Investments

System Service investments involve modifications to the system in order to address system-wide critical issues that go “beyond-the-asset”, such that ORPC’s operational objectives continue to be achieved while addressing anticipated future customer electricity service requirements. System Service investments are designed to provide reinforcement to critical supply points, manage any capacity and/or operational constraints and integrate new communications technologies to ensure that critical feeder or system-level outages can be responded to and managed in an optimal timeframe. Key investments within this category include Station Expansion and System Enhancements. Table 4-9 summarizes total year-over-year expenditures from 2015 onwards to 2026.

Expenditures in the forecast period from 2022-2026 total $520K, which represents a reduction in spending when compared to the investments undertaken from 2015-2019 totalling $705K. This reduction in spending is primarily due to the shifting focus of the System Service investments away from operational and capacity constraints – which were resolved within the previous 2015-2019 investment period –towards reinforcement of supply points to manage the security of supply risk as well as the renewal and upgrade of SCADA technologies at key substations within ORPC’s system.

Table 4-9: System Service Expenditures – 2015 – 2026

	Historical Period Spending ($K)					Bridge		Forecast Period Spending				
DSP Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Service	$ 161.2	$ 167.9	$ 156.5	$ 221.9	$ 106.5	$ 44.2	$ 1.1	$ 105.0	$ 161.9	$ 62.3	$ 70.1	$ 75.3

As shown in Table 4-4, actual System Service expenditures across the 5-year period from 2015-2019 were 64% lower than the original forecast as published within the 2015-2019 DSP. Key reasons for these reductions in investment include the following:

- A significant reduction in expenditures for station-related improvements projects. Most notably, the planned upgrades at Pembroke MS1 were not carried out. Instead, as noted in Section 4.3.3, the focus changed to converting feeders connected to the Pembroke MS1 and MS3 stations.

- The outage management work that would further provide linkages between the AMI and SCADA to identify pockets of outages was embedded within the delivery of the ESRI mobile mapping solution. As a result, savings were achieved within the System Service category.

Ultimately, reductions in System Service investments allowed ORPC to balance the overspending occurring within the System Renewal category in order to minimize the overall variance across all investments.

4.3.5. General Plant Investments

General Plant investments represent modifications, replacements or installation of new assets that are not part of the distribution system but ultimately serve to provide the backbone of ORPC's 24/7 operations. This includes land and buildings, fleet vehicles, tools, and equipment as well as IT hardware and software – all of which contribute towards the day-to-day operations and management of the distribution system. Table 4-10 summarizes total year-over-year expenditures from 2015 onwards to 2025.

Expenditures in the forecast period from 2022-2026 total $624.5K, which represents a reduction in spending when compared to the investments undertaken from 2015-2019 totalling just over $1.2M. This reduction in spending is primarily due to the reduced Fleet and IT investments that are occurring within the 2022-2026 spending period. ORPC purchased new bucket trucks and vehicles as part of the 2015-2019 historical period, and as such, these vehicles remain in good operational condition. The predominant focus within the General Plant investment category has shifted within the DSP planning period to IT investments, along with Operational Technology and Facilities investments.

Table 4-10: General Plant Expenditures – 2015 – 2026

	Historical Period Spending ($K)					Bridge		Forecast Period Spending				
DSP Category	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
General Plant	$ 113.1	$ 234.6	$ 374.7	$ 51.5	$ 427.1	$ 174.7	$ 398.8	$ 139.2	$ 19.4	$ 29.9	$ 7.4	$ 428.4

As shown in Table 4-4, actual General Plant expenditures across the 5-year period from 2015-2019 were 10% higher when compared to the original forecast as published within the 2015-2019 DSP. As shown in Table 4-5, actual expenditures in 2015, 2016 and 2018 were all lower when compared to the plan, with only 2017 and 2019 actual expenditures being higher when compared to the plan. Reasons for these higher amounts include the following:

- A need to upgrade IT software sooner than expected, due to suppliers indicating they would no longer support outdated systems currently utilized by ORPC. In addition, mandatory upgrades needed to be implemented to ensure continued support for these systems. New investments were also included for cybersecurity software in order to comply with the recently issued Cybersecurity Framework by the OEB.

- A need to replace an additional 2010-vintage Radial Boom Derrick ("RBD") truck that prematurely failed and was no longer safe to be used. Due to reliability, safety and increasing cost issues, ORPC decided to replace the truck in 2018 and purchased a new RBD truck. The tender was successfully awarded to Wajax Industries of Kitchener, Ontario. ORPC took possession of the new truck in the third quarter of 2019. The 2010 RBD truck was sold in the fall of 2019 in an 'as-is' condition for $47,500.

    - The main issue associated with the 2010 RBD truck was related to the boom, which would frequently stop working during operation on site. As a result, on several occasions, powerline technicians were forced to evacuate from the bucket using bucket evacuation techniques. All repairs and maintenance associated with this truck relied heavily on the services of an outside company. On several occasions, ORPC used the services of Altec Industries to complete necessary repairs. Due to travel and lodging costs, this was found to be cost prohibitive. ORPC then used the services of Ricks Die-Electric Repairs to complete repairs when necessary. This resulted in a more cost-effective method when repairs were required. However, the company was subsequently purchased by Altec Industries. This ultimately led to extended delivery times for required parts and made it cost prohibitive again. As a result of these changes and high operational costs, the decision was made to purchase a new truck.

    - In addition, there were also additional unplanned investments to repair other vehicles within ORPC's fleet to ensure they could be safely used. ORPC regularly inspects its fleet vehicles to ensure they are safe to be used; in each case a repair was considered before replacement. This resulted in the decision to not invest in two new trailers that were in the original plan, because they were deemed still safe to be used, and are rarely used. However, there was a need to replace a 1979 pole trailer that did not pass its safety inspections. Overall, this has resulted in a near doubling of the Fleet-related expenditures when compared to the original 2015-2019 plan. ORPC believes that these expenditures were justified due to the aforementioned safety drivers.

- In order to counterbalance the increase in fleet expenditure, ORPC implemented reductions relating to Operational Technology and Facilities investment programs. As noted in Section 3.1.2.4, as part of the Validation stage of ORPC's AM Process, the utility will continually review their investment programs and implement trade-offs where necessary in order to minimize overall variances. Based upon what was originally forecasted and with the increase in Fleet expenditures and further coupled with increases in System Renewal spending, OPRC decided to defer certain General Plant activities and re-assess other activities to see if they were still necessary. This work was then re-prioritized accordingly. For example, no investment was made in upgrading the Fire Alarm system as part of the Facilities program because the actual price would have been $100K when re-quoted, compared to the originally planned $38K. This increase was deemed too expensive, especially as the current-state Fire Alarm system remained operational as required by safety legislation. Other Facilities activities, including re-paving the parking lot, and office paving were re-evaluated and no longer considered a priority and were subsequently removed from the capital investment program.

4.3.6. System O&M Investments

System O&M investments represent all operational expenditures ("OPEX") made to the system, including maintenance activities designed to support the continued reliable operation of their asset base over its TUL, through the execution of visual inspection and testing programs. In addition, these investments include any and all costs related to reactive operations, including outage restoration and emergency repair and replacement of failed infrastructure. Table 4-11 summarizes total year-over-year expenditures from 2015 onwards to 2026. Expenditures in the forecast period from 2022-2026 total $7.5M.

Table 4-11: System O&M Expenditures – 2015 – 2026

DSP Category	Historical Period Spending ($K)					Bridge		Forecast Period Spending				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System O&M	$ 1,207	$ 1,244	$ 1,258	$ 985	$ 1,159	$ 1,287	$ 1,378	$ 1,478	$ 1,507	$ 1,538	$ 1,568	$ 1,600

5. SYSTEM ACCESS INVESTMENTS

5.1. CUSTOMER CONNECTIONS

5.1.1. Overview

ORPC is obligated under the DSC to connect new customer services that are funded through contributed capital. This includes new subdivision developments. Across all four of ORPC's service areas, ORPC communicate with the local municipalities to understand the potential for new developments over the next five-year period, 2022-2026.

Total program spending from 2022 onwards to 2026 is $392K (Net) which is a slight increase to spending levels over the historical period from 2015 onwards to 2019. This is mainly due to an increase in the number of new customer connections that are currently forecast across ORPC's service areas. As with all customer driven works, the number of actual connections could change significantly, if planned developments don't materialise, or new customer connection requests are identified. ORPC will respond and connect all new customer services, as obligated under the DSC.

5.1.2. Investment Description

Based on the current information provided by the local municipalities serviced by ORPC, the following new customer connections have been estimated across the four service areas:

- Pembroke – 28 new units/year
- Almonte – 79 new units/year
- Beachburg – 36 new units/year
- Killaloe – Currently no new major developments planned

For residential customers, ORPC defines a basic connection and recovers the cost of the basic connection as part of its revenue requirement. The basic connection for each customer includes, at a minimum: (a) supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and (b) up to 30 meters of overhead conductor or an equivalent credit for underground services.

As stated previously, with all customer-driven activities, the number of actual connections could change significantly, if planned developments don't materialise, or new customer connection requests are identified. ORPC will respond and connect all new customer services, as obligated under the DSC. *Table 5-1* highlights the outcomes emerging from the Customer Connections program at ORPC:

Table 5-1: Program Outcomes

Outcomes	Description
Customer Value	These investments are customer driven, and ORPC is obligated as per the DSC to enable connections for new and existing customers within the distribution system service area. By enabling these connections, it allows ORPC customers to access the electricity services that they require.
Safety	These investments provide necessary compliance to Ontario Regulation 22/04 and all safety objectives by ensuring that all connections are compliant with all

	applicable requirements, and that ESA permits are available prior to connecting new connections or upgrading existing connections.
Reliability	These investments ensure that connections are aligned to appropriate standards and available capacity within the system, thus reliability is maintained for both the customer and the distribution system as a whole.

5.1.3. Investment Drivers & Need

ORPC's Customer Connections program is designed to ensure that ORPC is able to deliver necessary electricity services to the customer via connection to the distribution system. This ultimately allows ORPC to comply with mandated service obligations. For these reasons, Customer Service Requests represents the primary (trigger) driver, with Mandated Service Obligations being the secondary driver.

Table 5-2: Program Drivers

	Driver	Description
Primary	Customer Service Requests	The primary driver is Customer Service Requests. ORPC is obligated to ensure that it enables any request from a customer (residential or commercial), who meets the ORPC connection standards.
Secondary	Mandated Service Obligations	The secondary driver for this program is to comply with the mandated service obligations as defined in the DSC.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

5.1.3.1. Customer Service Requests

The primary driver of the Customer Connections program is to complete customer service requests by enabling the connection of these customers to the distribution system. Each of ORPC's service areas contain customers (both residential and commercial) who require new connections due to new buildings and premises being built. ORPC regularly communicates with the local municipalities to gather this information. This is used to forecast the estimated number of new connection requests that will be required.

5.1.3.2. Mandated Service Obligations

The secondary driver of the Customer Connections program is to meet all requirements as stated in the DSC for new customers, as long as those customers meet ORPC's design standards for new connections. As part of its Service Quality metrics, ORPC is required to connect new residential and small business customers on time at least equal to or greater than 90% of the time. This is further discussed in Section 2.3.1.1.

5.1.4. Investment Timing & Pacing

The pace of investment within this program is designed to meet customer service requests and the associated mandated service obligations. As this work remains customer-driven, the pacing of these investments may change, as it will depend on when a customer wants to connect. The proposed investment pacing is based on the information ORPC that has received from the local municipalities in regard to the number of new potential connections.

5.1.4.1. Program Execution Risks and Risk Mitigation

ORPC undertakes Customer Connection activities on a routine basis and does not perceive there to be any risk with delivering these types of investments under normal operating conditions.

5.1.4.2. Investment Pacing & Prioritization

The proposed investment pacing is based upon the information that ORPC has received from the local municipalities in regard to the number of new potential connections. As the work is customer-driven, the pacing of these investments may change, as it will depend on when a customer wants to connect.

Whilst these types of projects are generally of high priority due to them being customer-driven and part of ORPC's mandated service obligations, other impacts within the system may result in ORPC needing to adapt their delivery plan.

In general, during the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date.

5.1.5. Options Analysis

As stated in Section 3.3.2.2.2, ORPC only executes its project evaluation procedure for projects that are not driven by mandated service obligations or third-party questions. This is namely due to the fact that Customer Connections investments are non-discretionary and must be executed in order to comply with regulations as described in the DSC.

5.1.6. List of Projects

Table 5-3 illustrates the breakdown of Net Costs associated with the Customer Connections projects due to be carried out in the 2022 test year. This breakdown was estimated based upon information received from the local municipalities.

Table 5-3: Customer Connection Forecast Cost for 2022

Project	Cost
4 Semi-Detached Single Storey Homes	$2,196
Orchard View Suites (Phase 2)	$64,502
42 Unit Apartment Building	$33,263
Burcom Development – 48 Houses	$42,500
9 Townhomes at 627 Nelson Street Pembroke	$12,000
Total	**$154,461**

5.2. EXTERNALLY INITIATED PLANT RELOCATION

5.2.1. Overview

The Externally Initiated Plant Relocation program involves investments where ORPC is obligated to relocate electricity distribution assets in order to accommodate construction performed by a third party. This would include investments relating to the upgrading and expansion of public infrastructure, including road widening, bridge construction, walkway construction, railway crossings or transit systems.

Within the scope of these activities, ORPC is allowed to recover a proportion of the costs from the third party, thereby introducing cost efficiencies for the utility when replacing existing infrastructure in conjunction with third-party relocation efforts. Across all four of ORPC's service areas, ORPC communicates with the local municipalities to understand the potential for any requests for relocating any assets over the next five-year forecast period from 2022 onwards to 2026.

Total program spending from 2022 to 2026 is $455K, which represents an increase in spending when compared to the historical period from 2015 to 2019. This is due to the fact that multiple projects with the City of Pembroke have been identified during the course of developing the DSP. As investments relating to this category are driven by third-party efforts, it is possible that the number of actual projects, and required investments by ORPC may change from what has been planned. ORPC will have to respond and relocate infrastructure as needed should new third-party requests emerge.

5.2.2. Investment Description

This program consists of the relocation of existing overhead and underground distribution assets to accommodate modifications to roadways by the City of Pembroke, the Township of Whitewater (Beachburg only), the Town of Mississippi Mills (Almonte Ward Only), and the Township of Killaloe, Hagarty & Richards (Killaloe only). Investments made within this category as well the timing and pacing of the investment will depend on the specific nature of the work being executed by the third-party entities.

Over the DSP planning period from 2022 onwards to 2026, the City of Pembroke will be performing road widening and improvements to Pembroke Street West that will require the relocation of overhead assets owned by ORPC. This work will be done in four phases over the next 5-year period as follows, with Phase 1 and 2 being carried out in 2020 and 2021:

- Phase 1 – City Limits to Crandall Street
- Phase 2 – Crandall Street to Reynolds Ave
- Phase 3 – Reynold's Ave to Miramichi
- Phase 4 – Miramichi to Christie Street

Pembroke Street represents a critical main artery within the City of Pembroke, with the road widening and improvements necessary in order to enhance road and pedestrian traffic within the area. Key elements that will be performed by the City of Pembroke as part of the road widening and overall improvements to Pembroke Street West include the following:

- Upgrading of traffic signals including loops where required.

- Installation of new traffic lights at intersection of Pembroke Street West and Trafalgar Road
- Redesign of the island on Riverside drive to make the island larger
- New Accessibility for Ontarians with Disabilities Act (“AODA”) lights at Riverside Drive
- Setup of AODA signals at Crandall
- Setup of AODA lights at school for pedestrians only

Work to be performed by ORPC in conjunction with the above efforts include the following:

- Relocation of Hydro poles back approximately 2m between “Miramichi Lodge” and “Normandeau’s Car Care & Limo Service” to allow for boulevard to be widened.
- Relocation of poles back along Pembroke Street in front of Riverside Park
- Possible relocation of pole next to “The Hot Spot” tanning studio and the Riverside intersection

Table 5-4 highlights the outcomes emerging from the Externally Initiated Plant Relocation program at ORPC.

Table 5-4: Program Outcomes

Outcomes	Description
Efficiency	Cost efficiencies are achieved with ORPC is able to replace infrastructure in conjunction with the third-party municipalities and cities, since the third-party is required to provide capital contributions into the investment. Therefore, ORPC has an opportunity not only to relocate assets but also to replace these assets at the same time.
Customer Value	Externally Initiated Plant Relocation represent investment activities driven by cities and municipalities, and often involve the construction of new infrastructure that will benefit the public and customers as a whole. ORPC is obligated by the OEB to enable these relocations, and customers broadly benefit from the infrastructure improvements to the area.
Reliability	Relocation projects provide an opportunity for ORPC to replace infrastructure that may be beyond their TUL and/or infrastructure in Poor/Very Poor condition, and also allow for changes to configuration and overall design.

5.2.3. Investment Drivers & Need

The Externally Initiated Plant Relocation program is designed to ensure that ORPC delivers on its mandated service obligations to relocate infrastructure in response to third-party requests.

As noted in *Table 5-5*, this program is primarily driven by the need to comply with mandated service obligations. However, customer service requests remain a secondary driver, particularly because infrastructure improvement projects impact the broader customer base, and those projects in of themselves are driven by the needs of the residents within those respective cities and municipalities.

Table 5-5: Program Drivers

	Driver	Description
Primary	Mandated Service Obligations	The primary driver for this program is to comply with the Mandated Service Obligations as defined in the distribution system code.
Secondary	Customer Service Requests	The secondary driver for this program is Customer Service Requests, as these city and municipality-driven initiatives are often initiated based upon the needs of the residents within the area. Outcomes from these investments produce broader benefits for the customers/residents.

The following subsections serve to provide further details on the above-stated primary program driver.

5.2.3.1. Mandated Service Obligations

The primary driver for Externally-Initiated Plant Relocation is to meet all Mandated Service Obligations – in this case to the City of Pembroke who has requested the need to perform the road widening activities on Pembroke Street West. ORPC must be prepared to execute the relocation activities in conjunction with the timelines of the city and the road widening work that is to take place, such that overall impacts can be minimized, and work can be performed as efficiently as possible.

5.2.3.2. Customer Service Requests

Infrastructure improvement projects within cities are more broadly driven by the residents within the area. Key outputs from these projects include improved infrastructure and services for the residents. In this case, the specific work taking place on Pembroke Street West will result in better pedestrian and traffic flow, with new technologies installed for people with disabilities. Replacement of ORPC infrastructure in conjunction with these activities will allow for potential reliability issues to be mitigated.

5.2.4. Investment Timing & Pacing

Relocation projects are initiated by the decisions of municipal governments and customers. As a result, ORPC has very limited control over the timing of relocation projects. ORPC maintains a high level of communication with all parties involved, in order to ensure a timely and efficient exchange of information. This ensures that all relocation projects are accounted for and appropriately coordinated with other projects/programs. The priority of relocation projects is High, as they are part of ORPC’s mandated service obligations and therefore unable to be deferred without consequences.

5.2.4.1. Program Execution Risks and Risk Mitigation

The scheduled risk for executing this program is primarily the timing of the city/municipality, and in this particular case, the timing of the City of Pembroke to perform the rebuilding of Pembroke Street West. In general, ORPC has limited authority over the timing and scope of these projects. ORPC maintains a high level of frequent communication with all municipalities to ensure a timely and efficient exchange of information.

5.2.4.2. Investment Pacing & Prioritization

The proposed investment pacing is based upon the information that ORPC has received from the local municipalities in regard to the specific third-party activities to take place. In this case, the road widening will be driven by the City of Pembroke, and the overall pacing of the investment may change depending on the City’s overall plan and how they have prioritized this work.

Whilst these types of projects are generally of high priority due to them being driven by the city/municipality and part of ORPC mandated service obligations, other factors may result in changes to the overall schedule.

5.2.5. Options Analysis

As stated in Section 3.3.2.2.2, ORPC only executes its project evaluation procedure for projects that are not driven by mandated service obligations or third-party questions. This is namely due to the fact that Externally Initiated Plant Relocation investments are non-discretionary and must be executed in order to comply with regulations as described in the DSC.

5.3. METERING PROGRAM

5.3.1. Overview

The Metering program includes expenditures related to the supply and installation of revenue meters that are installed at each customer service point for retail settlement and billing purposes for all customers connected to ORPC's distribution system. Revenue meters have four primary drivers, including (a) new meters for new customers, (b)) replacement of failed units, (c) reliability (elimination of meter types that have history of poor reliability) and (d) standardization. Without metering investments, ORPC will not be able to accurately and correct measure and bill customers for the electricity that they use.

Overall, these investments are required by the DSC, and are therefore customer-driven and mandatory. All maintenance activities related to meters follow the requirements of Measurement Canada guidelines, including the group sampling and reseal program. ORPC has developed the Metering investment program based upon historical information, forecast meters that will require replacement and customer forecast information.

As further noted in Table 5-6, total program spending from 2022 onwards to 2026 is $396K, which represents an increase to spending levels over the historical period from 2015 onwards to 2019. This increase is primarily driven by the increase to the number of sample testing and reverifications that are required over the forecast period, as well as an increase in the number of new meters required. With most of ORPC's first-generation smart meters being installed in 2008-2009, there will be a significant number of these meters requiring re-verification over the next five years.

Table 5-6: Investment Summary Details

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$2.7	$7.0	$35.4	$91.4	$101	$39.2	$60.0	$95.4	$86.1	$68.8	$88.8	$56.5
Primary Driver	Mandated Service Obligations											
Secondary Drivers	Failure Risk											
Outcomes	Improved Reliability, Improved Efficiency, Improved Customer Value.											

5.3.2. Investment Description

ORPC has sub-divided Metering investments across four main sub-programs, and three project-specific investments, including the following:

- Sub-Programs:
    - General
    - Instrument Transformers
    - Meter Sample Testing & Re-Verification
    - Meter Purchasing

Figure 5-1: Typical ORPC Smart Meter Installation

These investments have been further detailed in the subsections below:

5.3.2.1. General Sub-Program

This sub-program includes the purchase of smaller items that are used for maintenance and repairs. This includes but not limited to, meter seals, meter rings, disconnect sleeves, American Wire Gauge ("AWG") metering wire, Arc / Flame Resistant ("FR") Face shields, Test Switch/Block and S-to-A Adapters. The number of items that are required for purchase are reviewed each year by ORPC to ensure that the appropriate amount is purchased. The current forecast is based on historical precedence.

5.3.2.2. Instrument Transformer Sub-Program

From time to time, the current and potential transformers within the installed meters must be replaced. A relatively small investment is required to execute this work, but this work is ultimately critical in ensuring that the meters continue to function and operate as intended, providing accurate bills for ORPC's customers. ORPC is forecasting that they will require approximately 60 current transformers and 54 potential transformers over the 2022-2026 period.

5.3.2.3. Meter Sample Testing & Re-Verification Sub-Program

ORPC is required to have its residential revenue meters tested on a periodic basis, to ensure compliance with Measurement Canada standards. Between 2022 to 2026, approximately 800 of ORPC's residential smart meters will require testing by Measurement Canada using compliance sampling methods. If the units pass the sample testing, their seal period will be extended, and they can remain in service for the number of years as determined by the statistical sampling process. On the other hand, if the units fail sample testing, they will have to be removed from service and replaced by the end of the year that they are sampled in.

ORPC has a number of different subtypes of meters within their system, and only three-meter subtypes have a large enough population in the system such that they can go through the sample testing process. All other meter types must be 100% re-verified. ORPC executes this reverification process by utilising existing stock to replace expiring stock and will send the meters that were replaced for reverification. Once these meters are verified, they are then used as the new stock ready for the next round of reverification.

5.3.2.4. Meter Purchasing Sub-Program

ORPC needs to install and replace meters over the DSP planning period from 2022 to 2026, either due to seal expiry or due to new customer connections. Meters to be purchased by ORPC are forecasted based upon historical information, the quantity of meters expected to reach their seal expiry date, as well as the forecast of new customer connections. OPRC is looking to purchase approximately on 300 new meters on average each year over the DSP planning period from 2022 to 2026. ORPC will review these quantities every year to reflect any updated information available to them.

Table 5-7: Program Outcomes

Outcomes	Description
Efficiency	To enable efficiencies in delivery of the Metering program, ORPC will look to purchase the new meters and associated equipment in bulk. Additionally, by delivering this metering program and addressing meters that are expiring, ORPC will have reduced the number of meters that would be susceptible to unexpected failure and therefore reduce the cost for ORPC having to reactively repair these meters. Through the deployment of smart meters, ORPC can leverage the data to determine: • Whether or not an in-service transformer is currently overloaded • When performing a transformer change-out, determining if the new transformer size can be reduced or if it the size should be increased (to match the loading demand) • If a customer wants to upgrade their service, to see if the currently installed transformer will be suitable enough to support that new service connection
Customer Value	By upgrading and renewing meters that are expiring, this will ensure that customer meters continue functioning, capturing accurate electricity usage, and therefore enabling ORPC to produce an accurate bill.
Reliability	By installing new meters and ensuring they are up to current standards, this ensures that the reliability of the meters continues to be maintained, thus enabling customers to be billed accurately for the electricity they use.

5.3.3. Investment Drivers & Need

ORPC's Metering program is designed to ensure that ORPC complies with the mandated service obligations, as well as mitigate any failure risks of their metering infrastructure within the system.

As noted in Table 5-8, this program is primarily driven by the need to comply with mandated service obligations. The secondary driver is the need to mitigate failure risks from the meters failing and being unable to bill customers accurately.

Table 5-8: Program Drivers

	Driver	Description
Primary	Mandated Service Obligations	The primary driver for this program is to comply with the Mandated Service Obligations as defined by the DSC and Measurement Canada. By replacing meters that have expired with new meters, ORPC ensures that it complies with its obligations to provide, install, and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor's distribution system. This ensures that customers will receive accurate bills.
Secondary	Failure Risk	Additionally, by addressing expired meters, this reduces the risk of the meters failing and therefore maintaining the reliability for ORPC to able to bill its customers accurately.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

5.3.3.1. Mandated Service Obligations

The primary driver of the Metering program is to comply with mandated service obligations. ORPC is obligated to install and maintain meters at all customer connection points from both residential and commercial customers. This is in order for ORPC to accurately measure and bill the amount of electricity that each customer uses. Each meter can be utilized for a pre-determined amount of time before it expires and requires replacement, thus ensuring the accuracy and reliability of meter reads.

The forecasted number of meters due to be replaced and installed are based both upon historical information, information based upon the number of meters expected to reach their seal expiry date, and the forecast of new customer connections.

5.3.3.2. Failure Risk

As many of ORPC's meters are reaching their seal expiry date, this will increase the risk of failure and the inability of the utility to measure and bill customers in an accurate manner. By replacing meters at their end of life, this will reduce the risk of failure and ensure that there is no detrimental effect on the customer's bill.

5.3.4. Investment Timing & Pacing

Table 5-9 summarizes the overall investment associated with the Metering program, during the Historical period from 2015 to 2019, the 2020 and 2021 Bridge years, as well as the Forecast period from 2022 to 2026.

The pace of investment within this program is designed to meet its mandated service obligations.

Table 5-9: Timing & Pacing of Investment

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$2.7	$7.0	$35.4	$91.4	$101	$39.2	$60.0	$95.4	$86.1	$68.8	$88.8	$56.5

5.3.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Meter Procurement* – Delivery of meters from the vendor introduces the largest possible risk to the program schedule. If meters are not received in a timely manner, there will be a delay in installation which leads to a delay in energizing new or upgraded services. To mitigate this risk, ORPC orders meters with enough lead time to ensure that meters are available in inventory prior to being needed for installation or replacement.

- *Unexpected Priority Calls* – In the regular course of utility operations, instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC uses where necessary contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility’s plans.

5.3.4.2. Investment Pacing & Prioritization

The proposed investment pacing is based upon the information that ORPC possesses with respect to meters that are expiring and from customer connection information. ORPC has planned the work over the forecast period to align with being able to deliver within it resources available.

Whilst these types of projects are generally of high priority due to these investments being part of ORPC’s mandated service obligations, impacts from other unplanned operational conflicts may arise that may result in execution delays.

5.3.5. Options Analysis

As stated in Section 3.3.2.2.2, ORPC only executes its project evaluation procedure for projects that are not driven by mandated service obligations or third-party questions. This is namely due to the fact that Metering investments are non-discretionary and must be executed in order to comply with regulations as described in the DSC and by Measurement Canada.

5.3.6. List of Projects

Table 5-10 details the various sub-programs and project-specific investments over the DSP planning period from 2022 onwards to 2026.

Table 5-10: Metering Program Expenditures – 2022-2026

Project Category	2022	2023	2024	2025	2026
General	$3,454	$3,496	$3,808	$3,403	$3,573
Instrument Transformers	$4,410	$4,118	$4,862	$4,540	$5,360
Meter Sample Testing & Re-Verification	$27,419	$26,444	$11,465	$28,174	$0
Meter Purchasing	$58,783	$52,006	$48,664	$52,722	$47,616
Total	**$95,397**	**$86,065**	**$68,799**	**$88,839**	**$56,550**

6. SYSTEM RENEWAL INVESTMENTS

6.1. UNDERGROUND RENEWAL

6.1.1. Overview

ORPC's underground distribution system consists of underground cables and transformers, with a very small population of underground switches. In total, underground infrastructure accounts for 7% of the total population of assets within ORPC's system. Underground polymeric cables are designed to provide underground distribution of electricity between the substation and underground transformers, while underground pad mounted transformers are designed to step down the primary voltage to a voltage level suitable for residential and commercial customers.

The Underground Renewal program is primarily driven by the need to mitigate the Failure Risk of underground assets and is designed to replace underground transformers and cables that are either approaching, at or already exceeding their TUL within the DSP planning period or have been found to be in Poor or Very Poor condition, respectively. These assets will be replaced with the newest underground infrastructure that aligns to current ORPC standards. This program will also target underground transformers with PCB's for replacement in order to mitigation potential environmental and safety-related risks.

Total program spending from 2022 onwards to 2026 is $284K, which closely aligns to spending levels over the historical period from 2015 onwards to 2019, with only inflationary increases occurring within the forecast period.

6.1.2. Investment Description

ORPC's Underground Renewal program is designed to target those underground assets introducing Failure Risk, Functional Obsolescence or Environmental & Safety Risks with new underground assets that confirm to ORPC's current-state standards, which have been derived by the Utilities Standards Forum ("USF") and are commonly applied at LDC's across Ontario.

For instance, legacy first-generation direct-buried XLPE cables will be replaced with new tree-retardant cross-linked polyethylene ("TR-XLPE") cables in conduit. Current generation TR-XLPE cables have been developed using "super-smooth super-clean" ("SS/SC") manufacturing techniques, which greatly reduce the risk of impurities to penetrate the cables' insulation material during the manufacturing process. All new TR-XLPE cable segments are installed in polyvinyl chloride (PVC) conduit. This conduit is directly buried into the earth in non-roadway applications and is concrete encased in roadway applications in order to reduce the risk of physical factors such as the weight of moving vehicles.

By installing new TR-XLPE cable segments in conduit, these cable segments can be fully removed device-to-device and replaced with new cable segments should they fail in the future. Replacement of the entire cable segment allows for the degradation of the cable insulation, including the effects of electrical treeing and partial discharge to be completely eliminated from the system. This is in contrast to direct-buried cables, where ORPC can only splice the cable during a failure event, as the cable cannot be fully removed from the system due to the nature of its installation. The PVC conduit also provides added protection against customer dig-ins.

Existing underground transformers that are at, approaching or have already exceeded their TUL will also be replaced within the scope of this program with the newest standard transformers. Where necessary, the newer transformers may possess a larger nameplate rating in order to support more customers within the system. This program will also target those underground transformers containing PCB's for replacement with new transformers.

Assets to be replaced within this program have been prioritized based upon either the APUL (i.e., assets at, already exceeding or to exceed their TUL in the 5-year DSP planning period) or ACA (i.e., assets in Very Poor or Poor condition) results. Furthermore, the projects proposed for execution in the will be prioritized on the basis of the connected customers who would see an outage should a future cable or transformer failure take place. In addition to transformers and cables being replaced within a given project location, the program will also replace aging underground switch cubicles which allow for isolation, sectionalization and restoration of customers during outage events.

The total program spending of $243K over the forecast period remains consistent with the historical spending of $242K from 2015 to 2019, with the cost increase in the forecast period being driven by inflationary increases. Key projects to occur in the forecast period include:

Pembroke:

- **Boundary Road:** Install 2 – Four-Position Switch Cubicles, 2 Cement Pad mount Transformer bases and Transformers, 1800m of direct-buried conduit. Replace existing underground XLPE cables with new 15kV 1/0 CU Primary TRXLPE cables.

- **O'Brien St:** Replace 800m of 15kV Primary XLPE cables, 4 pad-mounted distribution transformers, and 2 - 4 position switch cubicles.

Table 6-1 highlights the outcomes emerging from the Underground Renewal program at ORPC:

Table 6-1: Program Outcomes

Outcomes	Description
Efficiency	Replacement of direct-buried cables with new cables in conduit will allow for enhanced work practices to occur should these newly installed cables fail in the future, as entire cable segments can now be pulled from device-to-device without the need of excavation, thereby reducing the overall restoration time to the customer.
Customer Value	Projects have been prioritized within the test year based upon connected customers to the associated underground assets. By leveraging this customer information in combination with probabilistic inputs from the APUL and ACA analyses, ORPC is applying a risk-based approach to identifying the most problematic underground locations to be managed within the system. In addition, the potential environmental and safety risks associated with PCB transformers are being mitigated via the execution of this program.
Reliability	Replacement of underground assets approaching, at or beyond their TUL or assets in Very Poor or Poor condition will result in the mitigation of potential reliability issues within the system. Replacement of first generation XLPE cables also mitigates the specific risks associated to this asset subtype due to their accelerated degradation when compared to the new standardized TR-XLPE cables.

6.1.3. Investment Drivers & Need

ORPC's Underground Renewal program is designed to target aging, deteriorated and functionally obsolete underground infrastructure for replacement with new infrastructure that conform to ORPC's current-state standards.

As noted in Table 6-2, this program is primarily driven by the need to mitigate the Failure Risk associated with these assets. The secondary driver is functional obsolescence, where legacy infrastructure such as direct-buried XLPE underground cables no longer align to ORPC's current standards and operational practices, and therefore must be replaced with new infrastructure that aligns to the current-state standards.

Table 6-2: Program Drivers

	Driver	Description
Primary	Failure Risk	First-generation XLPE cables introduce elevated failure risks within the system due to the impurities within the cables' insulation, which can lead to electrical treeing and partial discharge. Pad-mounted transformers with PCB's will also be replaced within this program, therefore eliminating potential environmental and safety risks.
Secondary	Functional Obsolescence	Underground direct-buried cables can only be excavated and repaired via cable splicing at the time of failure. This process can be very time-intensive, due to the enhanced complexity of locating the cable fault. The installed splice represents only a "band-aid" solution for the cable, as degradation can continue to spread to the other unaffected portions of the cable, thereby resulting in future failure events. In general, direct-buried cables do not conform to ORPC's current standards and are therefore functionally obsolete.
	Safety	Underground transformers containing PCBs will be targeted for replacement within this program. These assets can introduce safety and environmental risks to both ORPC field crews and the public.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

6.1.3.1. Failure Risk

The primary driver of the Underground Renewal program is Failure Risk, as this program is targeting those underground cables and transformers that are either approaching, at or exceeding their TUL, or are in Poor or Very Poor condition.

Figure 6-1 illustrates the results of the APUL analysis for underground assets, revealing that 15% of underground assets (underground transformers and underground cable segments) are already past their TUL, with another 15% of underground assets to exceed their TUL over the forecast period from 2022 to 2026. APUL results at the asset class level are very similar to the results across all underground assets evaluated.

Underground asset results from the ACA, as detailed in Figure 6-2, illustrate a slightly different picture, revealing that only 3% of all underground assets are in Very Poor condition with another 2% of assets in Poor condition. However, when examining these results at the asset class level, we do start to see substantial differences regarding the percentages of underground cables and transformers in Very Poor and Poor condition, respectively.

First-generation XLPE cables, the only type of polymetric cables available at the time, were installed prior to 1990 within ORPC's distribution system. These cables have been found to result in the ingress of impurities and contaminants within the cables' insulation. As a result, these cables possess an elevated risk of water and electrical treeing as well as partial discharge – all of which can result in the eventual failure of the cable insulation and overall failure of the cable, resulting in an outage to customers. Currently, 28% of underground cable segments have been found to be in Very Poor condition, with no cable segments in Poor condition and another 37% of cable segments in Fair condition, respectively. With respect to APUL results, 14% of cable segments were found to be already past TUL, with an additional 16% of cable segments to exceed their TUL over the forecast period.

Figure 6-1: Underground Asset APUL Results

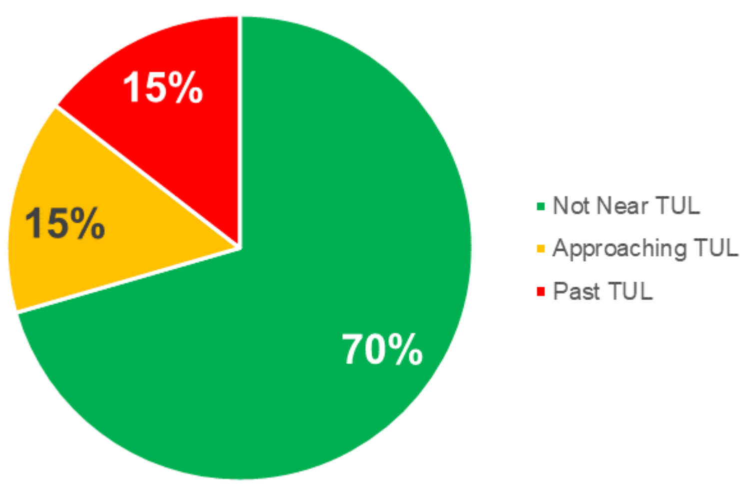
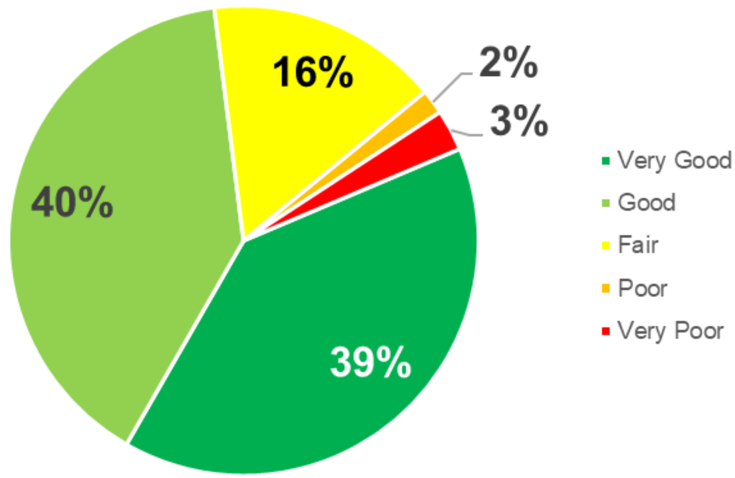


Figure 6-2: Underground Asset ACA Results



Out of the total underground transformer population, none of these assets were found to be in Very Poor condition, with only 2% in Poor condition and 13% in Fair condition, respectively. Conversely, APUL results reveal that 15% of underground transformers are already past TUL, with another 15% approaching their TUL over the forecast period. As explained in Section 3.2.4, the deviation between ACA and APUL results indicate that while ORPC's underground transformers are heavily aged, these assets do not reveal signs of accelerated degradation. ORPC's maintenance program has also had an effect on managing the continued operation of these assets such that any form of accelerated degradation is minimized.

6.1.3.2. Functional Obsolescence & Safety

Secondary drivers of the Underground Renewal program include Functional Obsolescence, where the existing legacy equipment no longer aligns to current ORPC standards or operational practices, as well as Safety, where those same legacy assets can introduce heightened safety risks to field crews as well as the general public.

Legacy direct-buried cables are considered functionally obsolete and will be replaced with new cables in either direct-buried or concrete-encased conduit. When direct-buried cables fail, the only option is to excavate the location of the cable failure, cut out the portion of failed cable, and install a splice that reconnects the two ends of the cable segment. Direct-buried cables can lead to lengthier outage impacts for customers, as it is more complex for in-field crews to locate the faulted cable segment when it is directly buried in the earth.

The splice in of itself represents a "band-aid" solution for resolving the issue with the cable. The action of splicing the cable represents more of a repair, rather than an outright replacement of the cable, due to the fact that the degradation within the cable can continue to spread to the adjacent unaffected portions of the cable. The splice itself may also fail in the future. For these reasons, ORPC's current standard involves the installation of cables within conduit. These conduits allow for entire cable segments to be fully replaced device-to-device should they fail in the future. By fully replacing the cable, all degradation associated with the failed cable is completely removed from the system. The new cables-in-conduit also reduce the complexities of fault finding and restoration, thereby reducing the overall outage impacts to the customer while improving internal efficiencies within the organization.

Underground transformers containing PCB's are also targeted for replacement within this program. These assets can introduce safety and environmental risks should an oil leak or catastrophic failure occur, and therefore these assets must be replaced with new standardized transformer equipment.

6.1.4. Investment Timing & Pacing

The pace of investment within this program is designed to strike a balance between the needs of the assets (based upon APUL and ACA results as well as the need to mitigate environmental and safety-related risks), available resources to execute the work within ORPC as well as customer preferences to keep electricity rates as digestible as possible. The total expenditures of $284K over the forecast period is consistent with the historical spending.

