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Overview of Rate Base

Ex.2/Tab 1/Sch.1 - Rate Base Overview

ORPC's Rate Base is determined by taking the average of the balances at the beginning and the end of the 2016 Test Year, plus a working capital allowance of 7.5% of the sum of the cost of power and controllable expenses. The use of a 7.5% rate is consistent with the Board's letter of April 12, 2012.

The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. ORPC does not have non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Table 1 below presents Ottawa River Power's Rate Base calculations for all required years including the 2016 Test Year. ORPC has calculated its 2016 rate base to be $12,324,122. This rate base is also used to determine the proposed revenue requirement found at Exhibit 6.Tab 1.Schedule 2.

Table 2.1: Test Year Rate Base

Particulars	Board Appr 2010	Test Year 2016	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	8,553,872	10,128,657	1,574,785	18.%
Ending Balance	8,858,732	10,484,931	1,626,199	18.%
Average Balance	8,706,302	10,306,794	1,600,492	18.%
Working Capital Allowance	2,817,560	2,017,328	-800,232	-28%
Total Rate Base	11,523,862	12,324,122	800,260	6.9%

Table 1.4: Working Capital Allowance

Expenses for Working Capital	Board Appr 2010	Test Year 2016	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	360,476	630,467	269,990	74%
3550-Distribution Expenses - Maintenance	705,409	802,123	96,713	13%
3650-Billing and Collecting	616,443	733,000	116,557	18%
3700-Community Relations	58,624	67,000	8,376	14%
3800-Administrative and General Expenses	859,815	1,062,375	202,559	23%
6105-Taxes other than PILS	-29,915			100%
Total Eligible Distribution Expenses	2,570,853	3,294,964	724,111	28%
3350-Power Supply Expenses	16,212,879	23,602,740	7,389.861	46%
Total Expenses for Working Capital	18,783,732	26,897,704	8,113,972	42%
Working Capital factor	15.00%	7.50%		-50%
Total Working Capital	2,817,560	2,017,328	-800,232	-28%

Ex.2/Tab 1/Sch.2 - Rate Base Trend

Table 2.2 below presents ORPC's Rate Base calculations for all required years including the 2015 Test Year. Year over year variance analysis follows.

Table 2.2: Rate Base Trend

	CGAAP	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	NEWGAAP	NEWGAAP
Particulars	**Last Board Approved**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Net Capital Assets in Service:								
Opening Balance	8,553,872	8,858,732	8,482,758	8,193,020	7,921,309	8,518,626	8,792,238	10,128,657
Ending Balance	8,858,732	8,482,758	8,193,020	7,921,309	8,518,626	8,792,238	10,128,657	10,484,931
Average Balance	8,706,302	8,670,745	8,337,889	8,057,164	8,219,967	8,655,432	9,460,447	10,306,794
Working Capital Allowance	2,822,047	2,623,852	2,797,823	3,051,520	3,368,475	3,497,343	3,413,454	2,017,328
Total Rate Base	**11,528,349**	**11,294,597**	**11,135,712**	**11,108,684**	**11,588,442**	**12,152,775**	**12,873,901**	**12,324,122**
	CGAAP	**CGAAP**	**CGAAP**	**CGAAP**	**NEWGAAP**	**NEWGAAP**	**NEWGAAP**	**NEWGAAP**

Expenses for Working Capital	**Last Board Approved**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Eligible Distribution Expenses:								
Distribution Expenses - Operation	360,476	388,095	548,028	562,813	595,899	589,388	617,080	630,467
Distribution Expenses - Maintenance	705,409	491,364	721,496	693,882	840,521	707,406	766,322	802,123
Billing and Collecting	616,443	600,482	528,100	533,838	577,268	634,033	710,315	733,000
Community Relations	58,624	41,451	53,320	47,391	52,864	55,452	61,000	67,000
Administrative and General Expenses	859,815	821,877	833,118	817,920	1,026,994	915,963	969,266	1,062,375
Taxes other than Income Taxes	-	-	-	-	-	-	-	-
Sub-account LEAP Funding	-	-	-	-	-	-	-	-
Total Eligible Distribution Expenses	2,600,768	2,343,269	2,684,062	2,655,844	3,093,547	2,902,242	3,123,984	3,294,964
Power Supply Expenses	16,212,879	15,149,079	15,968,092	17,687,620	19,362,954	20,413,375	19,632,374	23,602,740
Total Expenses for Working Capital	18,813,647	17,492,348	18,652,154	20,343,464	22,456,500	23,315,618	22,756,358	26,897,704
Working Capital factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Total Working Capital	**2,822,047**	**2,623,852**	**2,797,823**	**3,051,520**	**3,368,475**	**3,497,343**	**3,413,454**	**2,017,328**

ORPC's rate base remained, for the most part, unchanged from the 2010 Board Approved until 2013. The reason for this is the lack of capital investments in 2011 and 2012 and 2013. OPRC's generally spends approximately 1M/year in capital investments and as shown in the table below, ORPC spent half of this amount in 2011 and 2012.

Table 2.3: Rate Base Trend

	2010BA	2010	2011	2012	2013	2014	2015	2016
Additions	$1,167,330	$979,370	$494,207	$457,683	$1,339,021	$1,049,402	$1,109,670	$1,245,950
Retirements	-$168,857	-$768,245	-$61,182	-$24,248	-$51,999	-$469,392	$0	$0

Under the new management, ORPC started the asset review portion of its Distribution System Plan in early 2014 which triggered a higher level of capital investment in its distribution system. Other factors that have affected the rate base over the past years is the replacement of a major transportation equipment in both 2010, 2013 and 2016, along with the addition of 1.6M in smart meters being moved into the rate base in 2015. Details of investments in the utility's fleet can be found in the Distribution System Plan at Ex.2/Tab 5/Sch.2

ORPC confirms that NBV of assets found at Appendix 2BA reconciles with balances in the rate base calculation.

Ottawa River Power has no non-distribution capital expenditures.

Ottawa River is fully embedded within Hydro One Networks's Distribution system and as such has no IESO revenues/payments to reconcile.

Detailed year over year variance analysis of the Rate Base are found at the next section.
Ex.2/Tab 1/Sch.2

Ex.2/Tab 1/Sch.3 - Rate Base Variance Analysis

The following paragraphs provide a narrative on the changes that have driven the increase in rate base since ORPC's 2010 cost of service.

2016 Test Year vs. 2015 Bridge Year:

Table 2.4 - 2016-2015 Rate Base Variance

Particulars	**2016**	**2015**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	10,128,657	8,792,238	1,336,419	15.20%
Ending Balance	10,484,931	10,128,657	356,274	3.52%
Average Balance	10,306,794	9,460,447	846,346	8.95%
Working Capital Allowance	2,017,328	3,413,454	(1,396,126)	-40.9%
Total Rate Base	**12,324,122**	**12,873,901**	**- 549,779**	**-4.27%**

Expenses for Working Capital				**NEWGAAP**
Eligible Distribution Expenses:	**2016**	**2015**	**Var**	**%**
3500-Distribution Expenses - Operation	630,467	617,080	13,386	2.17%
3550-Distribution Expenses - Maintenance	802,123	766,322	35,800	4.67%
3650-Billing and Collecting	733,000	710,315	22,685	3.19%
3700-Community Relations	67,000	61,000	6,000	9.84%
3800-Administrative and General Expenses	1,062,375	969,266	93,109	9.61%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	3,294,964	3,123,984	170,980	5.47%
3350-Power Supply Expenses	23,602,740	19,632,374	3,970,366	20.22%
Total Expenses for Working Capital	26,897,704	22,756,358	4,141,346	18.2%
Working Capital factor	7.5%	15%	-7.5%	-50.00%
Total Working Capital	**2,017,328**	**3,413,454**	**- 1,396,126**	**-40.9%**

Not taking into account the impacts related to the working capital allowance rate, the average opening and closing balance for both 2015 and 2016 saw a significant increase due to higher level of capital. Capital investment in the utility's distribution system is required in order to keep the system running in a safe and reliable manner. The utility is also planning on replacing deteriorated poles as a result of its asset assessment. Details regarding pole replacements can be found in Distribution System Plan filed at Ex.2/Tab 5/Sch.2 .The utility is also planning on purchasing a Radial Boom Truck to replace a 1994 truck that is currently part of the fleet. Details can also be found in Distribution System Plan filed at Ex.2/Tab 5/Sch.2

The rest of the increase can be attributed to regular maintenance of the distribution system.

The Working Capital Allowance projected for 2016 saw a decrease mainly due to the change from 15% to 7.5%. The OM&A included in the derivation of the Working Capital Allowance is discussed in detail throughout Exhibit 4.