6.1.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Weather* – Poor weather (particularly prolonged spells) can negatively affect the planned pace and timeliness of planned work. ORPC plans to replace underground assets primarily in the Spring to Fall timeframe, avoiding the Winter season where snow, ice and low temperatures can negatively affect execution volumes and costs.

- *Unexpected Priority Calls* – In the regular course of utility operations, instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC uses where necessary contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility's plans.

- *General Access* – The activities comprising in this program frequently involve work on private residential and commercial property, at times resulting in access issues that may slow down the pace of work execution. ORPC addresses these issues through regular communication with customer affected, ensuring work is done in a timely manner and with as minimal impact to the customer as possible.

6.1.4.2. Investment Pacing & Prioritization

As per ORPC's long-term planning sub-process, individual underground assets have been prioritized for replacement across the system based upon the ACA and APUL results, as well as environmental and safety-related considerations. Projects within this program were prioritized for execution based upon the connected customers to the project assets, who will face resulting outages as well as potential environmental and safety impacts should these assets fail within the system.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

6.1.5. Options Analysis

As ORPC is not executing any major projects in its Underground Renewal program in 2022, there are no material investments and associated options that can be explored at this time. However, ORPC will endeavour to execute its Project Evaluation procedure to evaluate the Underground Renewal activities from 2023 and onwards as the detailed execution plan is prepared by ORPC's asset managers and planning engineers.

6.1.6. List of Projects

Table 6-3 illustrates the two of the main projects that will carried out from 2023 onwards. As these are multi-year projects, these initiatives will be executed over the course of the DSP planning period due to the complex nature of underground infrastructure replacement and available resourcing within ORPC.

Table 6-3: Underground Renewal Projects and Cost

Project Location	Project Description	Cost ($K)
Boundary Road, Pembroke	Install 2 – Four-Position Switch Cubicles, 2 Cement Pad mount Transformer bases and Transformers, 1800m of direct-buried conduit. Replace existing underground XLPE cables with new 15kV 1/0 CU Primary TRXLPE cables	$81.5
O'Brien St, Pembroke	Replace 800m of 15kV Primary XLPE cables, 4 pad-mounted distribution transformers, and 2 - 4 position switch cubicles	$120
Total		$202

6.2. OVERHEAD RENEWAL

6.2.1. Overview

ORPC's overhead distribution system consists of poles, overhead conductor and transformers, with a small population of switches. In total, overhead infrastructure accounts for 90% of the total population of assets within ORPC's system. Overhead poles are designed to support other overhead assets and accessories, including overhead conductors, pole-mounted transformers, overhead switches, insulators, and arrestors, and ultimately support the route for the distribution of electricity between the substation and the pole-mounted transformers, which are designed to step down the primary voltage to a voltage level suitable for residential and commercial customers.

The Overhead Renewal program is primarily driven by the need to mitigate the Failure Risk of overhead assets and is designed primarily to replace poles and overhead transformers, alongside any overhead conductor and switches that are either approaching, at or already exceeding their TUL within the DSP planning period or have been found to be in Poor or Very Poor condition, respectively. In addition, many of the poles forecast to be replaced are legacy non-standard design poles. These assets will be replaced with the newest overhead infrastructure that aligns to current ORPC standards. This program will also target overhead transformers with PCB's for replacement in order to mitigate potential environmental and safety-related risks. In addition, the program will also look to continue ORPC's voltage conversion plan in the Pembroke service area: This involves converting sections of the system from 4.16 kV to 12.47 kV, upgrading the infrastructure as required. This will allow ORPC to mitigate losses in the system and bring the system up to latest standards and in alignment with other utilities. In the long term, this will allow the decommissioning of the Pembroke MS1 and MS3 substations.

As further noted in *Table 6-4* total program spending from 2022 onwards to 2026 is $2.46M which closely aligns to spending levels over the historical period from 2015 onwards to 2019, with only inflationary increases occurring within the forecast period.

Table 6-4: Investment Summary Details

	Historical						Bridge	Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$304	$358	$519	$745	$272	$423	$381	$441	$463	$484	$524	$544
Primary Driver	Failure Risk											
Secondary Drivers	Functional Obsolescence, Safety											
Outcomes	Improved Reliability, Improved Efficiency, Improved Customer Value.											

6.2.2. Investment Description

ORPC's Overhead Renewal program is designed to target those overhead assets introducing Failure Risk that are already exceeding, at or will exceed their TUL within the DSP planning period or have been found to be in Poor or Very Poor condition. At the same time, this program will also convert legacy 4.16 kV infrastructure, which is aging and functionally obsolete to the 12.47 kV voltage level. Finally, pole-mounted transformers containing PCBs which can contribute towards environmental and safety risks will be replaced with new transformers that conform to ORPC's current-state standards, which have been derived by the Utilities Standards Forum ("USF") and are commonly applied at LDC's across Ontario.

Within the Pembroke service area, 4.16 kV feeders connected to the MS1 and MS3 substations will be converted to the 12.47 kV system voltage, thereby allowing for these substations to eventually be decommissioned in the future. These 4.16 kV assets are some of the oldest in the system and no longer align to ORPC's current standards. Infrastructure at Pembroke MS1 and MS3 substations are also aging and deteriorated, and at risk of failure. Through the execution of the conversion activities, new 12.47kV infrastructure will be installed that aligns to ORPC's current standards, and customers will be supplied by newer substation equipment. Furthermore, through the eventual decommissioning of the Pembroke MS1 and MS3 substations (to take place beyond 2025), ORPC will achieve internal cost savings by no longer needing to maintain these assets.

Existing overhead transformers that are at, approaching or have already exceeded their TUL will also be replaced within the scope of this program with the newest standard transformers. Where necessary, the newer transformers may possess a larger nameplate rating in order to support more customers to be connected within the system. This program will also target those overhead transformers containing PCB's for replacement with new transformers, thereby mitigating possible environmental and safety risks.

Assets to be replaced within this program have been prioritized based upon either the APUL (i.e., assets at, already exceeding or to exceed their TUL in the 5-year DSP planning period) or ACA (i.e., assets in Very Poor or Poor condition) results. Furthermore, the projects proposed for execution in the test year (2022) were prioritized on the basis of the connected customers who would see an outage should a future failure take place. In addition, through the continuation of voltage conversion plan, customers will be transitioned away from the aging 4.16kV overhead asset infrastructure and supporting aging infrastructure at the Pembroke MS1 and MS3 stations and transitioned to newer standardized 12.47 kV infrastructure and supporting substations. In addition, many of the projects proposed within this program target poles and insulators that are of a shortened height and no longer align to standard design practices. In addition, legacy accessories such as porcelain insulators will be replaced with standardized polymeric insulators. These porcelain insulators have issues with respect to the connections made between the overhead conductor and the insulator cap at the top of the insulator, where the connection can become loose and/or the cap can become degraded or crack, and lead to a catastrophic flashover event. During a flashover, these porcelain insulators will fail in a highly destructive manner, introducing a serious safety event to the nearby public or field crews. Additionally, legacy poles will also be replaced with poles that meet the current standards. This will ensure poles are at the correct height to support the overhead conductor, allow accessories such as insulators to be attached more easily and to current standards. All this ensures that these assets can be maintained safely and easily by the field crews.

The total program spending of $2.46M over the forecast period remains consistent with the historical spending of $2.20M from 2015 to 2019, with the cost increase in the forecast period being driven by inflationary increases.

Key projects to occur in the 2022 test year include:

Pembroke:

- **Esther St:** Replace 7 spans of 3-phase, #2 solid copper conductor on Esther St. between MacKay St. and Maple Ave. Install 4 - 45'/3 poles and 2 - 40'/3 poles between Maple Ave. and Cecilia St. Replace 2 OH transformers between Maple Ave. and Cecilia
- **John St:** Replace 6 poles located between Pembroke St. E. and Sussex St., crossing John St
- **McKenzie St:** Replace 4 poles and 1 OH transformer
- **Third Ave:** Replace 5 poles
- **Thompson St:** Replace 1 - 35' end of life wood pole with a 45' class 3 pole. Replace 4 end of life 35' secondary poles with 4 - 40' class 3 wood poles.

Almonte:

- **Larose St:** Upgrade 3 existing poles behind Larose St. adding 1 pole to relocate transformer from backyard and upgrade 1 pole behind. Johanna St. transfer existing conductor and services
- **Naismith Drive:** Upgrade 4 poles and secondary conductor in the rear lot
- **Evelyn St:** Upgrade 3 poles and secondary conductor in rear lot
- **Florence St:** Upgrade 3 poles on Florence St. and 1 on Maude St.

Table 6-5 highlights the outcomes emerging from the Overhead Renewal program at ORPC:

Table 6-5: Program Outcomes

Outcomes	Description
Efficiency	Replacement of legacy overhead infrastructure with new standard infrastructure allows the utility to apply current operating practices and procedures when maintaining and inspecting these assets, which can result in cost savings to the utility. The conversion of 4.16 kV plant to the standardized 12.47 kV system voltage will eventually allow for the supplying Pembroke MS1 and MS3 substations to be fully decommissioned, which will result in significant cost savings to the utility as these assets will no longer need to be maintained or serviced.
Customer Value	Projects have been prioritized within the test year based upon connected customers to the associated overhead assets. By leveraging this customer information in combination with probabilistic inputs from the APUL and ACA analyses, ORPC is applying a risk-based approach to identifying the most problematic underground locations to be managed within the system. In addition, the potential environmental and safety risks associated with PCB transformers are being mitigated via the execution of this program.
Reliability	Replacement of overhead assets approaching, at or beyond their TUL or assets in Very Poor or Poor condition will result in the mitigation of potential reliability issues within the system. In turn, potential reliability impacts can be avoided within the system, along with the associated emergency repair and restoration costs.

6.2.3. Investment Drivers & Need

ORPC's Overhead Renewal program is designed to target aging, deteriorated and functionally obsolete overhead infrastructure for replacement with new infrastructure that conforms to ORPC's current-state standards.

As noted in *Table 6-6* this program is primarily driven by the need to mitigate the Failure Risk associated with these assets. Secondary drivers include Functional Obsolescence and Safety associated with the legacy plant, as this infrastructure no longer aligns to ORPC's current standards or operational practices.

Table 6-6: Program Drivers

	Driver	Description
Primary	Failure Risk	This primary driver for this program is to mitigate failure risk associated with the overhead plant, including the replacement of poles, transformers and conductor that are already exceeding, at or to exceed their TUL over the DSP planning period or in Very Poor or Poor condition. This will include the replacement of leaning poles, poles with severe groundline rot, cracks, and/or pole top feathering. This also includes the replacement of pole-mounted transformers with tank corrosion, leaking oil, or transformers with PCBs. The failure of these overhead assets can result in significant customer impacts due to an outage event. Finally, legacy porcelain insulators will be replaced with polymeric insulators, which possess a more robust construction and are less susceptible to cracking, particularly at the insulator cap where the connection is made to the overhead conductors.
Secondary	Functional Obsolescence	This program will also be targeting functionally obsolete assets for replacement with the new infrastructure that aligns with current ORPC standards and operating practices. This includes the relocation of difficult-to-access rear lot overhead plant, as well as the replacement of aging and obsolete 4.16 kV overhead infrastructure connected to the Pembroke MS1 and MS3 substations. These substations also contain ORPC's oldest vintage assets, and through these conversion efforts, customers will be connected to the newer, more robust and secure 12.47 kV system. In addition, many of the poles are legacy non-standard design poles which require to be replaced and brough into line with the current standards, allowing maintenance to be carried out safer and easier by field crews.
	Safety	As overhead assets become deteriorated, they lose their structural integrity and pose increasing risks to ORPC's staff servicing the assets as well as the general public. Catastrophic failure of overhead plant can result in downed pole lines and conductor that can result in direct safety and environmental impacts to customers. Porcelain insulators are heavily aged within the system and are susceptible to cracks. In particular, the insulator cap which connects to the overhead conductor can crack, thereby loosening the connection to the conductor, and resulting in a catastrophic flashover event. This failure mode would be highly destructive, with shards of glass exploding in a grenade-like manner. Finally, pole-mounted transformers with PCBs can expose safety and environmental risks to customers and field crews should an oil leak occur. Through the execution of this program, these safety risks will be mitigated.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

6.2.3.1. Failure Risk

The primary driver of the Overhead Renewal program is Failure Risk, as this program is targeting those overhead assets that are either approaching, at or exceeding their TUL, or are in Poor or Very

Poor condition. For wood poles, key failure modes including excessive leaning, rot at or below the groundline, horizontal or vertical cracks, woodpecker hole damage and excessive feathering at the top of the pole. For transformers, key failure modes include transformer tank corrosion and leaking. *Figure 6-3* presents examples of deteriorated and aging overhead assets within ORPC's distribution system.

Figure 6-3: Examples of Deteriorated & Aging Overhead Assets

Figure 6-4 illustrates the results of the APUL analysis for overhead assets, revealing that 25% of overhead assets are already past their TUL, with another 16% of overhead assets to exceed their TUL over the forecast period from 2022 to 2026.

ACA results as illustrated in Figure 6-5 illustrate a different picture, indicating that approximately 20% of overhead assets are either in Very Poor or Poor condition, respectively. However, when further breaking down these results at the asset class level, we do start to see further differences regarding the percentages of poles and pole-mounted transformers in Very Poor and Poor condition, respectively.

Out of the total pole-mounted transformer population, none of these assets were found to be in Very Poor condition. However, 20% of these assets are in Poor condition and 38% are in Fair condition, respectively. With respect to APUL results, 23% of pole-mounted transformers were found to be already past TUL, with an additional 21% of overhead transformers to exceed their TUL over the forecast period. Key degradation modes captured through the ACA analysis include leaking transformers, corrosion of the transformer tank as well as contamination of the transformer bushings. Additionally, overhead transformers containing PCB's are also targeted for replacement within this program. These assets can introduce environmental and safety risks should an oil leak or catastrophic failure occur, and therefore these assets must be replaced with new standardized transformer equipment.

Currently 10.8% of overhead poles have been found to be in Very Poor condition, and 11.6% poles in Poor condition and another 43% of poles in Fair condition, respectively. This equates to around 914 poles being in Poor and Very Poor condition. However, APUL results indicate that 28% of poles are already past TUL, with another 16% approaching their TUL over the forecast period. As explained in Section 3.2.4, the deviation between ACA and APUL results indicate that while ORPC's poles are heavily aged, a significant amount of these assets does not reveal signs of accelerated degradation. ORPC's maintenance program has had an effect on managing the continued operation of these assets such that any form of accelerated degradation is minimized. However, as these assets continue to age, they will require replacement such that the risk of possible failure can be avoided. In addition to replacement of the poles, attached components such as porcelain insulators and overhead conductor will also be replaced. Porcelain insulators are heavily aged within the system, are highly susceptible to cracks due to their brittle design. ORPC has been experiencing issues with these insulators, where the insulator cap that makes the connection to the overhead conductor will crack, thereby loosening the connection between the insulator and the conductor. This can result in a catastrophic flashover event, where the insulator can shatter in a highly destructive manner.

In regard to the test year projects, the following projects are primarily driven by failure risk with the poles in these areas being in Very Poor condition as highlighted through the ACA report:

- Almonte: Larose St, Naismith Drive, Evelyn St, Florence St
- Pembroke: Third Ave and Thompson St

Figure 6-4 Overhead Asset APUL Results

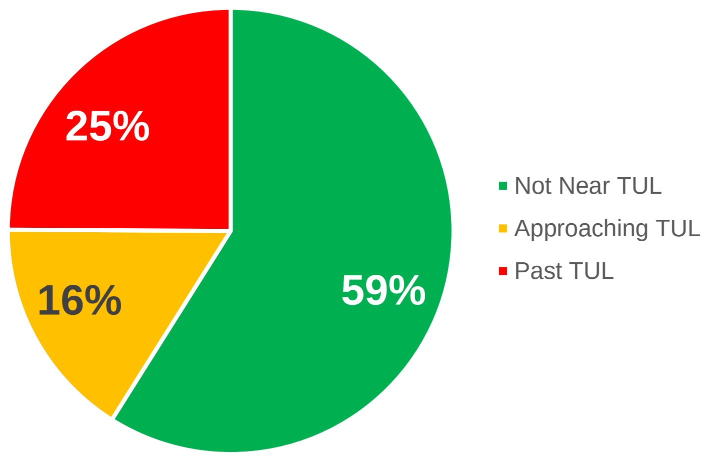
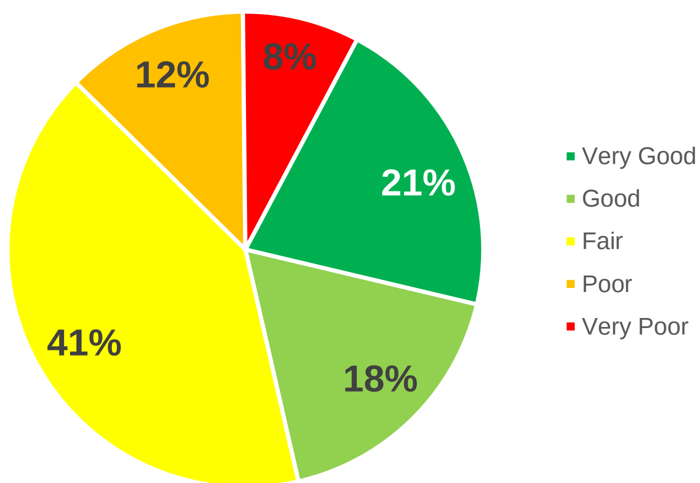


Figure 6-5 Overhead Asset ACA Results



6.2.3.2. Functional Obsolescence & Safety

Secondary drivers for the Overhead Renewal program include Functional Obsolescence and Safety – both of which apply to the legacy infrastructure, including the 4.16 kV plant that no longer aligns to current ORPC standards or operational practices. This also happens to be some of the oldest assets within ORPC's system. The 4.16 kV feeders to be converted are connected to the Pembroke MS1 and MS3 substations, which also contain the aging and deteriorating substation infrastructure.

By transitioning these connected customers to standardized 12.47 kV infrastructure, these new assets will now align to current ORPC standards and operating practices, and the Pembroke MS1 and MS3 substations can eventually be decommissioned (beyond the 5-year term of this plan), thereby introducing cost savings to the utility as the associated substation assets will no longer need to be maintained. The 12.47 kV infrastructure ultimately provides a larger capacity and newer, more reliable infrastructure. As part of this investment program, legacy poles of a shortened height that no longer align with standard design practices, will be replaced with the current standard design such that it allows for the assets to be maintained using standardized operating procedures. Shorter poles require top pole extenders to be installed to allow the overhead conductors to be connected, which no longer align to standard design practices and can introduce further issues when performing maintenance procedures.

Deteriorating and aging overhead plant in general can expose field crews and the general public to potential safety risks. The catastrophic failure of wood poles, as an example, can result in downed conductor spans, leaking transformers and property damages. Legacy porcelain insulators can also introduce significant safety risks within the system. Should a catastrophic flashover event occur, these insulators can shatter in a highly destructive manner, with shards of glass exploding in a grenade-like manner. As part of this program, these legacy assets will be replaced with polymeric insulators, which do not possess the same brittle construction and therefore do not introduce these safety risks into the system. Pole-mounted transformers with PCBs can also introduce serious safety and environmental risks to the surrounding area should the transformer tank corrode, resulting in leaking oil. Through the replacement of these legacy assets within this program, the associated safety and environmental risks can be mitigated.

In regard to the test year projects identified, the following projects are driven primarily by functional obsolescence along with the secondary driver of failure risk:

- Pembroke - Esther Street Pole Replacements
- Pembroke – John Street Pole Replacements
- Pembroke – McKenzie Street Pole Replacements

6.2.4. Investment Timing & Pacing

Table 6-7 summarizes the overall investment associated with the Overhead Renewal program, during the Historical period from 2015 to 2019, the 2020 and 2021 Bridge years, as well as the Forecast period from 2022 to 2026.

The pace of investment within this program is designed to strike a balance between the needs of the assets (based upon APUL and ACA results as well as the need to mitigate environmental and safety-related risks), available resources to execute the work within ORPC as well as customer preferences to keep electricity rates as digestible as possible. For these reasons, total expenditures of $2.46M over the forecast period remain consistent with the historical spending of $2.20M from 2015 to 2019, with the cost increase in the forecast period being driven mainly by inflationary increases.

Table 6-7: Timing & Pacing of Investment

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$304	$358	$519	$745	$272	$423	$381	$441	$463	$484	$524	$544

6.2.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Weather* – Poor weather (particularly prolonged spells) can negatively affect the planned pace and timeliness of planned work. ORPC plans to replace underground assets primarily in the

Spring to Fall timeframe, avoiding the Winter season where snow, ice and low temperatures can negatively affect execution volumes and costs.

- *Unexpected Priority Calls* – In the regular course of utility operations, instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC uses where necessary contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility's plans.

- *General Access* – The activities comprising in this program frequently involve work on private residential and commercial property, at times resulting in access issues that may slow down the pace of work execution. ORPC addresses these issues through regular communication with customer affected, ensuring work is done in a timely manner and with as minimal impact to the customer as possible.

6.2.5. Investment Pacing & Prioritization

As per ORPC's long-term planning sub-process, individual overhead assets have been prioritized for replacement across the system based upon the ACA and APUL results, as well as environmental and safety-related considerations. Projects within this program were prioritized for execution in the test year (2022) based upon the connected customers to the project assets, who will face resulting outages as well as potential environmental and safety impacts should these assets fail within the system.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

6.2.6. Options Analysis

Project Alternatives

ORPC evaluated each discretionary Overhead Renewal project above material threshold and determined the project pacing using the project evaluation process as outlined in Section 3.3.2. For each Overhead Renewal project, the project scope is defined based on ACA results, APUL information, customer needs, resource availability, and capital cost. The risk costs associated with each alternative were determined using the methodology outlined in Section 3.3.2.

Each project within the Overhead Renewal program was evaluated at:

- Decelerated Pace;
- Moderate Pace; and
- Accelerated Pace.

Decelerated Pace Alternative – This is defined as the alternative in which the full project scope and investment are completed over a 5-year period. For this alternative, it is assumed that unplanned outages are more likely to occur than historical data predicts, because unplanned outages due to asset failure have a higher probability of occurrence at a decelerated asset renewal pace. It is also assumed that the expected volume of transformer oil leaks is more than the expected volume at the Moderate Pace alternative, due to higher probability of oil leaks at a decelerated asset renewal pace.

Moderate Pace Alternative – This is defined as the alternative in which the full project scope and investment are completed over a 1-year period as defined within this plan. For this alternative, it is assumed that unplanned outages are equally as likely to occur as historical data predicts. The expected volume of transformer oil leaks, when applicable, is estimated based on a fixed portion of the total volume of oil in scope.

Accelerated Pace Alternative – This is defined as the alternative in which the full project scope and investment are completed over a half-year period. For this alternative, it is assumed that unplanned outages are less likely to occur than historical data predicts, because at an accelerated asset renewal pace, unplanned outages due to asset failure have a lower probability of occurrence. It is also assumed that transformer oil leaks are less likely to occur than expected for the Moderate Pace alternative, because at an accelerated asset renewal pace, oil leaks due to asset failure have a lower probability of occurrence. It is also assumed that planned construction outages will be two times the duration and the number of affected customers compared to the Moderate Pace alternative.

Project Evaluation Results

The evaluation process was applied to all projects within the Overhead Renewal program. The pacing alternative that produced the lowest TCO for residual risk values over the project lifecycle was selected. In all evaluated projects, the Moderate Pace alternative, which completes the full project scope in a 1-year period, was recommended as a result of the process. The results for all evaluated projects are shown below in Table 6-8. This is reflected in OPRC's Overhead Renewal capital expenditure plan in Table 6-7.

Table 6-8: TCO for Residual Risk Values for Overhead Renewal Project Alternatives

	TCO Value for Residual Risk ($M)		
	Decelerated Pace Alternative	Moderate Pace Alternative	Accelerated Pace Alternative
Overhead Renewal Projects	$2.102M	$2.085M	$2.203M

6.2.7. List of Projects

ORPC has identified projects that will address overhead assets in the test year 2022 and the costs associated with undertaking each.

Table 6-9: Overhead Renewal Test Year Projects and Cost

Project Location	Project Description	Cost ($K)
Esther St, Pembroke	Replace 7 spans of 3-phase, #2 solid copper conductor on Esther St. between MacKay St. and Maple Ave. Install 4 - 45'/3 poles and 2 - 40'/3 poles between Maple Ave. and Cecilia St. Replace 2 OH transformers between Maple Ave. and Cecelia	$51.6
John St, Pembroke	Replace 6 poles located between Pembroke St. E. and Sussex St., crossing John St	$43.3
McKenzie St, Pembroke	Replace 4 poles and 1 OH transformer	$25.0
Third Ave, Pembroke	Replace 5 poles	$61.3
Thompson St, Pembroke	Replace 1 - 35' end of life wood pole with a 45' class 3 pole. Replace 4 end of life 35' secondary poles with 4 - 40' class 3 wood poles	$26.1
Larose St, Almonte	Upgrade 3 existing poles behind Larose St. adding 1 pole to relocate transformer from backyard and upgrade 1 pole behind. Johanna St. transfer existing conductor and services	$81.0
Naismith Drive, Almonte	Upgrade 4 poles and secondary conductor in the rear lot	$37.5
Evelyn St, Almonte	Upgrade 3 poles and secondary conductor in rear lot	$50.6
Florence St, Almonte	Upgrade 3 poles on Florence St. and 1 on Maude St.	$43.9
Test Year Total	Excluding Minor Capital Renewal Projects	$441

6.3. STATION RENEWAL

6.3.1. Overview

ORPC has a total of 12 substations within the Almonte (4) and Pembroke (8) service areas. These stations contain critical infrastructure designed to manage the electricity system supply within these ORPC service areas. Station infrastructure consists of power transformers, circuit breakers, protective relays, station switches and battery banks. ORPC's substations are responsible for providing safe, reliable and effective operation of the distribution system.

The Station Renewal program is primarily driven by the need to mitigate Failure Risk at the substation level by replacing power transformers, circuit breakers, protective relays, station switches and battery banks that are approaching, at or already exceeding their TUL within the DSP planning period or have been found to be in Poor or Very Poor condition, respectively. These assets will be replaced with the newest station assets that align to current ORPC standards.

ORPC had an unexpected failure of a power transformer at Pembroke MS6 substation in late June 2021. This has forced ORPC to increase its investment in its test year to address the need to replace the failed power transformer. It is estimated that the replacement of the transformer will be $750k and be carried out in 2022. This includes the purchasing installation, commissioning of a new standardized power transformer and removal of the failed transformer. The Westinghouse S# B-3S7347 transformer that was built in 1974 will be replaced with a new standardized transformer. ORPC have had a third-party expert (Van Kooy Transformer Consulting Service Inc.) investigate the options to replace/repair the transformer and deemed that only a replacement was possible.

In addition, ORPC has identified three further substation locations that will require investment between 2023 and 2026 of $908K, which represents an increase to spending levels when compared to the historical period from 2015 to 2019. This increased amount will be necessary in order to proactively replace oil-filled circuit breakers – the oldest vintage across ORPC's complete population of circuit breakers – at Pembroke MS4 substation, an aging power transformer at Almonte MS2 substation and the switchgear containing air-blast circuit breakers at Almonte MS3 substation.

Across ORPC's system, nearly 80% of their station infrastructure is exceeding their TUL, with another 8% to exceed their TUL over the DSP planning period. However, at the same time, there are no station assets currently in Very Poor or Poor condition. Note, the asset condition analysis was completed before the failure of the transformer on Pembroke MS6. With the failure of this transformer, it is likely the ACA result would identify this transformer as in Very Poor condition. This divergence between the APUL and ACA results suggest that while ORPC's station assets are heavily aged, they are also not experiencing accelerated degradation as identified by visual inspections and testing results, meaning that ORPC is continuing to properly maintain and manage the performance of these assets as part of O&M activities.

6.3.2. Investment Description

ORPC's Station Renewal program is designed to target those stations assets contributing towards Failure Risk and Functional Obsolescence within the system. Existing legacy substation infrastructure will be replaced with new standardized equipment that aligns to ORPC's current-state standards and operating practices.

This will include the replacement the failed power transformer at Pembroke MS6 substation in 2022, to ensure the full functionality and capacity of the substation is restored. In addition, the replacement of an aging power transformer at Almonte MS2 substation, oil-filled circuit breakers at Pembroke MS4 substation, as well as air-blast circuit breakers and the associated switchgear at the Almonte MS3 substation will also be carried out.

In late June 2021, one of the power transformers at Pembroke MS6 Station unexpectedly failed, leaving the station running on one transformer. ORPC investigated the failure and damage and found that the damage was a result of HV B-phase bushing and winding failing. In addition, there is evidence of carbon spread throughout the transformer. Although this is typical for a transformer of this age. The transformer was nearing its end of life at the time of its failure. The weak point in all oil filled transformers is the cellulous insulation that is wrapped around the winding conductors, interconnecting internal leads and between the windings, and the windings and the core. Over time with the normal loading/heating of the insulation, deterioration is inevitable. As the insulation ages, it loses its ability to flex in response to the normal stresses of operation and becomes brittle. Whilst DGA is the best method to track this, the DGA for this transformer did not show any signs of the degradation. There is generally no way to predict a catastrophic failure. ORPC did engage a third-party to investigate if the transformer could be prepared but ultimately it has been deemed the only option is to do a complete replacement due to the age of the existing transformer and the costs associated to repair it. The PCB levels in the transformer oil rules out the ability for it to be repaired by a third party. The transformer will need to be disposed as hazardous waste due to the PCB levels. Due to the importance of the Station and the need to ensure that customers continue to have reliable service, ORPC will replace the transformer in 2022. The transformer will be replaced with a new standardized power transformer.

Nearly 80% of ORPC's station assets are past their TUL, with another 8% of assets to exceed their TUL during the DSP planning period. This means that while ORPC's assets may not be experiencing forms of accelerating aging, they are still heavily aged and will eventually fail due to the natural aging and utilization processes. At the same time, legacy oil-filled and air-blast circuit breakers no longer align to ORPC's standards, and can be complex to maintain, due to the lack of available manufacturer support and reducing spare parts inventory. By comparison, standardized equipment such as SF_6-insulated circuit breakers possess extensive manufacturing support and installation of these new assets will create new efficiencies for ORPC from a maintenance and support perspective. Assets targeted to be replaced within this program have been prioritized based upon the APUL results.

The key projects to take place from 2023 will include the following:

- At Almonte MS2 substation, the aging power transformer 2A1 (installed in 1975) will be replaced with a new standardized power transformer.

- At Pembroke MS4 substation, three of ORPC's oldest circuit breakers will be replaced with new standardized SF_6-insulated circuit breakers. This includes the 1932-vintage oil-filled circuit breakers 6M2P and B3 breakers, along with the 1939-vintage 6M1P-B breaker.

- At Almonte MS3 substation, the switchgear and 1965-vintage air-blast circuit breakers housed within, including the 3F1 and 3F2 circuit breakers will be replaced with new standardized SF_6-insulated circuit breakers.

In addition to replacing the power transformer on Pembroke MS6 station, ORPC will leverage the 2022 year to develop the detailed execution plan. It will consider the necessary system isolation and load transfers that will need to be put into place to ensure that the work can be safely executed in the period from 2023 onwards to 2026. *Table 6-10* highlights the outcomes emerging from the Station Renewal program at ORPC:

Table 6-10: Program Outcomes

Outcomes	Description
Efficiency	Replacement of failed and legacy station equipment including oil-filled and air-blast circuit breakers will eliminate the need to maintain these assets and their associated accessories and allow ORPC to install standardized equipment that are fully supported by the manufacturer and can be maintained using current-state maintenance procedures.
Customer Value	Station infrastructure can have a tremendous impact on overall system reliability and performance. Replacement of failed and aging stations equipment will result in system reliability being sustained and mitigate the possible risks of failure including outages and safety impacts to customers. Results from the recent ORPC DSP Survey have indicated that Reliability remains a critical priority for customers, and execution of this work will ensure that customers will continue to receive a reliable electricity supply.
Reliability	Replacement of failed and aging stations infrastructure will result in sustained reliability and system performance.

6.3.3. Investment Drivers & Need

ORPC's Station Renewal program is designed to target failing, aging, deteriorated and functionally obsolete stations assets for replacement with new infrastructure that conforms to ORPC's current-state standards.

As noted in *Table 6-11*, this program is primarily driven by the need to mitigate the Failure Risk associated with these assets. It has already been seen that in late June 2021 the power transformer at Pembroke MS6 station failed unexpectedly, which shows the risk of failure is evident for ORPC's aging and legacy station infrastructure. Functional obsolescence represents a secondary driver, where legacy infrastructure such as oil-filled and air-blast circuit breakers will be replaced with standardized sulfur-hexafluoride (SF_6) insulated circuit breakers, which align to ORPC's current-state practices and operating procedures and can be maintained at a lower cost for the utility.

Table 6-11: Program Drivers

	Driver	Description
Primary	Failure Risk	The primary driver for this program is Failure Risk, as the assets to be targeted for replacement have either failed or are approaching, at or already exceeding their TUL during the DSP planning period. Station infrastructure represents the most critical components within ORPC's distribution system. Should this infrastructure fail, there will be significant reliability impacts to the connected customers. It has already been seen that in late June 2021 that ORPC suffered an unexpected failure of a one of the transformers on one of its stations, which required replacement to ensure reliability is sustained for its customers. Through the proactive replacement and management of station equipment, ORPC can mitigate further failures and minimize the Failure Risk within their system.
Secondary	Functional Obsolescence	This program will be targeting Functionally Obsolete stations assets that no longer align with ORPC's standards and operating practices. This includes oil-filled and air-blast circuit breakers, which are no longer supported by the original manufacturers and possess limited spare parts. Replacement of these assets with standardized assets allows will allow for a reduced maintenance cost in the future, due to the extensive support from the manufacturer for standardized stations equipment.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

6.3.3.1. Failure Risk

The Station Renewal program is designed to target those station assets that are either approaching, at or exceeding their TUL, or are in Poor or Very Poor condition. Figure 6-6 illustrates the results of the APUL analysis for station assets, revealing that nearly 80% of station assets are already past their TUL, with another 8% of station assets to exceed their TUL over the forecast period from 2022 to 2026.

Conversely, the ACA results presented in Figure 6-7 indicate that there are no stations assets in Very Poor or Poor condition, and that 12% of ORPC's assets are in Fair condition. As explained in Section 3.2.4, these results indicate that while ORPC's stations assets are heavily aged, the utilities' maintenance program has had an effect on managing the continued operation of these assets such that any form of accelerated degradation is mitigated. At the same time, however, these assets will eventually fail due to normal aging and utilization. This is evident from the recent unexpected failure of the power transformer at Pembroke MS6 substation in late June 2021. This shows that whilst OPRC have a comprehensive maintenance program, due to the age of some of the assets unexpected failures can occur which require ORPC to address.

Figure 6-6: Station Asset APUL Results

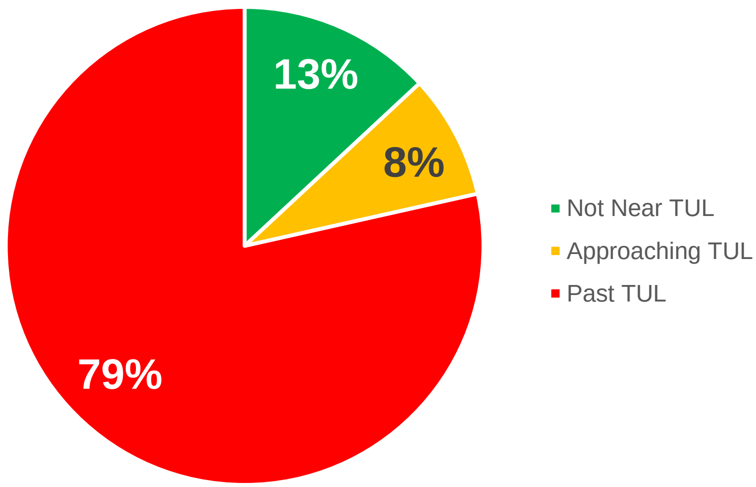
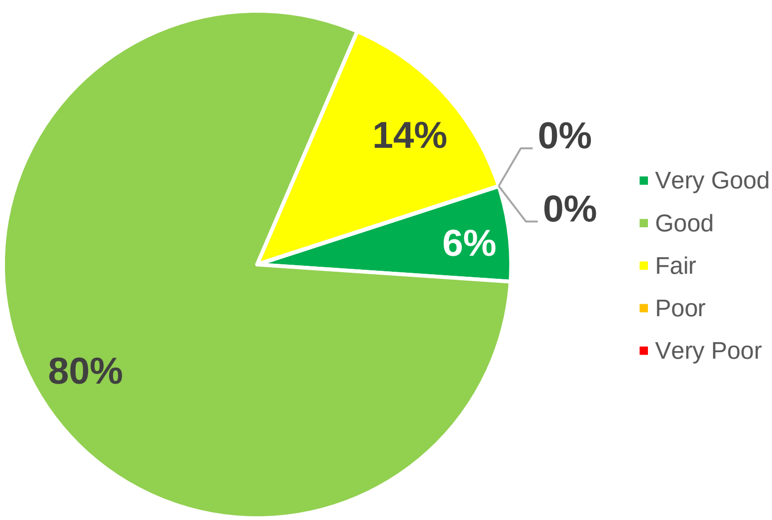


Figure 6-7: Station Asset ACA Results



ORPC's power transformers are designed to step-down the voltage from the 44kV voltage level down to either 12.47 kV or 4.16 kV voltage levels, respectively. These assets consist of a winding core that is surrounded by paper insulation and immersed in dielectric mineral oil. The mineral oil is designed to act as a dielectric medium and also cool the transformer. The paper insulation is designed to insulate the windings within the transformer. As the transformer remains in operation, the paper insulation will breakdown within the mineral oil over time. This process is known as depolymerization and will eventually result in the mineral oil turning into sludge, with its dielectric properties being significantly reduced. Once the paper insulation has broken down, an internal winding fault will occur within the transformer, resulting in its failure. A catastrophic internal fault can result in an explosion, resulting in potential safety and environmental impacts. This has been evident from the recent failure of the power transformer at Pembroke MS6 station in late June 2021. Following an investigation, it was found the cause of the damage to the 1974 transformer was due to the failure of the bushing and winding. The DGA did not show any signs of internal arcing or overloading. The general oil quality results show some deterioration but in general there is no indication of the likelihood of sudden failure. As part of its investment program for 2022, ORPC will replace the transformer.

Also, within the scope of this investment program, the 2A1 power transformer at Almonte MS2 will be replaced. This is a 1975-vintage 5 MVA Canadian General Electric transformer that was tested as recently as this year. The DGA and oil quality of this transformer have been graded as Fair and Very Poor, respectively. The high concentration of methane, carbon monoxide, carbon dioxides suggest that the transformer possesses overheated oil and cellulose insulation. Total dissolved combustible gas has also exceeded the normal concentration at which an internal fault may occur. The dielectric breakdown of the oil is below the minimum standard value. A very low dielectric breakdown voltage may result in faults or even arcing internally at operating voltage, which ultimately makes this transformer unsafe to operate in its current condition. This transformer is currently utilized up to 44%, but as of 2019 has achieved the highest peak loading amounts. At 45 years of age, this transformer has exceeded its TUL result.

ORPC's circuit breakers are designed to provide protection of electrical circuits from damages as a result of fault current, overloads, short circuits, or other contingency events. These assets are designed to open the circuit upon detection of fault current in order to sufficiently protect upstream and downstream assets. ORPC's system consists of four different circuit breaker sub-types, including oil-filled circuit breakers, magnetic-air circuit breakers, air-blast circuit breakers and SF_6-insulated circuit breakers. Each circuit breaker sub-type is distinguished by the medium used to interrupt the arc associated with the fault current. Each breaker will first open the circuit to form the fault current arc within the interrupting medium.

For oil-filled circuit breakers, this arc is formed within the dielectric oil, which then acts as the medium to interrupt the fault current. Air-blast circuit breakers operate by "blasting" through the arc using compressed air mechanism, which drives the arc into an arc chute. Magnetic-air circuit breakers utilize the principle of magnetic effects to expand and eliminate the arc. Finally, for current standard SF_6-insulated circuit breakers, the arc is encapsulated within SF_6 gas, which acts as the medium to eliminate the fault current. Unlike other circuit breaker types, SF_6-insulated circuit breakers possess the fewest moving parts and can therefore be maintained at a lower cost versus the other breaker types. Should a circuit breaker fail, it will be unable to clear the fault and backup protection would trip the upstream breakers, thus causing a much more severe shutdown of the 44 kV system. Circuit breakers are typically housed within switchgear, which also contains the instrument transformers and relays which work in conjunction with the circuit breakers to sufficiently detect the fault current.

Within the scope of this investment program, the three oldest vintage circuit breakers within ORPC's inventory will be replaced. These include two 1933-vintage GE oil-filled circuit breakers as well as one 1939-vintage Westinghouse oil-filled circuit breaker that will require replacement over the DSP planning period. At 81 and 87 years of age respectively, these breakers have operated well beyond their TUL and must be replaced in order to ensure that reliability can be appropriately managed, and a major outage event can be avoided within the system.

Finally, at Almonte MS3, two 1965-vintage air-blast circuit breakers – 3F1 and 3F2 respectively – along with the associated switchgear, will be replaced within the DSP planning period. These CLM Industries breakers are now 55 years of age and past their TUL value. Ultimately, a failure of the power transformers, circuit breakers or switchgear will result in an extensive outage impact to customers, along with potential safety and environmental impacts. Through the execution of the Station Renewal program, ORPC will be able to mitigate the possible failure risks associated with failing, aging and legacy assets.

6.3.3.2. Functional Obsolescence

The secondary driver of the Station Renewal program is Functional Obsolescence, where the existing legacy equipment, including older vintage power transformers, oil-filled and air-blast circuit breakers and switchgear will be replaced with the newest standardized equipment and technologies. With legacy equipment, a major challenge is sourcing of spare parts should a major failure occur. Due to the lack of manufacturer support and minimal spare parts, an especially severe outage can result in an extended impact to customers if spare parts cannot be appropriately sourced.

Through the replacement of oil-filled and air-blast circuit breakers, ORPC will achieve operational savings as they will no longer need to support and maintain these assets leveraging specialized maintenance tasks and activities. The new SF_6-circuit breakers to be installed within the system possess fewer moving parts and align to current operating practices and standards.

6.3.4. Investment Timing & Pacing

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.

Due to the failure of the power transformer on Pembroke MS6, ORPC will need to carry out its replacement in 2022 to restore the operational capability of the substation to ensure ORPC can continue to meet customer requirement now and in the future. In addition, there are nearly 80% of ORPC's stations assets are past their TUL, with another 8% to approach their TUL within the DSP planning period. To account for this aging infrastructure, ORPC has made the decision to execute a series of further Station Renewal investments beginning in 2023. In 2022, ORPC plans to develop the detailed execution plan that will consider the necessary system isolation and load transfers that will need to be put into place to ensure that the work can be safely executed in the period from 2023 onwards to 2026.

The average investment over the forecast period from 2022 to 2026 is also much greater when compared to the historical period from 2015 to 2019. This accounts for the total 87% of stations assets already at or expected to exceed their TUL during the forecast period. In order to manage this emerging asset wall, it will be necessary to increase stations investment during the forecast period while still balancing this overall investment with customer preferences to keep rates digestible and overall resource availability and system constraints within ORPC.

6.3.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Unexpected Priority Calls* – In the regular course of utility operations, instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC uses where necessary contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility's plans.

- *Weather* – Poor weather (particularly prolonged spells) can negatively affect the planned pace and timeliness of planned work. ORPC plans to replace underground assets primarily in the Spring to Fall timeframe, avoiding the Winter season where snow, ice and low temperatures can negatively affect execution volumes and costs.

- *System Stability* – When executing Stations Renewal activities, it is important to understand possible instabilities and contingency impacts that may be introduced due to the need to isolate and take specific equipment offline. The detailed execution plan to be developed in 2022 will help manage this risk accordingly.

6.3.4.2. Investment Pacing & Prioritization

As per ORPC's long-term planning sub-process, other than the failed power transformer that will be replaced in 2022, individual station assets have been prioritized for replacement across the system based upon the ACA and APUL results, as well as environmental and safety-related considerations.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

6.3.5. Options Analysis

ORPC only have one major investment in the 2022. This is the replacement of the failed power transformer at Pembroke MS6 station. ORPC need to replace this as soon as possible to ensure reliability is sustained for its customers. Without a functioning power transformer this limits the capacity of the station and provides no backup should there be a failure of the other power transformer on the station or elsewhere in the Pembroke network area. ORPC engaged a third-party provider (van Kooy Transformer Consulting Services Inc.) to look at the options available, including the option of repair. However, it is clear that repair is not a sustainable option or value for money for ORPC's customers. The cost of a repair, which would only be a temporary fix with the likelihood of another failure high, would be around 75% of the cost of a new transformer. In addition, it has been found that the transformer has a contamination level of 20ppm PCB in oil which precludes it from the possibility of repair. The transformer has to be disposed as hazardous waste. ORPC have been quoted an initial $400,000 for the removal of the transformer, purchasing of a new transformer, installation and commissioning.

For Stations Renewal from 2023 onward, ORPC will endeavour to execute its Project Evaluation procedure to evaluate the Stations Renewal activities, as the detailed execution plan is prepared by ORPC's asset managers and planning engineers.

6.3.6. List of Projects

Table 6-12 outlines the four major stations investments to occur from 2022 onwards to 2026.

Table 6-12: Stations Renewal 2022-2025 Projects and Cost

Project Location	Project Description	Cost ($K)
Pembroke MS6 Power Transformer	Replace failed T1 1974 vintage transformer.	
Almonte MS3 Switchgear	Replace 3F1 and 3F2 1965-vintage air-blast breakers and containing switchgear.	
Pembroke MS4 Oil-Filled Circuit Breaker	Replace three oil-filled circuit breakers – 6M2P (1932), B3 (1932) and 6M1P-B (1939) respectively.	
Almonte MS2 Power Transformer	Replace the 2A1 1975-vintage power transformer.	
Pembroke MS6 Feeders	Replacing four existing 50' poles and one 60' pole due to rot at ground level on 6M1 and 6M2 Feeder.	
Total Spending (2022 – 2026)		$1.7M

7. SYSTEM SERVICE INVESTMENTS

7.1. SYSTEM ENHANCEMENT

7.1.1. Overview

ORPC performs regularly reviews of their distribution system as part of their System-Wide Analysis to determine if any upgrades, reconfigurations, or reinforcements are required to ensure the system is flexible and adaptable for the future, ensuring that the utility can continue to be able to serve customers and provide a reliable security of supply. The System Enhancement program has been designed as an outcome of this analysis to manage system-wide reliability concerns that go beyond any individual asset issues.

Over the DSP planning period from 2022 to 2026, this program will focus on reinforcement of key 44kV supply points between the transmitter and ORPC's service areas in Pembroke and Almonte, respectively. These 44kV lines represent the sole supply points which allow for ORPC to provide electricity to customers within these service areas.

To further reinforce these supply points, investments within the System Enhancement program will replace overhead infrastructure, including poles, conductor, and insulators. This will include the replacement of assets that are at, approaching or already exceeding their TUL within the DSP planning period, or have been found to be in Poor or Very Poor condition. Through the execution of this work, overall security of supply for customers in the Pembroke and Almonte service areas will be maintained. This program will replace legacy infrastructure, such as aging poles and porcelain insulators with the newest standardized poles and polymeric insulators that align to ORPC's current standards and practices. Throughout the planning period, ORPC will continuously review the requirements of their system to ensure the proposed investments are addressing the most critical parts of the system to ensure continued security of supply.

Total program spending from 2022 onwards to 2026 is $305K which is an increase on spending levels over the historical period from 2015 onwards to 2019 due to the need to invest in critical infrastructure to ensure the security of supply is maintained.

7.1.2. Investment Description

Within the 2022 test year, ORPC will target aging infrastructure along the 44kV supply line which connects the City of Pembroke to HONI's transmission system. This 44kV supply features a double circuit with connected Feeders 6M1 and 6M2. The wooden poles that carry the overhead conductor are at, exceeding or will reach their TUL over the next 5-year period. A failure along this line would result in an outage impacting both circuits, resulting in an immediate loss of supply to the entire City of Pembroke. Within the scope of this program, ORPC plans to replace poor condition poles, including four existing 50' poles and one 60' pole due to rot at ground level. In addition, overhead conductor and legacy porcelain insulators will also be replaced with standardized conductor and polymeric insulators. Figure 7-1 illustrates the issues and degradation with these poles.

Figure 7-1: Degradation of the 44kV Supply Lines into City of Pembroke

Table 7-1 highlights the outcomes emerging from the System Enhancement program at ORPC:

Table 7-1: Program Outcomes

Outcomes	Description
Reliability	Replacement of aging wood poles, conductor, and porcelain insulators along this 44kV line will contribute to the overall reinforcement of the supply point, thus managing the security of supply for customers within the Pembroke service area.
Customer Value	The 44kV lines targeted for reinforcement within this program provide the sole sources of supply for the Pembroke and Almonte service areas, respectively. Should any major or catastrophic failure occur along these lines, it would result in a significant reliability impact to customers. Through the execution of this program, key assets along these lines will be replaced, thereby reinforcing the integrity of the line, and ultimately providing a reliable supply point for the connected customers.

7.1.3. Investment Drivers & Need

ORPC's System Enhancement program is designed to reinforce critical supply points within ORPC's distribution system through the replacement of existing and legacy overhead assets with new overhead assets that align to ORPC's current standards and practices. Should a serious failure occur along one of these lines, ORPC will be unable to provide necessary supply to their customers within the connected service areas.

As noted in *Table 7-2*, this program is primarily driven by the need to maintain reliability issues and the security of supply within ORPC's network. The secondary driver is to address the failure risk of these overhead system critical assets.

Table 7-2: Program Drivers

	Driver	Description
Primary	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. This program addresses the assets that require rebuilding that support the critical 44kV circuits that supply ORPC's service areas. These assets will either be replaced in such a manner that the security-of-supply risk is appropriately mitigated, and associated asset infrastructure is brought up to the latest ORPC standards.
Secondary	Failure Risk	Many of the assets that carry the critical 44kV supply are either past their TUL and/or are in Poor or Very Poor condition. There are also legacy assets such as porcelain insulators that are heavily aged within the system and are susceptible to cracks. In particular, the insulator cap which connects to the overhead conductor can crack, thereby loosening the connection to the conductor, and resulting in a catastrophic flashover event. Should any of these assets fail, there would be a significant and prolonged interruption to the customers within this service area
	Safety	Catastrophic failure of porcelain insulators is highly destructive, with shards of glass exploding in a grenade-like manner.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

7.1.3.1. Reliability

The primary driver for this program is to address the need to maintain system-wide reliability within the applicable service areas that are supported by these critical supply points. For instance, within the test year, investment will focus on the 6M1-6M2 supply point, which is a double-circuit 44kV line supplying the City of Pembroke. Should any pole, insulator or conductor catastrophically fail along this pole line, both circuits can be compromised resulting in a significant outage event to the entire Pembroke service area.

A previous catastrophic failure took place in 2019, where a large fire at a lumber mill introduced structural and fire damages to both 6M1 and 6M2 feeders which resulted in an outage of 10-12 hours total to the entire service area. In this particular case, ORPC had to send out its crews to perform the repairs before any restoration could be performed, as there is no other way to provide electricity supply into the City of Pembroke. By performing the reinforcements as proposed within this program, ORPC can mitigate the substantive reliability risks to customers and maintain security of supply to the Pembroke and Almonte service areas.

7.1.3.2. Failure Risk

Assets targeted for replacement within this program are either already exceeding, at or to exceed their TUL over the five-year DSP planning period from 2022 onwards to 2026. These assets may also be in Poor or Very Poor condition. Finally, many of these assets feature legacy designs that are no longer aligned to ORPC's current practices or standards. For instance, aging and legacy porcelain insulators are comprised of brittle material that is susceptible to cracking, which can result a flashover event.

Replacing this aging infrastructure with new assets will mitigate the possible Failure Risks associated with these supply points and ensure that security of supply is sufficiently protected for the customers within these service areas.

7.1.3.3. Safety

Legacy infrastructure such as porcelain insulators can introduce safety risks to the general public as well as field crews. For instance, the insulator cap which connects the porcelain insulator to the overhead conductor can crack, thereby loosening the connection to the conductor, and resulting in a catastrophic flashover event. This failure mode would be highly destructive, with shards of glass exploding in a grenade-like manner. The overhead conductor could also come loose from the insulator, resulting in a downed and energized conductor line that would introduce serious safety impacts for nearby customers.

7.1.4. Investment Timing & Pacing

The pace of investment within this program is designed to strike a balance between the needs of the system by reinforcing these critical supply points through the replacement of aging and deteriorating asset infrastructure, as well as the need to balance customer preferences to keep electricity rates as digestible as possible. For these reasons, total expenditures of $305K over the forecast period remain consistent with the historical spending of $196K from 2015 to 2019, with the cost increase in the forecast period being driven by inflationary increases. For these reasons, total expenditures of $305K over the forecast period is an increase compared with the historical spending of $196K from 2015 to 2019, with the cost increase due to the need to invest in critical infrastructure to ensure the security of supply is maintained.

7.1.5. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Weather* – Poor weather (particularly prolonged spells) can negatively affect the planned pace and timeliness of planned work. ORPC plans to replace assets primarily in the Spring to Fall timeframe, avoiding the Winter season where snow, ice and low temperatures can negatively affect execution volumes and costs.

- *Unexpected Priority Calls* – In the regular course of utility operations instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC uses, when necessary, contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility's plans.

- *Outages* – For the 6M1 and 6M2 System Enhancement project, as this is the main supply into the City of Pembroke, there is a need to plan the work so that planned outage impacts can be avoided.

- *Third Party Access* – Some of the overhead assets that carry the 44kV circuits, are located on private properties, which means access is not easily obtained. ORPC will communicate well in advance with third parties who own land where ORPC assets reside, to ensure that access is granted, and the work is carried out with as little disruption to the party involved.

7.1.6. Investment Pacing & Prioritization

Projects within this program were prioritized based upon the criticality of the assets that require replacement, that carry the 44kV supply line, due to aging and poor condition assets, that cause security of supply concerns. Investments proposed within this program will address immediate concerns of reliability within these service lines through the replacement of aging and deteriorated plant.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

7.1.7. Options Analysis

7.1.7.1. Project Alternatives

ORPC evaluated each discretionary System Enhancement project above material threshold and determined the project pacing using the project evaluation process as outlined in Section 3.3.2. For each System Enhancement project, the project scope is defined based on ACA results, APUL information, customer needs, resource availability, and capital cost. The risk costs associated with each alternative were determined using the methodology outlined in Section 3.3.2.

Each project within the System Enhancement program was evaluated at:

- Decelerated Pace;

- Moderate Pace; and
- Accelerated Pace.

Decelerated Pace Alternative – This is defined as the alternative in which the full project scope and investment are completed over a 5-year period. For this alternative, it is assumed that unplanned outages are more likely to occur than historical data predicts, because unplanned outages due to asset failure have a higher probability of occurrence at a decelerated asset renewal pace.

Moderate Pace Alternative – This is defined as the alternative in which the full project scope and investment are completed over a 1-year period as defined within this plan. For this alternative, it is assumed that unplanned outages are equally as likely to occur as historical data predicts.

Accelerated Pace Alternative – This is defined as the alternative in which the full project scope and investment are completed over a half-year period. For this alternative, it is assumed that unplanned outages are less likely to occur than historical data predicts, because at an accelerated asset renewal pace, unplanned outages due to asset failure have a lower probability of occurrence. It is also assumed that planned construction outages will be two times the duration and the number of affected customers compared to the Moderate Pace alternative.

7.1.7.2. Project Evaluation Results

The evaluation process was applied to all projects within the System Enhancement program. The pacing alternative that produced the lowest TCO for residual risk values over the project lifecycle was selected. In all evaluated projects, the Accelerated Pace alternative, which completes the full project scope in a half-year period, was recommended as a result of the process. This project pacing is appropriate for the System Enhancement program because the critical supply points in question must be addressed in a timely manner, and therefore an accelerated project pacing is justified. The results for all evaluated projects are shown below in Table 7-3.

Table 7-3: TCO for Residual Risk Values for System Enhancement Project Alternatives

	TCO Value for Residual Risk ($M)		
	Decelerated Pace Alternative	**Moderate Pace Alternative**	**Accelerated Pace Alternative**
System Enhancement Project	$11.78M	$11.73M	$11.61M

7.1.8. List of Projects

ORPC has not identified any projects that will be addressed within the test year, 2022.

7.2. STATION EXPANSION

7.2.1. Overview

ORPC is planning on investing in upgrades to their SCADA system technologies that are being deployed within their substations over the next 10-year time horizon. This SCADA system is used to remotely monitor substation information, including transformer loading and temperature, while also allowing power system controllers to monitor and remotely operate circuit breaker assets. ORPC's current SCADA system has been in place for a number of years. It has now become obsolete, with more regular failures occurring, leading to more disruption to customers and an impact on the reliability of the network.

The Station Expansion program is primarily driven by the need to introduce critical improvements at the substation level in order to mitigate system-wide issues and instabilities within the system. With respect to investments within the DSP planning period from 2022-2026, this program will address the reliability of the SCADA system installed across ORPC's substations. The program will focus on the elements of the SCADA system that are most at risk of failing and the components that are functionally obsolete. The main components that will be addressed include the remote terminal units ("RTUs") and the electro-mechanical relays. These assets will be replaced with the newest equivalent devices that align to current ORPC standards and are used by other utilities.

Total program spending from 2022 onwards to 2026 is $215K which is significantly less when compared to spending levels over the historical period from 2015 onwards to 2019. This is due to ORPC assessing what is the most critical over the next five years within this program when compared to other programs within the DSP and balancing this against customer preferences to keep electricity rates as digestible as possible.

7.2.2. Investment Description

ORPC's current SCADA system and associated technologies have been in place for several years. It has now become obsolete, with more regular failures occurring. Added to this, the number of spares available to fix the system are few and far between. The spares that are available tend to have a premium attached to them, making repairs more costly.

A critical communications component of a substation is the RTU. This device collects information from substation relays and sends it to the utility's control room SCADA system. Without a functional RTU, a substation's SCADA is not functional, which can cause truck rolls for things which could be done remotely and increases the utility's operational expenses. A feeder hold-off, for example, could be done in a control room, but if the RTU is not functional then a crew must go to the substation to perform the hold off procedure. Substation communications also aid in outage restoration times by serving information to control rooms for troubleshooting or aiding in switching.

Another element linked to a substation SCADA system is an electro-mechanical relay. A relay is used to protect a circuit from damage due to a fault or operating outside of rated parameters. Relays can detect different abnormal conditions depending on the type of relay and its capabilities. If a relay detects, for example: a fault, over or under voltage, or prolonged high-current conditions, it will send a signal to the interrupting device to open. This interrupts the abnormal condition and prevents further damage to physical assets. Relays can measure voltage, current, and return operating data to a utility's control room.

Repair times and cost vary, depending on what has failed, the location of the failure, the time of the failure and the availability of spares.

ORPC has assessed what options are available to address these issues as described. In addition, ORPC has identified the priority stations that must have their SCADA system and associated technologies upgraded over the next five-year period, acknowledging that it is not practical or costs effective to address all systems across all substations within the next five years. Additionally, ORPC have allocated some expenditure in 2022 to carry out a detailed review of all its SCADA across its substations to be carried out by a third party. The output of this will be a detailed strategy and action plan for upgrading its SCADA components across its substations. This detailed review will look to further determine ORPC long term plan for upgrading its SCADA system such that ORPC can make adjustment to their investment plan to deliver the highest priority investments. Currently, the two stations that will be addressed between 2022-2026 will be MS4 and MS8 within the Pembroke service area. For MS4, this will involve replacing both the RTU and the electromechanical relay, whereas for MS8, only the RTU will need replacing. Once the old assets are removed, if in working condition, these will be kept as 'grey' spares for the remaining SCADA systems. This will allow ORPC to pace the replacement of all SCADA systems over a longer period.

Table 7-4 highlights the outcomes emerging from the Overhead Renewal program at ORPC:

Table 7-4: Program Outcomes

Outcomes	Description
Efficiency	By completing these SCADA upgrades at MS4 and MS8, this will reduce the need for field engineers to be sent out to these sites to operate them, as these systems should be more reliable and not fail as frequently. In addition, it will also reduce the time and cost of sourcing spare parts and fixing the old system. This will result in some short-term O&M cost savings with more realised in later years when more stations are upgraded.
Customer Value	ORPC has actively taken the decision not to replace all SCADA systems at all stations in the next five years, recognising this would be a costly exercise that would impact customers and their electricity rates. By pacing the investments over a longer period, ORPC has balanced the need to replace the SCADA system on the most critical stations over the next five-year period before replacing others in later years in the future. Ultimately, ORPC is balancing the needs of the system with customer preferences to keep electricity rates as digestible as possible. In addition, ORPC is carrying out a detailed review of its SCADA systems across its service areas, to develop a longer-term investment plan which will ensure ORPC target the highest priority investments, with balancing these with customer preferences to keep electricity rates as digestible as possible
Reliability	Through upgrading of the SCADA system to safeguard its reliability, ORPC is able to continue to operate assets such as circuit breakers remotely while also monitoring the system for major system-wide outage events. Upgrading the SCADA system will ensure that failures are minimized, and that more grey spares are becoming available for remaining stations with the old SCADA system. This will ensure that ORPC can continue to monitor their system safely and maintain the reliability that customers expect.

7.2.3. Investment Drivers & Need

ORPC's Station Expansion program is designed to target end of life and functionally obsolete SCADA system components, including legacy relays and RTUs and replace these with new and update SCADA infrastructure that conforms to ORPC's current-state standards and best practices.

As noted in Table 7-5, this program is primarily driven by the need to address reliability issues with the current SCADA system on its substations. The secondary driver is to address the functional obsolescence of the SCADA system, which is outdated, and spares are no longer readily available, increasing the risk to ORPC if a failure were to occur.

Table 7-5: Program Drivers

	Driver	Description
Primary	Reliability	The primary driver for this program is to address reliability issues with the current SCADA system installed at ORPC stations. The current SCADA system installed is past its end of life. The system is no longer supported, with spares no longer available. ORPC has experienced failures of this system in the past, and this has impacted the way the utilities ability to operate the system, often resulting in manual in-field switching and response as opposed to remote management of the system from the control room. Within the scope of this program, ORPC will install new SCADA hardware that meet ORPC and industry standards, increasing the reliability of these system and in turn the reliability of the network.
Secondary	Functional Obsolescence	ORPC's current SCADA system has now become functionally obsolete. The system is no longer supported, and spares are very scarce. This makes these systems and ORPC's network more susceptible to failures. Through beginning a plan to upgrade and replace these systems, ORPC will increase the resilience of their system and remove obsolescence.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

7.2.3.1. Reliability

The primary driver of the Station Expansion program is to address reliability issues with the current SCADA system installed on ORPC Stations. This program is targeting assets within the SCADA systems that are most at risk of failure. The failure of a SCADA system significantly impacts the reliability of the system. Without a functioning SCADA system, ORPC cannot monitor the status of its stations and also cannot remotely operate any of the equipment.

By upgrading the SCADA system, enabling a more reliable system, this will reduce the likelihood of it failing and the need to be sending out field crews to go undertake switching operations that can be done remotely. In addition, this will mitigate the cost and time of having to repair the SCADA system when it fails, with the assets that are removed from the old system at MS4 and MS8 being used as 'grey' spares that can be used for the remaining stations until they are replaced. Overall, this should reduce OPRC's system O&M costs relating to these activities.

7.2.3.2. Functional Obsolescence

ORPC's current SCADA system installed at its stations has become functionally obsolete. This means that it is no longer supported, and very few spares are now available making repairs lengthy and costly. By developing a plan to replace its systems over a long-term period, ORPC will begin to address these obsolete issues, by installing new equipment at two of its stations. The old equipment at these stations can then be kept as 'grey' spares for the other stations, thus improving resilience across its stations, until these systems are replaced as part of the long-term plan.

In developing their workplan, ORPC has engaged with their peer utilities and a group of leading experts in this field to identify the best options available to them and to try and achieve an element of best practice across nearby utilities.

7.2.4. Investment Timing & Pacing

The pace of investment within this program is designed to strike a balance between the needs of the addressing end of life, obsolete station SCADA systems, available resources to execute the work within ORPC as well as customer preferences to keep electricity rates as digestible as possible. In addition, ORPC will undertake a detailed third-party assessment of its SCADA systems across its service areas, which will inform ORPC longer-term investment plan for upgrading SCADA components within its substations. For these reasons, total expenditures of $215K over the forecast period represents a decrease in spending when compared to historical spending from 2015 to 2019.

7.2.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Resource Availability* – There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, ORPC will: (i) adopt a long-term resource plan based on project tasks and activities; and (ii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.

- *Outage Planning* – Any planned outages that may be required as a consequence to execute this investment program will be communicated in advance and work will be conducted at the least disruptive times to minimize impacts to customers.
- *Unexpected Priority Calls* – In the regular course of utility operations, instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC utilizes where necessary contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility's plans.

7.2.4.2. Investment Pacing & 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.

In addition, ORPC has assessed what is the most pragmatic approach to addressing all the SCADA systems on all Stations. ORPC feels its proposed spending and pacing for the forecast period will address immediate concerns of reliability of these systems and the need to find more spares, balancing this with customer preferences to keep electricity rates as digestible as possible. To further complement this, ORPC are undertaking a detailed review of its SCADA systems across its service areas to help inform its longer-term investment plan and readjust any projects to reflect the outcomes of this review.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

7.2.5. Options Analysis

7.2.5.1. Project Alternatives

ORPC evaluated each discretionary Station Expansion project above the material threshold and determined the project pacing using the project evaluation process as outlined in Section 3.3.2. For each Station Expansion project, the project scope is defined based on system need, resource availability, capital cost, and asset obsolescence. The risk costs associated with each alternative were determined using the methodology outlined in Section 3.3.2.

The Station Expansion project was evaluated at:

- Current Condition (Status Quo); and
- Moderate Pace.

Current Condition (Status Quo) Alternative – This is defined as the alternative in which the SCADA system is to undergo no upgrades. For this alternative, it is assumed that unplanned system outages are consistent with historical estimates. The TCO for residual risk value for the Current Condition alternative captures the risk cost for system-wide customer outages, based on historical data.

Moderate Pace Alternative – This is defined as the alternative in which the SCADA system is to undergo upgrades at Pembroke MS4 and MS8 respectively as defined within this plan. For this alternative, it is assumed that the duration of unplanned system outages at Pembroke MS4 and MS8 are less likely than in the Current Condition Alternative. The TCO for residual risk value for the Moderate Pace alternative captures the risk cost the system-wide customer outages, assuming that outage events at Pembroke Substations 4 and 8 cause shorter customer connection losses.

7.2.5.2. Project Evaluation Results

The evaluation process was applied to the Station Expansion project. The alternative that produced the lowest TCO for residual risk values over the project lifecycle was selected. In the Station Expansion project, the Moderate Pace alternative, completing SCADA system upgrades at Pembroke Substations 4 and 8, was recommended as a result of the process. The results for the evaluated project are shown below in Table 7-6.

Table 7-6: TCO for Residual Risk Values for Station Expansion Project Alternatives

	TCO Value for Residual Risk ($M)	
	Current System Alternative	**Moderate Pace Alternative**
Station Expansion Project	$205.6M	$203.5M

7.2.6. List of Projects

ORPC has identified two main projects that will be addressed over the next forecast period, 2022-2026 and the costs associated with these. This is in addition to ORPC carrying out a detailed third-party assessment of its SCADA system to develop a long-term investment strategy and plan to upgrade its SCADA components across ORPC's substations.

Table 7-7: Station Expansion Projects and Cost

Project Location	Project Description	Cost ($K)
MS 4, Pembroke	Replace the remote terminal unit (RTU) and the electro-mechanical relay	$110
MS 8, Pembroke	Replace the remote terminal unit (RTU)	$60
Total		**$170**

8. GENERAL PLANT INVESTMENTS

8.1. INFORMATION TECHNOLOGY

8.1.1. Overview

ORPC's IT infrastructure is a critical backbone in the 24/7 operations of the network, including its day-to-day business operations. These systems and hardware allow ORPC to perform its operations which includes, but not limited to:

- Collecting and recording customer data including metering information, allowing them to produce and issues bills to customers.
- Performing maintenance activities and recording the data from this whilst in the field, on laptops and mobile devices.
- Access maps and drawings from systems such as GIS to either develop projects, or to collect or record information about the distribution system.

In addition, these IT systems represent critical infrastructure that hold sensitive information, and therefore it is important that utilities protect these systems from cybersecurity attacks. Recently, the OEB have updated and set out a cybersecurity framework that utilities must comply with. ORPC takes these requirements seriously and have assessed the systems they have and the requirements of their framework and developed an investment plan to deliver on this compliance.

IT systems and hardware usually have a limited lifespan before they either become redundant and unsupported or require updating to meet future requirements. ORPC has always desired to utilize their systems and hardware as long as practically possible to maximise the benefits from investment, whilst ensuring customer rate impacts remain digestible. For the forecast period from 2022-2026, ORPC has reviewed its portfolio of IT systems, to ensure that they prioritise investments in that are critical to ensuring the continued day-to-day business processes and operations. This is then followed by investments that will realise cost savings and efficiencies in the future, such as investing in better technology for field staff to undertake their day-to-day tasks.

As further noted in Table 8-1, total program spending from 2022 onwards to 2026 is $93K which is a decrease to spending levels when compared with the historical period from 2015 onwards to 2019. This is mainly due to the significant investments having been carried out in 2021 to upgrade servers and the related hardware than has become functionally obsolete and is no longer supported.

Table 8-1: Investment Summary Details

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$61.3	$22.7	$40.3	$16.9	$30.1	$42.0	$336.3	$66.0	$1.4	$12.4	$1.4	$11.4
Primary Driver	Business Operations Support											
Secondary Drivers	N/A											
Outcomes	Improved Reliability, Improved Efficiency, Improved Customer Value.											

8.1.2. Investment Description

ORPC relies upon IT systems to execute its day-to-day operations, including customer-facing and operationally critical functions. ORPC's largest investment will be updating its e-billing system which has reached end of life and is now obsolete. In addition, investment is required to automate its customer information system. ORPC is intending to invest $92,600 across four categories over the five-year period of the DSP from 2022 onwards to 2026:

- E-Billing System
- Customer Information System Automation
- Computer Hardware for employees
- Printers

These categories are further explained within the following subsections:

8.1.2.1. E-Billing System

ORPC's current e-billing system is currently not operating at the level of standard that customers expect. The main issue with the current system is related to reliability and ease of use, as well as a limited range of functions for customers. The portal is often reported as not working by ORPC's customers, with data not loading or e-billing emails being sent late or in some cases not at all. In addition, customer account lockouts happen randomly causing significant problems for both ORPC and customers. ORPC have spent a considerable amount of time working with the current vendor to try and resolve these issues. ORPC's staff have to spend a lot of time assisting customers or correcting problems related to e-billing, with some customers getting no e-bill at all, or they continue to get paper and e-bills even though they have opted out of paper billing. Whilst there have been cases where the vendor has made some improvements, the same issues keep reappearing. ORPC want to invest in a new platform with a proven vendor which will significantly improve customer ease and satisfaction.

The new platform will be provided by Harris, who bought Silverblaze (which is considered a very capable and a preferred third-party solution for Ontario LDC's). Not only does the industry regard it as a good product, it also allows ORPC to tie it directly into its customer information system (CIS) and offers a lot of other benefits. It comes with a modernized bill print design tool, enabling ORPC to improve bills for both digital and print customers. Another major benefit of this new platform is that it will enable more customer choice and ease of access to basic account changes, such as registering move in/move out dates and meter readings, changes to address and other contact details.

8.1.2.2. Customer Information System Automation

ORPC current customer information system (CIS) is being upgraded in 2021, and with the proposed implementation of a new e-billing system which will enable the CIS to be able to be tied into directly, this will lead to significant productivity gains and even better customer service. ORPC are proposing to enable the automation for the CIS via the new Harris e-billing platform. The automation if the customer information system will address the scheduling, reading and production of meter verification reports. Through automating these processes, that ORPC staff currently carry out manually, will reduce the time by 1.5 hours a month for each of the four staff members who carry these steps out currently. The automation workflow within the systems runs the Reading Load based on a customers predefined reading requirement. The files are automatically processed, allowing the automation platform to generate the meter reading verification reports. The system also allows for the scheduling of meter readings in advance and allowing it to load meters and create the relevant files can increase reliability and decrease dependencies on individuals. These files are then processed overnight, to allow meter readers to begin their routes first thing in the morning. Once the meter readers have completed their meter reads, this information is automatically accessed by the e-billing system and the verification reports are produced, ready for review.

ORPC’s staff currently perform these tasks manually. They have several steps (loading the cycle, then sending the meter reads and grabbing the file name and the status number). They then need to wait 4 to 5 days for the meter reads to come in. Staff then must run the meter reading verification report and the final report before transferring into a billing batch. If these processes can be automated through the new Harris e-billing platform, this would improve productivity, reduce the number of errors and delays customers may experience. In addition, by automating these parts of the billing process, it frees up more time for ORPC staff to address any other issues that do occur.

8.1.2.3. Computer Hardware

All laptops will have expired their warranty period during the DSP planning period from 2022 to 2026, and therefore all eight laptops will require upgrading at a cost of $1,500 per existing laptop. Of the hardware currently in use within ORPC’s offices, all eleven front-office PC’s will require a replacement in the next five years, at a cost of $1,000 per station. There is a requirement to purchase four iPads for field staff to undertake work in the field in a more effective manner, at a cost of $700 a unit. This will allow the field operatives to input data straight from the field, rather than have to fill out a paper form and then digitize this information at a later date. As with all hardware used, there will be additional unforeseen repairs and upgrades required over the five-year period and therefore ORPC are allocating an additional $5,000 to account for these based on historical knowledge.

8.1.2.4. Printers

ORPC currently have two printers. These require maintenance twice a year, which requires OPRC to purchase maintenance kits, at a cost of $350 per kit per printer. This would come to an annual allowance of $1,400 a year.

The Information Technology program proposes to invest in hardware, software, and communication assets that provide critical support to ORPC’s customer and business-facing services. ORPC relies on IT systems to execute capital and operational programs, including customer-facing and operationally critical functions.

Table 8-2 highlights the outcomes emerging from the Information Technology program at ORPC:

Table 8-2: Program Outcomes

Outcomes	Description
Efficiency	By ensuring that OPRC employees have updated and functioning IT hardware, they are able to execute their jobs efficiently and effectively, whether working remotely, in the field, or at ORPC office. Additionally, through the investment into iPad's, this will allow the field operatives to input inspection and testing data immediately into a central system, mitigating the need to fill out a handwritten form and then transfer to the central system at a later date. Through the upgrading of the e-billing system and the automation of the customer system information, this ensures that ORPC staff can improve its productivity, reducing time on manual steps that can be automated and focussing on addressing customer issues, and ensuring they receive bills in a more efficient manner.
Customer Value	Additionally, by having IT systems that are up to date and functioning, it will ensure bills and queries are dealt with in a quick and efficient manner.
Reliability	By having working, secure and reliable systems and hardware, ORPC are able to perform their day-to-day tasks than ensure the network operates as it should delivering what customer requires and maintaining the reliability that is expected.

8.1.3. Investment Drivers & Need

ORPC's Information Technology program is designed to ensure that the ORPC business processes can continue uninterrupted due to any failures with IT systems and hardware. A failure of these systems could have a significant impact on ORPC being able to undertake its day-to-day processes, such as billing customers and managing maintenance and other capital projects.

As noted in Table 8-3, this program is primarily driven by the need to ensure that ORPC's day-to-day business operations continue to function efficiently.

Table 8-3: Program Drivers

	Driver	Description
Primary	Business Operations Efficiency	The primary driver for this program is to ensure OPRC can continue its day-to-day business processes, such as billing and managing maintenance and projects. If OPRC did not invest in these IT systems and hardware, this would have a detrimental impact on how OPRC would operate day to day, leading to delays in projects, responding to customers and issuing bills to customers. Through making significant improvements to the e-billing system and automating the customer information system, this will allow ORPC to issues bills in a more efficient manner, whilst freeing up ORPC staffs time to address customer concerns.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

8.1.3.1. Business Operations Efficiency

As previously discussed, the IT systems and hardware that ORPC has in place represent a critical backbone of ORPC's 24/7 operations. Put simply, without these systems ORPC would not be able to operate and manage their activities reliably and efficiently as customers would expect. ORPC has previously looked to maximise the use of its current systems and hardware to ensure that it has extracted as much value from them for as long as possible. However, following a recent review of its systems and hardware ORPC must upgrade and renew a significant amount of its IT portfolio. Some of these investments have been carried out in 2021 with the remaining significant investments being carried out in 2022.

The following explains the potential impact of not investing in some of these systems and hardware:

E-Billing System – If ORPC continue with its current e-billing system platform, customers will continue to have issues with the bills they receive. This includes delayed bills, paper bills instead of e-bills even if they have opted out of paper bills, and in some cases, they will receive both. In addition, customer will continue to be unexpectedly locked out of accounts, causing ORPC staff to devote significant time to address these issues as well as correcting problem relating to the e-billing. ORPC intend to replace the current e-billing platform with a proven system that is used by other Ontario LDC's. This new system will significantly improve customer experience, enabling easier access to their accounts and even being able to change basic information including if they are moving in or out of a property. It is also expected that the enrollment of more customers to e-billing will be possible, as the new system is more reliable that the current one. Currently ORPC have around 26% of customer enrolled in e-billing, ORPC are predicting that this will increase to at least 50% with the new system which could enable annual savings of up to $30,000 by not sending paper bills. In addition, ORPC staff currently spend on average responding to 4 e-billing calls a day, usually when a customer is locked out of their account. They also spend significant time having to print and scan bills directly to e-billing customers when problems occur. Through investing in a more reliable system, ORPC will spend less time on these tasks and able to spend more time on other tasks, thus enabling productivity gains. . Additionally, the new system also allows for the customer information system to be tied into it, thus enabling further process improvements.

Customer Information system Automation– ORPC staff currently carry out manually several steps of the meter reading and reporting process, which takes significant amount of time and also allows for potential errors to be introduced. Through the automation of these manual steps, this allows for ORPC staff to carry out the other steps of the e-billing process in a more efficient manner, as well as carry out other tasks. It is estimated that through the automation of the meter reading, each of the four ORPC staff member will save around 1.5 hours per month each, resulting in productivity gains of around $3,000.

8.1.4. Investment Timing & Pacing

Table 8-4 summarizes the overall investment associated with the Information Technology program, during the Historical period from 2015 to 2019, the 2020 and 2021 bridge years, as well as the Forecast period from 2022 to 2026.

The pace of investment within this program is designed to strike a balance between the needs of renewing and upgrading its IT systems as well as comply with cyber security legislation and the available resources to execute the work within ORPC as well as customer preferences to keep electricity rates as digestible as possible. Due to the fact that the systems and hardware ORPC is using are unreliable and do not meet customer expectations, and are fundamental in the 24/7 operations, an increase in expenditure across the forecast period is expected. This has resulted in $92.6K of expenditures in the forecast period compared with $171K of expenditures over the historical 2015-2019 period.

Table 8-4: Timing & Pacing of Investment

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$61.3	$22.7	$40.3	$16.9	$30.1	$42	$336.3	$66	$1.4	$12.4	$1.4	$11.4

8.1.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Resource Availability* – There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, ORPC will: (i) adopt a long-term resource plan based on project tasks and activities; and (ii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.

- *IT Systems Integration* – Different systems may not be properly integrated with each other when a system or group of systems are upgraded or replaced. If the current level of integration is not maintained, business processes could be impeded, and process inefficiencies could be introduced from manual data updates. ORPC considers and analyzes new component configurations in defining project scopes and conducts thorough due diligence during technical feasibility studies.

- *Regulatory requirements* – Currently unknown new regulatory requirements can require additional resources and time to implement. If new regulatory requirements emerge at a higher-than-expected rate, resources will be re-allocated to ensure that ORPC complies with these requirements. Projects will be rescheduled as necessary in accordance with the project prioritization considerations.

8.1.4.2. Investment Pacing & Prioritization

ORPC undertakes a thorough review of their Information Technology systems and hardware to determine what the most urgent investments are required over the forecast period. ORPC has prioritized investments that are critical to ensuring the continued day-to-day business processes and operations and compliance. This is then followed by investments that will realise cost savings and efficiencies in the future, such as investing in better technology for field staff to undertake their day-to-day tasks.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

8.1.5. Options Analysis

8.1.5.1. Project Alternatives

ORPC evaluated each discretionary Information Technology project above material threshold and determined the project pacing using the project evaluation process as outlined in Section 3.3.2. For each Information Technology project, the project scope is defined based on asset condition by inspection, customer needs, resource availability, capital cost, and asset obsolescence. The risk costs associated with each alternative were determined using the methodology outlined in Section 3.3.2.

The Information Technology project was evaluated at:

- Current Condition (Status Quo); and
- Moderate Pace.

Current Condition (Status Quo) Alternative – This is defined as the alternative in which the Information Technology program scope is to undergo no system upgrades. For this alternative, it is assumed that there are additional O&M costs associated with failing e-billing systems, and that the probability of incorrect bills for customers is higher than that of the Moderate Pace alternative.

Moderate Pace Alternative – This is defined as the alternative in which the Information Technology program scope is to undergo system upgrades at a moderate pace, considering system need, resource availability, and cost. For this alternative, it is assumed that there is an increase in productivity due to a reduction mailing and meter reading labour. The improvement of the e-billing system is also assumed to cause a decrease in customer calls due to operational issues, which increases employee productivity. Finally, a reduction in postage costs is applied, assuming an uptake of the e-billing system from 24% currently to 50% after upgrades.

8.1.5.2. Project Evaluation Results

The evaluation process was applied to the Information Technology project. The alternative that produced the lowest TCO for residual risk values over the project lifecycle was selected. In the Information Technology project, the Moderate Pace alternative, which completes system upgrades considering system need, resource availability, and cost, was recommended as a result of the process. The results for the evaluated project are shown below in Table 8-5.

Table 8-5: TCO for Residual Risk Values for Information Technology Project Alternatives

	TCO Value for Residual Risk ($M)	
	Current System Alternative	**Moderate Pace Alternative**
Information Technology Projects	$0.057M	$0.112M

8.1.6. List of Projects

ORPC has identified projects that will need to be addressed over the next forecast period, 2022-2026 and the pacing of these costs in Table 8-6.

Table 8-6: Information Technology Five-Year Projects and Cost

Project	2022	2023	2024	2025	2026
E-Billing System	$45,000	$0	$0	$0	$0
Customer Information System Automation	$10,000	$0	$0	$0	$0
Computer Hardware	$10,000	$0	$11,000	$0	$10,000
Printers	$1,000	$1,400	$1,400	$1,400	$1,400
Total	**$66,000**	**$1,400**	**$12,400**	**$1,400**	**$11,400**

8.2. Facilities

8.2.1. Overview

ORPC has service centres in both the Almonte and Pembroke service areas. These service centres represent a critical backbone of ORPC's 24/7 operations, as they house the office and field staff who undertake the daily operations, including customer billing, engineering & planning, field services as well as operations within the control room.