2015 Bridge Year vs. 2014 Actual:

Table 2.5 - 2015-2014 Rate Base Variance

Particulars	**2015**	**2014**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	8,792,238	8,518,626	273,612	3.21%
Ending Balance	10,128,657	8,792,238	1,336,419	15.20%
Average Balance	9,460,447	8,655,432	805,015	9.30%
Working Capital Allowance	3,413,454	3,497,343	(83,889)	-2.40%
Total Rate Base	**12,873,901**	**12,152,775**	**721,126**	**5.93%**

Expenses for Working Capital				**NEWGAAP**
Eligible Distribution Expenses:	**2015**	**2014**	**Var**	**%**
3500-Distribution Expenses - Operation	617,080	589,388	27,692	4.70%
3550-Distribution Expenses - Maintenance	766,322	707,406	58,916	8.33%
3650-Billing and Collecting	710,315	634,033	76,282	12.03%
3700-Community Relations	61,000	55,452	5,548	10.01%
3800-Administrative and General Expenses	969,266	915,963	53,303	5.82%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	3,123,984	2,902,242	221,742	7.64%
3350-Power Supply Expenses	19,632,374	20,413,375	(781,002)	-3.83%
Total Expenses for Working Capital	22,756,358	23,315,617	(559,259)	2.40%
Working Capital factor	15%	15%		0.00%
Total Working Capital	**3,413,454**	**3,497,343**	**- 83,889**	**2.40%**

The total projected rate base in 2015 of $12.7 million is $584k or 4.8% higher than 2014. The main reason for the increase in Rate Base is due to the addition of 1.6M in smart meters related expenses to the opening balance of 2015. This is in addition to the regular maintenance of the distribution system. The increase in capital expenditures is offset by a reduction in power supply expenses. The reason for the reduction in Cost of Power is in turn due to the reduction in load in 2014. Details of the load forecast is presented at Exhibit 3 and a detailed description of the capital investments for 2015 can be found in the Distribution System Plan filed at Exhibit 2, Tab ?, Schedule ?

The Working Capital Allowance between 2014 and 2015 remained stable. The OM&A included in the derivation of the Working Capital Allowance is discussed in detail throughout Exhibit 4.

2014 Bridge Year vs. 2013 Actual:

Table 2.6 - 2014-2013 Rate Base Variance

Particulars	**2014**	**2013**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	8,518,626	7,921,309	597,318	7.54%
Ending Balance	8,792,238	8,518,626	273,612	3.21%
Average Balance	8,655,432	8,219,967	435,465	5.30%
Working Capital Allowance	3,497,343	3,368,475	128,868	3.83%
Total Rate Base	**12,152,775**	**11,588,442**	**564,333**	**4.87%**

Expenses for Working Capital				**NEWGAAP**
Eligible Distribution Expenses:	**2014**	**2013**	**Var**	**%**
3500-Distribution Expenses - Operation	589,388	595,899	(6,511)	1.09%
3550-Distribution Expenses - Maintenance	707,406	840,521	(133,115)	15.84%
3650-Billing and Collecting	634,033	577,268	56,765	9.83%
3700-Community Relations	55,452	52,864	2,588	4.90%
3800-Administrative and General Expenses	915,963	1,026,994	(111,032)	10.81%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	2,902,242	3,093,547	(191,305)	6.18%
3350-Power Supply Expenses	20,413,375	19,362,954	1,050,422	5.42%
Total Expenses for Working Capital	23,315,617	22,456,501	859,116	3.83%
Working Capital factor	15%	15%		0.00%
Total Working Capital	**3,497,343**	**3,368,475**	**128,868**	**3.83%**

The total projected rate base in 2014 of $12.1 million is $564K or 4.9% greater than 2013. Similar to 2015, the capital spending can be attributed to regular maintenance of the distribution system. $103K was spent in the Almonte service area on the Mill Run Phase 1B Development to provide system access. $61 K was expended on the 44 KV Betterment, from Highway 15 to

Substation 2, in Almonte. $86K was spent on the Martin St. Betterment in Pembroke. Another $65K was invested in the Robertson Road rebuild in Beachburg, Ontario. $210K was invested in the rebuild of Substation 2 in Pembroke, as well as ground grids in other substations. Working capital allowance saw a marginal increase of 128K which mirrors the increase in OM&A and Cost of Power Details of the OM&A expenditures are presented at Exhibit 4. Details of the OM&A expenditures are presented at Exhibit 4.

2013 Actual vs. 2012 Actual:

Table 2.7 - 2013-2012 Rate Base Variance

Particulars	**2013**	**2012**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	7,921,309	8,193,020	(271,711)	3.32%
Ending Balance	8,518,626	7,921,309	597,318	7.54%
Average Balance	8,219,967	8,057,164	162,803	2.02%
Working Capital Allowance	3,368,475	3,051,520	316,955	10.39%
Total Rate Base	**11,588,442**	**11,108,684**	**479,758**	**4.32%**

Expenses for Working Capital				**CGAAP**
Eligible Distribution Expenses:	**2013**	**2012**	**Var**	**%**
3500-Distribution Expenses - Operation	595,899	562,813	33,086	5.88%
3550-Distribution Expenses - Maintenance	840,521	693,882	146,639	21.13%
3650-Billing and Collecting	577,268	533,838	43,430	8.14%
3700-Community Relations	52,864	47,391	5,473	11.55%
3800-Administrative and General Expenses	1,026,994	817,920	209,074	25.56%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	3,093,547	2,655,844	437,703	16.48%
3350-Power Supply Expenses	19,362,954	17,687,620	1,675,333	9.47%
Total Expenses for Working Capital	22,456,501	20,343,464	2,113,037	10.39%
Working Capital factor	15%	15%		0.00%
Total Working Capital	**3,368,475**	**3,051,520**	**316,955.00**	**10.39%**

The total projected Rate Base in 2013 of $11.5 million is $479K or 4.32% greater than 2012. The increase is primarily due to projects such as the Fraser St. Reconductoring ($90K), the Martin St. Betterment ($92K), the Siegel Development ($93K), the Mackay St 44KV Ecress ($71K) and the beginning of The Mill St. Run Phase 1A Development (63K). Additionally a

Double Bucket Truck ($403K) was purchased to replace a 1997 truck. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw an increase proportional to the increase in OM&A. Details of the OM&A expenditures are presented at Exhibit 4.

2012Actual vs. 2011 Actual:

Table 2.8 - 2012-2011 Rate Base Variance

Particulars	**2012**	**2011**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	8,193,020	8,482,758	(289,738)	3.42%
Ending Balance	7,921,309	8,193,020	(271,711)	3.32%
Average Balance	8,057,164	8,337,889	(280,725)	3.37%
Working Capital Allowance	3,051,520	2,797,823	253,697	9.07%
Total Rate Base	**11,108,684**	**11,135,712**	**- 27,028**	**0.24%**

Expenses for Working Capital				**CGAAP**
Eligible Distribution Expenses:	**2012**	**2011**	**Var**	**%**
3500-Distribution Expenses - Operation	562,813	548,028	14,785	2.70%
3550-Distribution Expenses - Maintenance	693,882	721,496	(27,614)	3.83%
3650-Billing and Collecting	533,838	528,100	5,738	1.09%
3700-Community Relations	47,391	53,320	(5,929)	11.12%
3800-Administrative and General Expenses	817,920	833,118	(15,198)	1.82%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	2,655,844	2,684,062	(28,218)	1.05%
3350-Power Supply Expenses	17,687,620	15,968,092	1,719,528	10.77%
Total Expenses for Working Capital	20,343,464	18,652,154	1,691,310	9.07%
Working Capital factor	15%	15%		0.00%
Total Working Capital	**3,051,520**	**2,797,823**	**253,697.00**	**9.07%**

2012 shows a marginal decrease in Rate Base which is more reflective of a typical year with additions related to typical maintenance of the distribution system. The largest projects were the beginning of Maple St. Reconductoring at $65K and the 44 KV pole replacement ($87) in a section of Pembroke. Additionally a Backhoe was purchased to replace a 1985 model. (The increase in Working Capital Allowance mirrors the increase in OM&A and the increase in Cost of Power as detailed at Exhibit 4.)

2011Actual vs. 2010 Actual:

Table 2.9 - 2011-2010 Actual Rate Base Variance

Particulars	**2011**	**2010**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	8,482,758	8,858,732	(375,974)	4.24%
Ending Balance	8,193,020	8,482,758	(289,738)	3.42%
Average Balance	8,337,889	8,670,745	(332,856)	3.84%
Working Capital Allowance	2,797,823	2,623,852	173,971	6.63%
Total Rate Base	**11,135,712**	**11,294,597**	**(158,885)**	**1.41%**

Expenses for Working Capital				**CGAAP**
Eligible Distribution Expenses:	**2011**	**2010**	**Var**	**%**
3500-Distribution Expenses - Operation	548,028	388,095	159,933	41.21%
3550-Distribution Expenses - Maintenance	721,496	491,364	230,132	46.84%
3650-Billing and Collecting	528,100	600,482	(72,382)	12.05%
3700-Community Relations	53,320	41,451	11,869	28.63%
3800-Administrative and General Expenses	833,118	821,877	11,241	1.37%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	2,684,062	2,343,269	340,793	14.54%
3350-Power Supply Expenses	15,968,092	15,149,079	819,014	5.41%
Total Expenses for Working Capital	18,652,154	17,492,348	1,159,806	6.63%
Working Capital factor	15%	15%		0.00%
Total Working Capital	**2,797,823**	**2,623,852**	**173,971.00**	**6.63%**

The 2011 Rate Base shows a decrease of 159K from 2010 Actuals. The main reason for this decrease is due to underspending in the capital expenditures in comparison to other years. The largest projects that took place in 2011 were the finalization of the Ottawa Street poles and reconductoring ($78K), the New Algonquin College Campus in Pembroke ($56K), the Alexander St. rebuild ($62K) and the Beachburg Road Line upgrade ($60K). The working capital allowance mirrors the increase in OM&A as detailed at Exhibit 4.