These service centres also house the depots for ORPC's in-field crews, including equipment, vehicles and workshops that allow for repairs and maintenance to be carried out. In addition, these service centres in Almonte and Pembroke are also accessible to the general public. This provides capabilities for customers to pay their bills, ask questions, and register complaints in person to ORPC staff. Without facilities investment, there would a be detrimental impact to ORPC operations that could affect both the safety of staff and the general public, as well as have an indirect impact on the reliability of the system.

As further noted in *Table 8-7*, total program spending from 2022 onwards to 2026 is $80.5k which is a reduction to spending levels when compared to the historical period from 2015 to 2019. This reduced spending is a reflection of the improved performance of the Facilities assets in the current state, as well as a product of the Facilities work that has already taken place during the historical period to mitigate safety concerns and risks.

Table 8-7: Investment Summary Details

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$25.3	$81.3	$7.7	$0.0046	$4.2	$76.6	$48.9	$49.0	$13.0	$12.5	$1.0	$5.0
Primary Driver	Non-System Physical Plant											
Secondary Drivers	System Maintenance Support											
Outcomes	Improved Reliability, Improved Efficiency, Improved Customer Value.											

8.2.2. Investment Description

ORPC plans to make repairs and investment in its two service centres in Almonte and Pembroke, due to existing or emerging deficiencies that pose health and safety hazards to its employees and the general public. In addition, when developing its investment plan, ORPC made the following considerations:

- Existing or emerging deficiencies that could be reasonably considered as having negative effects on the productivity or efficiency of utility operations.

- Existing or emerging deficiencies that if ignored, could lead to increased investments in the future and can otherwise be mitigated through smaller short-term investments to prevent further escalation of the deficiency.

ORPC regularly executes minor maintenance work to ensure the basic operation of their facilities infrastructure. ORPC has undertaken a full review of their facilities infrastructure to understand what are the most urgent activities that must be executed to ensure that the buildings remain safe for both staff and its employees. Additionally, investments have been proposed that will address the thermal efficiency of the service centres, which in turn will result in reduced operating costs due to better energy usage. Should these investments not go ahead, there will be increased risk exposure to both the staff and the general public. Should a major issue occur at a service centre, it could result in a closure of a portion of the facility, which would have a direct impact on internal utility productivity. Should a major facility failure occur within the depot, it could delay or otherwise obstruct the ability for field crews to get to their work sites or respond to outages in a timely manner.

As per ORPC's validation stage of the AM Process (further discussed in Section 3.1.2.4), the utility will regularly monitor and review all investments before undertaking them, and where possible will purchase material and solutions that can be bought off the shelf and therefore carries no premium cost.

Figure 8-1: Pembroke Service Centre / Main Office Building

Work Package Information

The following information details the investments that ORPC are looking to undertake over the next forecast period from 2022 onwards to 2026:

Pembroke:

- **Eavestrough Repair:** The eavestrough on the garage building is 50+ years old, is rotting and has many areas damaged by falling ice. ORPC has made repairs over the years, but it is at the point that the temporary patch jobs are no longer feasible or effective at preventing it from leaking. For example, during a period of quick melting or rainfall, large amounts of water pour from different sections of the eavestrough. This has been causing erosion on the cement and asphalt around the perimeter of the building, which results in the need for additional repairs and maintenance. In addition, during the winter, the melting water and overnight/mid-day freezing causes tripping and falling hazards for employees due to large patches of ice from the water exiting various holes in the eavestrough. It is therefore imperative that a more permanent repair is made to ensure that the building and its surroundings remain a safe environment for its employees.

- **Office Building Roof Repair:** The roof on both office buildings (front/back) is starting to show signs of failure. The bitumen membrane has "air pockets" where the seal between the roof surface and deck has failed. Historically, these will eventually fail and allow water to penetrate the membrane. This would result in water leaking into the building, causing damage to ceilings, drywall, office furniture, documents, and various equipment. ORPC is proposing where possible to make repairs to tackle these leaks as they begin to arise. In addition, ORPC will look to make a few minor proactive repairs where and when it is deemed necessary to prevent a larger leak and repair.

- **Front Office East Window:** The front office (east window) poses a safety concern to the general public due to the type of glass that is used in this location. This is a large 8' x 8' window, made of single pane glass facing a public sidewalk. A member of the public could be severely injured if they put pressure or fell into the window, due to the way this particular glass breaks. The glass is also not thermally efficient and freezes up in the winter. By changing this window out to newer tempered and thermally efficient glass, OPRC would reduce the risk of a public safety issue and reduce the transfer of heat/cold into the office, which in turn would enable savings on the HVAC as well as become more environmentally friendly through using less energy.

- **Entryway Retaining Wall:** The only accessible entryway to the rear office lower level is through an interlocking stone walkway/ramp. This ramp is now beginning to slant and deteriorate due to frost and exposure to the elements. In order to maintain a safe and usable accessible entrance, and to maintain AODA compliance, the wall will require maintenance.

- **Air Quality Handler:** The front office main floor and basement utilizes an air quality handler. It circulates air from outside/inside as well as capturing/introducing moisture to control humidity. The unit is aging and requires some minor maintenance to continue to operate it. By having this unit in operation, ORPC can control the comfort level for staff and customers in the building, as well as create a suitable humidity level that allows the utility to properly store and maintain paper records, bills, and envelopes.

Almonte:

- **Office/Lunchroom Improvements:** The Almonte work center has an aging room that is utilized as both an office for the Distribution Department Coordinator ("DDC") and a lunchroom for all Almonte ORPC operations staff. Currently the office functionality is not efficient enough to allow the DDC to operate from this location full time. The DDC spends time travelling between the Almonte Office and the work center to fulfill their duties. The work center office does not have a computer, proper office furniture or an internet connection, and it also lacks any proper physical filing system space or areas to host meetings. By investing in this space, the intent is to allow the DDC to spend less time travelling between locations to accomplish various duties that require access to computer equipment, internet services, filing systems and meeting space. This will also allow ORPC to downsize the office requirements for the existing Almonte office and relocate to a smaller, more affordable location to house the reduced footprint. Creating a more useful space for the DDC will require some work to reconfigure the breakroom for the Operations staff and allow for privacy for the DDC to conduct business with customers, developers, and staff.

- **Garage Door Pole Barn:** The pole barn utilizes an old wood-based sliding door that is unreliable and often gets stuck, introducing delays to the workday and presenting a safety hazard. The intent is to replace the door with a newer style metal sliding door that is both more efficient, safe, and reliable in operation.

- **Work Centre Windows:** The work center windows are old (1980's or earlier) and have issues with opening/closing. They are also very inefficient, requiring more use of the HVAC. By replacing these windows this would improve the thermal efficiency of the building and require less use of the HVAC, saving money and being beneficial to the environment

In addition, ORPC are investing in new furniture for both locations replacing old and unsafe furniture in these locations. This will ensure that staff and customers who enter these premises will continue to be safe.

Table 8-8 highlights the outcomes emerging from the Facilities program at ORPC:

Table 8-8: Program Outcomes

Outcomes	Description
Efficiency	This initiative will enable a number of efficiencies for ORPC. Environmental efficiencies will be achieved through the replacement of legacy windows, which will result in less utilization of the HVAC system and overall reduction in energy consumption. Productivity efficiencies are also achieved as this initiative will ensure that ORPC's workplaces remain fully functional, allowing in-office staff to perform their duties in an optimized manner, and allowing in-field staff to perform their necessary actions and get to their work site in an efficient and timely manner. Where possible, repairs are undertaken before investing in brand new materials. In addition, ORPC will look to utilise standard materials that can be bought off the shelf, which will generally ensure that this initiative remains cost competitive.
Customer Value	In replacing and refurbishing areas and building that pose potential safety issues and concerns, this ensures that ORPC are reducing the Public Safety risks associated with these facilities should members of the public visit. In addition, a safe, warm and clean environment ensures that staff can undertake their work effectively and efficiently by delivering what customers need.
Reliability	Through these investments, there are no direct impact on reliability of the network in terms of planned outages. However, some of these facilities house equipment and materials that are used on a daily basis to help maintain the reliability of the system, and therefore there is an indirect impact. There is also a direct impact of maintaining and upgrading the facilities as in-field crews can continue to get to their work sites and/or respond to outages in a timely manner.

8.2.3. Investment Drivers & Need

ORPC's Facilities program is designed to target deteriorated areas within ORPC's service centres, including the work centres for office staff, workshops and garage areas for storing its maintenance vehicles and equipment. Without functioning buildings and well-kept equipment, ORPC will be unable to deliver their daily operations in a safe and efficient manner. If crews are unable to get to their vehicles or equipment due to a major facilities failure, this would have a direct impact on the reliability of the system. At the same time, a failure in the work centres for office staff can also impact productivity, which can lead to indirect reliability impacts on the system.

As noted in *Table 8-9*, this program is primarily driven by the need to renew and invest in its own facilities and non-system physical plant associated with these assets. The secondary driver is System Maintenance Support because service centers house critical equipment as well as vehicles used to drive maintenance activities across the system.

Table 8-9: Program Drivers

	Driver	Description
Primary	Non-System Physical Plant	The primary driver for this program is renew and invest in ORPC's non-system physical plant. Within the context of this program, it is to invest in ORPC's facilities that house in-office & operations staff and equipment that is used for maintenance and operations. In addition, both of OPRC's front office buildings are accessible to the general public such that they are able to pay bills and ask queries. If OPRC did not invest in these facilities it would significantly impact their operations and their ability to continue to maintain a safe and reliable system.
Secondary	System Maintenance Support	The facilities house the maintenance equipment, vehicles and contain the workshops for the field staff to undertake repairs. Through investing in these facilities, ensuring they are fit for purpose, this protects the equipment stored, ensuring that they will work when needed. In addition, the ORPC workshops are used by the field staff to carry out critical repair and minor maintenance activities. By investing in these buildings, ORPC will ensure they can carry out their operations efficiently and reliably.

The following subsections serve to provide further details on the above-stated primary and secondary program drivers.

8.2.3.1. Non-System Physical Plant

The primary driver of the Facilities program is to renew and invest ORPC's non-system physical plant such as its buildings that house its employees and such that the organization can continue to operate in an effective manner. It is critical that ORPC ensures it buildings - which are the backbone of its 24/7 operations - are maintained to a safe standard that not only allows its employees to work efficiently and safely, but also ensures that the maintenance equipment and materials used by the utility are kept in good condition, thus enabling the operations staff to undertake their activities effectively while ensuring that the reliability of the system is maintained.

8.2.3.2. System Maintenance Support

ORPC executes maintenance of their system on a daily basis. To enable them to do this, ORPC's service centres contain workshops and garages that store and house the vehicles, equipment, and replacement assets required to carry out the maintenance and operational activities. They also use the workshops to carry out minor repairs to equipment. If ORPC does not keep these facilities in a good condition, this could mean some of the equipment and tools deteriorate through exposure to the weather or other external elements. This could impact the ability of ORPC to undertake their day-to-day operations, which in turn could affect the reliability of the system.

8.2.4. Investment Timing & Pacing

Table 8-10 summarizes the overall investment associated with the Facilities program, during the Historical period from 2015 to 2019, the 2020 and 2021 Bridge years, as well as the Forecast period from 2022 to 2026.

The pace of investment within this program is designed to strike a balance between the needs of renewing its facilities and the available resources to execute the work within ORPC as well as customer preferences to keep electricity rates as digestible as possible. For these reasons, total expenditures of $80.5K over the forecast period is a reduction when compared with the historical spending of $118.5K from 2015 to 2019. This shows that ORPC has been critical in assessing and determining what are the most urgent activities required to be executed during the forecast period.

Table 8-10: Timing & Pacing of Investment

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$25.3	$81.3	$7.7	$0.0046	$4.2	$76.6	$48.9	$49.0	$13.0	$12.5	$1.0	$5.0

8.2.4.1. Program Execution Risks and Risk Mitigation

ORPC anticipates and proactively manages program execution risks to minimize program delivery issues. Among the key risk categories that the utility tracks are the following:

- *Weather* – Poor weather (particularly prolonged spells) can negatively affect the planned pace and timeliness of planned work. ORPC plans to undertake any outdoor-related facilities activities in the Spring to Fall timeframe, thus avoiding the Winter Season.

- *Unexpected Priority Calls* – In the regular course of utility operations, instances occur where resources are pulled from planned projects to address reactive work requirements during emergency scenarios. ORPC uses where necessary contractor labour to supplement its regular internal resources to ensure planned work program delivery at levels commensurate to the utility’s plans.

8.2.4.2. Investment Pacing & Prioritization

ORPC has undertaken a thorough review of its Facilities infrastructure to determine what the most urgent investments that are required over the forecast period. ORPC has prioritized investments that are critical to continued reliable and safe operations followed by investments that will realise cost savings in the future.

During the course of the DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

8.2.5. Options Analysis

8.2.5.1. Project Alternatives

ORPC evaluated each discretionary facilities project above material threshold and determined the project pacing using the project evaluation process as outlined in Section 3.3.2. For each facilities project, the project scope is defined based on asset condition, customer needs, resource availability, and capital cost. The risk costs associated with each alternative were determined using the methodology outlined in Section 3.3.2.

The Facilities project was evaluated at:

- Current Condition (Status Quo); and
- Moderate Pace.

Current Condition (Status Quo) Alternative – This is defined as the alternative in which the Facilities program scope is to undergo no system upgrades. For this alternative, it is assumed that system O&M costs and property insurance costs are consistent with historical estimates.

Moderate Pace Alternative – This is defined as the alternative in which the Facilities program scope is to undergo system upgrades at a moderate pace, considering resource availability and cost. For this alternative, it is assumed that system O&M costs and property insurance costs are lower than historical estimates, because system upgrades yield less risk of failure.

8.2.5.2. Project Evaluation Results

The evaluation process was applied to the Facilities project. The alternative that produced the lowest TCO for residual risk values over the project lifecycle was selected. In the Facilities project, the Moderate Pace alternative, which completes facility system upgrades considering need, resource availability, and cost, was recommended as a result of the process. The results for the evaluated project are shown below in *Table 8-11*.

Table 8-11: TCO for residual risk values for Facilities project alternatives

	TCO Value for Residual Risk ($M)	
	Current System Alternative	**Moderate Pace Alternative**
Pembroke and Almonte Office Building Upgrades	$1.267M	$1.079M

8.2.6. List of Projects

ORPC has identified projects that will needed to be addressed over the next forecast period, 2022-2026 and the pacing of these costs.

Table 8-5: Facilities Five-Year Projects and Cost

Project	2021	2022	2023	2024	2025
Pembroke Eavestrough Repair	$27,000	$0	$0	$0	$0
Pembroke Office Building Roof Repair	$0	$10,000	$0	$0	$0
Pembroke Front Office East Window	$0	$0	$0	$0	$5,000
Pembroke Office Entryway Retaining Wall	$0	$3,000	$0	$0	$0
Pembroke Air Quality Handler	$0	$0	$0	$1,000	$0
Almonte Office/Lunchroom Improvements	$15,000	$0	$0	$0	$0
Almonte Garage Door for Pole Barn	$0	$0	$6,500	$0	$0
Almonte Work Centre Bathroom Repairs	$0	$0	$3,000	$0	$0
Almonte Garage/Work Centre Windows	$0	$0	$3,000	$0	$0
Furniture	$5,000	$0	$0	$0	$0
Tools, Shop, Garage Equipment	$2,000	$0	$0	$0	$0
Total	**$49,000**	**$13,000**	**$12,500**	**$1,000**	**$5,000**

8.3. Operational Technology

8.3.1. Overview

ORPC plans to improve its testing and inspection regimes, which will allow the utility to make better decisions on replacing and/or repairing assets in the field. Improvements in testing and inspection regimes also allow for an increase in the amount and quality of data collected. The Operational Technology program is designed to equip ORPC with enhanced tools, monitoring and testing products that will enable the utility to make more informed asset investment decisions such that the utility can continue to provide safe, reliable, and effective services to its customers.

As further noted in *Table 8-12*, total program spending from 2022 onwards to 2026 is $19.2K which is a slight reduction to spending levels over the historical period from 2015 onwards to 2019.

Table 8-12: Investment Summary Details

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$14.1	$14.0	$4.35	$3.55	$1.83	$2.5	$0	$19.2	$0	$0	$0	$0
Primary Driver	System Maintenance Support											
Secondary Drivers	N/A											
Outcomes	Improved Reliability, Improved Efficiency, Improved Customer Value.											

8.3.2. Investment Description

To improve its inspection methods, ORPC has identified the need to invest in an infrared (“IR”) thermal imaging camera: FLIR T530, with a 24° and 42° lens. The FLIR T530 provides infrared thermography outputs of overhead and underground infrastructure and can be used to accurately troubleshoot hot spots and potential faults. With a 180° rotating lens platform and a bright 4" LCD, the FLIR T530 is engineered to help users diagnose hard-to-reach components in any environment. Advanced on-camera measurement tools, laser-assisted autofocus, and FLIR’s industry-leading image quality ensure it is possible to find and diagnose problems quickly.

Specifically, ORPC will use this IR camera, as illustrated in Figure 8-2, to inspect assets such as poles, insulators, transformers, conductor. This will allow ORPC to identify defective equipment sooner than otherwise and possible look at alternatives to replacement, such as repairs, to be able to mitigate the issues, thereby avoiding unexpected outages and therefore increasing the reliability of the distribution system.

Figure 8-2: FLIR T530

Table 8-13 highlights the outcomes emerging from the Operational Technology program at ORPC:

Table 8-13: Program Outcomes

Outcomes	Description
Efficiency	Following the completion of this program, ORPC will be able to integrate the resulting data into their decision-making analytics such as ACA in order to better identify and prioritize investment work that is required. In addition, by enhancing their testing methodologies with the IR camera, this will allow their field technicians to be more targeted in the maintenance they undertake and being able to address issues efficiently and proactively before they materialise, reducing the likelihood of an outage.
Customer Value	ORPC's fundamental approach to determining investment is grounded in a data-driven approach. By investing in an IR camera this, will enable ORPC to gather more data on its assets, improve its testing and inspection process. This enables ORPC to address the most critical areas on its distribution system.
Reliability	By improving its testing and inspecting process, enabling it to better assess the condition of its assets, this will allow ORPC to proactively address the most critical assets, ensuring that the reliability of the system is maintained.

8.3.3. Investment Drivers & Need

ORPC's Operational Technology program is designed to improve its maintenance regimes and provide technology that will help crews enhance the data they collect and the ability to assess more assets.

As noted in *Table 8-14*, this program is primarily driven by the need to improve the system maintenance support for ORPC, through the investing in operational technologies that enhance its testing and inspection methods.

Table 8-14: Program Drivers

	Driver	Description
Primary	System Maintenance Support	The primary driver for this program is to improve its system maintenance support. ORPC undertake regular inspection and testing of its assets on its system. They are always looking to make improvements to these processes, improving what they can test and the quality of data. Through investing in an IR camera, this will enhance their testing capabilities, helping improve and enhance the development of their investment plans.

The following subsections serve to provide further details on the above-stated primary program driver.

8.3.3.1. System Maintenance Support

The primary driver of this program is system maintenance support, as this program will allow for infrared thermography results to be captured throughout the system which can then be integrated within ORPC's AM Process and decision-making processes. In particular, outputs from the IR camera would enhance the ACA results, thereby allowing ORPC to make more granular decisions and better prioritize their asset base.

As explained in ORPC's ACA report, *"while ORPC's existing framework provides a significant volume of data, certain procedural and technological enhancements could further enhance the granularity of this data as well as the asset condition results and facilitate calculation of a greater proportion of numerical degradation scores"*[21]. The introduction of new testing and monitoring technologies such as the IR camera contained within this program will allow for new quantifiable results to be extracted from the field and integrated into the ACA framework, which will allow for more granular HI results to be produced for the utility, thereby enhancing decision-making.

The IR camera will allow for better and earlier identification of defective assets, which will allow ORPC to address these assets before they fail and cause potential unexpected outages. This in turn will reduce the number of unexpected outages that field operatives have to reactively respond to, reducing premium reactive spend and also take these staff away from planned jobs that also need to be completed.

Customers will continue to experience a reliable network as a result, with the number of unexpected outages being further minimized with the ability to identify defective equipment with the IR camera. By utilizing the IR camera to help identify defective equipment, that would otherwise be hard to detect, this will allow ORPC to proactively address the defective equipment and maintain the reliability of the system.

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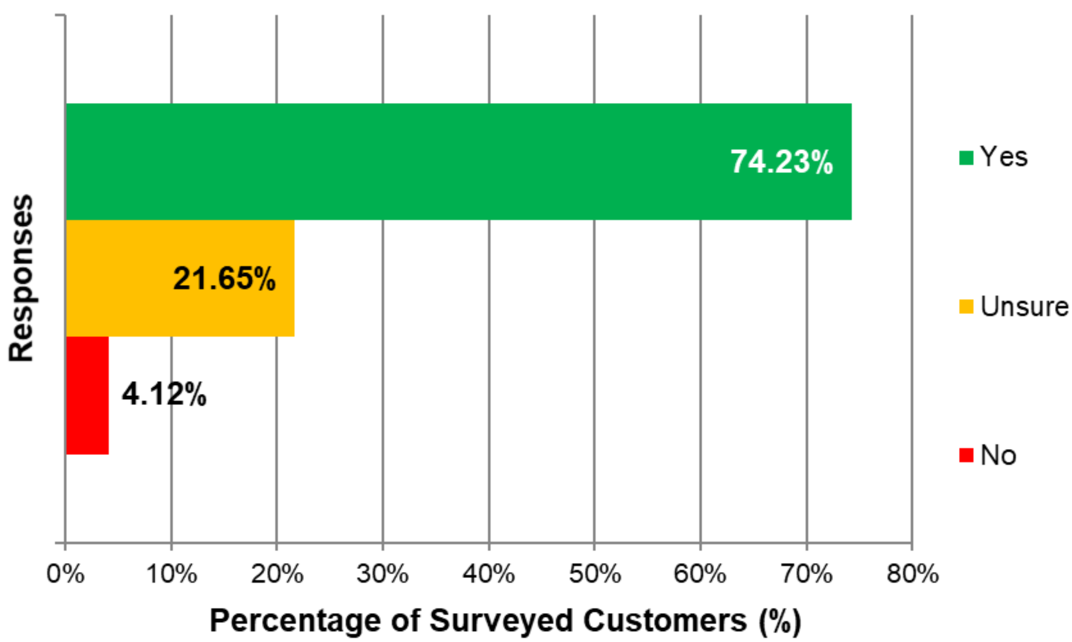
[21] "Ottawa River Power Corporation Asset Condition Assessment Report 2020", p.10, METSCO, 2020.

Through the collection of more data on their assets across the system, ORPC will be able to leverage this information when planning its future capital investments. This will help the utility to identify the assets that require the most urgent investment in a more granular and precise manner. This information is then ultimately leveraged to produce the future capital investment programs, and results in overall continuous improvements to ORPC's AM Process and corresponding outputs.

As part of the DSP Survey that was conducted in 2020 to capture specific customer preferences with respect to ORPC's investment plan, customers were asked about whether ORPC should invest into testing procedures and monitoring technologies to further enhance the condition outputs used as part of the decision-making process. Figure 8-3 reveals that nearly 75% of customers agree that ORPC should invest into new monitoring technologies to better support their condition-based decision-making. This would include the IR camera that is being proposed within this investment program.

Figure 8-3: Survey Question: Should ORPC Invest in Testing Procedures & Monitoring Technologies to Further Enhance Condition Outputs?



Complete results from the DSP Survey are further provided in Exhibit 1, Appendix 1E.

8.3.4. Investment Timing & Pacing

Table 8-15 summarizes the overall investment associated with the Operational Technology program, during the Historical period from 2015 to 2019, the 2020 and 2021 Bridge years, as well as the Forecast period from 2022 to 2026.

To ensure that ORPC is able to leverage the benefits from this program as rapidly as possible, this investment has been prioritized for the 2022 test year. This will allow ORPC to train its operations staff in the use of the camera and begin to use it when undertaking its testing and inspection programs. This will also allow ORPC to begin gathering further data that will influence future investment decisions, not only in the forecast period but also beyond that.

Table 8-15: Timing & Pacing of Investment

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$14.1	$14.0	$4.35	$3.55	$1.83	$2.5	$0	$19.2	$0	$0	$0	$0

8.3.4.1. Program Execution Risks and Risk Mitigation

There are no immediate risks with undertaking this investment.

8.3.5. Investment Pacing & Prioritization

ORPC has determined that over the forecast period from 2022 to 2026, the purchase of this IR camera will be the sole component of this investment program in order to help ORPC improve their testing and inspection methods.

During the course of DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

8.3.6. Options Analysis

8.3.6.1. Project Alternatives

ORPC evaluated each discretionary Operational Technology project above material threshold and determined the project pacing using the project evaluation process as outlined in Section 3.3.2. For each Operational Technology project, the project scope is defined based on system need, resource availability, and capital cost. The risk costs associated with each alternative were determined using the methodology outlined in Section 3.3.2.

The Operational Technology project was evaluated at:

- Current Condition (Status Quo); and
- Moderate Pace.

Current Condition (Status Quo) Alternative – This is defined as the alternative in which the Operational Technology assets are to undergo no system expansion with regard to the purchase of an IR camera for use in asset inspections. For this alternative, it is assumed that unplanned system outages caused by defective equipment are consistent with historical estimates.

Moderate Pace Alternative – This is defined as the alternative in which the Operational Technology assets are to undergo system expansion with the addition of an IR camera for use in asset inspections. For this alternative, it is assumed that unplanned system outages caused by defective equipment are less likely than in the Current Condition Alternative.

8.3.6.2. Project Evaluation Results

The evaluation process was applied to the Operational Technology project. The alternative that produced the lowest TCO for residual risk values over the project lifecycle was selected. In the Operational Technology project, the Moderate Pace alternative, which adds an IR camera to the program scope for use in asset inspections, was recommended as a result of the process. The results for the evaluated project are shown below in *Table 8-16*.

Table 8-16: TCO for residual risk values for Operational Technology project alternatives

	TCO Value for Residual Risk ($M)

	Current System Alternative	Moderate Pace Alternative
Operational Technology Project	$127.4M	$120.3M

8.4. FLEET

8.4.1. Overview

ORPC has seven large vehicles within its fleet that operate across four main service areas, carrying out essential maintenance, support capital investment work and respond to emergency outages. ORPC plans to purchase a Posi-Plus 400-50 large truck vehicle to replace an existing vehicle that has had multiple failures since it was bought in 2008. The maintenance cost on this vehicle have been steadily increasing since it was first purchases, alongside it having multiple failures resulting in the vehicle being out of service of extended periods of time. The Fleet 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.

As further noted in *Table 8-17*, total program spending from 2022 onwards to 2026 is $432K which is a reduction to spending levels over the historical period from 2015 onwards to 2019. This is mainly due to ORPC needing to replace one large vehicle in the next five-year period.

Table 8-17: Investment Summary Details

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$12.4	$116.6	$322.4	$31.0	$391	$53.6	$13.6	$5.0	$5.0	$5.0	$5.0	$412
Primary Driver	System Maintenance Support											
Secondary Drivers	N/A											
Outcomes	Improved Reliability, Improved Efficiency, Improved Customer Value.											

8.4.2. Investment Description

ORPC has a varying fleet of vehicles that are used to carry out operations across its four service areas. This includes seven large vehicles which are predominantly used to carry out maintenance, support capital investment works and respond to emergency outages. ORPC's fleet strategy is to aim to replace vehicles on a 15-year cycle. ORPC have identified one of their vehicles, Truck 8-08 (a Posi-Plus 400-50), that will require replacement in 2026. 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 and an exhaust and emissions system failure in 2018. 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 at $10,000 a year, compared to an average of $6,000 a year for its other large vehicles in its fleet. The vehicle will be replaced with a Posi-Plus 400-50, similar to the truck in Figure 8-2.

Truck 8-08 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 is used 981 hours per year on average. It has 140,000km and with 11,781 engine hours.

OPRC have also allocate $5,000 each year to allow for minor 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.

Figure 8-2: Posi Pluss 400-50 Truck

Table 8-18 highlights the outcomes emerging from the Fleet program at ORPC:

Table 8-18: Program Outcomes

Outcomes	Description
Efficiency	The reliability of large vehicles in the fleet impact several areas including supporting maintenance activities, supporting capital projects, and supporting response time to emergency calls. Equipment availability directly impacts crew productivity and scheduled replacements reduces the risk of unplanned vehicle and equipment failures. ORPC will also be able to reduce its maintenance cost associated with a new vehicle through the purchase of a new truck. A new truck has lower maintenance tasks and costs associated in its younger years and is also protected which will require less maintenance to be performed and typically come with a warranty from the manufacturer.
Customer Value	ORPC' crew will be able to continue to maintain and improve response times to outages, system reliability and crew effectiveness.
Reliability	ORPC will be able to continue to maintain, operate and respond to emergency failures of assets in a safe, timely and efficient manner. The purchase of a new truck ensures that ORPC can continue to maintain its business operations and system reliability performance.

8.4.3. Investment Drivers & Need

The Fleet 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.

As noted in *Table 8-19*, this program is primarily driven by the need to renew and invest in its own vehicles to carry out critical system maintenance activities, support capital investment projects, and respond to emergency power outages.

Table 8-19: Program Drivers

	Driver	Description
Primary	System Maintenance Support	The primary driver for this program is to improve its system maintenance support. ORPC undertake regular inspection and testing of its assets on its system. To do this, ORPC crew use its large vehicles. Through replacing a truck that has increasing maintenance costs and that is regularly unavailable for use, ORPC will be able to continue to carry out its essential maintenance activities, support capital project and respond in a timely and safe manner to emergency outages.

The following subsections serve to provide further details on the above-stated primary program driver.

8.4.3.1. System Maintenance Support

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, respond to emergency outages. In addition to having reached its end of 15-year cycle, the vehicle has experienced multiple failure, with an engine rebuild being carried out in 2015 and an exhaust and emissions system failure in 2018. 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 at $10,000 a year, compared to an average of $6,000 a year for its other large vehicles in its fleet. The vehicle is a critical part of OPRC's fleet, with it being used on average 981 hours per year. Through purchasing the new truck, the security of a reliable truck to use will increase, ensuring that critical maintenance can continued to be carried out. In addition, as ORPC plan to carry out a significant amount of capital project the vehicle is critical in supporting the execution of these, with it being used as material handler on capital projects. If ORPC did not invest in a new vehicle, a vehicle would have to be rented from nearby utilities or hired from a third-party service when required, which presents its own set of business risk and cost increases. It would also introduce delays to restoration times for emergency work, as well as cause issues with coordinating planned works.

8.4.4. Investment Timing & Pacing

Table 8-20 summarizes the overall investment associated with the Fleet program, during the Historical period from 2015 to 2019, the 2020 and 2021 Bridge years, as well as the Forecast period from 2022 to 2026.

To ensure that ORPC is able to continue to maintain and respond to network issues, the investment in a new vehicle will be required in 2026. This will allow ORPC to continue to carry out its routine maintenance activities, support capital investment projects, as well as respond to any emergencies that arise.

Table 8-20: Timing & Pacing of Investment

	Historical					Bridge		Forecast				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPEX ($K)	$12.4	$116.6	$322.4	$31	$391	$53.6	$13.6	$5	$5	$5	$5	$412

8.4.4.1. Program Execution Risks and Risk Mitigation

There are no immediate risks with undertaking this investment.

8.4.5. Investment Pacing & Prioritization

ORPC has determined that over the forecast period from 2022 to 2026, the purchase of a new Fleet vehicle will be the major component of this investment program in 2026 in order to help ORPC to be able to maintain its network and respond to any emergencies in an efficient and safe manner.

During the course of DSP execution, should an unplanned operational conflict arise such that a project cannot be completed as scheduled, a decision will be made to defer this project or components of this project to a later date. Unplanned conflicts may include unscheduled jobs of a higher priority.

8.4.6. Options Analysis

As ORPC is not executing any material Fleet investments in 2022, there are no material investments and associated options that can be explored at this time. When considering alternative to a new truck in 2026, ORPC have considered different options including:

- Consideration of hiring a vehicle from a third-party provider or hiring from a nearby utility:
  - The nearest neighbouring utility only has two large vehicles in their fleet. ORPC has a minimum number of large vehicles in its fleet required to conduct its business. In the past ORPC has shared its vehicle to assist with neighbouring utilities on large projects. ORPC has utilized assistance from neighbouring utilities including large vehicles during storm restorations. Hiring a vehicle from a third-party provider instead of purchasing an additional vehicle could induce delays to restoration times for emergency work, as well as causing issues with coordination of planned work.
- Consideration of purchasing a green emissions truck:
  - ORPC has two green vehicles in its small vehicle fleet. Large trucks are currently not available on the commercial market as EV's or hybrids. ORPC will continue to monitor this, and if a green emissions large truck becomes available the cost and benefit will be assessed.

APPENDIX A – NEEDS ASSESSMENT REPORT

OTTAWA RIVER POWER

RELIABILITY ASSESSMENT REPORT 2021

Historical Period: 2015-2020

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INTRODUCTION

This report has been prepared by METSCO Energy Solution Inc, on behalf of Ottawa River Power Corporation (“ORPC”), and in support of the Distribution System Plan (“DSP”) authoring process in compliance with the Ontario Energy Board (‘OEB”) *Chapter 5 Consolidated Distribution System Plan Filing Requirements* (“the Filing Requirements”) dated June 24, 2021.

ORPC’s distribution system is comprised of many components and processes which provide power to its customers. It consists of several complex and interconnected devices and assets which work collectively to achieve this goal. These components and their related processes are frequently monitored and refined in order to ensure that they are operating optimally and providing the required service. However, the distribution system can malfunction for a variety of reasons and ORPC’s customers may experience service interruptions as a result. These outages are problematic as they negatively affect customer experience, reliability performance, and ORPC’s ability to achieve its corporate objectives.

This report analyzes various aspects of ORPC’s distribution system reliability performance in order to understand the nature and impact of service interruptions. Specifically, this report analyzes ORPC’s historical reliability performance, outages by cause code, Major Event Days (“MED”). These analyses allow ORPC to identify factors which pose a risk to system reliability and take action to mitigate these risks.

1. HISTORICAL PERFORMANCE

System Reliability

Methods and Measures

The reliability of supply is primarily measured by the internationally accepted indices System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") as defined within the OEB's Electricity Reporting & Record-Keeping Requirements dated March 31, 2020[1]. SAIDI represents the length of outage customers experience in the year on average, expressed as hours per customer as shown in Equation 2-1, and is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI represents the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer as shown in Equation 2-2. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered a sustained interruption if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served} \qquad (EQ\ 2\text{-}1)$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served} \qquad (EQ\ 2\text{-}2)$$

To meet the reporting requirements, ORPC also considers the impacts of other defined parameters such as Loss of Supply ("LOS") and Major Event Days ("MED") to calculated adjusted values of reliability indices. LOS is defined as an interruption that is caused due to a problem and/or failure of assets owned and/or operated by another party, and/or in the bulk electricity supply system. Similarly, MED is defined as an event that is beyond the control of ORPC and is unforeseeable, unpredictable, unpreventable, and unavoidable. MEDs are calculated using the IEEE STD 1366-2012 methodology.

Historical Performance

The historical reliability performance is shown in the Table 1-1 excluding Loss of Supply ("LOS") and Major Event Day ("MED") for the 2015-2020 period, including the target that was set.

Table 1-1: 2015 to 2020 reliability performance metrics

Metric	Target	2015	2016	2017	2018	2019	2020	Average (Exclude MED & LOS)	Average (Include MED & LOS)
SAIDI	1.64	3.95	1.55	0.95	0.53	0.79	0.56	1.39	7.9
SAIFI	1.01	2.56	0.84	0.62	0.24	0.59	0.53	0.9	3.1

The SAIDI and SAIFI charts shown in Figure 1-1 and Figure 1-2 are required as part of the DSP requirements. The data that support these charts are shown in Table 1-2 and Table 1-3.

[1] "Electricity Reporting and Record Keeping Requirements", Section 2.1.4.2, p. 9, Ontario Energy Board, March 31, 2020. URL: https://www.oeb.ca/sites/default/files/RRR-Electricity-20200331.pdf

Table 1-2: Historical SAIDI Performance

Metric	2015	2016	2017	2018	2019	2020
SAIDI	10.35	3.36	4.35	1.73	25.00	2.63
SAIDI Excluding LoS	3.95	3.31	0.95	0.53	7.68	0.56
SAIDI Excluding Los and MED	3.95	1.55	0.95	0.53	0.79	0.56

Table 1-3: Historical SAIFI Performance

Metric	2015	2016	2017	2018	2019	2020
SAIFI	4.17	1.18	2.55	1.29	3.33	6.06
SAIFI Excluding LoS	2.56	1.15	0.62	0.24	1.35	0.53
SAIFI Excluding Los and MED	2.56	0.84	0.62	0.24	0.59	0.53

Figure 1-1: Historical SAIFI Performance

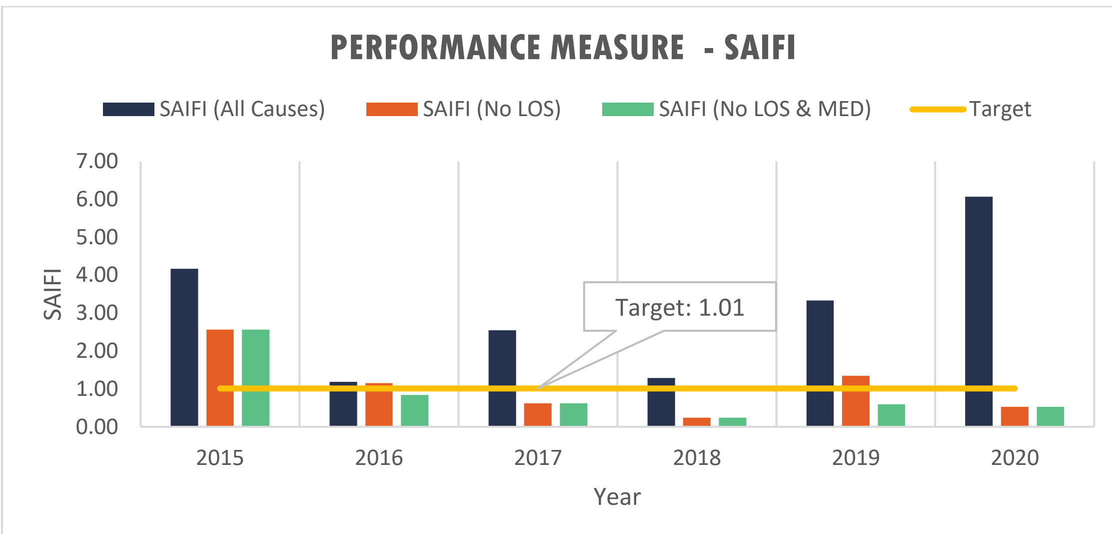

Figure 1-2: Historical SAIDI Performance

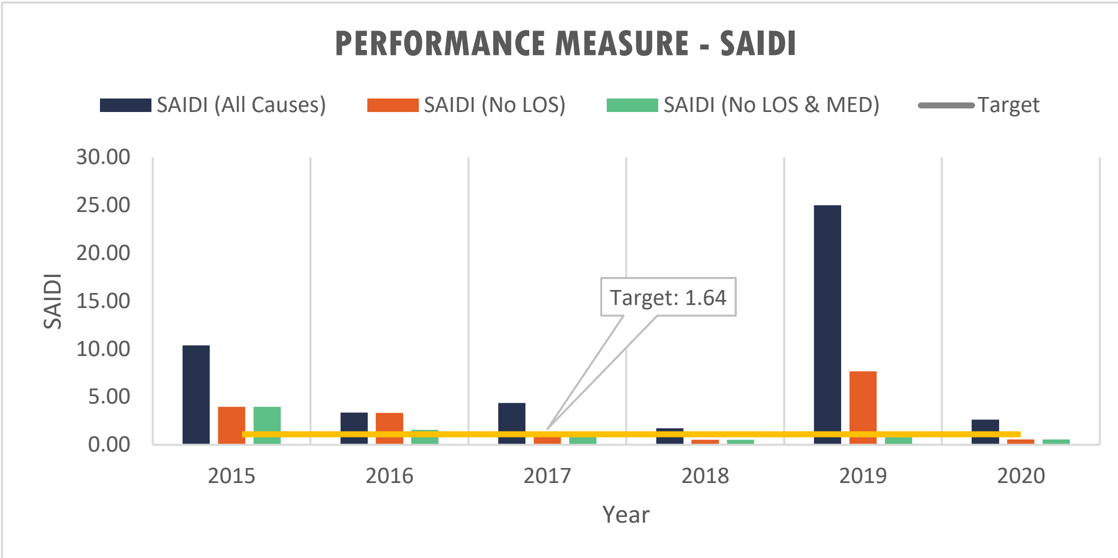

Table 1-4: Number of outages (2015-2020)

Categorization	2015	2016	2017	2018	2019	2020
All interruptions	41	35	72	145	127	128
All interruptions excluding LOS	36	34	65	135	124	120
All interruption excluding MED and LOS	34	33	65	135	119	120

Excluding LOS events and MEDs, ORPC's reliability performance in recent years demonstrates an improvement trend. On average, an ORPC customer experiences one outage per annum and without power for 1.55 hours. In the summer of 2015, a significant storm resulted in widespread damages within the Pembroke service area, resulting in longer than average interruptions for large sections of the City. Assets in the sub transmission system were initially affected by foreign interference, later resulted in unplanned and scheduled outages due to defective components. Both causes contributed to 2015 SAIFI & SAIDI performance being worse than their targets. However, since this time, the reliability of ORPC's system had greatly improved. Both SAIDI and SAIFI for the remaining historical period were favourable with respect to its target with respect to excluding LOS and MED

2. DESCRIPTION OF MEDs

In addition, ORPC's system has experienced MEDs in 2015, 2016, and 2019 within the historical period from 2015 onwards to 2020. During this period, *Loss of Supply* introduced the majority of the MEDs – with interruptions exceeding 220,000 customer hours. Table 2-1 summarizes the impact of MEDs in terms of number of interruptions, customer interruptions ("CI") and customer hours of interruptions ("CHI"). Table 2-2 lists the details of each identified MED.

Table 2-1: MEDs by cause code (2015-2020)

Major Events Details	2015	2016	2017	2018	2019	2020
Number of Interruptions						
2 - Loss of Supply	1	-	-	-	3	-
6 - Adverse Weather	-	1	-	-	-	-
7 - Adverse Environment	-	-	-	-	1	-
8 - Human Element	-	-	-	-	1	-
Number of Customer Interruptions						
2 - Loss of Supply	7,140	-	-	-	22,510	-
6 - Adverse Weather	-	3,429	-	-	-	-
7 - Adverse Environment	-	-	-	-	7,372	-
8 - Human Element	-	-	-	-	1,215	-
Number of Customer Hours of Interruptions						
2 - Loss of Supply	30,955	-	-	-	196,786	-
6 - Adverse Weather	-	19,313	-	-	-	-
7 - Adverse Environment	-	-	-	-	77,406	-
8 - Human Element	-	-	-	-	809	-

Table 2-2: List of MEDs over the historical period

Date	Customer Interrupted	Description
27-Jul-15	7130	4.3hrs, Pembroke, 2-Loss of Supply
27-Jul-15	10	5.8hrs, Pembroke, 2-Loss of Supply
20-Jun-16	310	4.2hrs, Pembroke, 6-Adverse Weather
21-Jun-16	3119	17.8hrs, Pembroke, 6-Adverse Weather
2-Jan-19	7372	10.5hrs, Pembroke, 7-Adverse Environment
30-Jan-19	7372	7.3hrs, Pembroke, 2-Loss of Supply
13-Aug-19	8000	14.5hrs, Pem/Kill/Beach, 2-Loss of Supply
10-Oct-19	1215	0.7hrs, Pembroke, 8-Human Element
14-Dec-19	7138	3.8hrs, Pembroke, 2-Loss of Supply

This assessment uses the 10% fixed percentage approach to calculate MEDs. There was one MED in 2015 caused by a loss of supply that resulted in 7,140 customers experiencing an outage with a total of 30,955 customer hours of interruption ("CHI"). In June 2016, there was one MED that was caused by major storms and lightning in the Pembroke area. This resulted in 3,429 customers experiencing an outage with a total of 19,313 CHI. No MEDs were recorded in 2017 and 2018. In 2019, there were 5 MED's[2]. Three of the MED's were due to Loss of Supply:

- Jan-19 resulting in 7,372 customers interrupted with a total of 53,447 CHI in Pembroke.

[2] It should be noted that whilst these events should be classified as MED's, they were not reported as such in ORPC's RRR filing at the time.

- Aug-19 resulting in 8,000 customers interrupted with a total of 116,000 CHI across Pembroke, Killaloe and Beachburg.
- Dec-19 resulting in 7,138 customers interrupted with a total of 27,339 CHI in Pembroke.

There was one MED in 2019 due to a fire at the Lumber Mill resulting in 7,372 customers interrupted with a total of 77,406 CHI. There was also a MED in October 2019 due to human elements resulting in 1,215 customers interrupted with a total of 809 CHI. No MED’s were recorded in 2020.

3. OUTAGES BY CAUSE CODES

The following tables breakdown the number of outages (Table 3-1), customers interrupted (Table 3-2) and customer hours of interruption (Table 3-3) by OEB's cause codes for the 2015-2020 period.

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Table 3-1: Outage numbers by cause codes (2015-2020)

Cause Code	2015	2016	2017	2018	2019	2020	Total Outages	%
0-Unknown/Other	2	-	2	1	1	1	7	1%
1-Scheduled Outage	2	-	24	89	68	66	249	45%
2-Loss of Supply	5	1	7	10	3	8	34	6%
3-Tree Contacts	1	1	8	9	3	6	28	5%
4-Lightning	3	2	2	-	-	-	7	1%
5-Defective Equipment	13	9	9	19	27	22	99	18%
6-Adverse Weather	3	8	6	3	7	8	35	6%
7-Adverse Environment	-	-	-	1	1	1	3	1%
8-Human Element	2	2	2	1	3	-	10	2%
9-Foreign Interference	10	12	12	12	14	16	76	14%

Table 3-2: Customers Interrupted numbers by cause codes (2015-2020)

Cause Code	2015	2016	2017	2018	2019	2020	Total CI	%
0-Unknown/Other	875	-	850	650	45	523	2,493	1%
1-Scheduled Outage	7,150	-	456	913	1,244	1,283	11,046	5%
2-Loss of Supply	17,470	376	21,363	11,750	22,510	34,751	108,220	52%
3-Tree Contacts	6	14	283	203	60	364	930	0%
4-Lightning	827	3,009	425	-	-	-	4,261	2%
5-Defective Equipment	8,836	2,093	2,838	424	3,207	30,684	48,082	23%
6-Adverse Weather	2,513	5,294	1,276	305	728	1,548	11,664	6%
7-Adverse Environment	-	-	-	15	7,372	77	7,464	4%
8-Human Element	4	31	586	21	1,357	-	1,999	1%
9-Foreign Interference	7,616	2,144	100	196	1,286	154	11,496	6%

Table 3-3: Customer Hours Interrupted numbers (rounded) by cause codes (2015-2020)

Cause Code	2015	2016	2017	2018	2019	2020	Total CHI	%
0-Unknown/Other	572	-	742	2,002	21	26	3,363	1%
1-Scheduled Outage	28,570	-	1,369	1,586	3,785	1,853	37,163	7%
2-Loss of Supply	69,604	496	37,715	13,474	96,786	20,871	338,946	64%
3-Tree Contacts	51	4	552	572	102	257	1,538	0%
4-Lightning	858	4,460	278	-	-	-	5,596	1%
5-Defective Equipment	11,775	3,375	4,903	268	1,962	5,077	27,360	5%
6-Adverse Weather	182	26,586	2,188	798	868	1,702	32,324	6%
7-Adverse Environment	-	-	-	124	77,406	151	77,681	15%
8-Human Element	16	66	246	68	1,081	-	1,477	0%
9-Foreign Interference	907	1,790	195	530	1,964	116	5,502	1%

Overall, the largest number of outages (45%) experienced by ORPC's customers was due to a scheduled outage. Scheduled outages are consistent with line rebuilds and asset upgrades. However, these outages only account for 5% of customers interrupted and 7% of CHI. The largest contributor to the number of customers interrupted and the CHI comes from 34 Loss of Supply Events, resulting in 338,946 CHI and 108,220 customers interrupted. The next largest contributor for CHI was the adverse environment cause code. This was due to a major fire at a Lumber Mill in 2019 resulting in 77,406 CHI. 23% of customers interrupted was due to defective equipment with a large amount in 2015 and 2020. As previously discussed in the MED section, there was also a significant number of CHI (32,324) due to adverse weather. The main contributor of this was due to a major storm and lightening in June 2016. All other cause codes are of smaller value, although still of importance and ORPC should look to reduce these numbers as much as possible, including reducing the number of outages identified as unknown/other.

4. CONCLUSIONS

In general, the customers of ORPC have experienced some significant outages in the planning period, but these are highly driven by a few major incidents, most of which are Loss of Supply or externally caused major events.

From the context of the utility customer, reliability includes all causes of outages. In 2020, it shows that the performance of ORPC has a SAIDI of 0.56 which is well below the “estimated” target levels of 1.64. For SAIFI ORPC recorded 0.53 which is well below the “estimated” target levels of 1.01. The average SAIDI and SAIFI for the 2015-2020 period are 1.34 and 0.9 respectively which are both well below the “estimated” target levels. This demonstrates that ORPC have managed there network effectively and invested where necessary to maintain the levels of reliability.

Major Event reporting has been inconsistent over the previous 4 years, and this report has been structured to align with the previously published reports. From 2019, major event reporting follows the OEB 10% method.

With Loss of Supply and Major Events removed the reliability performance has met published targets as well as the “estimated target” which is based on the previous 5-year average results. ORPC should establish corporate targets for reliability as the 5-year average method can force continual improvement beyond economic means.

Overall, the success that ORPC has had over the previous 6 years indicates that current levels of spending on reliability initiatives should be maintained. However, one area of concern would be defective equipment, as this is a high contributor to ORPC’s SAID and SAIFI scores. Equipment failures should be investigated for trends and may indicate a need for Renewal Investment or Targeted Maintenance.

The most significant of the outage impacts on the ORPC customer are often deemed “uncontrollable”. However, these should be documented and not assumed. For instance, alternate sources of supply, additional stations, and undergrounding the entire system would eliminate the problems, but are clearly cost prohibitive. In any case, “uncontrollable” outages should be reviewed on an individual or systemic basis to identify if any future solutions can be implemented to mitigate these outages.

5. RECOMMENDATIONS

While the reliability performance of ORPC is good, it is worthwhile to note areas where in processes and activities could result in improvements. The following concepts are presented for further review and the costs to implement should be considered before initiating any project.

Reporting Tool:	The OEB requirements for RRR reporting and for the DSP are different, and the needs of the utility are different again. ORPC can likely save some time and effort by creating a standard Outage Reporting tool to automate the process. The tools developed in this study are a good starting point.
Standardization:	Some standardization in reporting would be beneficial. The application of Cause-Codes should be defined such as the differences between a weather or a lightning event, or what to report if wind causes a tree contract. Also, it may be useful to define an Event with an overall event code and “Sub-Events”.
Targets:	ORPC should establish corporate reliability targets and work towards meeting them. It is likely that any target set will already be met.
Investigate:	Increased investigation may be warranted, particularly into unknown events (mostly one significant event), and defective equipment.
Show Improvements.	The requirements of the OEB and in particular the DSP process include demonstrating improvement over the historical period with a plan to continue to improve. There is an opportunity to document and demonstrate improvement in “understanding of the outage characteristics”, “review of major outages and consideration given (and often rejected) to design improvements, process and data collection improvement.

APPENDIX B – REGIONAL INFRASTRUCTURE PLANNING REPORT

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Renfrew Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

The Renfrew Region consists of Renfrew County and it is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast.

The Needs Assessment ("NA") report for the Renfrew region was completed in March, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time although circuit X1P is nearing its capacity and will be monitored on a regular basis over the next three to five years.

There are no other major development projects planned for the Renfrew Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB, the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the Renfrew Region.

The next regional planning cycle for the region is expected to be undertaken in five years from the start of this planning cycle (2015) or earlier if there is a new need emerging in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

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[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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NEEDS ASSESSMENT REPORT

Region: Renfrew

Revision: Final
Date: March 11, 2016

Prepared by: Renfrew Study Team

Transmission

Distribution

Peterborough to Renfrew Region Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Renfrew Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or 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"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	March 11, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Renfrew Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Renfrew Region belongs to Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 11, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment 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.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period under normal and single contingency condition.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.

System Reliability, Operation and Restoration Needs

There are no transmission system reliability issues and no operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

All load within the region can typically be restored within eight hours as per the ORTAC requirement for loads under 150 MW.

In recent years, maintenance activity in the region with respect to vegetation management has been enhanced resulting in an improvement in reliability and/or load restoration.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities. Further details of these investments can be found in Section 3.2 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows:

- Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

- No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Renfrew Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Renfrew Region Needs Assessment study team. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 4, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region. The 2014 peak load in this Region was 124 MW.

The electricity supply to the region is mainly through one 230kV circuit X1P and three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). 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 roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

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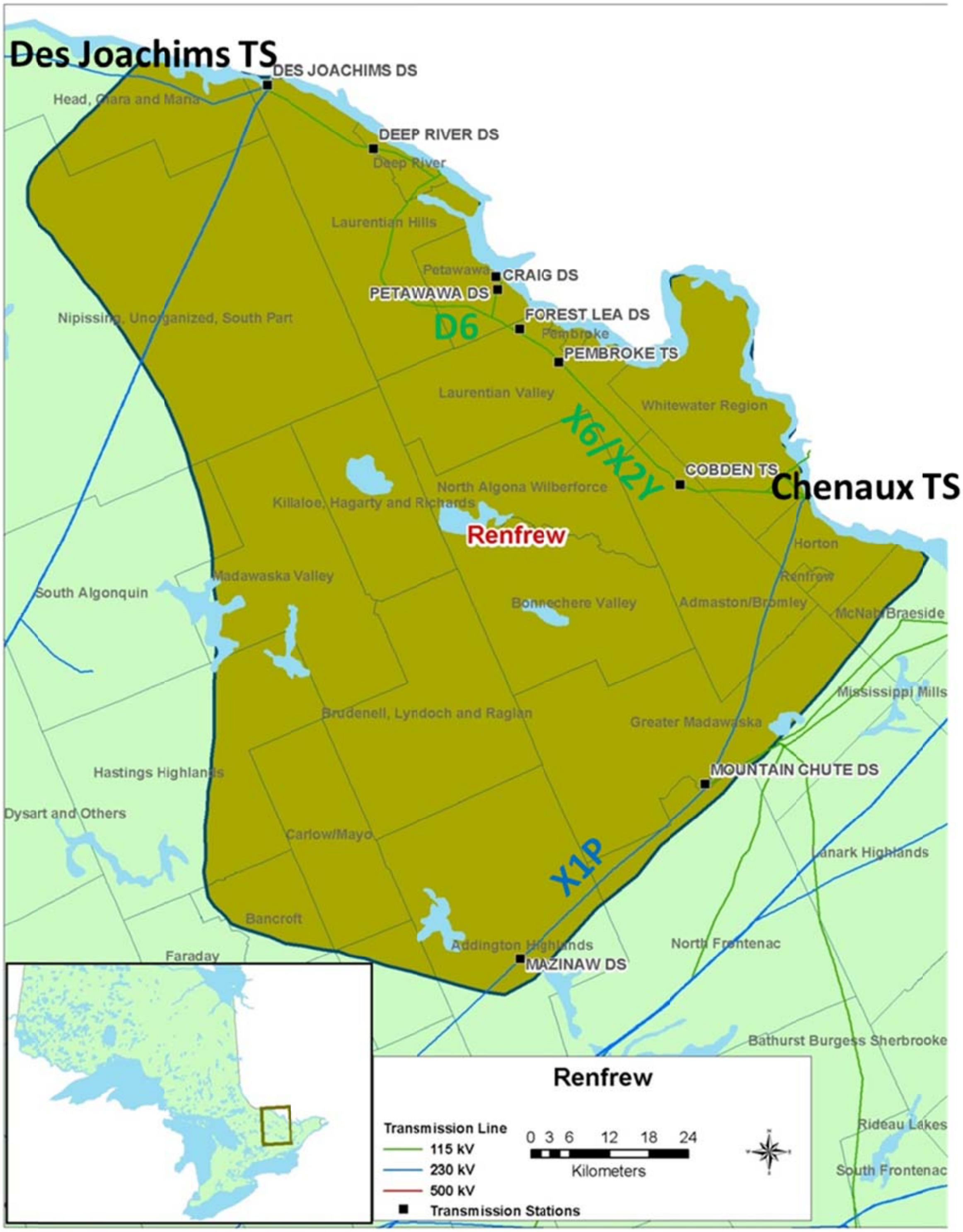

Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des 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 Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker

- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units 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 Chalk River Customer Transformer Station (CTS).

- All the 115kV circuits X6/X2Y/D6, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- 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 DS typically has load less than 1MW.

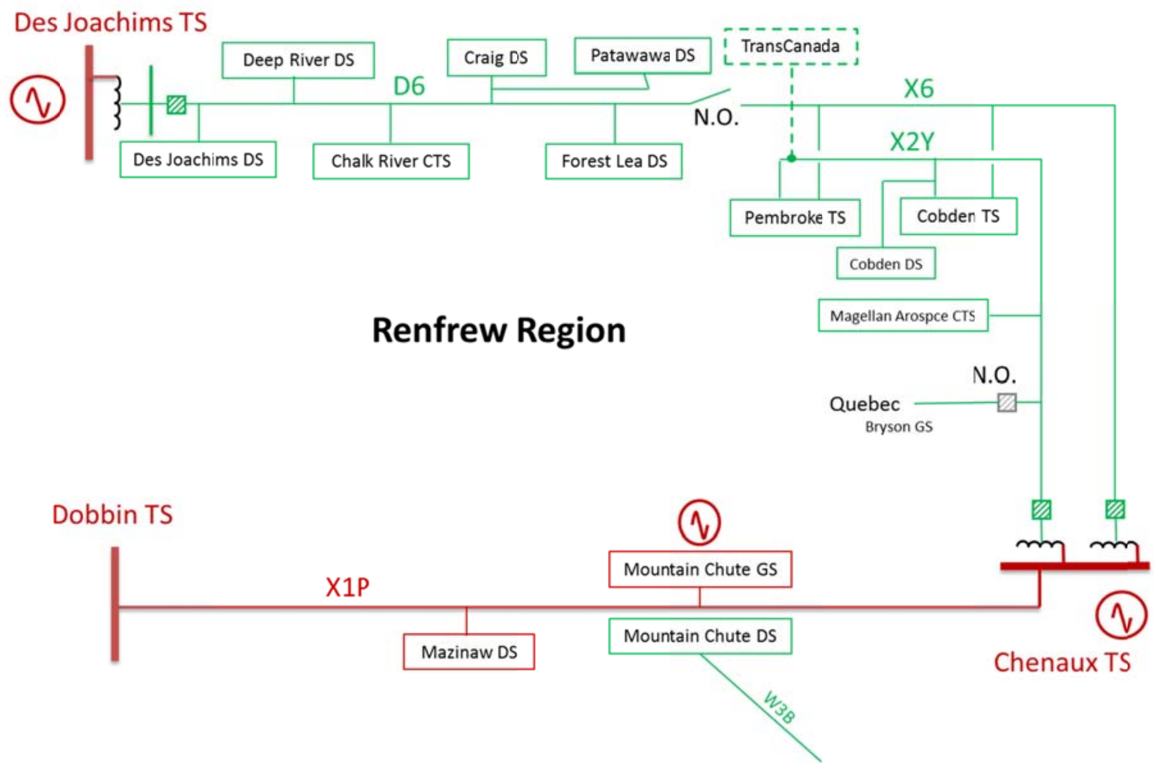

Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life for an in service date of end of 2016. This will also result in uprating the transformer capacity from 10MVA to 12.5MVA.
- Mountain Chute DS transformer will be replaced due to end-of-life with an in service date of end of 2016. This will also result in uprating the transformer capacity from 3MVA to 12.5MVA.
- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life with an in service date of end of 2018. The existing units are rated 78MVA and 115MVA respectively. The new T3/T4 will both have continuous rating of 125MVA. This is a transmission pool investment and LDCs are not expected to pay.
- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
    i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
    ii. List of existing reliability and operational issues
    iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. It is assumed that the loads at these two stations would not increase over the study period.
- Any relevant planning information, including planned transmission and distribution investments are provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC's load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year's coincidental peak load.

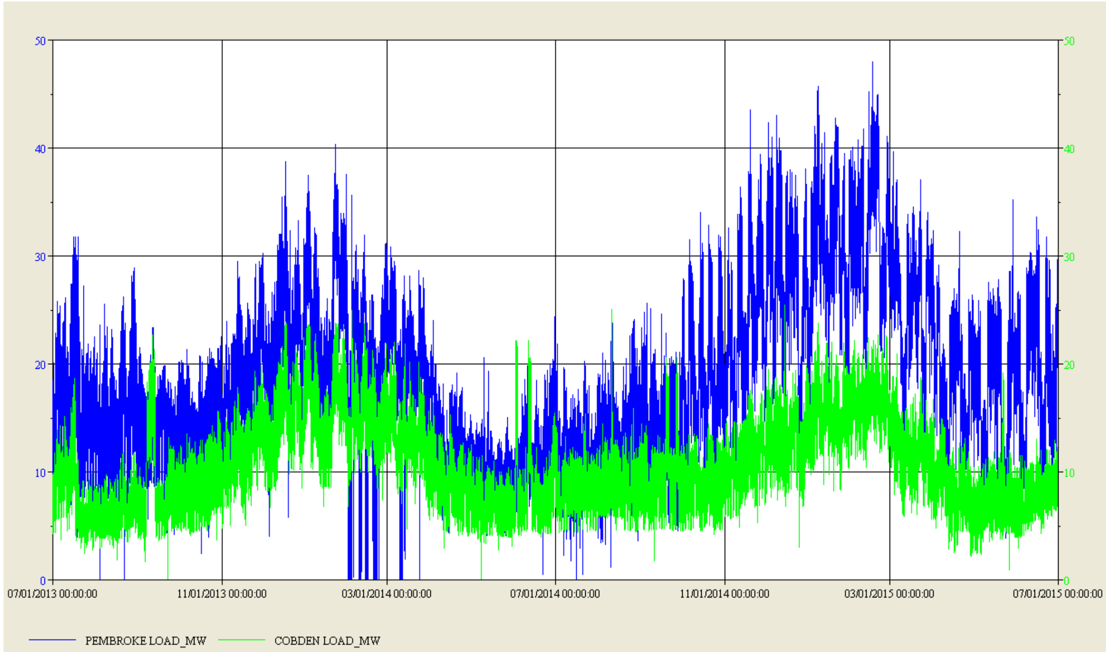

Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

   - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range. Projected coincidental peak loads are used in such assessment.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MW)	Transformer Rating/LTR* (MW)
Cobden DS	T3	7.2	11.3
Cobden TS	T1/T2	27.1	37.5
Craig DS	T1/T2	12.2	15.9
Deep River DS	T1/T2/T3	11.1	23.8
Des Joachims DS	T1	3.3	11.3
Forest Lea DS	T1/T2	9.2	9.9
Mazinaw DS	T1	3.4	5.4
Mountain Chute DS	T1	1.0	11.3
Pembroke TS	T1/T2	49.1	49.6
Petawawa DS	T1/T2	14.3	14.8
Chalk River CTS***		10	N/A
Magellan Aerospace CTS***		3.1	N/A
Chenaux TS	T3/T4	101.7**	112.5
Des Joachims TS	T6/T7	57.1	112.5

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.

The projected regional peak loads can be supplied even if the local generations at Des Joachims GS and Chenaux GS are out of service. In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit. .

6.2 System Reliability, Operation and Restoration Review

- The Region's total coincidental peak load is less than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- All loads are expected to be restored within 8 hours.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be

achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.

- Studies show that under this contingency, Des Joachims TS may not be able to radially supply all the loads in the Region, under peak load conditions.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storms, extended outages on D6 were experienced in the past (in 2011 for example). Further, outage analysis indicated that the most common cause for sustained outages was under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. As a result, improved vegetation management and outage responses have effectively reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact
2011	4	7792	Tree Contact

Studies show that under D6 terminal outage at the Des Joachims terminal, load can be restored by transferring D6 to Chenaux TS 115kV via X6 supply. Note, there is a maximum limit of 125 MW, which is the peak regional load in 2015, that can be supplied radially from Chenaux.

a) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Hydro One and the LDCs will continue to monitor and assess the load restoration performance under X1P and D6 outages.

- Major Hydro One facilities and equipment are continually monitored to ensure their safe and reliable operation. Circuit X1P is one of these facilities and, as such, its performance is monitored by Hydro One's Ontario Grid Control Centre (OGCC) in Barrie. OGCC's records will be reviewed regularly to ascertain the adequate performance of this circuit. The next planning cycle will take place in five years however, if the performance of X1P fall below adequate levels the Hydro One will undertake to assess and address this issue with the LDCs.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

> No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region. Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: January 2016 – June 2017
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A. LOAD FORECAST

Table A-1: Station Net Load Forecast (MW)

Transformer Station Name	Rating (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	11.3	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.2
Cobden TS T1/T2	37.5	25.8	25.9	26.0	26.0	26.2	26.5	26.6	26.8	26.9	27.1
Craig DS T1/T2	15.9	11.2	11.3	11.3	11.4	11.6	11.7	11.9	12.0	12.1	12.2
Deep River DS T1/T2/T3	23.8	10.9	11.0	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1
Des Joachims DS T1	11.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Forest Lea DS T1/T2	9.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2
Mazinaw DS T1	5.4	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4
Mountain Chute DS T1	11.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Pembroke TS T1/T2	49.6	46.0	46.3	46.5	46.7	47.1	47.6	48.0	48.3	48.7	49.1
Petawawa DS T1/T2	14.8	12.8	13.1	13.2	13.4	13.6	13.8	13.9	14.1	14.2	14.3

Table A-2: Regional Coincidental Net Load Forecast (MW)

Transformer Station Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Cobden TS T1/T2	25.5	25.5	25.7	25.8	25.9	26.1	26.3	26.5	26.8	27.1
Craig DS T1/T2	11.1	11.2	11.3	11.3	11.4	11.5	11.6	11.8	11.9	12.1
Deep River DS T1/T2/T3	10.8	10.7	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.0
Des Joachims DS T1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Forest Lea DS T1/T2	9.0	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.2	9.2
Mazinaw DS T1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Mountain Chute DS T1	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS T1/T2	38.7	38.9	39.3	39.6	39.9	40.3	40.8	41.3	42.0	42.6
Petawawa DS T1/T2	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Total Regional Load	125.2	127.2	128.0	128.2	128.6	129.3	130.3	131.4	132.7	133.8

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Renfrew Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

The Renfrew Region consists of Renfrew County and it is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast.

The Needs Assessment ("NA") report for the Renfrew region was completed in March, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time although circuit X1P is nearing its capacity and will be monitored on a regular basis over the next three to five years.

There are no other major development projects planned for the Renfrew Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB, the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the Renfrew Region.

The next regional planning cycle for the region is expected to be undertaken in five years from the start of this planning cycle (2015) or earlier if there is a new need emerging in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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NEEDS ASSESSMENT REPORT

Region: Renfrew

Revision: Final
Date: March 11, 2016

Prepared by: Renfrew Study Team

Transmission

Distribution

Peterborough to Renfrew Region Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Renfrew Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	March 11, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Renfrew Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Renfrew Region belongs to Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 11, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment 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.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period under normal and single contingency condition.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.

System Reliability, Operation and Restoration Needs

There are no transmission system reliability issues and no operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

All load within the region can typically be restored within eight hours as per the ORTAC requirement for loads under 150 MW.

In recent years, maintenance activity in the region with respect to vegetation management has been enhanced resulting in an improvement in reliability and/or load restoration.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities. Further details of these investments can be found in Section 3.2 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows:

- Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

- No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Renfrew Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Renfrew Region Needs Assessment study team. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 4, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region. The 2014 peak load in this Region was 124 MW.

The electricity supply to the region is mainly through one 230kV circuit X1P and three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). 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 roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

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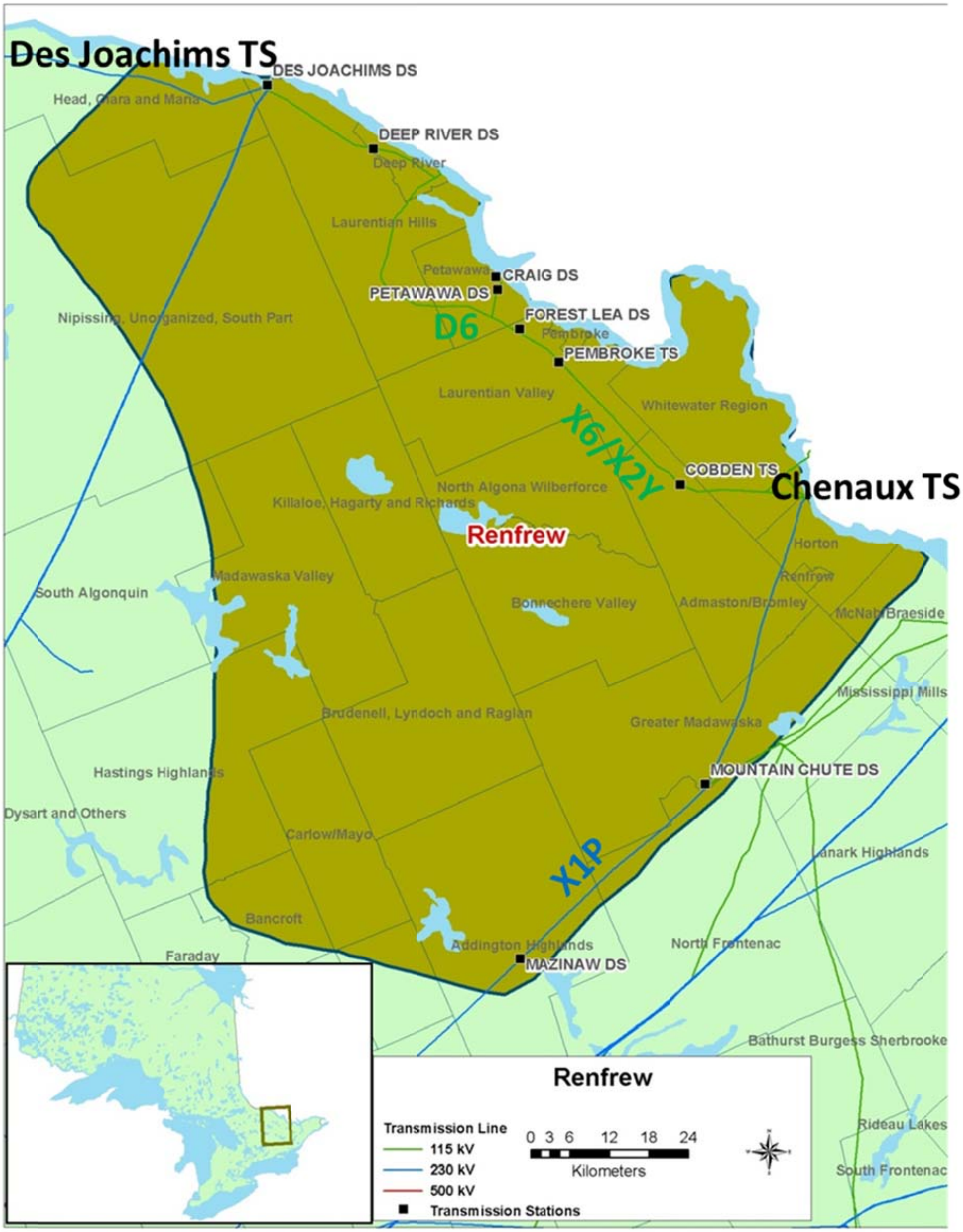


Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des 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 Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker

- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units 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 Chalk River Customer Transformer Station (CTS).

- All the 115kV circuits X6/X2Y/D6, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- 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 DS typically has load less than 1MW.

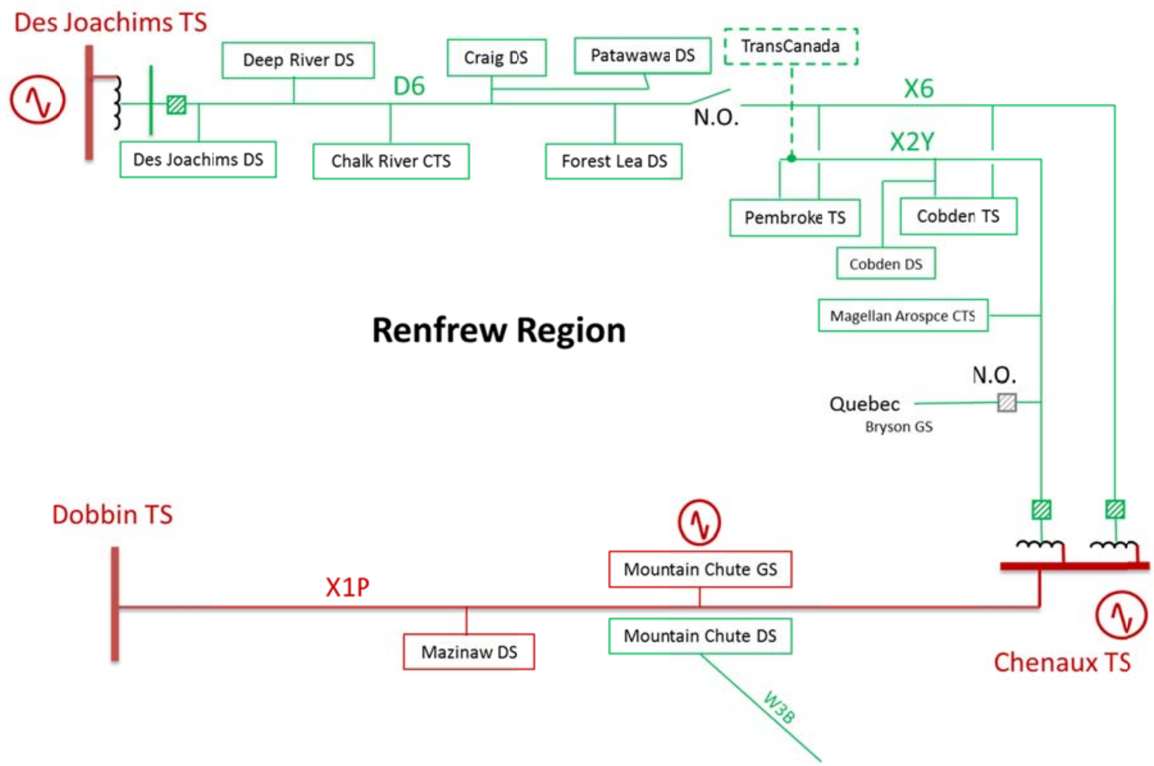


Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life for an in service date of end of 2016. This will also result in uprating the transformer capacity from 10MVA to 12.5MVA.
- Mountain Chute DS transformer will be replaced due to end-of-life with an in service date of end of 2016. This will also result in uprating the transformer capacity from 3MVA to 12.5MVA.
- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life with an in service date of end of 2018. The existing units are rated 78MVA and 115MVA respectively. The new T3/T4 will both have continuous rating of 125MVA. This is a transmission pool investment and LDCs are not expected to pay.
- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
  i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. It is assumed that the loads at these two stations would not increase over the study period.
- Any relevant planning information, including planned transmission and distribution investments are provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC's load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year's coincidental peak load.

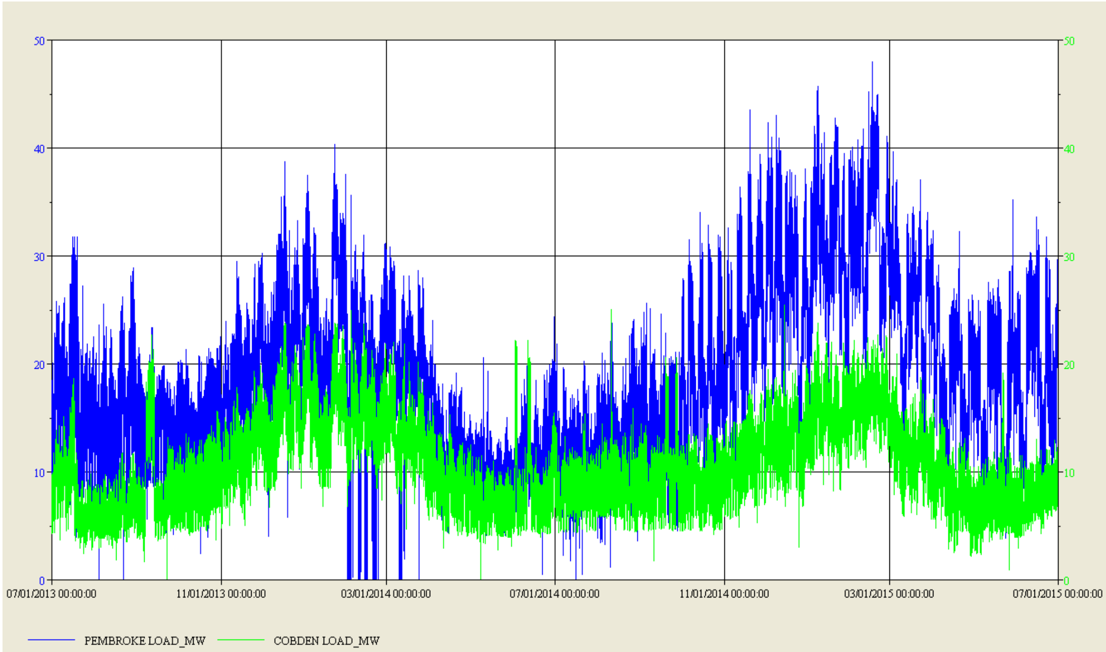


Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

   - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range. Projected coincidental peak loads are used in such assessment.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MW)	Transformer Rating/LTR* (MW)
Cobden DS	T3	7.2	11.3
Cobden TS	T1/T2	27.1	37.5
Craig DS	T1/T2	12.2	15.9
Deep River DS	T1/T2/T3	11.1	23.8
Des Joachims DS	T1	3.3	11.3
Forest Lea DS	T1/T2	9.2	9.9
Mazinaw DS	T1	3.4	5.4
Mountain Chute DS	T1	1.0	11.3
Pembroke TS	T1/T2	49.1	49.6
Petawawa DS	T1/T2	14.3	14.8
Chalk River CTS***		10	N/A
Magellan Aerospace CTS***		3.1	N/A
Chenaux TS	T3/T4	101.7**	112.5
Des Joachims TS	T6/T7	57.1	112.5

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.

The projected regional peak loads can be supplied even if the local generations at Des Joachims GS and Chenaux GS are out of service. In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit. .

6.2 System Reliability, Operation and Restoration Review

- The Region's total coincidental peak load is less than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- All loads are expected to be restored within 8 hours.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be

achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.

- Studies show that under this contingency, Des Joachims TS may not be able to radially supply all the loads in the Region, under peak load conditions.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storms, extended outages on D6 were experienced in the past (in 2011 for example). Further, outage analysis indicated that the most common cause for sustained outages was under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. As a result, improved vegetation management and outage responses have effectively reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact
2011	4	7792	Tree Contact

Studies show that under D6 terminal outage at the Des Joachims terminal, load can be restored by transferring D6 to Chenaux TS 115kV via X6 supply. Note, there is a maximum limit of 125 MW, which is the peak regional load in 2015, that can be supplied radially from Chenaux.

a) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Hydro One and the LDCs will continue to monitor and assess the load restoration performance under X1P and D6 outages.

- Major Hydro One facilities and equipment are continually monitored to ensure their safe and reliable operation. Circuit X1P is one of these facilities and, as such, its performance is monitored by Hydro One's Ontario Grid Control Centre (OGCC) in Barrie. OGCC's records will be reviewed regularly to ascertain the adequate performance of this circuit. The next planning cycle will take place in five years however, if the performance of X1P fall below adequate levels the Hydro One will undertake to assess and address this issue with the LDCs.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region. Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: January 2016 – June 2017
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A. LOAD FORECAST

Table A-1: Station Net Load Forecast (MW)

Transformer Station Name	Rating (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	11.3	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.2
Cobden TS T1/T2	37.5	25.8	25.9	26.0	26.0	26.2	26.5	26.6	26.8	26.9	27.1
Craig DS T1/T2	15.9	11.2	11.3	11.3	11.4	11.6	11.7	11.9	12.0	12.1	12.2
Deep River DS T1/T2/T3	23.8	10.9	11.0	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1
Des Joachims DS T1	11.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Forest Lea DS T1/T2	9.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2
Mazinaw DS T1	5.4	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4
Mountain Chute DS T1	11.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Pembroke TS T1/T2	49.6	46.0	46.3	46.5	46.7	47.1	47.6	48.0	48.3	48.7	49.1
Petawawa DS T1/T2	14.8	12.8	13.1	13.2	13.4	13.6	13.8	13.9	14.1	14.2	14.3

Table A-2: Regional Coincidental Net Load Forecast (MW)

Transformer Station Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Cobden TS T1/T2	25.5	25.5	25.7	25.8	25.9	26.1	26.3	26.5	26.8	27.1
Craig DS T1/T2	11.1	11.2	11.3	11.3	11.4	11.5	11.6	11.8	11.9	12.1
Deep River DS T1/T2/T3	10.8	10.7	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.0
Des Joachims DS T1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Forest Lea DS T1/T2	9.0	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.2	9.2
Mazinaw DS T1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Mountain Chute DS T1	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS T1/T2	38.7	38.9	39.3	39.6	39.9	40.3	40.8	41.3	42.0	42.6
Petawawa DS T1/T2	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Total Regional Load	125.2	127.2	128.0	128.2	128.6	129.3	130.3	131.4	132.7	133.8

APPENDIX C – IESO LETTER

IESO response to Ottawa River Power Corporation's REG Investment Plan 2021 - 2025

In accordance with the Ontario Energy Board's (OEB) Chapter 5 filing requirements to submit a Distribution System Plan with its Cost of Service application, on July 10, 2020, Ottawa River Power Corporation ("ORPC") sent its Renewable Energy Generation (REG) Investment Plan (Plan) which forms part of the DSP, to the Independent Electricity System Operator (IESO). The IESO has reviewed ORPC's Plan and notes that it contains no investments specific to connecting REG for the Plan period 2021 - 2025.