2010 Actual vs. 2010 Board-Approved:

Table 2.10 - 2011-2010 Board Approved Rate Base Variance

Particulars	**2011**	**2010**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	8,482,758	8,858,732	(375,974)	4.24%
Ending Balance	8,193,020	8,482,758	(289,738)	3.42%
Average Balance	8,337,889	8,670,745	(332,856)	3.84%
Working Capital Allowance	2,797,823	2,623,852	173,971	6.63%
Total Rate Base	**11,135,712**	**11,294,597**	**(158,885)**	**1.41%**

Expenses for Working Capital	**CGAAP**			
Eligible Distribution Expenses:	**2011**	**2010**	**Var**	**%**
3500-Distribution Expenses - Operation	548,028	388,095	159,933	41.21%
3550-Distribution Expenses - Maintenance	721,496	491,364	230,132	46.84%
3650-Billing and Collecting	528,100	600,482	(72,382)	12.05%
3700-Community Relations	53,320	41,451	11,869	28.63%
3800-Administrative and General Expenses	833,118	821,877	11,241	1.37%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	2,684,062	2,343,269	340,793	14.54%
3350-Power Supply Expenses	15,968,092	15,149,079	819,014	5.41%
Total Expenses for Working Capital	18,652,154	17,492,348	1,159,806	6.63%
Working Capital factor	15%	15%		0.00%
Total Working Capital	**2,797,823**	**2,623,852**	**173,971.00**	**6.63%**

The total Rate Base in 2010 Actual of $2 million is $443K lesser or -10% lesser than the 2010 Board Approved. The underspending can be attributed to the fact that rates were not approved until mid-year. The utility, like many others, tend to put capital investments on hold until the cost of service application is approved. This caused delays in ORPC investing time in maintaining and upgrading its system. Ottawa River Power did complete the final stage of Substation 1 in Almonte at a cost of $166K which was part of a complete new rebuild. ORPC also purchased the Radial Boom Truck as approved in the 2010 Cost of Service application ($265K).

Ex.2/Tab 1/Sch.4 – Fixed Asset Continuity Schedules

The Continuity Schedule calculates the cost, accumulated amortization, and net book value (NBV) for each Capital USoA. The information is presented for all relevant years at the next pages

File Number:	EB-2014-0105
Exhibit:	
Tab:	
Schedule:	
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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year 2010

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 293,411	$ 12,194		$ 305,605	-$ 193,750	-$ 99,861		-$ 293,610	$ 11,994
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 6,721	-$ 335		-$ 7,056	$ 3,753
N/A	1805	Land	$ 130,499			$ 130,499				$ -	$ 130,499
47	1808	Buildings	$ 453,550	$ 14,386		$ 467,936	-$ 247,903	-$ 8,653		-$ 256,556	$ 211,380
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,563,071	$ 166,448		$ 2,729,519	-$ 1,644,839	-$ 54,439		-$ 1,699,278	$ 1,030,241
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,107,720	$ 117,218		$ 8,224,938	-$ 5,835,293	-$ 262,546		-$ 6,097,839	$ 2,127,099
47	1835	Overhead Conductors & Devices	$ 2,430,844	$ 145,586		$ 2,576,431	-$ 545,720	-$ 80,770		-$ 626,490	$ 1,949,940
47	1840	Underground Conduit	$ 2,933,508	$ 40,594		$ 2,974,102	-$ 1,985,940	-$ 110,863		-$ 2,096,803	$ 877,299
47	1845	Underground Conductors & Devices	$ 330,339	$ 75,749		$ 406,088	-$ 57,662	-$ 14,729		-$ 72,391	$ 333,697
47	1850	Line Transformers	$ 3,522,772	$ 60,897		$ 3,583,669	-$ 1,988,167	-$ 127,509		-$ 2,115,676	$ 1,467,993
47	1855	Services (Overhead & Underground)	$ 875,350	$ 103,019		$ 978,369	-$ 160,437	-$ 34,294		-$ 194,731	$ 783,638
47	1860	Meters	$ 671,911	$ 10,436	-$ 588,700	$ 93,647	-$ 391,109	-$ 2,226	$ 357,001	-$ 36,334	$ 57,313
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 122,774	$ 5,883	-$ 668	$ 127,989	-$ 116,712	-$ 2,203	$ 669	-$ 118,247	$ 9,743
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 320,010	$ 2,297		$ 322,307	-$ 296,710	-$ 21,209		-$ 317,919	$ 4,389
10	1930	Transportation Equipment	$ 1,593,935	$ 277,694	-$ 178,877	$ 1,692,752	-$ 1,322,217	-$ 82,261	$ 178,877	-$ 1,225,601	$ 467,151
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 234,049	$ 2,335		$ 236,384	-$ 205,670	-$ 7,280		-$ 212,950	$ 23,434
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 29,544	$ 5,658		$ 35,202	-$ 29,544	-$ 566		-$ 30,110	$ 5,092
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 254,912			$ 254,912	-$ 251,594	-$ 839		-$ 252,433	$ 2,479
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 502,268	$ 64,230		$ 566,498	-$ 480,824	-$ 16,226		-$ 497,049	$ 69,449
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 1,278,491	-$ 125,255		-$ 1,403,746	$ 245,977	$ 73,942		$ 319,919	-$ 1,083,827
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 24,169,421**	**$ 979,370**	**-$ 768,245**	**$ 24,380,545**	**-$ 15,581,467**	**-$ 852,866**	**$ 536,547**	**-$ 15,897,787**	**$ 8,482,758**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 24,169,421**	**$ 979,370**	**-$ 768,245**	**$ 24,380,545**	**-$ 15,581,467**	**-$ 852,866**	**$ 536,547**	**-$ 15,897,787**	**$ 8,482,758**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 852,866**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 79,522
Stores Equipment	
Net Depreciation	-$ 773,344

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year **2011**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 305,605	$ 8,648		$ 314,253	-$ 293,610	-$ 7,338		-$ 300,949	$ 13,304
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 7,056	-$ 335		-$ 7,391	$ 3,418
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 467,936	$ 18,607		$ 486,543	-$ 256,556	-$ 8,513		-$ 265,068	$ 221,475
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,729,519	$ 90,613		$ 2,820,132	-$ 1,699,278	-$ 58,621		-$ 1,757,898	$ 1,062,234
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,224,938	$ 70,412		$ 8,295,350	-$ 6,097,839	-$ 232,997		-$ 6,330,836	$ 1,964,514
47	1835	Overhead Conductors & Devices	$ 2,576,431	$ 121,027		$ 2,697,458	-$ 626,490	-$ 104,945		-$ 731,435	$ 1,966,022
47	1840	Underground Conduit	$ 2,974,102	$ 58,881		$ 3,032,983	-$ 2,096,803	-$ 104,471		-$ 2,201,274	$ 831,710
47	1845	Underground Conductors & Devices	$ 406,088	$ 99,504		$ 505,592	-$ 72,391	-$ 17,487		-$ 89,878	$ 415,714
47	1850	Line Transformers	$ 3,583,669	$ 129,496		$ 3,713,165	-$ 2,115,676	-$ 108,607		-$ 2,224,283	$ 1,488,883
47	1855	Services (Overhead & Underground)	$ 978,369	$ 95,630		$ 1,073,999	-$ 194,731	-$ 40,330		-$ 235,061	$ 838,938
47	1860	Meters	$ 93,647	$ 11,289	-$ 39,732	$ 65,204	-$ 36,334	-$ 1,500	$ 28,655	-$ 9,179	$ 56,025
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 127,989	$ 2,572		$ 130,561	-$ 118,247	-$ 2,683		-$ 120,929	$ 9,632
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 322,307	$ 8,336		$ 330,643	-$ 317,919	-$ 4,629		-$ 322,548	$ 8,096
10	1930	Transportation Equipment	$ 1,692,752	$ 28,088	-$ 21,450	$ 1,699,390	-$ 1,225,601	-$ 103,527	$ 21,450	-$ 1,307,678	$ 391,712
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 236,384	$ 5,114		$ 241,498	-$ 212,950	-$ 6,648		-$ 219,598	$ 21,900
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 35,202			$ 35,202	-$ 30,110	-$ 1,132		-$ 31,241	$ 3,961
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 254,912			$ 254,912	-$ 252,433	-$ 839		-$ 253,272	$ 1,640
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 566,498			$ 566,498	-$ 497,049	-$ 26,710		-$ 523,759	$ 42,739
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 1,403,746	-$ 254,011		-$ 1,657,757	$ 319,919	$ 58,444		$ 378,363	-$ 1,279,395
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -				$ -	$ -
		Sub-Total	**$ 24,380,545**	**$ 494,206**	**-$ 61,182**	**$ 24,813,569**	**-$ 15,897,787**	**-$ 772,867**	**$ 50,105**	**-$ 16,620,549**	**$ 8,193,020**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 24,380,545**	**$ 494,206**	**-$ 61,182**	**$ 24,813,569**	**-$ 15,897,787**	**-$ 772,867**	**$ 50,105**	**-$ 16,620,549**	**$ 8,193,020**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 772,867**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 100,659
Stores Equipment	
Net Depreciation	-$ 672,208

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year **2012**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 314,253	$ -	$ -	$ 314,253	-$ 300,949	-$ 6,972		-$ 307,921	$ 6,331
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809	$ -	$ -	$ 10,809	-$ 7,391	-$ 335		-$ 7,726	$ 3,083
N/A	1805	Land	$ 130,499	$ -	$ -	$ 130,499	$ -	$ -		$ -	$ 130,499
47	1808	Buildings	$ 486,543	$ 60,160		$ 546,703	-$ 265,068	-$ 10,088		-$ 275,156	$ 271,546
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,820,132	$ 6,177		$ 2,826,309	-$ 1,757,898	-$ 59,953		-$ 1,817,851	$ 1,008,458
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,295,350	$ 88,303		$ 8,383,653	-$ 6,330,836	-$ 206,072		-$ 6,536,908	$ 1,846,745
47	1835	Overhead Conductors & Devices	$ 2,697,458	$ 239,543		$ 2,937,001	-$ 731,435	-$ 108,052		-$ 839,488	$ 2,097,513
47	1840	Underground Conduit	$ 3,032,983	$ 3,645		$ 3,036,628	-$ 2,201,274	-$ 101,990		-$ 2,303,264	$ 733,365
47	1845	Underground Conductors & Devices	$ 505,592	$ 43,959		$ 549,551	-$ 89,878	-$ 19,281		-$ 109,159	$ 440,392
47	1850	Line Transformers	$ 3,713,165	$ 119,724		$ 3,832,890	-$ 2,224,283	-$ 108,004		-$ 2,332,287	$ 1,500,603
47	1855	Services (Overhead & Underground)	$ 1,073,999	$ 50,079		$ 1,124,078	-$ 235,061	-$ 41,942		-$ 277,003	$ 847,075
47	1860	Meters	$ 65,204	$ 24,596		$ 89,800	-$ 9,179	-$ 2,189		-$ 11,368	$ 78,432
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 130,561			$ 130,561	-$ 120,929	-$ 2,539		-$ 123,468	$ 7,094
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 330,643	$ 5,308		$ 335,951	-$ 322,548	-$ 4,429		-$ 326,977	$ 8,975
10	1930	Transportation Equipment	$ 1,699,390	$ 145,403	-$ 24,248	$ 1,820,545	-$ 1,307,678	-$ 90,648	$ 24,248	-$ 1,374,078	$ 446,467
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 241,498	$ 12,399		$ 253,897	-$ 219,598	-$ 7,118		-$ 226,716	$ 27,181
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 35,202	$ 1,574		$ 36,776	-$ 31,241	-$ 1,289		-$ 32,530	$ 4,246
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 254,912			$ 254,912	-$ 253,272	-$ 839		-$ 254,111	$ 801
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 566,498	$ 4,116		$ 570,614	-$ 523,759	-$ 23,614		-$ 547,373	$ 23,241
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 1,657,757	-$ 347,304		-$ 2,005,061	$ 378,363	$ 65,960		$ 444,323	-$ 1,560,739
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 24,813,569**	**$ 457,683**	**-$ 24,248**	**$ 25,247,004**	**-$ 16,620,549**	**-$ 729,394**	**$ 24,248**	**-$ 17,325,695**	**$ 7,921,309**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 24,813,569**	**$ 457,683**	**-$ 24,248**	**$ 25,247,004**	**-$ 16,620,549**	**-$ 729,394**	**$ 24,248**	**-$ 17,325,695**	**$ 7,921,309**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 729,394**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 81,511
Stores Equipment	
Net Depreciation	-$ 647,883

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

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6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	CGAAP	Old CGAAP
Year	2013	

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 314,253	$ 46,620	$ -	$ 360,873	-$ 307,921	-$ 12,685	$ -	-$ 320,606	$ 40,266
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809		$ -	$ 10,809	-$ 7,726	-$ 335	$ -	-$ 8,061	$ 2,748
N/A	1805	Land	$ 130,499		$ -	$ 130,499	$ -		$ -	$ -	$ 130,499
47	1808	Buildings	$ 546,703	$ 93,745		$ 640,448	-$ 275,156	-$ 13,164		-$ 288,320	$ 352,128
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,826,309	$ 40,093		$ 2,866,402	-$ 1,817,851	-$ 60,502		-$ 1,878,354	$ 988,048
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,383,653	$ 161,461		$ 8,545,114	-$ 6,536,908	-$ 197,547		-$ 6,734,455	$ 1,810,659
47	1835	Overhead Conductors & Devices	$ 2,937,001	$ 224,632		$ 3,161,633	-$ 839,488	-$ 121,673		-$ 961,161	$ 2,200,472
47	1840	Underground Conduit	$ 3,036,628	$ 2,064		$ 3,038,692	-$ 2,303,264	-$ 100,080		-$ 2,403,344	$ 635,348
47	1845	Underground Conductors & Devices	$ 549,551	$ 33,860		$ 583,411	-$ 109,159	-$ 22,228		-$ 131,387	$ 452,024
47	1850	Line Transformers	$ 3,832,890	$ 119,766		$ 3,952,656	-$ 2,332,287	-$ 111,788		-$ 2,444,074	$ 1,508,582
47	1855	Services (Overhead & Underground)	$ 1,124,078	$ 118,992		$ 1,243,070	-$ 277,003	-$ 47,343		-$ 324,346	$ 918,724
47	1860	Meters	$ 89,800	$ 9,278		$ 99,078	-$ 11,368	-$ 3,555		-$ 14,923	$ 84,155
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 130,561	$ 1,388		$ 131,949	-$ 123,468	-$ 1,410		-$ 124,878	$ 7,072
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 335,951	$ 28,127		$ 364,078	-$ 326,977	-$ 9,619		-$ 336,595	$ 27,483
10	1930	Transportation Equipment	$ 1,820,545	$ 457,242	-$ 51,999	$ 2,225,788	-$ 1,374,078	-$ 125,583	$ 51,999	-$ 1,447,662	$ 778,126
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 253,897	$ 6,273		$ 260,170	-$ 226,716	-$ 6,673		-$ 233,389	$ 26,781
8	1945	Measurement & Testing Equipment	$ -	$ 18,090		$ 18,090	$ -	-$ 905		-$ 905	$ 17,186
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 36,776			$ 36,776	-$ 32,530	-$ 1,446		-$ 33,977	$ 2,799
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ 12,104		$ 12,104	$ -	-$ 605		-$ 605	$ 11,499
47	1970	Load Management Controls Customer Premises	$ 254,912			$ 254,912	-$ 254,111	-$ 801		-$ 254,912	-$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 570,614	$ 503		$ 571,117	-$ 547,373	-$ 13,679		-$ 561,052	$ 10,066
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,005,061	-$ 35,217		-$ 2,040,278	$ 444,323	$ 69,166		$ 513,489	-$ 1,526,790
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 25,247,004**	**$ 1,339,022**	**-$ 51,999**	**$ 26,534,027**	**-$ 17,325,695**	**-$ 782,454**	**$ 51,999**	**-$ 18,056,150**	**$ 8,477,876**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 25,247,004**	**$ 1,339,022**	**-$ 51,999**	**$ 26,534,027**	**-$ 17,325,695**	**-$ 782,454**	**$ 51,999**	**-$ 18,056,150**	**$ 8,477,876**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 782,454**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 109,896
Stores Equipment	
Net Depreciation	-$ 672,558