The IESO confirms that ORPC is a member of the Working Group in the Renfrew Region along with Renfrew Hydro Inc. and Hydro One Networks Inc. (Hydro One) (Transmission and Distribution). ORPC participated in Hydro One's Needs Assessment which formed the basis for the Regional Infrastructure Plan (RIP) published in June 2016. The Need Assessment found that there were no needs that required regional coordination.[1]

ORPC's Plan identifies upstream capacity constraints at Hydro One Distribution-owned stations, but as it currently has no REG connections, and does not anticipate new REG applications over the Plan period, no investments are proposed.

The IESO submits that where a distributor has no REG investments during the 5-year Distribution System Plan period no letter is required of the IESO to address the bullets points in the OEB's **Filing Requirements for Electricity Distribution Rate Applications** - Chapter 5, section 5.2.2 Coordinated planning with third parties:

d) For REG investments a distributor is expected to provide the comment letter provided by the IESO in relation to REG investments included in the distributor's DSP, along with any written response to the letter from the distributor, if applicable. The OEB expects that the IESO comment letter will include:

- Whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO
- The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments
- Whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan

The IESO appreciates having had the opportunity to review ORPC's Plan and looks forward to working together when the next planning cycle commences.

[1] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/renfrew/Documents/RIP%20Report%20-%20Renfrew.pdf

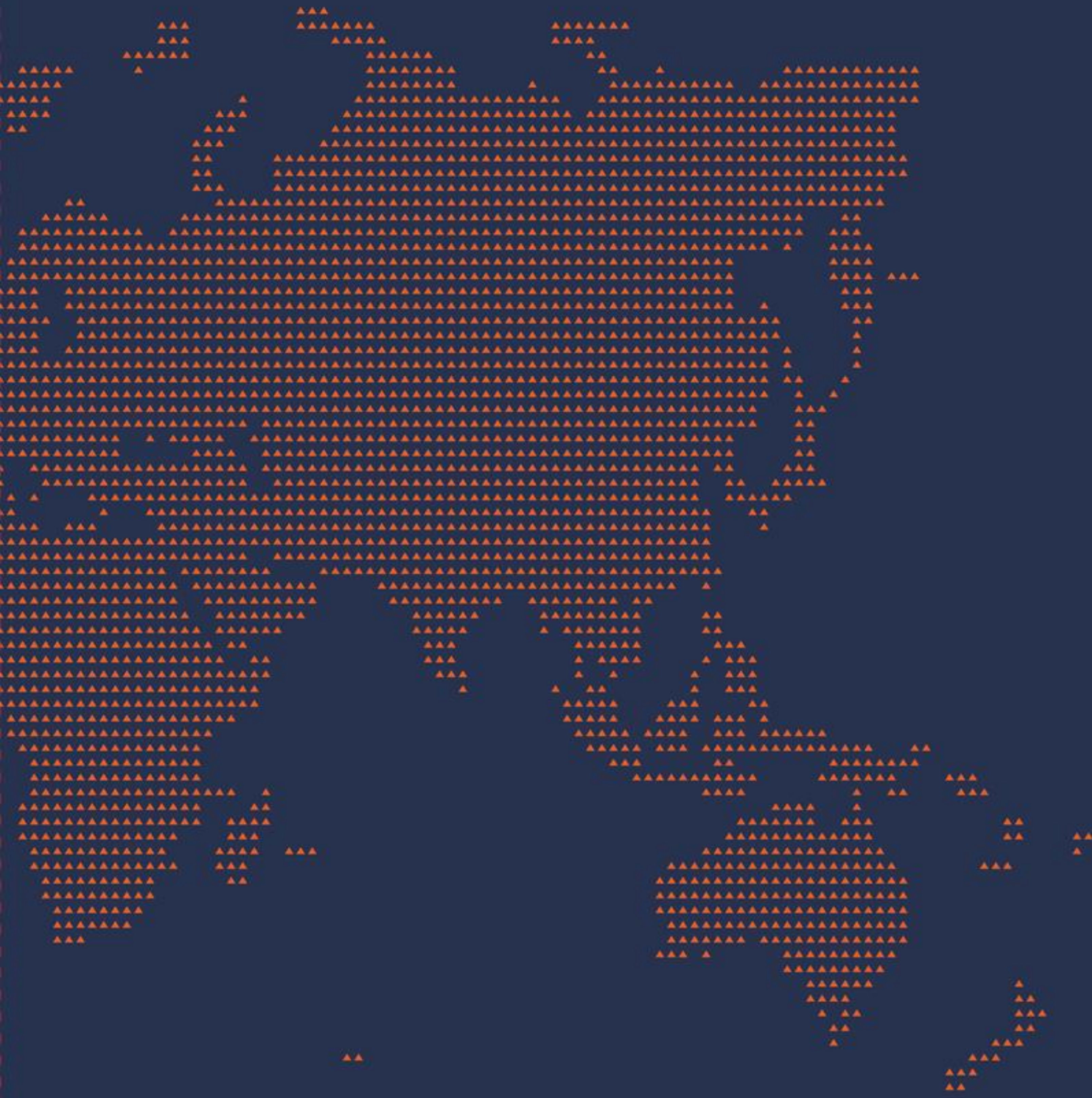
July 27, 2020

ieso
Connecting Today.
Powering Tomorrow.

APPENDIX D – ACA REPORT

METSCO

MAKING IT POSSIBLE



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ASSET CONDITION ASSESSMENT REPORT 2020

Prepared by

METSCO Report no. 19-189-001-F

August 2021

Disclaimer

This report was prepared by METSCO Energy Solutions Inc. ("METSCO") for the sole benefit of Ottawa River Power Corporation ("ORPC" or the Client), in accordance with the terms of the METSCO proposal and the Client Agreement.

Some of the information and statements contained in the Asset Condition Assessment ("ACA") are comprised of, or are based on, assumptions, estimates, forecasts and predictions and projections made by METSCO and ORPC. In addition, some of the information and statements in the ACA are based on actions that ORPC currently intends it will take in the future. As circumstances change, assumptions and estimates may prove to be obsolete, events may not occur as forecasted, predicted or projected, and ORPC may at a later date decide to take different actions to those it currently intends to take.

Except for any statutory liability which cannot be excluded, METSCO and ORPC will not be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using, or relying on any content of the ACA.

Asset Condition Assessment Report 2021

Final Report

August 2021

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Date	**Rev.**	**Status**	**By**	**Checked**	**Approval**

Executive Summary

Context of the Study

Ottawa River Power Corporation ("ORPC") is an electricity distributor operating a system made up of 11 substations and over 490 km of distribution lines delivering electricity to approximately 11,300 residential and commercial customers in the City of Pembroke, Beachburg, Killaloe, and Almonte Ward. ORPC engaged METSCO Energy Solutions Inc. ("METSCO") to prepare a comprehensive Asset Condition Assessment ("ACA") study for the assets comprising ORPC's distribution system. The ACA is required as one of the key inputs for the preparation of ORPC's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements for electricity distributors enacted by the Ontario Energy Board ("OEB").

Scope of the Study

METSCO's 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 METSCO assessed and calculated Health Index ("HI") values for the following asset classes:

- Poles
- Distribution Overhead Conductors
- Distribution Underground Cables
- Distribution Transformers
- Distribution Overhead Switches
- Station Power Transformers
- Station Circuit Breakers
- Station Protection Relays
- Station Overhead Switches
- Station Battery Banks

All asset condition data used in the study are maintained by ORPC as part of its regular asset management practices. The ACA results are based on condition data recorded by ORPC, its contractors and METSCO up to the end of December 2019. METSCO received ORPC's data between August of 2019 and March of 2020. In July 2021, ORPC began further pole inspection in the Pembroke area. The ACA for poles was updated with the updated pole data supplied as of July 30.

Methodology and Findings

For all asset classes that underwent assessment, METSCO 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 required by the asset manager at ORPC.

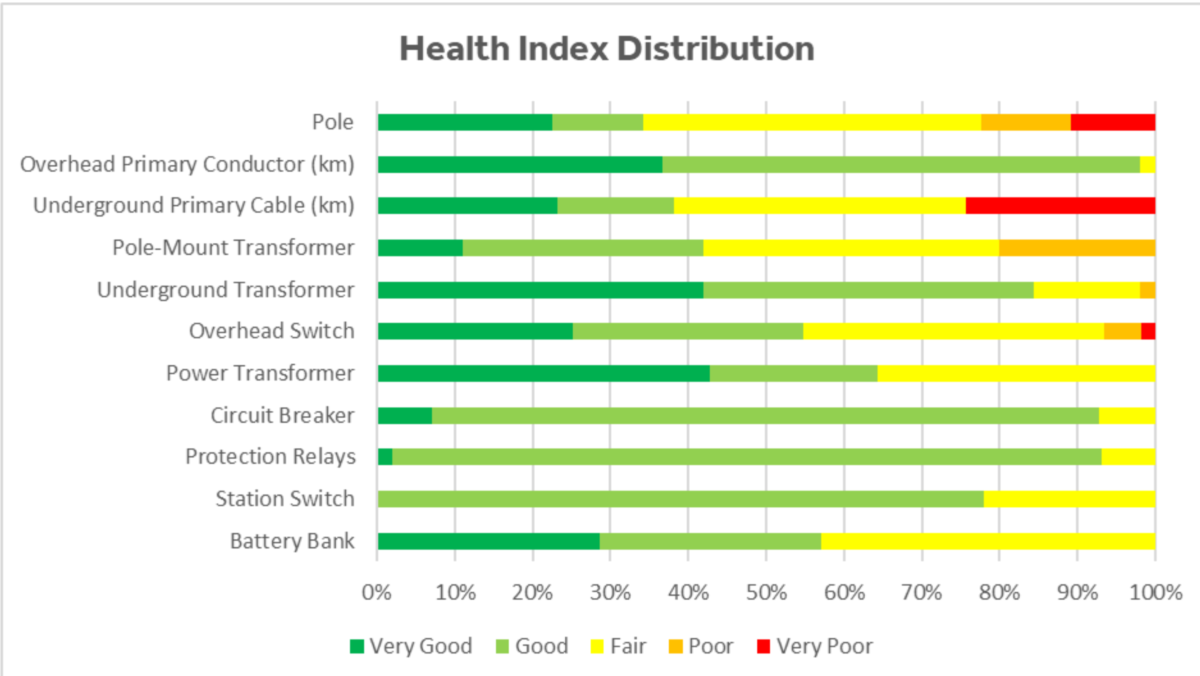
Table 0-1: HI Ranges and Corresponding Implications for the Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal 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

Using this scale, METSCO calculated HI for every asset in the scope of the assessment using the selected applicable and available "condition parameters"– individual characteristics of the state of an asset's components. Each condition parameter has a sub-scale assessment and a weighting contribution that represents the percentage in the overall HI made up by the particular parameter. METSCO's findings for each asset class were developed using this methodology, as described in more detail in Section 3 and Section 4.

The consolidated results of the ACA are summarized in Figure 0-1. The HI is not calculated for any distribution asset with a Data Availability Indicator ("DAI") less than 70% (i.e., less than 70% of the condition parameters – by weight – are available for that asset). The set of assets with unknown HI were extrapolated onto the known population.

Figure 0-1: Overall HI Results



As Figure 0-1 indicates, the majority of ORPC's distribution system falls into the condition category of Fair or better condition, with several specific asset classes containing units found to be in Poor and Very Poor condition – most notably underground cables and pole-mount transformers.

Table 0-2 presents the numerical HI summary for each asset class. The HI distribution is based on the total population count of a given asset class. For each asset class, the total population, average HI, average DAI, and the HI distribution are listed.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	HI Distribution (%)					Average Health HI	Average DAI
		Very Good	Good	Fair	Poor	Very Poor		
Distribution Assets								
Pole	4084	22.57%	11.73%	43.33%	11.58%	10.80%	62.52%	85.43%
Overhead Primary Conductor	150.0 km	36.67%	61.33%	2.00%	0.00%	0.00%	57.21%	86.03%
Underground Primary Cable	41.4 km	19.56%	15.01%	37.54%	0.00%	27.89%	55.76%	84.24%
Pole-Mount Transformer	1060	11.04%	30.85%	38.11%	20.00%	0.00%	62.23%	82.79%
Underground Transformer	367	41.96%	42.51%	13.62%	1.91%	0.00%	80.65%	58.68%
Overhead Switch	334	25.15%	29.64%	38.62%	4.79%	1.80%	69.65%	91.17%
Station Assets								
Power Transformer	14	42.86%	21.43%	35.71%	0.00%	0.00%	76.09%	100.00%
Circuit Breaker	42	7.14%	85.71%	7.14%	0.00%	0.00%	75.35%	78.23%
Protection Relay	101	1.98%	91.09%	6.93%	0.00%	0.00%	77.60%	100.00%
Station Switch	50	0.00%	78.00%	22.00%	0.00%	0.00%	73.65%	77.45%
Battery	7	28.57%	28.57%	42.86%	0.00%	0.00%	71.73%	96.43%

ORPC's Current Health Index Maturity and Continuous Improvement

While ORPC's existing framework provides a significant volume of data, certain procedural and technological enhancements could further enhance the granularity of this data as well as the asset condition results and facilitate calculation of a greater proportion of numerical degradation scores. To this end, Section 6 of this study includes a set of METSCO's recommendations for incremental data collection enhancements that ORPC can consider going forward based on its assessment of their relative cost-benefit tradeoffs. METSCO prioritized the individual items according to the significance of the additional insights they would enable ORPC to generate.

METSCO recommends ORPC to begin collecting and keeping condition records consistent for all assets across the service area with a more granular inspection scale. This will establish a stronger baseline of the asset health indices rather than being primarily dependent on age. METSCO also recommends ORPC to store condition records, such as inspection and testing results, in a common database to facilitate the process of identifying assets in need of replacement.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of ageing infrastructure, changing climate, evolving customer needs, and many other priorities. As such, adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

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1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an industry expert in Asset Condition Assessment ("ACA") and Asset Management ("AM") practices due to our extensive experience in conducting ACAs, developing AM plans, and implementing AM frameworks for transmission and distribution utilities across North America. METSCO'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. A selection of METSCO's past projects is attached as Appendix A to this report.

Ottawa River Power Corporation ("ORPC") is an electricity distributor operating in the City of Pembroke, Beachburg, Killaloe, and Almonte Ward. ORPC engaged METSCO to prepare a comprehensive ACA study for the assets comprising ORPC's electrical system. The ACA is required as one of the key inputs for the preparation of ORPC's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to objectively determine the condition of ORPC's assets as a key step in the capital expenditure process for renewal investments. Supplementary objectives include preparing the ACA results to be used for ORPC's upcoming rate filing as well as to continuously improve ORPC's AM framework.

A unique ACA methodology is applied to each asset class deployed within ORPC's system. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections and recording of asset condition to identify the assets most at risk at reaching the end-of-life criteria over the planning horizon. Each criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life.

The report covers the following major asset classes:

- Poles
- Distribution Overhead Conductors
- Distribution Underground Cables
- Distribution Transformers
- Distribution Overhead Switches
- Station Power Transformers
- Station Circuit Breakers
- Station Protection Relays
- Station Overhead Switches

- Station Battery Banks

All the asset condition data is maintained by ORPC as part of its regular AM and maintenance practice. All condition information was collected by ORPC, its contactors and METSCO up to the end of December 2019. This data was transmitted to METSCO between August 2019 and March 2020 to complete the ACA. In July 2021, ORPC began further pole inspection in the Pembroke area. The ACA for poles was updated with the updated pole data supplied as of July 30.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the ISO 5500X standards, discusses how the ACA fits into the overall AM framework; and provides an overview of METSCO's ACA methodology;
- Section 3 summarizes the asset Health Index ("HI") calculation methodology;
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes;
- Section 5 provides METSCO's conclusions; and
- Section 6 summarizes METSCO's recommendations for ORPC on data collection improvements for continuous improvement efforts for the ACA.

2 Context of the ACA within AM Planning

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework to objectively quantify and manage the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

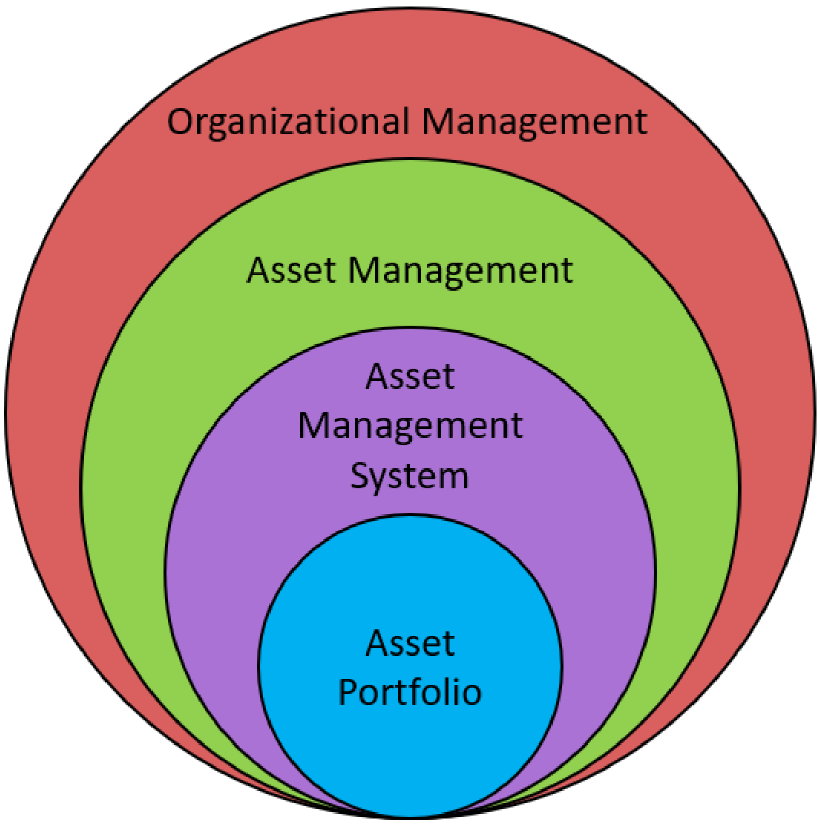
An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. The ACA

[1] ISO 55000 – Asset management – Overview, principles and terminology

is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy. [1]

Figure 2-1: Relationship between key AM terms[1]



2.2 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to: the collection and storage of technical specifications, historical asset performance, projected asset behaviour and degradation, the configuration of an asset or asset-group within the system, the operational relationship of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process it to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to best AM practices being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented.[2] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact of the decision-making process.

2.3 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical experts, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization as a whole. 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

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

specific use case. Distribution of the SAMP should be well-publicized within an organization and updated regularly, 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]

AM should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

3 Asset Condition Assessment Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study is divided into four phases:

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 single database of condition-related information for each ORPC asset class using the provided data sources. This includes consolidation of ORPC's asset inspection records, databases containing results of technical tests performed by ORPC contractors, and the entire database from the Geographic Information System ("GIS").

3. *HI and Data Availability Index ("DAI") Calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO 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 if applicable.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3.2 Data Sources

To assess the demographics and establish the unit population of ORPC's distribution system assets, METSCO was provided with ORPC's geospatial data from their current GIS. These data inputs were captured from ORPC's corporate asset registries containing information on asset vintage, model and year of commissioning. The database served as the primary asset library that contained asset nameplate information such as age and unique identifiers.

To assess the condition of ORPC's system, METSCO was provided with available asset inspection and maintenance data for asset classes in scope. Most of this data came from primary sources such as equipment inspection forms completed by ORPC staff or contractors or results of specific technical tests, such as the Dissolved Gas Analysis ("DGA") for station power transformer oil.

3.3 Asset Condition Assessment Methodologies

Before completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. Additive models – asset degradation factors and scores are used to independently calculate a score for each asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents which are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of ORPC's peer utilities.

3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To calculate the overall HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1 exemplifies of a HI formulation table.

Figure 3-1: HI Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the "oil quality" condition parameter for a station power transformer is based on multiple sub-conditions parameters like "acid number", "interfacial tension", "dielectric strength" and "water content".

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4 Best Condition
B – 3 Normal Wear
C – 2 Requires Remediation
D – 1 Rapidly Deteriorating
E – 0 Beyond Repair

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating the asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected over time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO limits the instances where it relies on only age as a parameter explicitly incorporated into the HI formulation. In some cases, however, the limited number of condition parameters available for calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing the condition of complex equipment containing several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.4.3 Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through the identification of condition parameters acknowledged being critical indicators of overall asset health.

3.4.4 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also 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 degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with Health Indices between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating a HI provides a succinct measure of the long-term health of an asset. Table 3-1 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 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal 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

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number and *α* is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter 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. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are extrapolated onto the subset of assets with a valid HI within the same asset class.

4 Health Index Formulations and Results

This section presents the developed HI formulation for each asset class, the calculated HI results, as well as the data available to perform the study.

4.1 Distribution Assets

4.1.1 Pole

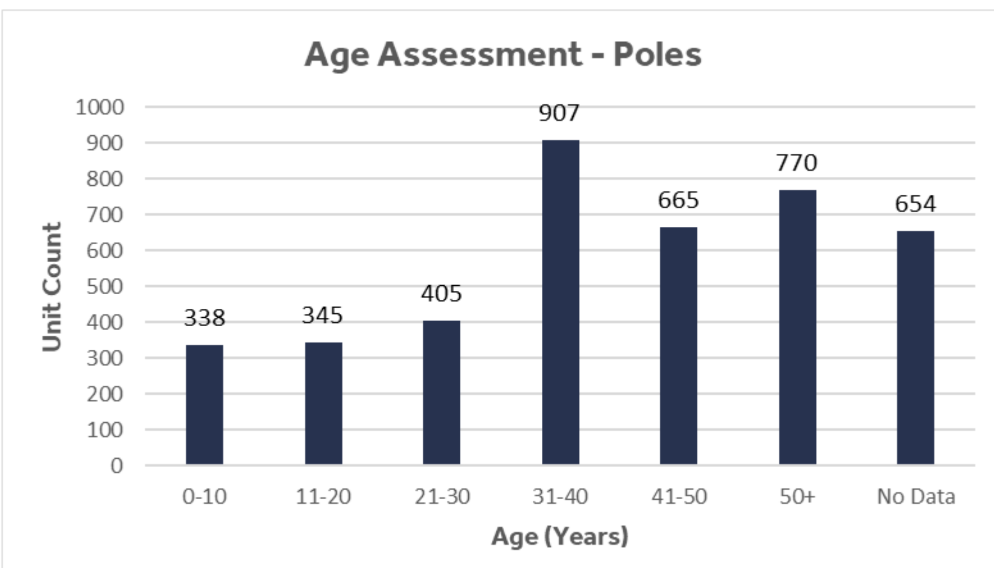
Poles are an integral part of any distribution system. They support the structures for the overhead distribution system. They are often found with installed assets such as overhead transformers, switches, reclosers, and streetlights. Poles under this assessment are made of wood, steel, and concrete. The HI for poles is calculated by considering a combination of end-of-life criteria summarized in Table 4-1.

Table 4-1: Pole HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	4	A,C,E	4,2,0	16
			Total Score	**28**

Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Aside from service age, visual inspection is another condition parameter to be considered. Visual inspections note defects, such as holes in wood poles or rusting in steel and concrete poles, as well as evidence of leaning.

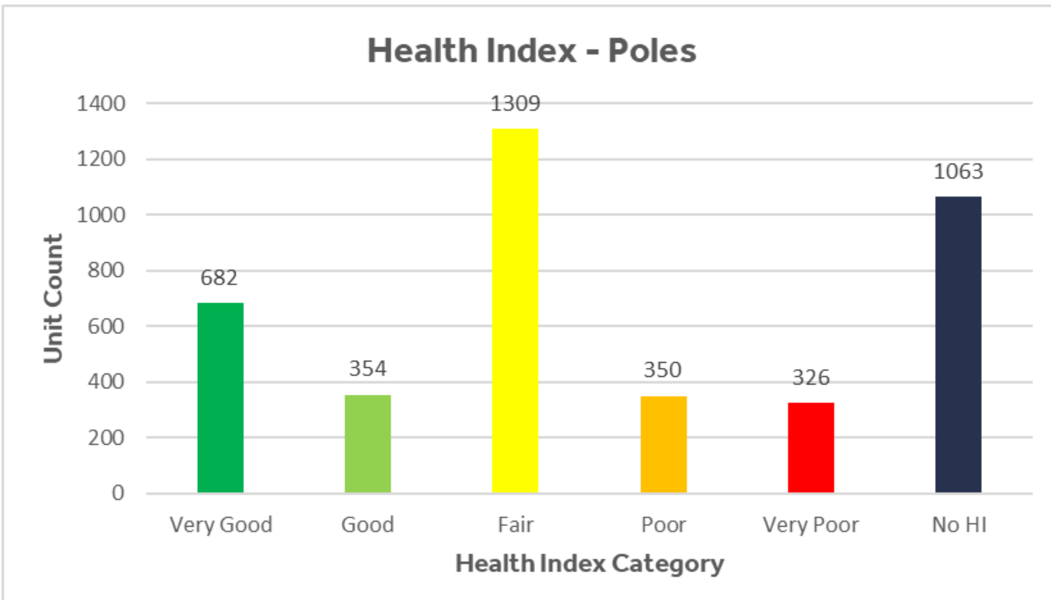
Figure 4-1: Poles Age Demographics



ORPC owns 4,084 poles within its service territory. The installation date is unknown for approximately 16% of the total in-service population. Figure 4-1 presents the age distribution for in-service poles.

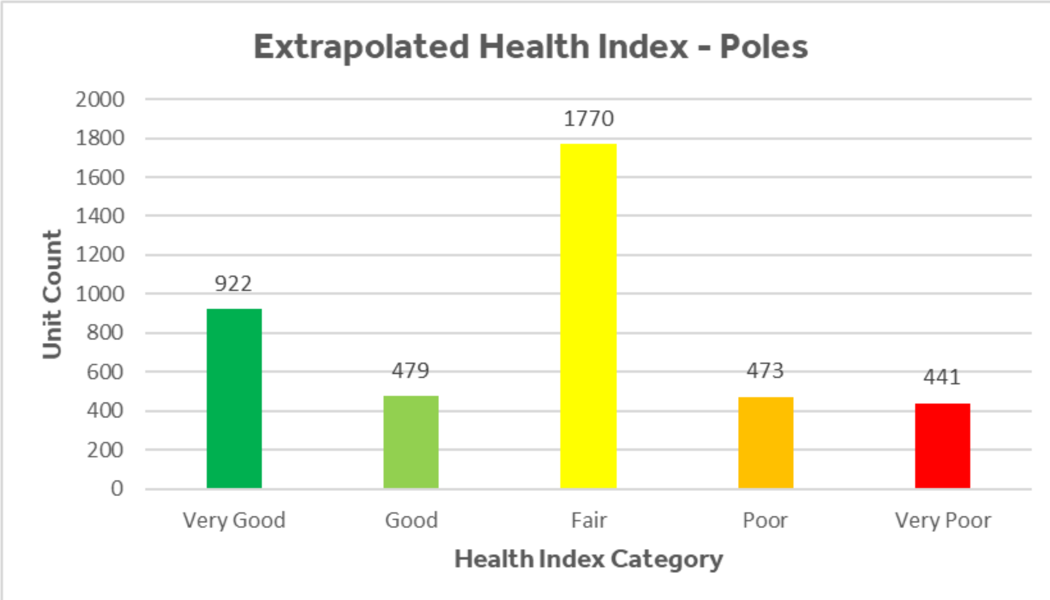
ORPC's pole inspection and nameplate data were used to calculate the HI based on the criteria provided in Table 4-1. ORPC are conducting pole inspections in the Pembroke area in 2021 and the inspection data as of July 30, 2021 are reflected in the HI results. As shown in Figure 4-2, a valid HI was calculated for 74% of the poles.

Figure 4-2: Poles HI Results



To complete the full analysis, the HI for the remaining 26% of the population has been extrapolated based on the HI distribution of the asset population with a valid Health Index score. The overall extrapolated HI distribution for the poles is presented in Figure 4-3. Approximately 34% of the poles are in Very Good or Good condition with approximately 43% of the poles being in Fair condition. Approximately 22% of the poles are in Poor or Very Poor condition. The average HI for the poles is 63% (Fair).

Figure 4-3: Extrapolated Pole HI Results



The average DAI across the wood pole asset class is 85%. Table 4-2 presents the DAI of each condition parameter used for the pole HI framework.

Table 4-2: Distribution Wood Poles condition parameters data availability

Condition Parameter	% of Assets with Data
Age	84%*
Visual Inspection	87%

**Note: Estimated service age included*

4.1.2 Overhead Conductor

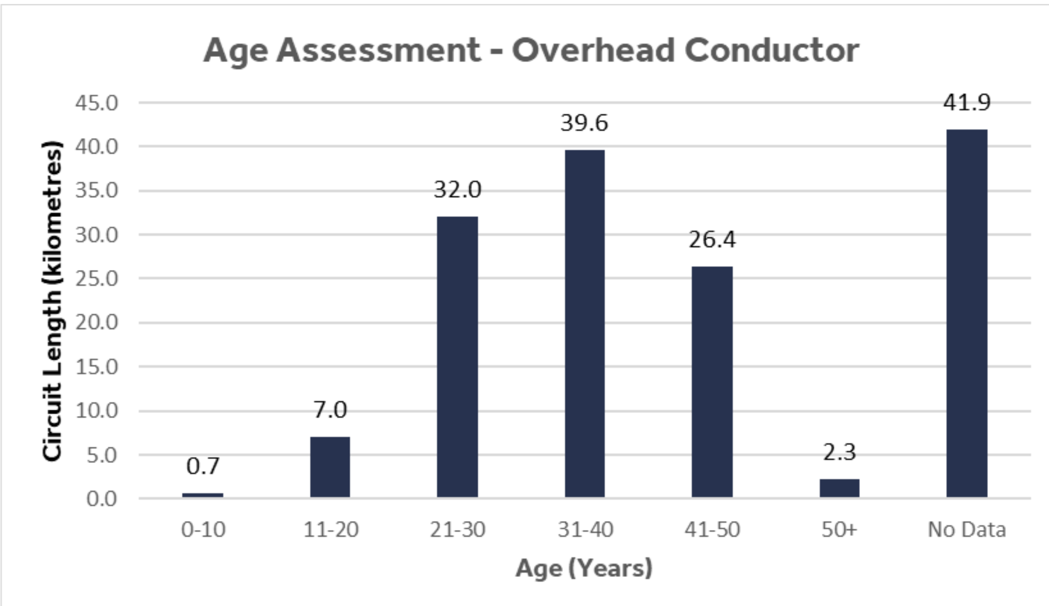
Overhead conductors transmit electricity from substations to customer premises and are supported by poles. Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age. In addition to age, an undersized conductor is the additional condition parameter used to evaluate the HI of overhead conductors. Undersized conductors carrying large loads can result in sub-optimal system operation due to high line losses and are susceptible to frequent breakdowns. The HI formulation for overhead conductors is summarized in Table 4-3.

Table 4-3: Overhead Primary Conductor HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Small Conductor Risk	5	A,E	4,0	20
			Total Score	**40**

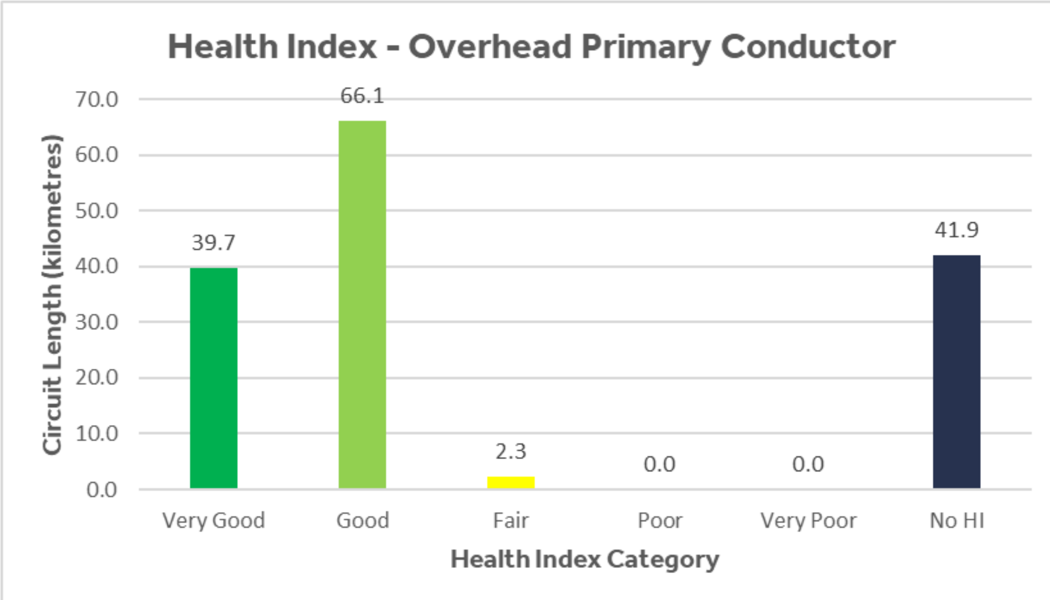
ORPC owns approximately 150 km of overhead primary conductor within its service territory. The installation date was unknown for the entire population. The average age of assets on the same street was used to estimate the age of the conductors. The applied assumption for the service age of assets was used in the HI calculation and was confirmed with ORPC. Figure 4-4 presents the overall overhead primary conductor age demographics.

Figure 4-4: Overall Overhead Primary Conductor Age Demographics



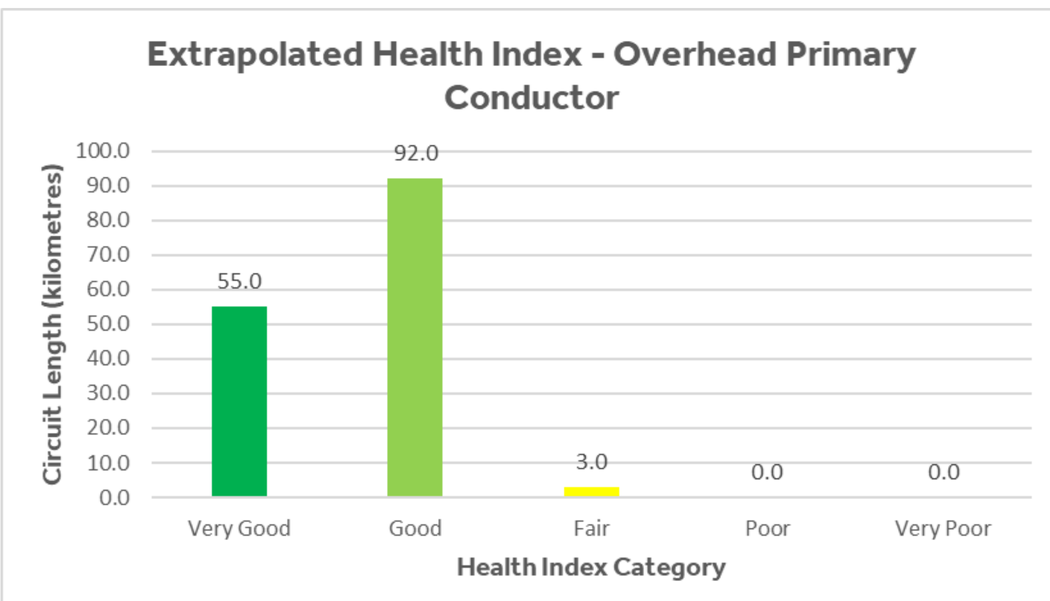
The overall HI for overhead primary conductor is illustrated in Figure 4-5. A valid HI was calculated for 72% of the conductor, using the extrapolated age results.

Figure 4-5: Overhead Conductor HI Results



To complete the full analysis, the remaining 28% of the population has been extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 4-6, the majority of the conductors are in Very Good and Good condition with less than 3% in Fair condition. The average HI for overhead primary conductor is 79% (Good).

Figure 4-6: Extrapolated Overhead Primary Conductor HI Results



The average DAI across the overhead primary conductor asset class are 86%. Table 4-4 presents the DAI of each condition parameter used for the overhead primary conductor HI calculation.

Table 4-4: Overhead Primary Conductor condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	72%*
Small Conductor Risk	100%

**Note: Estimated service age included*

4.1.3 Underground Cable

Like overhead conductors, underground cables also transmit electricity within the electrical distribution system, however, they are located below ground. Compared to overhead lines, they can be more reliable since they are not exposed to severe weather conditions, tree contacts or foreign interference. However, distribution underground cables are more expensive and are one of the more challenging assets in electricity systems from a condition assessment and AM viewpoint. Several test techniques, such as partial discharge ("PD") and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. Accordingly, the preference is given to non-destructive testing.

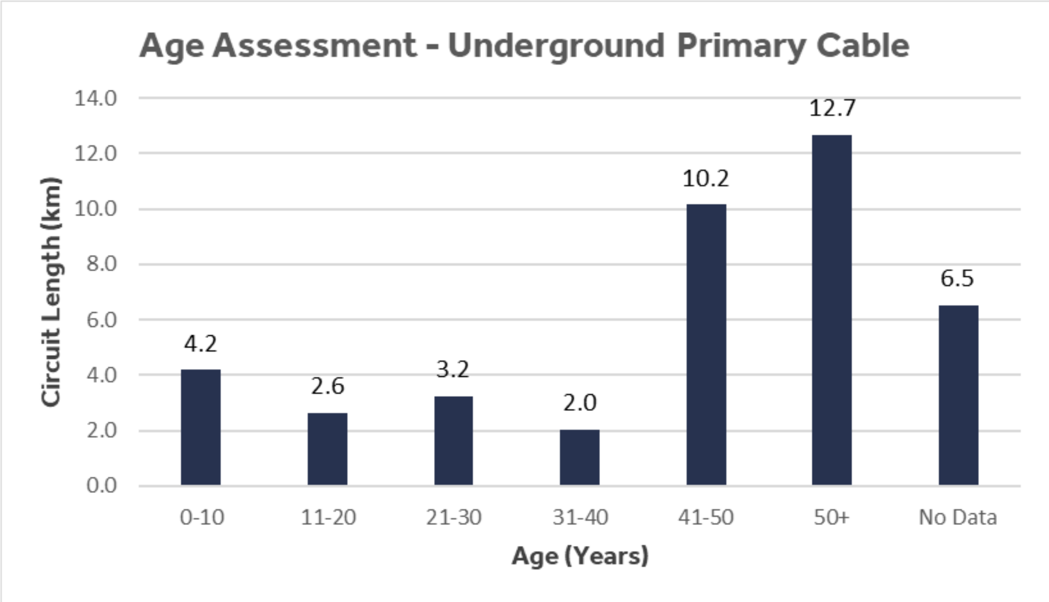
Table 4-5 summarizes the methodology to combine these criteria into an overall HI. In the absence of test results, a cable age can be used as a proxy for medium-term and long-term planning to predict quantities of cables that are expected to reach end-of-life.

Table 4-5: Underground Cable HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**16**

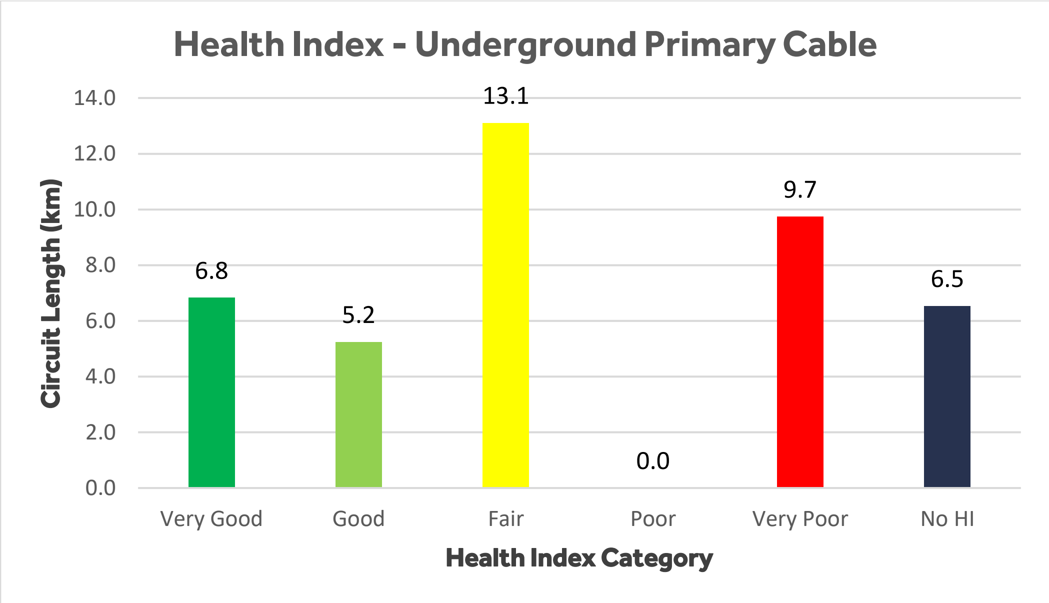
ORPC owns approximately 41 km of underground primary cable within its service territory. The installation date was unknown for all the underground primary cables. An assumption was made to use the average age of assets on the same street as a proxy and confirmed with ORPC. 84% of the population were assigned with an estimated age. The estimated age was used in the HI calculation. Figure 4-7 presents the underground primary cable age demographics.

Figure 4-7: Underground Cable Age Demographics



As presented in Figure 4-8, a valid HI was calculated for 84% of the underground primary cable, using the estimated age.