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP New CGAAP
Year 2013

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 314,253	$ 46,620		$ 360,873	-$ 307,921	-$ 12,685		-$ 320,606	$ 40,266
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 7,726	-$ 335		-$ 8,061	$ 2,748
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 546,703	$ 93,745		$ 640,448	-$ 275,156	-$ 13,164		-$ 288,320	$ 352,127
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,826,309	$ 40,093		$ 2,866,402	-$ 1,817,851	-$ 60,503		-$ 1,878,354	$ 988,048
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,383,653	$ 161,461		$ 8,545,114	-$ 6,536,908	-$ 184,628		-$ 6,721,536	$ 1,823,578
47	1835	Overhead Conductors & Devices	$ 2,937,001	$ 224,632		$ 3,161,633	-$ 839,488	-$ 112,037		-$ 951,524	$ 2,210,109
47	1840	Underground Conduit	$ 3,036,628	$ 2,064		$ 3,038,692	-$ 2,303,264	-$ 97,006		-$ 2,400,270	$ 638,422
47	1845	Underground Conductors & Devices	$ 549,551	$ 33,860		$ 583,411	-$ 109,159	-$ 20,253		-$ 129,412	$ 453,999
47	1850	Line Transformers	$ 3,832,890	$ 119,766		$ 3,952,656	-$ 2,332,287	-$ 102,651		-$ 2,434,938	$ 1,517,718
47	1855	Services (Overhead & Underground)	$ 1,124,078	$ 118,992		$ 1,243,070	-$ 277,003	-$ 43,918		-$ 320,921	$ 922,149
47	1860	Meters	$ 89,800	$ 9,278		$ 99,078	-$ 11,368	-$ 2,969		-$ 14,337	$ 84,741
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 130,561	$ 1,388		$ 131,949	-$ 123,468	-$ 1,410		-$ 124,878	$ 7,072
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 335,951	$ 28,127		$ 364,078	-$ 326,977	-$ 9,619		-$ 336,595	$ 27,483
10	1930	Transportation Equipment	$ 1,820,545	$ 457,242	-$ 51,999	$ 2,225,788	-$ 1,374,078	-$ 125,583	$ 51,999	-$ 1,447,662	$ 778,126
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 253,897	$ 6,273		$ 260,170	-$ 226,716	-$ 6,673		-$ 233,389	$ 26,781
8	1945	Measurement & Testing Equipment	$ -	$ 18,090		$ 18,090	$ -	-$ 905		-$ 905	$ 17,185
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 36,776			$ 36,776	-$ 32,530	-$ 1,446		-$ 33,977	$ 2,799
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ 12,104		$ 12,104	$ -	-$ 605		-$ 605	$ 11,499
47	1970	Load Management Controls Customer Premises	$ 254,912			$ 254,912	-$ 254,111	-$ 800		-$ 254,912	$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 570,614	$ 503		$ 571,117	-$ 547,373	-$ 13,679		-$ 561,052	$ 10,065
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,005,061	-$ 35,217		-$ 2,040,278	$ 444,323	$ 69,166		$ 513,489	-$ 1,526,790
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 25,247,004**	**$ 1,339,021**	**-$ 51,999**	**$ 26,534,026**	**-$ 17,325,695**	**-$ 741,703**	**$ 51,999**	**-$ 18,015,400**	**$ 8,518,626**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 25,247,004**	**$ 1,339,021**	**-$ 51,999**	**$ 26,534,026**	**-$ 17,325,695**	**-$ 741,703**	**$ 51,999**	**-$ 18,015,400**	**$ 8,518,626**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 741,703**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 109,896
Stores Equipment	
Net Depreciation	-$ 631,807

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP New CGAAP
Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 360,873	$ 40,967		$ 401,840	-$ 320,606	-$ 23,809		-$ 344,415	$ 57,424
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 8,061	-$ 335		-$ 8,396	$ 2,413
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 640,448	$ 24,730		$ 665,178	-$ 288,320	-$ 15,398		-$ 303,718	$ 361,459
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,866,402	$ 107,464		$ 2,973,866	-$ 1,878,354	-$ 62,026		-$ 1,940,380	$ 1,033,486
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,545,114	$ 74,730		$ 8,619,844	-$ 6,721,536	-$ 180,999		-$ 6,902,535	$ 1,717,309
47	1835	Overhead Conductors & Devices	$ 3,161,633	$ 344,599		$ 3,506,232	-$ 951,524	-$ 134,200		-$ 1,085,725	$ 2,420,507
47	1840	Underground Conduit	$ 3,038,692	$ 43,881		$ 3,082,573	-$ 2,400,270	-$ 95,103		-$ 2,495,373	$ 587,201
47	1845	Underground Conductors & Devices	$ 583,411	$ 176,031		$ 759,442	-$ 129,412	-$ 26,857		-$ 156,269	$ 603,173
47	1850	Line Transformers	$ 3,952,656	$ 158,090		$ 4,110,746	-$ 2,434,938	-$ 102,437		-$ 2,537,375	$ 1,573,371
47	1855	Services (Overhead & Underground)	$ 1,243,070	$ 80,284		$ 1,323,354	-$ 320,921	-$ 51,452		-$ 372,373	$ 950,981
47	1860	Meters	$ 99,078			$ 99,078	-$ 14,337	-$ 2,857		-$ 17,194	$ 81,884
47	1860	Meters (Smart Meters)	$ -	$ 31,909		$ 31,909	$ -	-$ 1,064		-$ 1,064	$ 30,845
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 131,949	$ 3,337		$ 135,286	-$ 124,878	-$ 1,151		-$ 126,029	$ 9,258
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 364,078	$ 10,557		$ 374,635	-$ 336,595	-$ 14,294		-$ 350,889	$ 23,746
10	1930	Transportation Equipment	$ 2,225,788	$ 58,879	-$ 27,760	$ 2,256,907	-$ 1,447,662	-$ 161,139	$ 27,760	-$ 1,581,041	$ 675,866
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 260,170	$ 39,977		$ 300,147	-$ 233,389	-$ 7,521		-$ 240,910	$ 59,237
8	1945	Measurement & Testing Equipment	$ 18,090			$ 18,090	-$ 905	-$ 1,809		-$ 2,714	$ 15,376
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 36,776	$ 2,148		$ 38,924	-$ 33,977	-$ 1,661		-$ 35,638	$ 3,286
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 12,104			$ 12,104	-$ 605	-$ 1,210		-$ 1,816	$ 10,288
47	1970	Load Management Controls Customer Premises	$ 254,912		-$ 254,912	$ -	-$ 254,912		$ 254,912	$ 0	$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 571,117	$ 611	-$ 186,720	$ 385,008	-$ 561,052	-$ 1,645	$ 179,132	-$ 383,565	$ 1,443
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,040,278	-$ 148,792		-$ 2,189,070	$ 513,489	$ 78,283		$ 591,772	-$ 1,597,299
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 26,534,026**	**$ 1,049,402**	**-$ 469,392**	**$ 27,114,036**	**-$ 18,015,400**	**-$ 808,685**	**$ 461,803**	**-$ 18,362,281**	**$ 8,751,755**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 26,534,026**	**$ 1,049,402**	**-$ 469,392**	**$ 27,114,036**	**-$ 18,015,400**	**-$ 808,685**	**$ 461,803**	**-$ 18,362,281**	**$ 8,751,755**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 808,685**			

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP New CGAAP
Year **2014**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 360,873	$ 40,967		$ 401,840	-$ 320,606	-$ 23,809		-$ 344,415	$ 57,424
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 8,061	-$ 335		-$ 8,396	$ 2,413
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 640,448	$ 24,730		$ 665,178	-$ 288,320	-$ 15,398		-$ 303,718	$ 361,459
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,866,402	$ 107,464		$ 2,973,866	-$ 1,878,354	-$ 62,601		-$ 1,940,955	$ 1,032,911
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,545,114	$ 74,730		$ 8,619,844	-$ 6,721,536	-$ 174,643		-$ 6,896,179	$ 1,723,665
47	1835	Overhead Conductors & Devices	$ 3,161,633	$ 344,599		$ 3,506,232	-$ 951,524	-$ 116,918		-$ 1,068,442	$ 2,437,790
47	1840	Underground Conduit	$ 3,038,692	$ 43,881		$ 3,082,573	-$ 2,400,270	-$ 93,372		-$ 2,493,642	$ 588,931
47	1845	Underground Conductors & Devices	$ 583,411	$ 176,031		$ 759,442	-$ 129,412	-$ 22,877		-$ 152,289	$ 607,153
47	1850	Line Transformers	$ 3,952,656	$ 158,090		$ 4,110,746	-$ 2,434,938	-$ 95,881		-$ 2,530,819	$ 1,579,927
47	1855	Services (Overhead & Underground)	$ 1,243,070	$ 80,284		$ 1,323,354	-$ 320,921	-$ 46,299		-$ 367,220	$ 956,134
47	1860	Meters	$ 99,078			$ 99,078	-$ 14,337	-$ 2,857		-$ 17,194	$ 81,884
47	1860	Meters (Smart Meters)	$ -	$ 31,909		$ 31,909	$ -	-$ 1,064		-$ 1,064	$ 30,845
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 131,949	$ 3,337		$ 135,286	-$ 124,878	-$ 1,151		-$ 126,029	$ 9,258
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 364,078	$ 10,557		$ 374,635	-$ 336,595	-$ 14,294		-$ 350,889	$ 23,746
10	1930	Transportation Equipment	$ 2,225,788	$ 58,879	-$ 27,760	$ 2,256,907	-$ 1,447,662	-$ 161,139	$ 27,760	-$ 1,581,041	$ 675,866
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 260,170	$ 39,977		$ 300,147	-$ 233,389	-$ 7,521		-$ 240,910	$ 59,237
8	1945	Measurement & Testing Equipment	$ 18,090			$ 18,090	-$ 905	-$ 1,809		-$ 2,714	$ 15,376
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 36,776	$ 2,148		$ 38,924	-$ 33,977	-$ 1,661		-$ 35,638	$ 3,286
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 12,104			$ 12,104	-$ 605	-$ 1,210		-$ 1,816	$ 10,288
47	1970	Load Management Controls Customer Premises	$ 254,912		-$ 254,912	$ -	-$ 254,912		$ 254,912	$ 0	$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 571,117	$ 611	-$ 186,720	$ 385,008	-$ 561,052	-$ 1,645	$ 179,132	-$ 383,565	$ 1,443
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,040,278	-$ 148,792		-$ 2,189,070	$ 513,489	$ 78,283		$ 591,772	-$ 1,597,299
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 26,534,026**	**$ 1,049,402**	**-$ 469,392**	**$ 27,114,036**	**-$ 18,015,400**	**-$ 768,201**	**$ 461,803**	**-$ 18,321,798**	**$ 8,792,238**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 26,534,026**	**$ 1,049,402**	**-$ 469,392**	**$ 27,114,036**	**-$ 18,015,400**	**-$ 768,201**	**$ 461,803**	**-$ 18,321,798**	**$ 8,792,238**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 768,201**			

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2014**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 360,873	$ 40,967		$ 401,840	-$ 320,606	-$ 23,809		-$ 344,415	$ 57,424
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 8,061	-$ 335		-$ 8,396	$ 2,413
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 640,448	$ 24,730		$ 665,178	-$ 288,320	-$ 15,398		-$ 303,718	$ 361,459
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,866,402	$ 107,464		$ 2,973,866	-$ 1,878,354	-$ 62,601		-$ 1,940,955	$ 1,032,911
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,545,114	$ 74,730		$ 8,619,844	-$ 6,721,536	-$ 174,643		-$ 6,896,179	$ 1,723,665
47	1835	Overhead Conductors & Devices	$ 3,161,633	$ 344,599		$ 3,506,232	-$ 951,524	-$ 116,918		-$ 1,068,442	$ 2,437,790
47	1840	Underground Conduit	$ 3,038,692	$ 43,881		$ 3,082,573	-$ 2,400,270	-$ 93,372		-$ 2,493,642	$ 588,931
47	1845	Underground Conductors & Devices	$ 583,411	$ 176,031		$ 759,442	-$ 129,412	-$ 22,877		-$ 152,289	$ 607,153
47	1850	Line Transformers	$ 3,952,656	$ 158,090		$ 4,110,746	-$ 2,434,938	-$ 95,881		-$ 2,530,819	$ 1,579,927
47	1855	Services (Overhead & Underground)	$ 1,243,070	$ 80,284		$ 1,323,354	-$ 320,921	-$ 46,299		-$ 367,220	$ 956,134
47	1860	Meters	$ 99,078			$ 99,078	-$ 14,337	-$ 2,857		-$ 17,194	$ 81,884
47	1860	Meters (Smart Meters)	$ -	$ 31,909		$ 31,909	$ -	-$ 1,064		-$ 1,064	$ 30,845
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 131,949	$ 3,337		$ 135,286	-$ 124,878	-$ 1,151		-$ 126,029	$ 9,258
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 364,078	$ 10,557		$ 374,635	-$ 336,595	-$ 14,294		-$ 350,889	$ 23,746
10	1930	Transportation Equipment	$ 2,225,788	$ 58,879	-$ 27,760	$ 2,256,907	-$ 1,447,662	-$ 161,139	$ 27,760	-$ 1,581,041	$ 675,866
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 260,170	$ 39,977		$ 300,147	-$ 233,389	-$ 7,521		-$ 240,910	$ 59,237
8	1945	Measurement & Testing Equipment	$ 18,090			$ 18,090	-$ 905	-$ 1,809		-$ 2,714	$ 15,376
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 36,776	$ 2,148		$ 38,924	-$ 33,977	-$ 1,661		-$ 35,638	$ 3,286
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 12,104			$ 12,104	-$ 605	-$ 1,210		-$ 1,816	$ 10,288
47	1970	Load Management Controls Customer Premises	$ 254,912		-$ 254,912	$ -	-$ 254,912		$ 254,912	$ 0	$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 571,117	$ 611	-$ 186,720	$ 385,008	-$ 561,052	-$ 1,645	$ 179,132	-$ 383,565	$ 1,443
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,040,278			-$ 2,040,278	$ 513,489	$ 78,283		$ 591,772	-$ 1,448,507
47	2440	Deferred Revenue[5]	$ -	-$ 148,792		-$ 148,792	$ -			$ -	-$ 148,792
			$ -			$ -				$ -	$ -
		Sub-Total	**$ 26,534,026**	**$ 1,049,402**	**-$ 469,392**	**$ 27,114,036**	**-$ 18,015,400**	**-$ 768,201**	**$ 461,803**	**-$ 18,321,798**	**$ 8,792,238**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 26,534,026**	**$ 1,049,402**	**-$ 469,392**	**$ 27,114,036**	**-$ 18,015,400**	**-$ 768,201**	**$ 461,803**	**-$ 18,321,798**	**$ 8,792,238**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 768,201**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 144,100
Stores Equipment	
Net Depreciation	-$ 624,101

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2014-0105
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	MIFRS
Year	**2015**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 401,840	$ 34,000		$ 435,840	-$ 344,415	-$ 34,862		-$ 379,277	$ 56,562
12	1611	Computer Software (Formally known as Account 1925) from acct 1555	$ 103,008			$ 103,008	-$ 103,008	$ -		-$ 103,008	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 8,396	-$ 335		-$ 8,731	$ 2,078
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 665,178	$ 106,000		$ 771,178	-$ 303,718	-$ 18,013		-$ 321,731	$ 449,446
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,973,866	$ 139,500		$ 3,113,366	-$ 1,940,955	-$ 65,202		-$ 2,006,157	$ 1,107,209
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,619,844	$ 154,820		$ 8,774,664	-$ 6,896,179	-$ 164,905		-$ 7,061,084	$ 1,713,580
47	1835	Overhead Conductors & Devices	$ 3,506,232	$ 210,000		$ 3,716,232	-$ 1,068,442	-$ 121,691		-$ 1,190,133	$ 2,526,099
47	1840	Underground Conduit	$ 3,082,573	$ 73,000		$ 3,155,573	-$ 2,493,642	-$ 80,379		-$ 2,574,021	$ 581,552
47	1845	Underground Conductors & Devices	$ 759,442	$ 243,650		$ 1,003,092	-$ 152,289	-$ 28,121		-$ 180,410	$ 822,682
47	1850	Line Transformers	$ 4,110,746	$ 187,000		$ 4,297,746	-$ 2,530,819	-$ 89,515		-$ 2,620,334	$ 1,677,412
47	1855	Services (Overhead & Underground)	$ 1,323,354	$ 101,000		$ 1,424,354	-$ 367,220	-$ 48,073		-$ 415,293	$ 1,009,061
47	1860	Meters	$ 99,078	$ 10,000		$ 109,078	-$ 17,194	-$ 2,857		-$ 20,051	$ 89,027
47	1860	Meters (Smart Meters)	$ 31,909	$ 65,000		$ 96,909	-$ 1,064	-$ 4,294		-$ 5,358	$ 91,551
47	1860	Meters (Smart Meters) from account 1555	$ 1,645,232			$ 1,645,232	-$ 553,128	-$ 102,942		-$ 656,070	$ 989,162
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 135,286	$ 5,000		$ 140,286	-$ 126,029	-$ 1,568		-$ 127,597	$ 12,690
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 374,635	$ 10,000		$ 384,635	-$ 350,889	-$ 15,446		-$ 366,335	$ 18,300
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) from acct 1555	$ 25,493			$ 25,493	-$ 22,821	-$ 1,782		-$ 24,603	$ 890
10	1930	Transportation Equipment	$ 2,256,907	$ 61,000		$ 2,317,907	-$ 1,581,041	-$ 159,297		-$ 1,740,338	$ 577,569
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 300,147	$ 10,000		$ 310,147	-$ 240,910	-$ 8,919		-$ 249,829	$ 60,318
8	1945	Measurement & Testing Equipment	$ 18,090			$ 18,090	-$ 2,714	-$ 1,809		-$ 4,523	$ 13,567
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 38,924	$ 1,200		$ 40,124	-$ 35,638	-$ 1,430		-$ 37,068	$ 3,056
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 12,104			$ 12,104	-$ 1,816	-$ 1,210		-$ 3,026	$ 9,078
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ 0			$ 0	$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 385,008	$ 22,500		$ 407,508	-$ 383,565	-$ 4,812		-$ 388,377	$ 19,131
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,040,278			-$ 2,040,278	$ 591,772	$ 82,515		$ 674,287	-$ 1,365,992
47	2440	Deferred Revenue[5]	-$ 148,792	-$ 324,000		-$ 472,792	$ -	$ 6,920		$ 6,920	-$ 465,872
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 28,887,769**	**$ 1,109,670**	**$ -**	**$ 29,997,439**	**-$ 19,000,755**	**-$ 868,027**	**$ -**	**-$ 19,868,782**	**$ 10,128,657**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 28,887,769**	**$ 1,109,670**	**$ -**	**$ 29,997,439**	**-$ 19,000,755**	**-$ 868,027**	**$ -**	**-$ 19,868,782**	**$ 10,128,657**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 868,027**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 141,610
Stores Equipment	
Net Depreciation	-$ 726,417