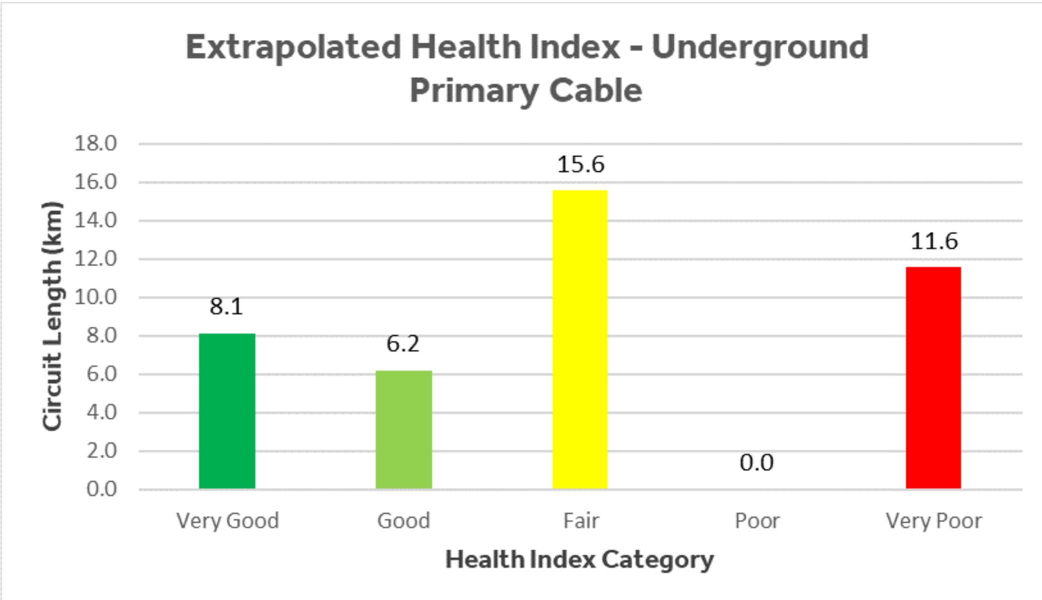
Figure 4-8: Underground Primary Cable IH Results



To complete the full analysis, the HI for the remaining 16% of the population has been extrapolated based on the HI distribution of the asset population with a valid HI score.

Most of the underground primary cables are in Very Good and Good condition with approximately 25% of the population in Very Poor condition, illustrated in Figure 4-9. The average HI for overhead primary cables is 56% (Fair).

Figure 4-9: Extrapolated Underground Primary Cable HI Results



4.1.4 Distribution Overhead (Pole-Mount) Transformer

Overhead (pole-mount) transformers are installed on poles above ground with the primary function to step down power from the medium voltage distribution system to the voltage rating for customer use. The HI for pole-mount transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-6. In addition to service age, visual inspection was used as a condition parameter to identify any of the following defects:

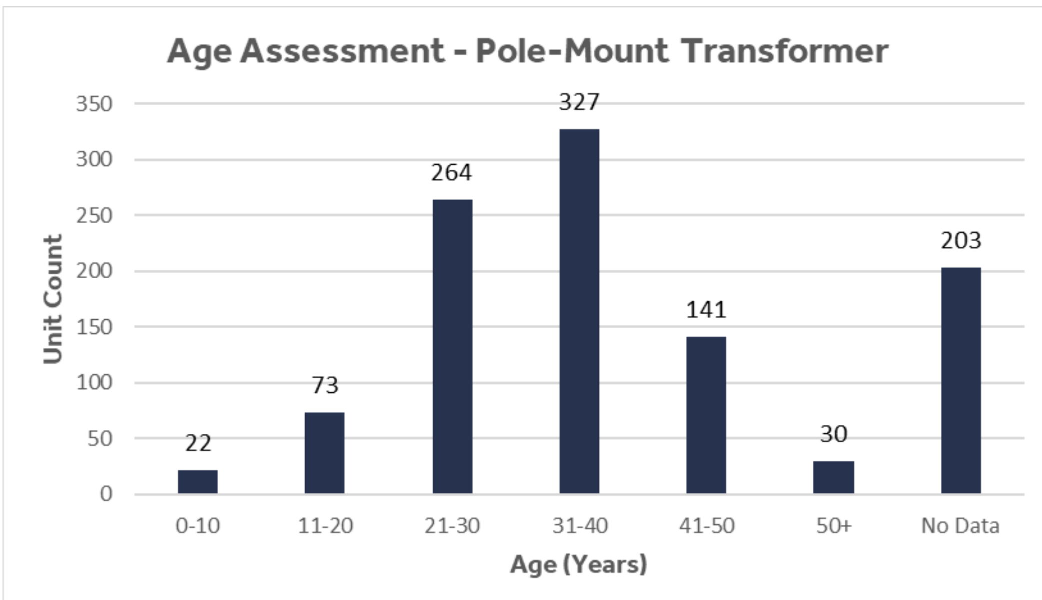
- Contamination/discoloration of bushings
- Leaking oil
- Tank corrosion/rust
- Ground lead attachments
- Ground wires unattached

Table 4-6: Pole-Mount Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	3	A,C,E	4,2,0	12
			Total Score	**24**

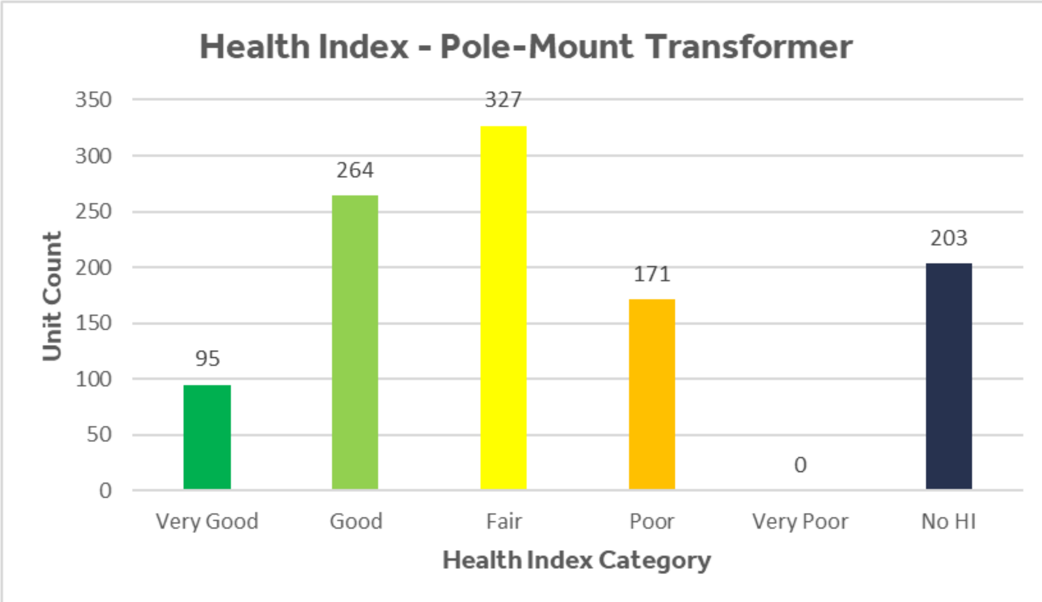
ORPC owns 1,060 pole-mount transformers within its service territory. GIS recorded installation dates for 8% of the asset population. Where the installation date was unknown, the average asset age for all assets on the same street was used to approximate the transformer age. The applied assumption for the service age was used in the HI calculation and was confirmed with ORPC. Figure 4-10 presents the age distribution for pole-mount transformers.

Figure 4-10: Pole-Mount Transformer Age Demographics



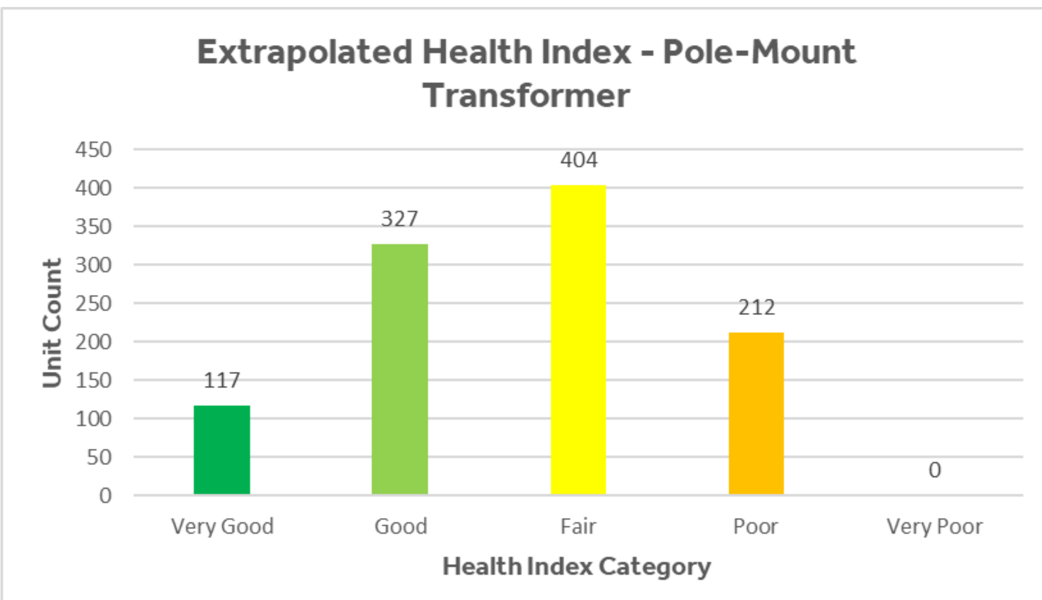
ORPC's transformer nameplate information and maintenance records were used to calculate the HI based on the criteria provided in Table 4-6. As shown in Figure 4-11, a valid HI was calculated for 81% of the pole-mount transformers, using the estimated age.

Figure 4-11: Pole-Mount Transformers HI Results



To complete the full analysis, the HI for the remaining 19% of the population has been extrapolated based on the HI distribution of the asset population with a valid HI score. The overall HI distribution is presented in Figure 4-12 for the pole-mount transformers. The average HI of the pole-mount transformers is 62% (Fair).

Figure 4-12: Extrapolated Pole-Mount Transformers HI Results



The average DAI for the condition parameters for pole-mount transformers is 83%. Table 4-7 presents the DAI of each condition parameter used for the pole-mount transformer HI calculation.

Table 4-7: Pole-Mount Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	81%*
Visual Inspection	85%

**Note: Estimated service age included*

4.1.5 Distribution Underground Transformer

Distribution underground transformers are utilized for similar functionalities as pole-mount transformers. They step down power from the medium voltage distribution system to the final utilization voltage for customers. Two types of underground distribution transformers are assessed within this report:

- Pad-mount transformer
- Vault transformer

Table 4-8: Underground Transformer HI Formulation

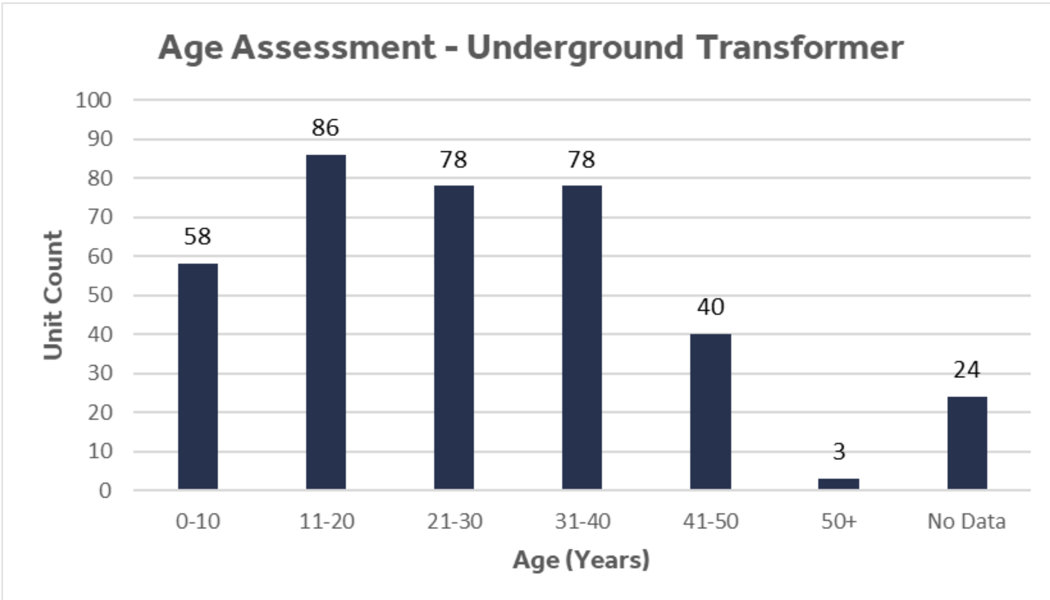
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	4	A,C,E	4,2,0	16
Condition of the Civil Structure	4	A,C,E	4,2,0	16
			Total Score	**44**

The Health Index for underground distribution transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-8. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur.

Visual inspections identify the presence of oil leaks, rust, and poor connections on the underground transformers. The civil structure condition is a stand-alone condition parameter since damage to the structure can expose the transformer to severe weather conditions and present serious safety concerns to humans should they come into contact with the contents inside. Hence, a civil structure that is deteriorated should be replaced to maintain safety performance.

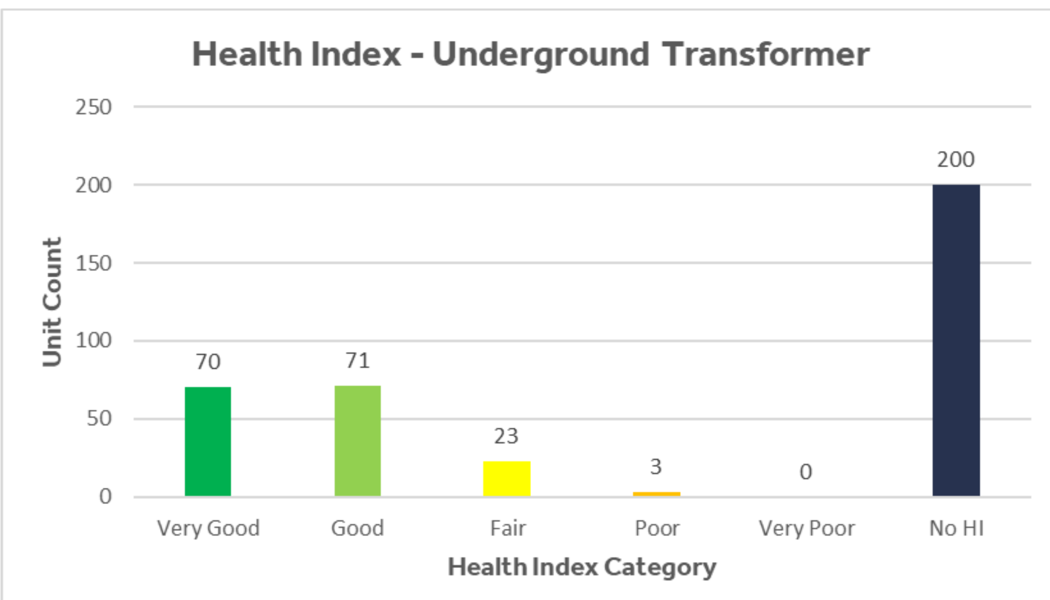
ORPC owns 367 underground transformers within its service territory. Where the installation date was unknown, it was estimated based on the average asset age for all assets located on the same street. The estimated service age of assets was used in the HI calculation and was confirmed with ORPC. Figure 4-13 presents the age distribution for underground transformers.

Figure 4-13: Underground Transformers Age Demographics



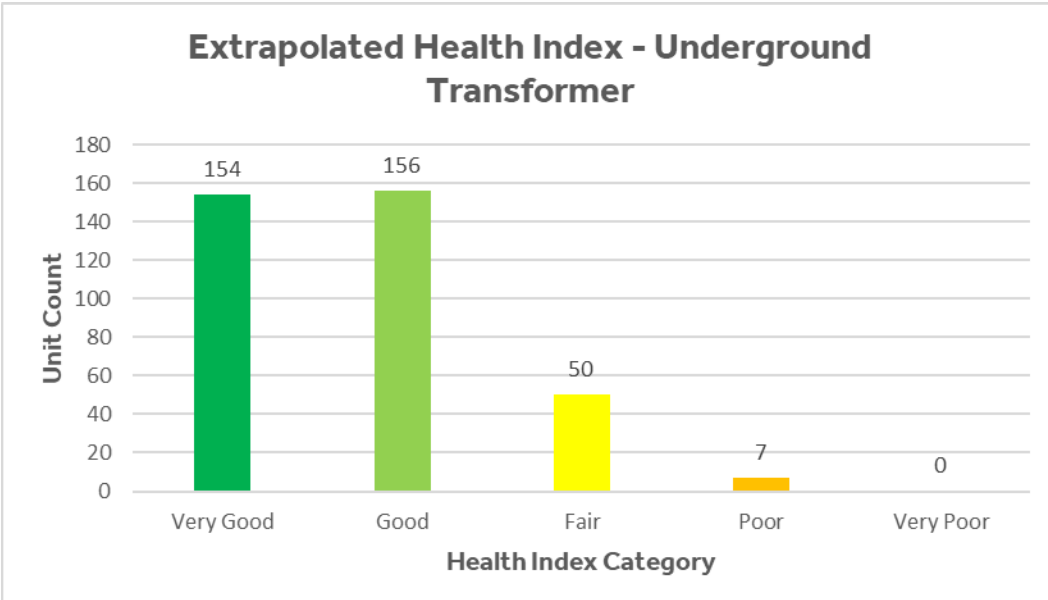
ORPC's transformer maintenance records and nameplate information were used to calculate the HI based on the criteria provided in Table 4-8. As presented in Figure 4-14, a valid HI was calculated for 46% of the population.

Figure 4-14: Underground Transformers HI Results



To complete the full analysis, the remaining 54% of the population have been extrapolated based on the HI distribution of the asset population with a valid HI score. As shown in Figure 4-15, most of the underground transformers are in Very Good or Good condition. The average HI of the underground transformers is 81% (Good).

Figure 4-15: Extrapolated Underground Transformers HI Results



The class-average DAI for underground transformers is 59%. Table 4-9 presents the DAI of each condition parameter used for the underground transformers HI calculation.

Table 4-9: Underground Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	93%*
Visual Inspection	46%
Condition of Civil Structure	46%

**Note: Estimated service age included*

4.1.6 Overhead Switch

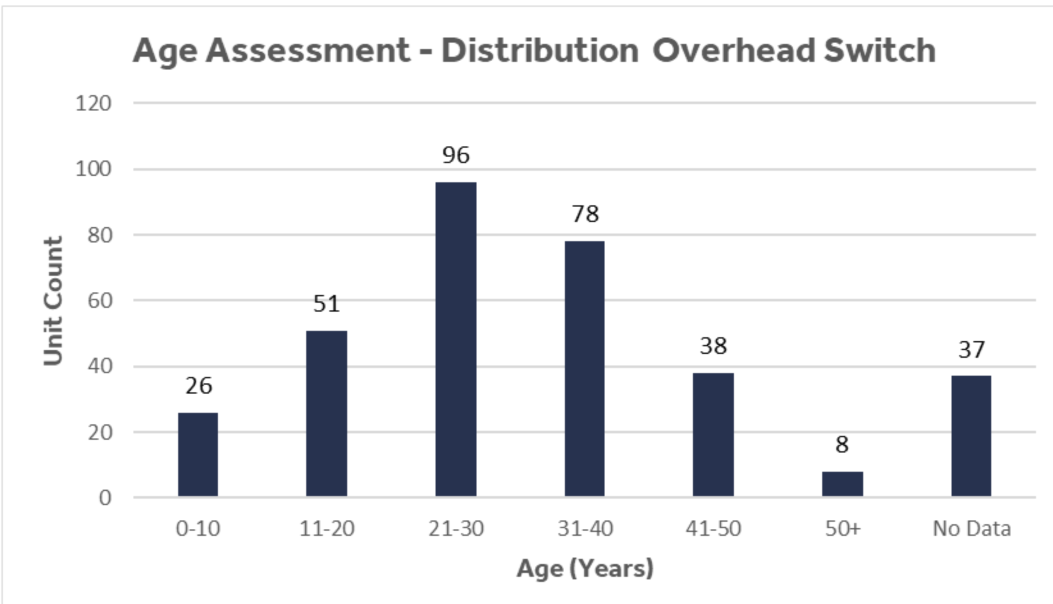
ORPC's overhead switch types include manual gang operated sectionalizing switches, inline switches, and inline fused switches and are located on its poles. Overhead switches provide isolation of lines sections or equipment when necessary. The HI for switches is calculated by considering a combination of end-of-life criteria summarized in Table 4-10.

Table 4-10: Distribution Overhead Switch HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	3	A,C,E	4,2,0	12
			Total Score	**24**

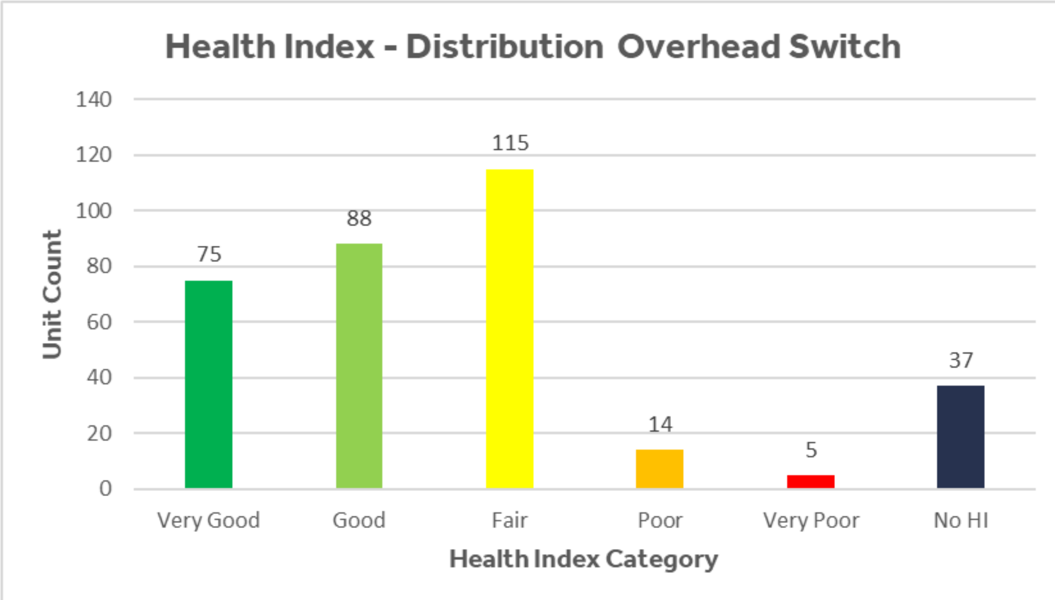
ORPC owns 334 overhead switches within its service territory. For assets with unknown installation dates, the average asset age on the same street was used as a proxy. The applied assumption for the service age of assets was used in the HI calculation and was confirmed with ORPC. Figure 4-16 presents the age distribution for overhead switches.

Figure 4-16: Distribution Overhead Switches Age Demographics



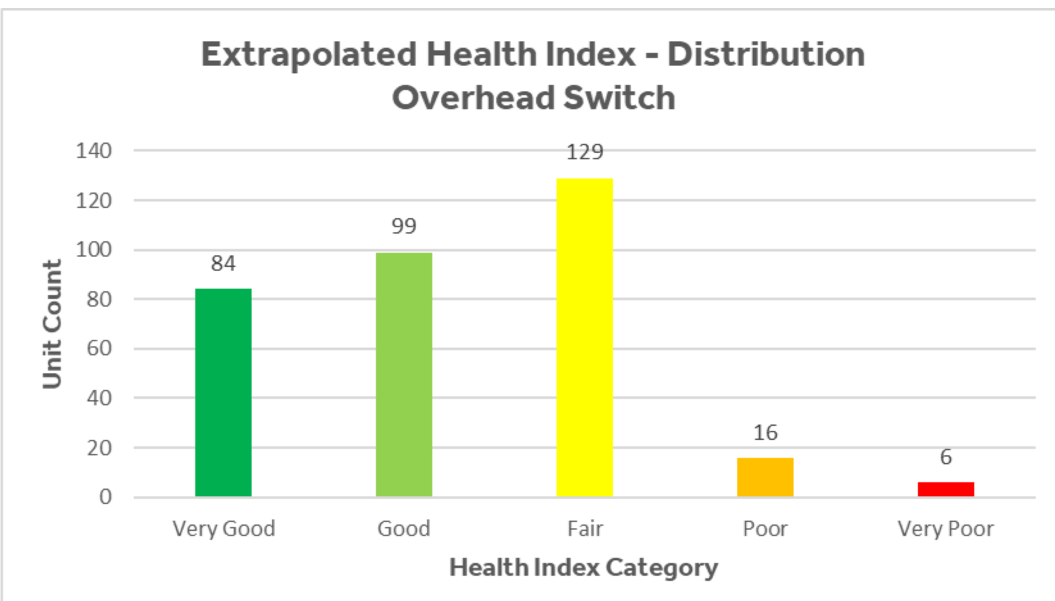
ORPC's nameplate information and maintenance records were used to calculate the HI based on the criteria provided in Table 4-10. As illustrated in Figure 4-17, a valid HI was calculated for 89% of the switches, using the estimated service age.

Figure 4-17: Overhead Switches HI Results



To complete the full analysis, the remaining 11% of the population has been extrapolated based on the HI distribution of the asset population with a valid HI score. Most of the switches are in Very Good and Good condition with less than 3% in Poor or Very Poor, as illustrated in Figure 4-18. The average Health Index for overhead switches is 70% (Good).

Figure 4-18: Extrapolated Overhead Switches HI Results



The average DAI for overhead switch data is 91%. Table 4-11 presents the DAI of each condition parameter used in the HI calculated.

Table 4-11: Distribution Overhead Switches condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	89%*
Visual Inspection	93%

**Note: Estimated service age included*

4.2 Station Assets

4.2.1 Power Transformers

Housed within municipal stations, power transformers are used to step down the voltage from the sub-transmission system to distribution levels. Computing the HI of a power transformer requires developing end-of-life criteria for its various components. Table 4-12 summarizes the HI formulation used for oil-type power transformers. The HI score for a power transformer is composed of fourteen condition parameters, each of which represents an aspect of a power transformer with a direct impact on the operational health of the asset.

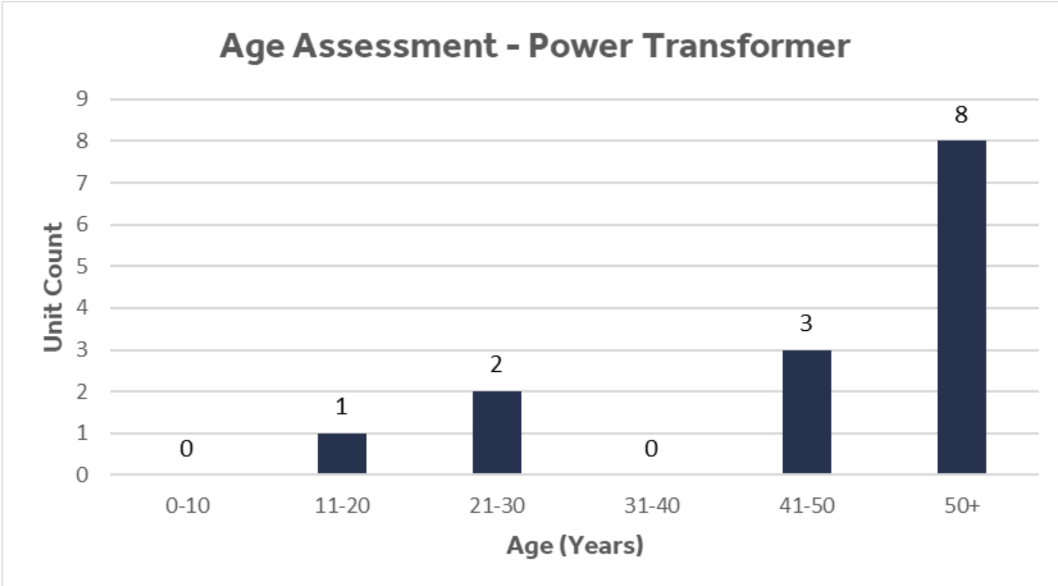
Table 4-12: Power Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Dissolved Gas Analysis	10	A,B,C,D,E	4,3,2,1,0	40
Insulation Power Factor	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality	8	A,C,E	4,2,0	32
Age	6	A,B,C,D,E	4,3,2,1,0	24
Bushing Condition	3	A,B,C,D,E	4,3,2,1,0	12
Main Tank Corrosion	2	A,B,C,D,E	4,3,2,1,0	8
Cooling Equipment	2	A,B,C,D,E	4,3,2,1,0	8
Gauges, Gas Pressure Relief and Gas Pressure Relay Condition	2	A,B,C,D,E	4,3,2,1,0	8
Bushing head condition	2	A,B,C,D,E	4,3,2,1,0	8
Transformer Foundation/Support Steel	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Conservator/Oil Preservation System Condition	1	A,B,C,D,E	4,3,2,1,0	4
Oil leaks	1	A,B,C,D,E	4,3,2,1,0	4
Grounding condition	1	A,B,C,D,E	4,3,2,1,0	4
Connectors	1	A,B,C,D,E	4,3,2,1,0	4
			Total Score	**200**

By performing DGA, it is possible to identify internal faults, PD, low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights. Oil leaks and overall condition of components are collected by visual inspection and serve as indicators of the total health of the asset.

ORPC owns 14 oil-type power transformers within its service territory. Figure 4-19 presents the age profile of power transformers in-service.

Figure 4-19: Power Transformer Age Demographics



ORPC requested METSCO to conduct a visual inspection of the power transformers. In addition, ORPC's historical inspection records and test results were used to calculate the HI based on the criteria provided in Table 4-12. The HI distribution for in-service power transformers presented is in Figure 4-19. The average HI for power transformer is 76% (Good).

Figure 4-20: Power Transformers HI Results

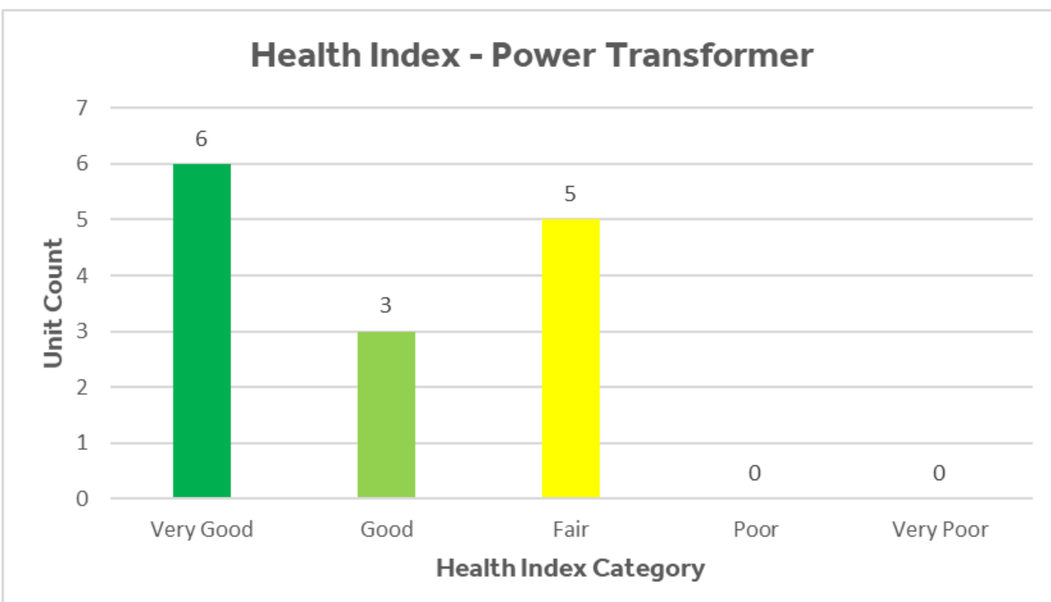
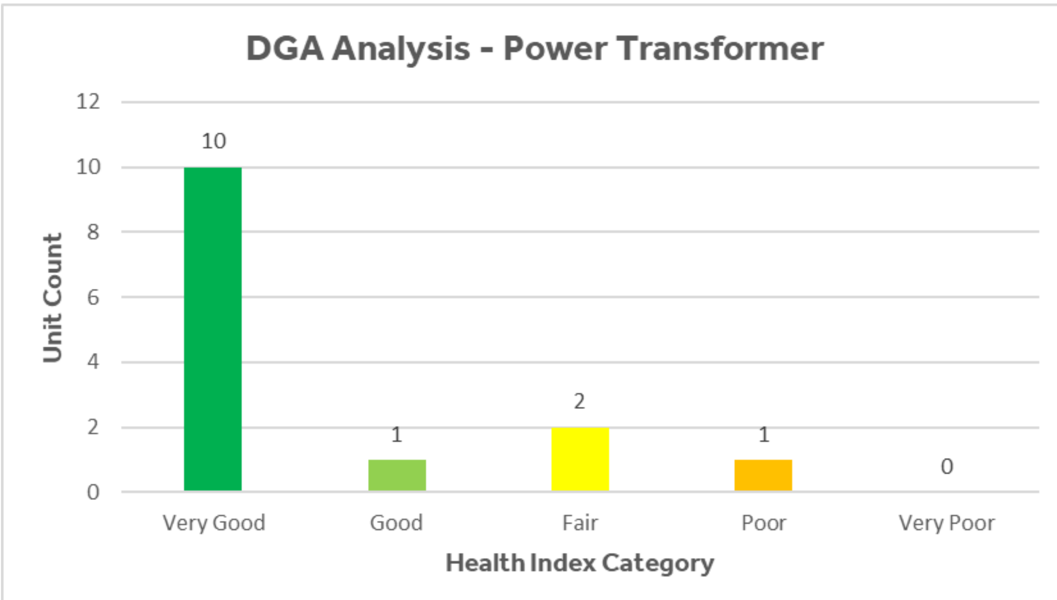


Figure 4-21 illustrates the DGA results for the power transformers. DGA can be a leading indicator as to how the power transformer's internal condition is before experiencing unfavourable results. The figure is presented to show there are power transformers tested that may require follow-up investigation although other condition parameters do not indicate any issues.

Figure 4-21: Power Transformers DGA Results



The average DAI for oil-type power transformer data is 100%. Table 4-13 presents the DAI of individual condition parameter used for the power transformer HI framework.

Table 4-13: Power Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Dissolved Gas Analysis	100%
Insulation Power Factor	100%
Oil Quality	100%
Age	100%
Bushing Condition	100%
Main Tank Corrosion	100%
Cooling Equipment	100%
Gauges, Gas Pressure Relief and Gas Pressure Relay Condition	100%
Bushing head condition	100%
Transformer Foundation/Support Steel	100%
Transformer Conservator/Oil Preservation System Condition	100%
Oil leaks	100%
Grounding condition	100%
Connectors	100%

4.2.2 Circuit Breakers

Located outdoors or in station switchgears, circuit breakers are electrical devices that operate automatically during a fault. It protects other electrical assets from damage due to short-circuit current. It operates when a fault is detected and can be programmed to automatically restore the connection once the fault is cleared or can be reset manually based on the severity of the fault.

Computing the HI of a circuit breaker considers end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. Three types of circuit breakers are assessed within this report: air-insulated, oil-insulated, and SF_6-insulated.

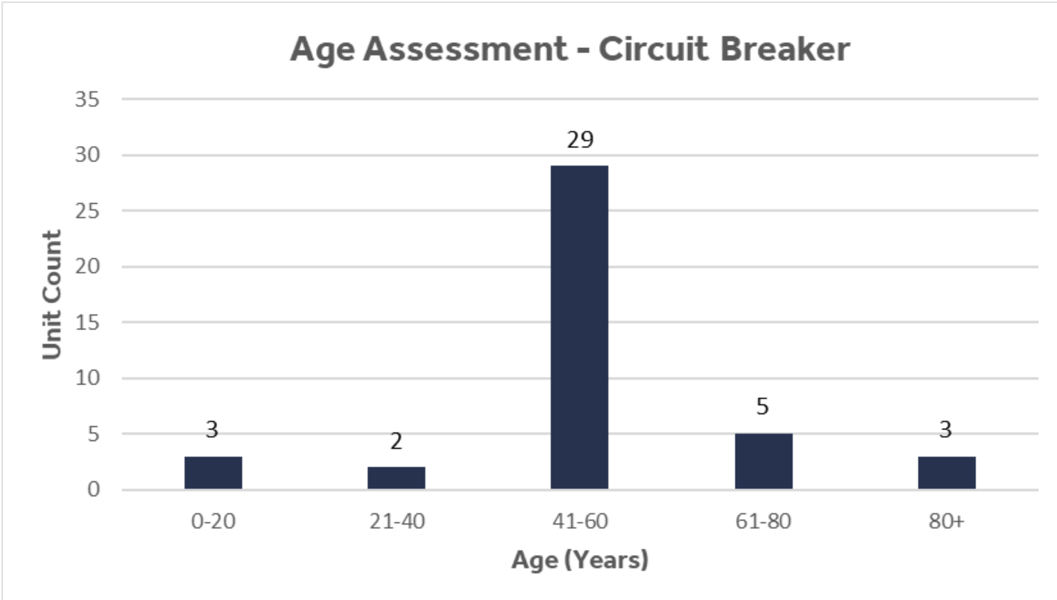
The HI for a circuit breaker is calculated by considering end-of-life criteria summarized in Table 4-14. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur.

Table 4-14: Circuit Breaker HI Formulation

<table>
<tr><th>Condition Parameter</th><th>Type</th><th>Weight</th><th>Ranking</th><th colspan="2">Numerical Grade</th><th>Max Score</th></tr>
<tr><td>Control & Operating Mechanism Components</td><td>All</td><td>2</td><td>A,B,C,D,E</td><td colspan="2">4,3,2,1,0</td><td>8</td></tr>
<tr><td>Foundation, Support Steel, Grounding</td><td>All</td><td>3</td><td>A,B,C,D,E</td><td colspan="2">4,3,2,1,0</td><td>12</td></tr>
<tr><td>Overall Condition</td><td>All</td><td>4</td><td>A,B,C,D,E</td><td colspan="2">4,3,2,1,0</td><td>16</td></tr>
<tr><td>Tank and Mechanism Box</td><td>Oil</td><td>4</td><td>A,B,C,D,E</td><td colspan="2">4,3,2,1,0</td><td>16</td></tr>
<tr><td>Oil Leaks</td><td>Oil</td><td>2</td><td>A,B,C,D,E</td><td colspan="2">4,3,2,1,0</td><td>8</td></tr>
<tr><td colspan="3">Total Score</td><td>Air/ SF6</td><td>36</td><td>Oil</td><td>60</td></tr>
</table>

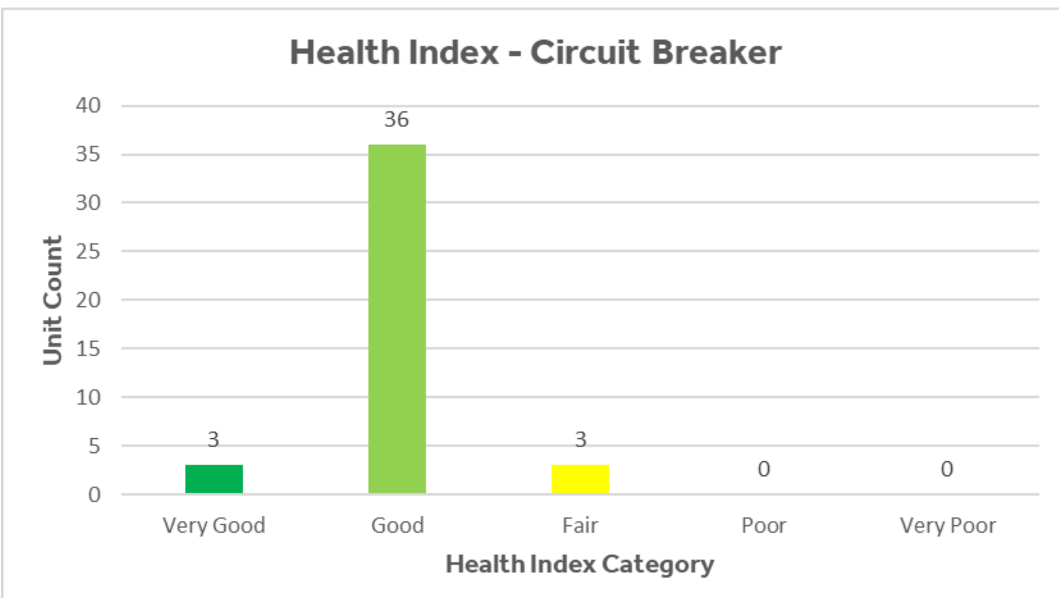
ORPC owns 42 circuit breakers within its service territory. Circuit breakers with unknown age are estimated to be the same age as the power transformer in the same municipal station as an approximate representation of the age. Figure 4-22 presents the age profile of the circuit breakers.

Figure 4-22: Circuit Breaker Age Demographics



METSCO's inspection of the circuit breakers was used to calculate the HI based on the criteria provided in Table 4-14. The overall HI distribution for the circuit breakers is presented in Figure 4-22. The average HI for circuit breakers is 75% (Good).

Figure 4-23: Circuit Breaker HI Results



The average DAI for circuit breakers is 79%. Table 4-15 presents the DAI of each condition parameter used for the circuit breakers HI calculation.