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2014-0105
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 435,840	$ 19,000		$ 454,840	-$ 379,277	-$ 35,926		-$ 415,203	$ 39,636
12	1611	Computer Software (Formally known as Account 1925) from acct 1555	$ 103,008			$ 103,008	-$ 103,008			-$ 103,008	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ 10,809			$ 10,809	-$ 8,731	-$ 335		-$ 9,066	$ 1,743
N/A	1805	Land	$ 130,499			$ 130,499	$ -			$ -	$ 130,499
47	1808	Buildings	$ 771,178	$ 38,000		$ 809,178	-$ 321,731	-$ 20,893		-$ 342,624	$ 466,553
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 3,113,366	$ 193,500		$ 3,306,866	-$ 2,006,157	-$ 70,752		-$ 2,076,909	$ 1,229,957
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,774,664	$ 137,700		$ 8,912,364	-$ 7,061,084	-$ 159,046		-$ 7,220,130	$ 1,692,234
47	1835	Overhead Conductors & Devices	$ 3,716,232	$ 191,200		$ 3,907,432	-$ 1,190,133	-$ 125,151		-$ 1,315,284	$ 2,592,148
47	1840	Underground Conduit	$ 3,155,573	$ -		$ 3,155,573	-$ 2,574,021	-$ 77,920		-$ 2,651,941	$ 503,632
47	1845	Underground Conductors & Devices	$ 1,003,092	$ 163,650		$ 1,166,742	-$ 180,410	-$ 31,168		-$ 211,578	$ 955,164
47	1850	Line Transformers	$ 4,297,746	$ 172,000		$ 4,469,746	-$ 2,620,334	-$ 91,420		-$ 2,711,754	$ 1,757,992
47	1855	Services (Overhead & Underground)	$ 1,424,354	$ 101,000		$ 1,525,354	-$ 415,293	-$ 44,089		-$ 459,382	$ 1,065,972
47	1860	Meters	$ 109,078	$ 7,500		$ 116,578	-$ 20,051	-$ 3,007		-$ 23,058	$ 93,520
47	1860	Meters (Smart Meters)	$ 96,909	$ 35,200		$ 132,109	-$ 5,358	-$ 7,634		-$ 12,992	$ 119,117
47	1860	Meters (Smart Meters) from account 1555	$ 1,645,232			$ 1,645,232	-$ 656,070	-$ 102,942		-$ 759,012	$ 886,220
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 140,286	$ 8,000		$ 148,286	-$ 127,597	-$ 2,218		-$ 129,815	$ 18,472
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 384,635	$ 10,000		$ 394,635	-$ 366,335	-$ 13,206		-$ 379,541	$ 15,094
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) from acct 1555	$ 25,493			$ 25,493	-$ 24,603	-$ 890		-$ 25,493	$ 0
10	1930	Transportation Equipment	$ 2,317,907	$ 328,000		$ 2,645,907	-$ 1,740,338	-$ 157,743		-$ 1,898,081	$ 747,826
8	1935	Stores Equipment	$ 1,761			$ 1,761	-$ 1,761			-$ 1,761	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 310,147	$ 10,000		$ 320,147	-$ 249,829	-$ 8,319		-$ 258,148	$ 61,999
8	1945	Measurement & Testing Equipment	$ 18,090			$ 18,090	-$ 4,523	-$ 1,809		-$ 6,332	$ 11,758
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 40,124	$ 1,200		$ 41,324	-$ 37,068	-$ 1,104		-$ 38,172	$ 3,152
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 12,104			$ 12,104	-$ 3,026	-$ 1,210		-$ 4,236	$ 7,868
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ 0			$ 0	$ 0
47	1975	Load Management Controls Utility Premises	$ 64,873			$ 64,873	-$ 64,873			-$ 64,873	$ 0
47	1980	System Supervisor Equipment	$ 407,508	$ 130,000		$ 537,508	-$ 388,377	-$ 30,229		-$ 418,606	$ 118,902
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,040,278			-$ 2,040,278	$ 674,287	$ 71,181		$ 745,468	-$ 1,294,811
47	2440	Deferred Revenue[5]	-$ 472,792	-$ 300,000		-$ 772,792	$ 6,920	$ 26,054		$ 32,974	-$ 739,818
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 29,997,439**	**$ 1,245,950**	**$ -**	**$ 31,243,389**	**-$ 19,868,782**	**-$ 889,776**	**$ -**	**-$ 20,758,558**	**$ 10,484,831**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 29,997,439**	**$ 1,245,950**	**$ -**	**$ 31,243,389**	**-$ 19,868,782**	**-$ 889,776**	**$ -**	**-$ 20,758,558**	**$ 10,484,831**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 889,776**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 140,056
Stores Equipment	
Net Depreciation	-$ 749,720

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

2010 – 2016 System Access investments are modifications or relocation a distributor is obligated to perform to provide a customer. Taking in consideration the lack of growth and development in the service area, there are no material projects initiated in this category. There are no projects initiated by other authorities, nor by system expansion requirements nor by Renewable Energy Generation. Specifics can be found in the Distribution System Plan at Ex.2/Tab 5/Sch.2

Table 2.11 at the next page presents the System Access Capital Projects for years 2010-2016

Gross Assets

Ex.2/Tab 2/Sch.1 - Gross Assets Variance Analysis

ORPC chose to break down and explain variances under the RRFE functions; System Access (Table 2.9), System Renewal (Table 2.10), System Services (Table 2.11) and General Plant (2.12). Additions can also be found in the continuity schedules at Ex.2/Tab 1/Sch.4 at the previous schedule.

Projects		Projects	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
System Access	2010	System Access																	
	2010	New Services						60456											60456
	2010	Logan Subdivision - Ketch Construction				3290		3950											7240
	2010	New Service on Minto St. - Beachburg	1310	441				621											2372
	2010	Line Extension 3 Fern Gully Lane Beachburg	1364	1512				995											3871
	2010	Shepard St. Pump Station Upgrade																	0
	2010	351 Matheson Dr - Townhouses				3655		225											3880
	2010	Blakely St Townhouses - Ryan Habraken Carpentry				3320		808											4128
	2010	Integrated Health Centre						639											639
	2010	Microfit Connection						786											786
	2010	Hydro One Networks - Walmart Tap	43897																43897
	2010	Enerdu - APT Service				5937		1487											7424
	2010	Transformers					100224.54												60897
	2010	Meters								10436									10436
Total System Access		Total System Access	46571	1953	0	16202	100224.54	69967	0	10436	0	0	0	0	0	0	0	0	206026

Projects		Projects	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940			Total
System Access	2011	System Access																	
	2011	New Services						33106		5018									38124
	2011	MicroFit Connections								1223.66									1223.66
	2011	Enerdu Apartment					13959												13959
	2011	Ottawa Street		312		42103	2545.59	31791		1445.54									78197.13
	2011	Patterson St - Line Extension	27821																27821
	2011	Equators Grind					13562												13562
	2011	Almonte Mews - Anne St - Townhouse project	1609	1643		28927	1413	121		293.35									34006.35
	2011	Noik @ Bell St - 12 Townhouses - Ken Siegel				2096		2883											4979
	2011	375 Country St, - 18 Unit Apt.								1329.43									1329.43
	2011	New Algonquin College			54240		746.31			1383.45									56369.76
	2011	Hyde Park Condominium - Jamieson St.	126	3825		1202	2872.75												8025.75
	2011	Rondeau Electric Mackay St	1310	1472		5587													8369
	2011	Crozier Electric.	2616	3084			2064.04												7764.04
	2011	Transformers					75699												75699
Total System Access	2011	Total System Access	33482	10336	54240	79915	112861.69	67901	0	10693.43	0	0	0	0	0	0			369429.12

Projects		USoA	1830	1835	1840	1845	1850	1855	1820	1860	1808			1925	1930	1940	1955	1980	Total
System Access																			
New Services	2012							43699.86		4333									48032.86
Beachburg Line Extension	2012						1870												1870
Almonte Mews - Anne St - Townhouse project	2012							966.67		128.92									1095.59
Noik @ Bell St - 12 Townhouses - Ken Siegel	2012				550	2528													3078
New Algonquin College	2012				569.41		18188.4			477.47									19235.28
Frank Neighbour Street Extension	2012				729.66	2735													3464.66
Hyde Park Condominium - Jamieson St.	2012					11235.38	21394.39			514.13									33143.9
Rondeau Electric Mackay St	2012					6875.77	11682												18557.77
Crozier Electric.	2012			538			4286.67												4824.67
Holiday Inn Suites - Good Night Hotel Inc	2012				586	5840	391			500.9									7317.9
LCBO - 1050 Pembroke St E - MARNAC Developement	2012		3664	4515			3293.88			793.63									12266.51
Lakeridge Trail Phase Ph 2 Poleline Extension	2012		6304	11052			1404.58												18760.58
CW Homes - 559 Nelson St - Townhomes	2012				1210														1210
Poleline Extension - Fern Gulley Lane	2012		3244	1761			1347.25												6352.25
Seigel Developement - Bell & Patricia St	2012		4820				38	111											4969
Reginal Homes - Mill Run Phase 1A	2012					9654	1160.66	916											11730.66
????	2012			18227															18227
Transformers	2012						17048												17048
																			0
Total System Access			18032	36093	3645.07	38868.15	82104.83	45693.53	0	6748.05	0			0	0	0	0	0	231184.63