Table 4-15: Circuit Breaker condition parameters data availability

Condition Parameter	% of Assets with Data
Control & Operating Mechanism Components	45%
Foundation, Support Steel, Grounding	74%
Overall Condition	100%
Tank and Mechanism Box	63%
Oil Leaks	100%

4.2.3 Protection Relays

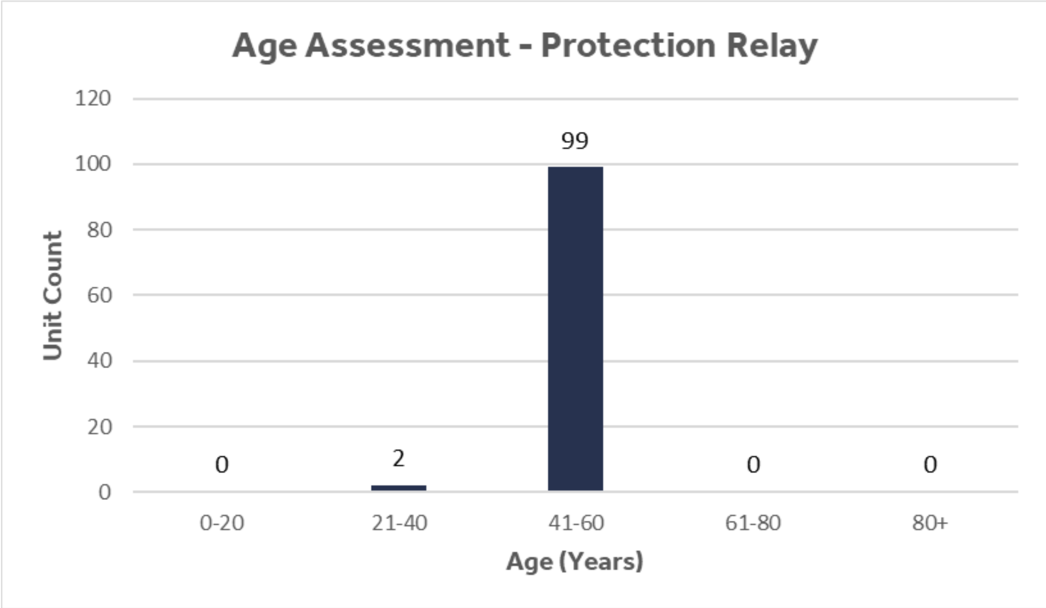
Projection relays detect abnormal operating conditions and initiate a trip in circuit breakers to isolate faulty circuits from healthy circuits. Protection relays obtain their input from instrument transformers, process the information and automatically take corrective action with adequate speed and selectivity. Table 4-16 summarizes the HI formulation used for protection relays.

Table 4-16: Protection Relay HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspections	3	A,B,C,D,E	4,3,2,1,0	12
Defect and Test Reports	4	A,C,E	4,2,0	16
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Non-Discretionary Obsolescence	5	A,E	4,0	20
			Total Score	**64**

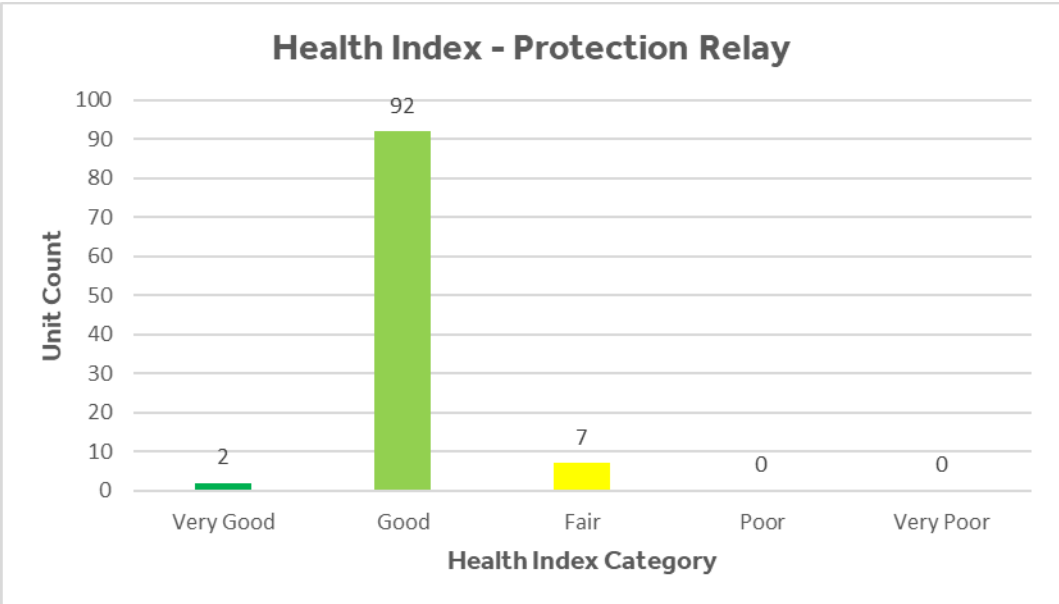
ORPC owns 101 protection relays. Protection relays without age information were estimated to have the same age as the connected circuit breaker. In the case of the connected circuit breaker installed prior to 1960, the relays were estimated to be installed in 1960 instead, as electromechanical relays were not available prior to this time. The estimated age was used in HI calculation and confirmed with ORPC. Figure 4-24 presents the age demographics of the protection relays.

Figure 4-24: Protection Relays Age Demographics



In addition to METSCO's inspection of the protection relays, nameplate information and test results were used to calculate the HI based on the criteria provided in Table 4-16. The HI distribution for protection relays is presented in Figure 4-25. The average HI for protection relays is 78% (Good).

Figure 4-25: Protection Relays HI Results



The average DAI for protection relays is 100%. Table 4-17 presents the DAI of each condition parameter used for the HI calculation.

Table 4-17: Protection relays condition parameters data availability

Condition Parameter	% of Assets with Data
Visual Inspection	100%
Defect and Test Reports	100%
Service Age	100%*
Non-Discretionary Obsolescence	100%

**Note: Estimated service age included*

4.2.4 Station Switches

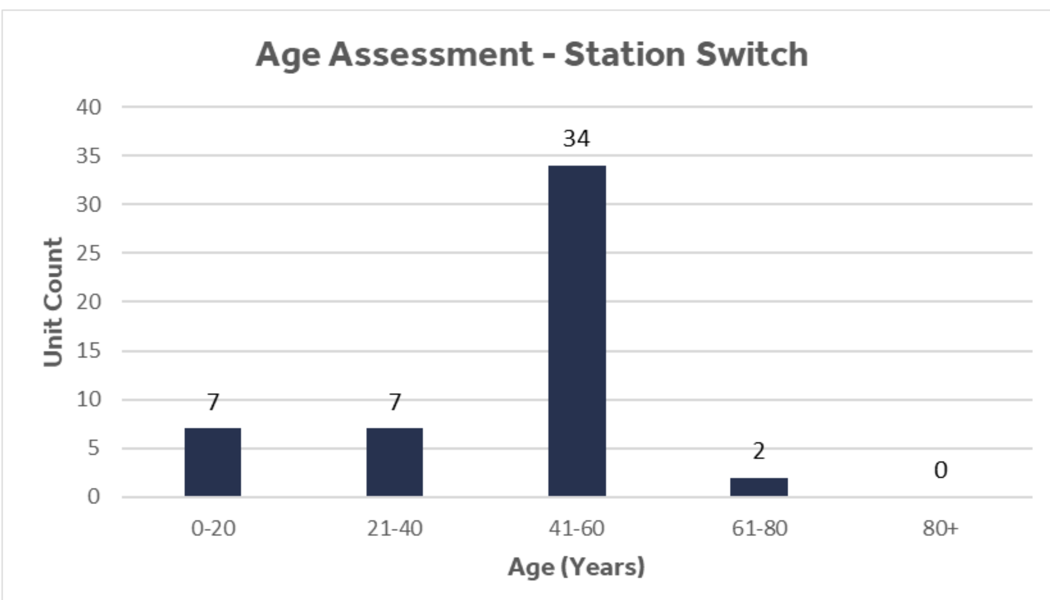
Table 4-18 summarizes the HI formulation for station switches, which provide isolation.

Table 4-18: Overhead Station Switch HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Bushings/insulators	3	A,B,C,D,E	4,3,2,1,0	12
Disconnect blades and contacts	4	A,B,C,D,E	4,3,2,1,0	16
Power Train Drive Assembly	4	A,B,C,D,E	4,3,2,1,0	16
Connectors and Conductors	3	A,B,C,D,E	4,3,2,1,0	12
Foundation/Support Steel/Grounding	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**68**

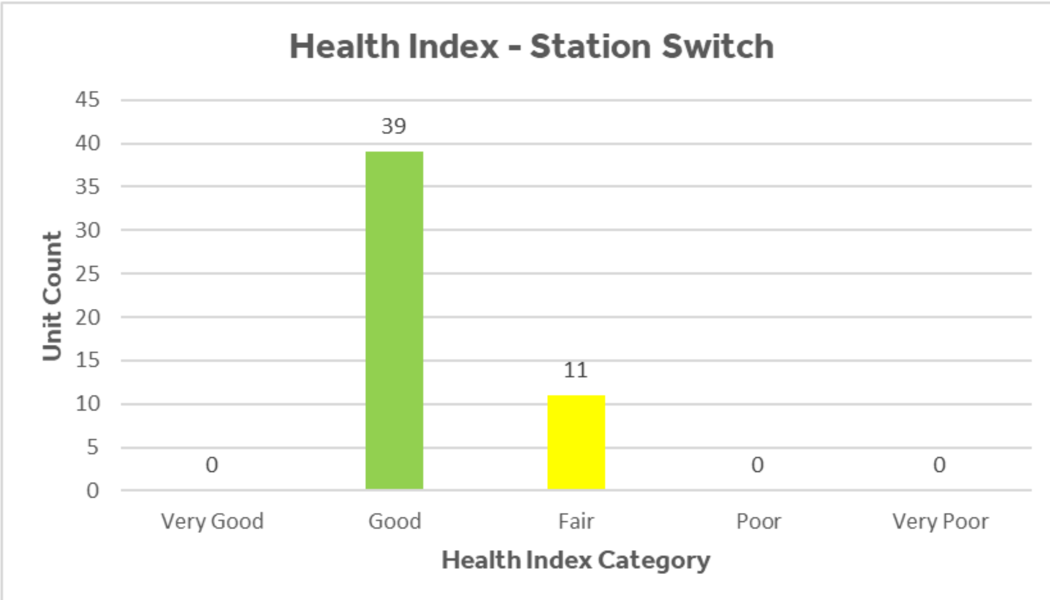
ORPC owns 50 station switches within its service territory. Figure 4-26 presents the age profile of the station switches.

Figure 4-26: Station Switch Age Demographics



The HI distribution for station switches is illustrated in Figure 4-27. Majority of the population is in Good condition. The average HI for station switches is 74% (Good).

Figure 4-27: Station Switch HI Results



The DAI across the station overhead switch asset class is 77%. Table 4-19 presents the DAI of individual condition parameters used for the station overhead switch HI framework.

Table 4-19: Overhead Station Switch condition parameters data availability

Condition Parameter	% of Assets with Data
Bushings/insulators	88%
Disconnect blades and contacts	86%
Power Train Drive Assembly	44%
Connectors and Conductors	88%
Foundation/Support Steel/Grounding	96%

4.2.5 Battery Banks

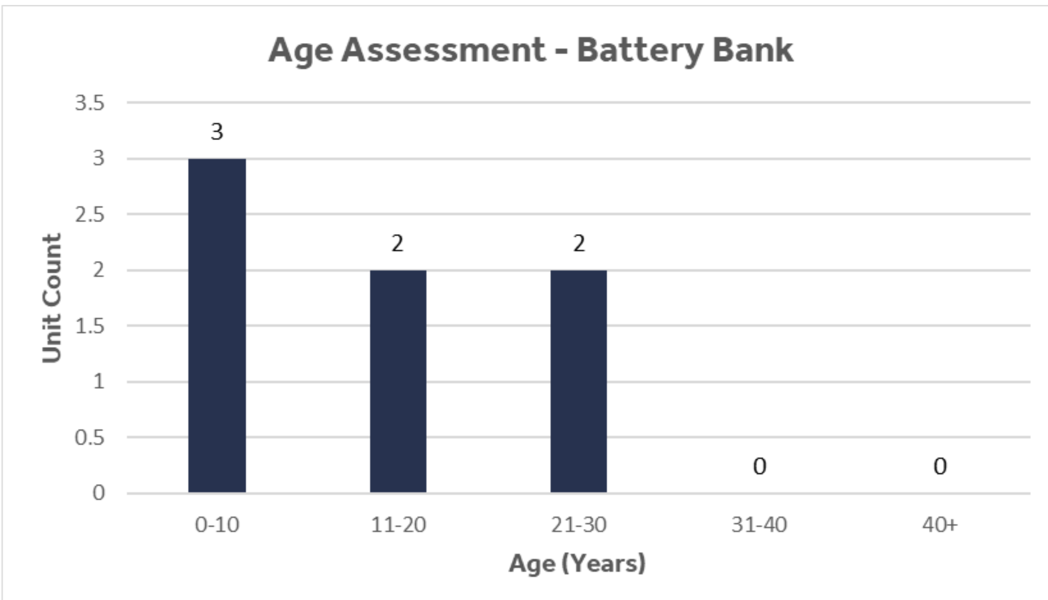
The battery system provides backup power to essential station functionalities such as lighting, communication, and P&C equipment in the event of a loss of supply to the station. The main components of the battery system are the charger and the battery bank which is comprised of several battery cells in series. The battery bank HI score is comprised of five condition parameters. Table 4-20 summarizes the criteria to compute the HI for station battery banks.

Table 4-20: Station Battery Bank HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Battery cells and trays/racks	2	A,B,C,D,E	4,3,2,1,0	8
Battery plate condition	3	A,B,C,D,E	4,3,2,1,0	12
Connections	2	A,B,C,D,E	4,3,2,1,0	8
Straps/cables	2	A,B,C,D,E	4,3,2,1,0	8
Electrolyte Level	3	A,C,E	4,2,0	12
			Total Score	**48**

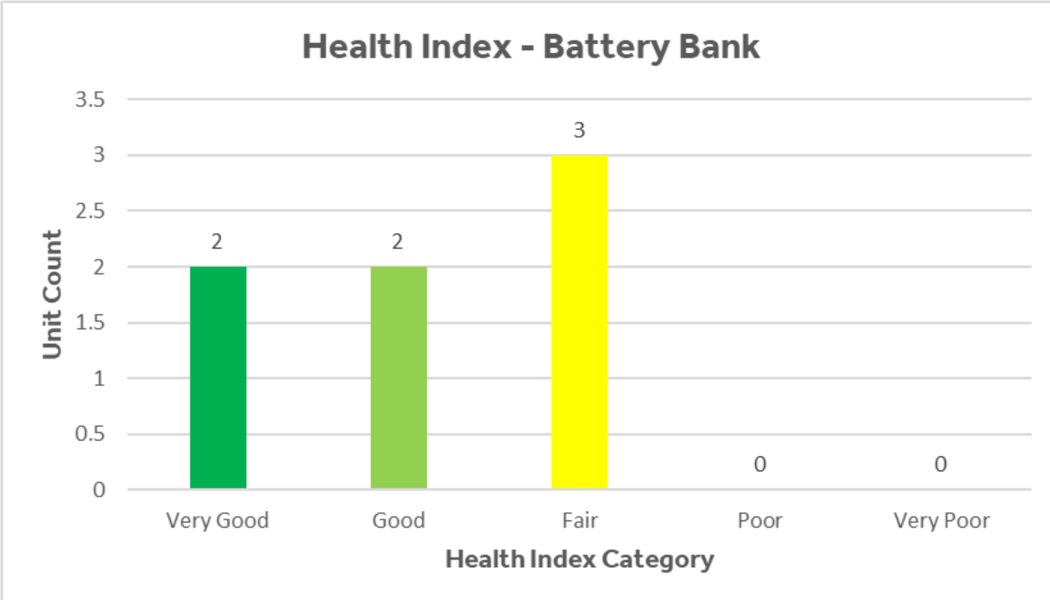
ORPC owns 7 battery banks. Figure 4-28 presents the age distribution for station battery banks.

Figure 4-28: Station Battery Banks Age Demographics



METSCO's visual inspection of the battery banks was used to calculate the HI based on the criteria provided in Table 4-20. The HI distribution for station battery banks is presented in Figure 4-29. The average HI for battery banks is 72% (Good).

Figure 4-29: Station Battery Banks HI Results



The class-average DAI for battery banks is 96%. Table 4-21 presents the DAI of each condition parameter used for the batteries HI framework.

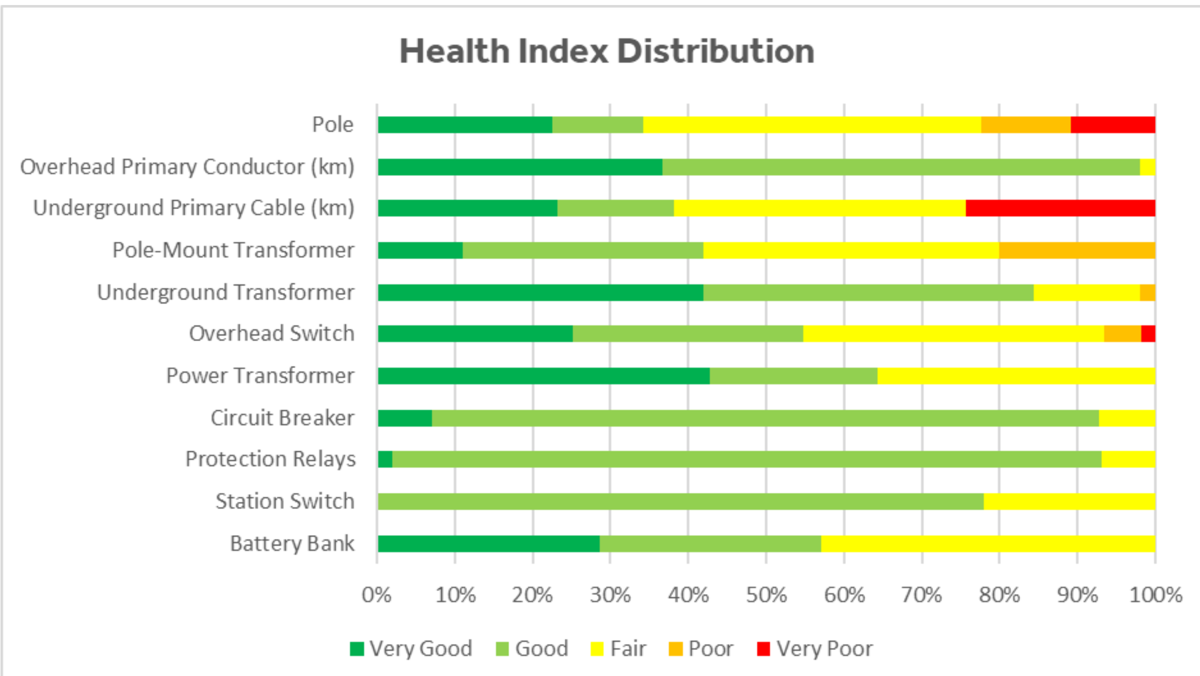
Table 4-21: Station Batteries & Chargers condition parameters data availability

Condition Parameter	% of Assets with Data
Battery cells and trays/racks	100%
Electrolyte Level	86%
Battery plate condition	100%
Connections	100%
Straps/cables	100%

5 Conclusion

As Figure 5-1 indicates, the majority of assets across ORPC's system are in Fair, Good or Very Good condition. This can indicate ORPC has taken steps in the past to manage their asset health and performance for the benefit of its customers. As with every system, however, there are populations of assets that will require ORPC's attention in future years as these assets continue to degrade from the Fair condition category into the Poor and Very Poor condition categories respectively.

Figure 5-1: Health Index Results



6 Recommendations

A complete ACA framework for ORPC represents an integral component of its broader AM 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 current 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 for ORPC's investment decision-making to be further enhanced with the current information regarding the state of the assets. However, there are also further opportunities to introduce new data to be collected and improve data availability to continuously improve the ACA framework.

This section breaks down METSCO's recommendations into the following categories:

1. HI improvements; and
2. Data availability improvements.

6.1 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 condition parameters 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 improving the ACA framework over time and should not be interpreted as suggesting that immediate action is warranted. The following tables highlight the condition parameter name, a short description of the reasoning to include the condition parameter, and a priority of importance to include it into the specific asset's class HI framework. The priority is dependent on the condition parameter's weighting in comparison to the current HI framework condition parameter's weights.

1. Poles

Field tests provide a quantitative result which greatly reduces the subjectivity of the assessment.

Table 6-1: Data Collection Recommendation for Pole

Criteria	Reasoning	Impact
Remaining pole strength	Field testing will result in an improvement in understanding the condition of the utility's asset.	**High**

2. Underground Primary Cables

ORPC has not experienced many cable failures on its system to date; however, should their rate of occurrence increase, then it would be prudent to track these. The condition of the concentric neutral and cable loading can also be assessed.

Table 6-2: Data Collection Recommendation for Underground Primary Cable

Criteria	Reasoning	Impact
Field Tests	Like cable failure, field testing will result in an improvement in understanding the condition of the utility's asset.	**High**
Cable Failure Statistics	Historical data assists in forecasting cable failure and affects utility asset management related objectives, such as safety and reliability.	**High**
Condition of Concentric Neutral	Corrosion of concentric neutrals is another mode of degradation. Insulation degradation and cable failures can be accelerated if the cable jacket is damaged allowing moisture to enter into the insulation system. Concentric neutral corrosion is a major problem particularly on unjacketed cables or when the neutrals of the cable are exposed to excessive moisture over time. The corrosion can lead to premature cable failures and/or cause touch potential risks. Time Domain Reflectometry (TDR) tests are performed to determine the degree of corrosion on concentric neutral cables.	**Medium**
Loading History	Overloading cables result in temperature increases over time, causing accelerated degradation of the cable.	**Low**

3. Overhead Distribution Transformers

Overloading of distribution transformers accelerates the degradation of the transformer. Abnormal operating temperate may indicate faulty components or overloading.

Table 6-3: Data Collection Recommendation for Overhead Distribution Transformer

Criteria	Reasoning	Impact
Infrared (IR) Scan Results	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Peak Loading	Overloading transformer results in temperature increases over time, causing accelerated degradation of the transformer.	**Medium**

4. Underground Distribution Transformers

Overloading of distribution transformers accelerates the degradation of the transformer. Abnormal operating temperate may indicate faulty components or overloading.

Table 6-4: Data Collection Recommendation for Underground Distribution Transformer

Criteria	Reasoning	Impact
IR Scan Results	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Peak Loading	Overloading transformer results in temperature increases over time, causing accelerated degradation of the transformer.	**Medium**

5. Overhead Switches

While ORPC visually inspects its overhead switches, the results do not capture all key components.

Table 6-5: Data Collection Recommendation for Overhead Switch

Criteria	Reasoning	Impact
IR Scan Results	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Visual Inspection - Condition of Operating Mechanism	The condition of the operating mechanism helps assess the life expectancy of the switch which affects the operability of the switch. Identification of this condition parameter over time provides degradation information of an asset.	**Medium**

6. Power Transformer

Faulty components or insulation breakdown may be identified via an IR scan.

Table 6-6: Data Collection Recommendation for Power Transformer

Criteria	Reasoning	Impact
IR Scan Results	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Load History	Overloading transformer results in temperature increases over time, causing accelerated degradation of the transformer.	**High**

7. Circuit Breaker

Field tests provide a means to ensure the breaker operates within specifications. Abnormal operating temperate may indicate faulty components.

Table 6-7: Data Collection Recommendation for Circuit Breaker

Criteria	Reasoning	Impact
Contact Resistance Tests	Defective contacts lead to higher losses and may result in arcing or other incidents. Identification of this condition parameter over time provides degradation information of an asset.	**High**
IR Scan Results	To identify if the circuit breaker is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Timing/Travel tests	Timing/ Travel test provides information as to whether the breaker's operating mechanism is operating properly. Identification of operation use over time provides degradation information of an asset.	**Medium**

8. Protection Relay

Relays that do not meet present system needs may pose risk to the system's safety and reliability.

Table 6-8: Data Collection Recommendations for Protection Relay

Criteria	Reasoning	Impact
Discretionary Obsolescence	Criterion affects utility AM related objectives.	**Low**

9. Station Switch

Excess operating temperatures may result from faulty components. Contact resistance tests ensure assets working within expected limits.

Table 6-9: Data Collection Recommendation for Station Switch

Criteria	Reasoning	Import
IR Scan	To identify if the station switch is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Contact Resistance Tests	Defective contacts lead to higher losses and may result in arcing or other incidents. Identification of this condition parameter over time provides degradation information of an asset.	**Medium**

6.2 Data Availability Improvements

Data availability is critical to producing 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. Utilities understand that it is critical to execute continuous improvement procedures as part of an AM data life-cycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA, the quality of the HI depends on the available data. For condition parameters with low data availability METSCO recommends that ORPC continue collecting the information related to these data points.

As a part of future improvement opportunities, it is recommended that ORPC shifts from paper inspection forms to electronic forms for inspection data collection. This shift will result in further improvements in being able to link inspection and testing results to specific assets and provide enhanced access to the maintenance history for an individual asset such that further analyses, such as trending, can be performed.

Lastly, METSCO has noticed that some condition parameters recorded by ORPC vary in the detail with respect to the grading scheme. Some parameters will have a pass-fail grade (e.g. Ok and Not-Okay). METSCO recommends that ORPC consider continuous improvements to expand these condition parameters to a five-point scale, such that a higher resolution of condition results can be produced.

7 Appendix A – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure 7-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over 10 years. Our founders are the pioneers of the first-ever Health Index methodology for power equipment in North America as well as the most robust high voltage risk-based analytics on the market today. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified experts to provide its service to ORPC.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

APPENDIX E – PEMBROKE MS6 TRANSFORMER REPORT

Verification and Test Report

Date:	2021-07-05
Customer:	Ottawa River Power Corporation
User:	Ottawa River Power Corporation
Project:	Emergency MS6 T1 Transformer
#REF. CFM:	CFM21-0199
#REF. Customer:	

CFM Services Inc.
1357 Jacques-Cartier sud
St-Jean-sur-Richelieu, Qc.
J3B 6Y8

2021-07-05

Justin Allen
Ottawa River Power Corporation
283 Pembroke Street West
Pembroke,ON
K8A 6Y6

PROJET: CFM21-0199 - Emergency MS6 T1 Transformer

M. Allen,

Please find enclosed the results of the MS6 T1 testing and investigation performed at Pembroke. This work was performed on June 30,2021.

Following the information available and our observations on site, we strongly suspect that the failure of the H2 bushing is the cause of damage to the transformer. The elements which make us think this assumption is that the bushing H2 literally exploded. We can see the effects of the enormous pressure inside the bushing (domed head, insulation paper and oil sprayed several meters, porcelain inside the tank is destroyed). But what suggests that it is the bushing that was the instigating cause is the carbon tracking inside of the bushing (see picture in the report), this kind of trace takes time to form, it is not due to a sudden fault, but ended up making a short-circuit, especially if there is an overvoltage (example during a thunderstorm). This trace gives us a good idea of the state of the bushing before the fault which must have been very bad condition. Without this trace of carbon inside the bushings, it would be difficult for us to estimate the cause of the failure. The short-circuit and the projection of porcelain from the H2 bushing probably caused the failure of the H2 winding.

It was a pleasure to make business with you and hope this report satisfy your expectations. If you have any questions or comments please do not hesitate to contact us.

Regards,

CFM Services Inc.,

Christian Comtois
Vice-President, Services Division

VERIFICATION AND TEST REPORT

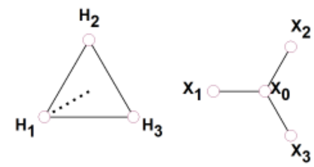
USER Ottawa River Power Corporation | CFM REF. # CFM21-0199
CUSTOMER Ottawa River Power Corporation | CUSTOMER REF. #

POWER TRANSFORMER

LOCATION Pembroke | ASSET ID 6T1
SUBSTATION MS6 | POSITION Outside

NAMEPLATE DATA

Manufacturer: Westinghouse | Class: ONAN/ONAF/ONAF | Phase: 3
Serial Number: B-3 S 7347 | Coolant: OIL | Year: 1974
Catalog No.: | Oil Volume: 1945 GAL | Weight: 64600 lb
Primary Volt.: 44 kV | B.I.L.: 250 kV | HV Winding: ALU
Secondary Volt.: 12.47/7.2 kV | B.I.L.: 110 kV | LV Winding: ALU
Rated Power: 10 / 13.33 / 16.66 MVA | Impedance: 5.4 % @ 10 MVA & 55 °C
Tap setting: 2 - 44 kV | Tank: OPEN-CONSER | Temp. rise: 55 °C
Test Reason: Bushing failed | Amb. temp.: 25 °C | Humidity: 60 %



Winding Connection / Vector: Dyn1

○ Indoor ◉ Outdoor

TRANSFORMER TURN RATIO

TEST					H1 - H0 / X1 - X2				H2 - H0 / X2 - X3				H3 - H0 / X3 - X1			
TAP #	Voltage (V) H/L		Test V	TTR	Actual Ratio	% Error	I exc mA	Ph (min)	Actual Ratio	% Error	I exc mA	Ph (min)	Actual Ratio	% Error	I exc mA	Ph (min)
2	44 000	7 200	80	6.111	6.3504	3.92	4.76	1.4358	192.1900	3 044.93	4.85	-56.59	12.3510	102.11	29.49	-0.0793

TRANSFORMER WINDING RESISTANCE

Winding temp. 22 °C

PRIMARY	Ohms		H1 - H3		H2 - H1		H3 - H2		VAR %
PRISE #	Voltage (V)	Test A	MESURE	Corrected @ 75°C	MESURE	Corrected @ 75°C	MESURE	Corrected @ 75°C	
2	4 400	10	1.041	1.256	1.044	1.259	2.083	2.513	50.02

SECONDARY	milli-Ohms		X1 - X0		X2 - X0		X3 - X0		VAR %
PRISE #	Voltage (V)	Test A	MESURE	Corrected @ 75°C	MESURE	Corrected @ 75°C	MESURE	Corrected @ 75°C	
---	7 200	10	23.830	28.744	23.641	28.516	23.730	28.624	0.79

NOTES

Megger on the bushing H2 head to flange => breakdown à 12 kVdc

C: Compliant NC: Noncompliant NA: Not applicable ND: Not available NV: Not verified NR: Not required * : see comments

COMMENTAIRES:

DEFICIENCES:
Winding H2 was failed, see pictures
H2 bushing failed, see pictures (tracking on de core, that probably the cause of the fault)
Transformer need to be replace or repair in a transformer shop

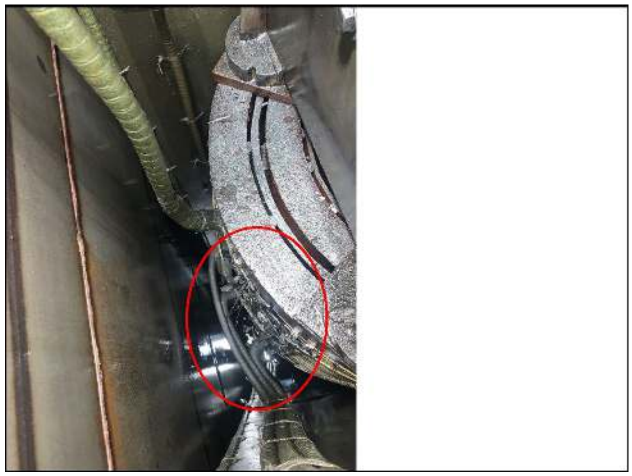
PHOTOS

TESTED BY: CC | TEST DATE: 2021-06-30 | PAGE : 1 of 4

POWER TRANSFORMER

Description
Winding H2 was failed
NOTES:
DATE:

Description
Winding H2 was failed
NOTES:
DATE:



Description
See the spire moved
NOTES:
DATE:

Description
Porcelaine completly destroyed inside the transformer
NOTES:
DATE:

Description
Porcelaine completly destroyed inside the transformer
NOTES:
DATE:

Description
High pressure inside de bushing
NOTES:
DATE:

POWER TRANSFORMER

Description
Tracking on the core of the bushing (tracking on de core, that probably the cause of the fault)
NOTES:
DATE:

Description
Color of the oil of the transformer Oil was full of carbon
NOTES:
DATE:

van Kooy
Transformer Consulting Services Inc.

Ph. 905 308-9888
Email john@vankooy.com
web site www.vankooy.com

July 28, 2021

To: Justin Allen, Ottawa River Power Corporation

Subject: Failed Transformer T1, at MS6, Westinghouse S# B-3S7347, built in 1974
10000/13333*/16666* kVA, ONAN/ONAF*/ONAF*, 55 °C Rise
*Additional rating available with the addition of cooling fans
HV 44 kV w DTC +1, -3 @ 2.5% Delta, LV 12.47 kV Wye
Factors Affection the Repair vs Buy New Decision

Executive Summary

This transformer at 47 years old at the time of failure was certainly near end of life.

Repairing this transformer would require replacing all of the windings, the bushings, perhaps other accessories and a paint job. This would reset the age clock. For the repair option to be economically considered, the transformer core, internal connections and the tap changer as well as the tank would need to be reused. This is not a technical concern but the No Load losses in this “old” core would be approximately 50% higher in losses than a modern core, affecting long term operating costs. The advantages of reusing that tank is that you know it will fit on the pad exactly as before. Unfortunately, this transformer has a contamination level of 20 ppm PCB in the oil. This precludes possibility of repair. This transformer must now be disposed of as hazardous waste.

Buying new would improve the losses of the Core (No Load Loss). Some care should be taken to ensure that the physical dimensions of the original design are matched to ease installation.

The cost of a repair (with PCB content in oil < 2 ppm) as described is ~ 75% the cost of a new transformer and the delivery for a repair is typically 4 to 8 weeks faster than from an OEM but this is based in large part on the Repair/OEM factory loading. It is best to test the cost/delivery of repair vs new with a few suppliers. A budget price for a new transformer would be in the $310,000.00 range with delivery in 36 weeks.

A budget price for removal of the existing PCB contaminate transformer, purchasing a new transformer, installing and commissioning testing would be in the $400,00.00 range.

General Comments on Review of the Provided Information

Based on the latest Oil test results it is apparent that this transformer has not been loaded very heavily, at least in recent years. Although the Dissolved Gas in Oil Analysis does not show any signs of internal arcing or overloading, there is no cure for old age. The General Oil Quality results show some deterioration but in general there is no indication of the likelihood of sudden failure. This is not unusual.

The failure appears to be limited to the HV B-phase bushing and winding but there is evidence of carbon spread throughout the transformer which is typical.

Repair or Buy New

At 47 years old, this transformer was nearing end of life at the time of failure. The weak point in all oil filled transformers is the cellulous insulation that is wrapped around the winding conductors, interconnecting internal leads and between the windings, and the windings and the core. Over time with the normal loading/heating of the insulation, deterioration is inevitable. As the insulation ages, it loses its ability to flex in response to the normal stresses of operation and becomes brittle. There is no way to predict catastrophic failure. Dissolved Gas in Oil Analysis (DGA) is the best method to monitor condition but will only pick up gradual degradation over time.

Repair – Due to the PCB contamination of 20 ppm, this option is not viable

Although it is possible that only one of the HV windings is damaged, all of the HV and LV windings and all cellulous insulation (paper, pressboard) in this 3-phase transformer have been subjected to long term aging and should be replaced. It may be possible to do a quick partial repair of the HV B-phase winding and replace the failed bushing with a used one but this is a high risk option.

Typically, a Repair Facility would quote on performing an inspection of the failure at their shop for a set fee (7 – 10K) and then after the evaluation, offer options including a single phase and three phase rewind, new bushings, new accessories, paint job, etc. It would be your responsibility to ship the transformer to the Repair Facility. My budget price estimate for a full repair is $232,000.00 but this should be validated by obtaining quotes.

To initiate a quote from a repair facility requires little in the way of documentation. A copy of the Nameplate drawing or a picture of the nameplate, a few pictures of the transformer in situ and information on the failure (in this case the CFM Services report) would be sufficient. A confirmation of the PCB level in the oil must also be provided. A PCB level of 2 or more ppm would result in the Repair Facility no-quoting the work or result in a cost that would exceed the price of a new transformer. Indicate a 2 week response time for reply to the quotation.

Repair Facilities and Contacts

Hitachi ABB, Stoney Creek, Ontario

Michael Havener, michael.havener@hitachi-powergrids.com

Alt. Bill Himmen, william.himmen@hitachi-powergrids.com

Surplec Industriel Inc, Sherbrooke, Quebec

Roland Carbonneau, rolandcarbonneau@surplec.com

PCB Contaminated Oil and Transformer Mitigator

Aevitas

Tom Maxwell, tom@aevitas.ca

Buy New

This is an opportunity to assess what the present and foreseeable future needs are for this transformer location. The original design is a 55 ^{o}C Rise design where today a 65 ^{o}C Rise is more common and gives the same output capability with less cost. The original design is rated at 10000/13333*/16666* kVA which allows for increased rating at the 13333 and 16666 kVA levels with the addition of fans. If the additional ratings are required, it is best to have the fans put on by the manufacturer and have the transformer tested to confirm the rating(s). If this transformer is to be paralleled with another transformer on the secondary side (12.47 kV) then it is important that the % Impedance is matched for each rating. I presume that the existing location and orientation of the HV and LV bushings is important to simplify installation.

A transformer specification is often provided to an OEM in order to obtain price and delivery. Since this is a replacement scenario as opposed to a new location/application situation, the specification can be quite basic. Once the rating has been verified, same as before or modified, then a technical description can be established to be added to whatever Terms and Conditions your Organization applies to larger purchases. I would recommend a minimum of a 3 year warranty (the industry standard is 12 months in service or 18 months from delivery, whichever occurs first).

The technical specification for an exact replacement would simply include the nameplate drawing/picture, some pictures of the transformer in situ and some sketches with the critical dimensions such as overall length, width and height of the tank, details of the LV throat/box and heights to the top of the HV bushings. If you still have the original Outline Drawing, this would serve the purpose.

Should you decide to modify the rating or other factors, then a more detailed technical specification would be required. The CSA specification for this size of transformer is C88-16.

In any case, for a new transformer option, I would recommend specifying a Circular Core and Coil configuration and the HV (44 kV) be designed as a Disk Type winding. This will add some cost but will result in greater reliability.

OEM Facilities and Contacts

Northern Transformers, Concord, Ontario
Colin Mark, cmark@northerntransformer.com

Pioneer Transformers, Granby Quebec, Sales Office in Mississauga
Sal Aiello, saiello@pioneertransformers.com, Ph. 905 625-0868 x 26

PTI Transformers, Regina, Saskatchewan
Colin Sturm, csturm@ptitransformers.com

Please contact me if you have any question or comments.

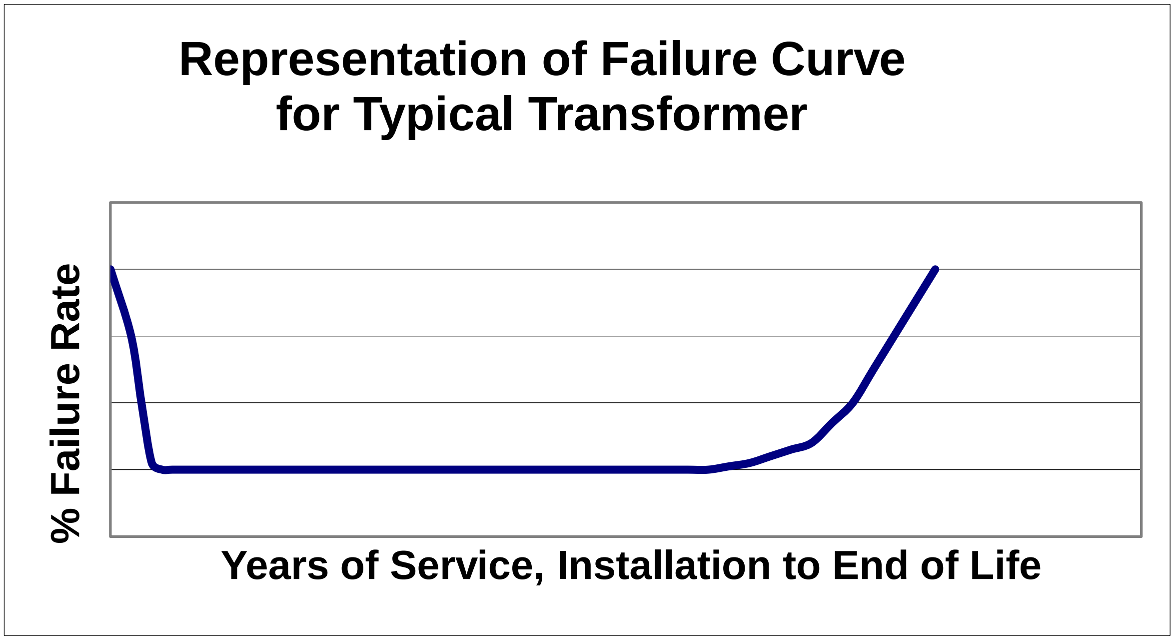
Regards,

van Kooy Transformer Consulting Services Inc.

per: Sjoerd (John) van Kooy

Appendix
Typicial Bathtub Failure Curve for Transformers

APPENDIX



In the first 12 to 18 months of Service, there is a small percentage of transformer failures related to manufacturing, application and installation/transportation issues. From this point out to 30, 40, 50 years (dependent on many factors including loading and application) the likelihood of failure remains constantly low. As the transformer approaches end of life, the failure rate increases with time.

Ideally the transformer is removed from service near the end of life in a controlled, planned process rather than having to respond to an emergency failure situation.