Projects		USoA	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
System Access																			
New Services	2013							35845.84		7266									43111.84
Almonte Mews - Anne St - Townhouse project	2013							4288		619.57									4907.57
Seigel Developement - Bell & Patricia St	2013		6295				47005	39605											92905
Reginal Homes - Mill Run Phase 1A ,	2013		4141	5045	736	24754	772	26842		256.5									62546.5
Creek Side Towns - Novatech Engineering	2013		2401		118			4359		914.53									7792.53
Everett St - 3 Unit Townhouse.	2013							340											340
Watchorn Drive Line Extension	2013		14730	14282			2124	2986											34122
Vera Cres; Install 2 Polls - Jeff Johnson	2013		2435	2774															5209
Lowe Court - Beachburg	2013		3062	3088															6150
Transformers	2013						45858												45858
Total System Access			33064	25189	854	24754	49901	114265.84	0	9056.6	0	0	0	0	0	0	0	0	302942.44

Projects		Projects	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
System Access		System Access																	
	2014	New Services - Capital					30623	39886.69		16558.91									87068.6
	2014	Micro Fit Connections								1984									1984
	2014	Anne St Townhouses						1935.14		315.08									2250.22
	2014	Noik Drive - 12 unit Apt					889.5	443.53											1333.03
	2014	Seigel Dev - Bell & Patricia St				5672.83	41.4												5714.23
	2014	OPP Detachment - Install UG Primary XLPE Cable			9139.48	15552.04	21089.45			97.87									45878.84
	2014	Fibre - Install duct from SW16 to OPP Building			1370.33														1370.33
	2014	Watchorn U/G Line Extension - Load Transfer			28289.97	7500.55	6128.07	4113.83											46032.42
	2014	Mill Run - Phase 1 B Developement			676.69	69022.02	11715.28	21184.68		340.88									102939.55
	2014	U/G Services - Townhouses - 329-339 Matheson Dr						3110.63											3110.63
	2014	New Gas Station - Almonte					14469.85	537.51		111.22									15118.58

	2014	Almonte - New Transformer Bank - Spring St Pumping Station					15598.67	465.31		110.36									16174.34
	2014	Install Transformer Bank - Stinson Paul Martin Drive					7541.31	343.61		175									8059.92
	2014	Rd Crossing - McKenzie St Development	1124.57	537.96															1662.53
	2014	Construct Line - Loadtransfer Cust. @ 68 Watchorn Rd	1006.5	726.34															1732.84
Total System Access		Total System Access	2131.07	1264.3	39476.47	97747.44	108096.53	72020.93	0	19693.32	0	0	0	0	0	0	0	0	340430.06

Projects		**Projects**	**1830**	**1835**	**1840**	**1845**	**1850**	**1855**	**1820**	**1860**	**1808**	**1915**	**1920**	**1925**	**1930**	**1940**	**1955**	**1980**	**Total**
System Access	**2015**	System Access																	0
0012	**2015**	New Services	20000	60000	53000	100000	80000	35000		10000									358000
	2015	Commercial	10000	30000	20000	50000	42500	15500		5000									173000
	2015	Scattered Residential Pembroke		20000		15000	8000	25500		4500									73000
	2015	Scattered Residential Beachburg		5000		13650	2000	5000		1500									27150
	2015	Scattered Residential Killaloe		5000			2000	5000		1500									13500
	2015	Scattered Residential Almonte		15000			6000	15000		3000									39000
																			0
Total System Access		Total System Access	30000	135000	73000	178650	140500	101000	0	25500	0	0	0	0	0	0	0	0	683650

Projects		**Projects**	**1830**	**1835**	**1840**	**1845**	**1850**	**1855**	**1820**	**1860**	**1808**	**1915**	**1920**	**1925**	**1930**	**1940**	**1955**	**1980**	**Total**
System Access		System Access																	
	2016	Scattered Residential Development Conductors		20500															20500
	2016	Scattered Residential Development Poles	17500																0
	2016	Scattered Residential Development Service wire						50500											50500
	2016	Scattered Residential Development Smart Meters Residential								10500									10500
	2016	Scattered Residential Development Transformers					18000												18000
	2016	Various Almonte Subdivisions				70650													70650
	2016	Various Almonte Subdivisions Services						31500											31500
	2016	Various Almonte Subdivisions Smart Meters Residential								10700									10700
	2016	Various Commercial Development Metering								7500									7500
	2016	Various Commercial Development OH Conductor		11000															11000
	2016	Various Commercial Development Poles	7000																0
	2016	Various Commercial Development Transformers					57000												57000
	2016	Various Commercial Development UG Cable				18000													18000
	2016	Various Pembroke Subdivisions				75000													75000
	2016	Various Pembroke Subdivisions Services						19000											19000
	2016	Various Pembroke Subdivisions Smart Meters Residential								14000									14000
	2016	Various Subdivision Transformers					62500												62500
																			0
Total System Access		Total System Access	24500	31500	0	163650	137500	101000	0	42700	0	0	0	0	0	0	0	0	476350

2010 – 2016 System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. The System Renewal expenditures for 2011 is stable and reflect normal yearly maintenance. In 2012 ORPC invested slightly more in Pole Replacement expenditure. The rest of the System Renewal expenditures once again reflect normal yearly maintenance. Overall expenditures in 2013 reflect normal yearly maintenance. In 2014 expenditures also reflect normal yearly maintenance with a slightly higher than normal investment in Pole Replacement expenditure and overhead conduits.
In 2015 ORPC plans on investing considerably more in Pole Replacement and overhead conduit expenditures. This investment supports the new Pole Replacement Program which is described in the Distribution System Plan which is found at Ex.2/Tab 5/Sch.2.

Table 2.12 at the next page presents the System Renewal Capital Projects for years 2010-2016

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
		Minor Capital Betterments	10406	26036				4045											40487
Renewal	2010	Farm St @ Almonte Lane Relocation	2008	8234															10242
	2010	Ottawa Street		31240				10616											41856
	2010	Sub-Station 1 in Almonte Rebuild							135131										135131
	2010	River Road - Bus Betterment		549				50											599
	2010	Replace Poles/Secondary Transformer - Craig St		8388															8388
	2010	Remove Lines - Bell St. and Angus Campbell Drive	6386	15341	39667	59547													120941
	2010	Morris St - Extension		7100															7100
	2010	Quarry Road - City Yard	5791	1771				299											7861
	2010	Replace Pole & Transfer Backlot - 498 Cecelia St						724											724
	2010	Install Transformer - 40 Watchorn Rd Beachburg	1581	815				1032											3428
	2010	Florence St. 44KV Airbrake Switch	11140	15922				8630											35692
	2010	Replace NRTC 35' with ORPC 40' Pole - 59 Robertson Rd	843	498				567											1908
	2010	Moffat St. Betterment 623 to 698	12217	16260				6386											34863
	2010	Alexander St. Rebuild	6186	1693	926			437											9242
	2010	Beachburg Road Line Upgrade	14089	9787				266											24142
	2010	Substation 4 -Pole Storage Building							31317										31317
Sub-Total System Renewal		Sub-Total System Renewal	70647	143634	40593	59547	0	33052	166448	0	0	0	0	0	0	0	0	0	513921

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940			Total
	2011	Minor Capital Betterments	15928	16372			5167.22	900											38367.22
	2011	Ottawa Street		3213			3798.01	16765											23776.01
	2011	Alexander St Rebuild	1750	31718	4642	19589	3753.75	438		595.15									62485.9
	2011	Beachburg Road Line Upgrade	8105	44971			2354.83	4367											59797.83
	2011	Line Upgrade - Laurier Ave	5325	6389				4045											15759
	2011	Ellis Avenue Line Upgrade	5605	8029				100											13734
	2011	Replace Feeder Cables in Substation #3					1560.09		18919										20479.09
	2011	Cassidy's Transfer Service Upgrade Warehouse 1001 Mackay St	218					1114											1332
	2011	Substation 4 Storage Building							27438										27438
	2011	Substation 7 - New Batteries							10250										10250
	2011	Substation 1 in Almonte - Completion							34006										34006
																			0
Sub-Total System Renewal		Sub-Total System Renewal	36931	110692	4642	19589	16633.9	27729	90613	595.15	0	0	0	0	0	0			307425.05

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808			1925	1930	1940	1955	1980	Total
	2012	Minor Capital Betterments	25215	67202			20176.77	3474		17847.5									133915.27
	2012	Energy Retrofit at Substation 1							4460										4460
	2012	Fraser St. Reconductoring		307															307
	2012	Maple St. Reconductoring	6258	55694			2489.5	911											65352.5
	2012	Martin St. Betterment	64																64
	2012	Pole Replacement on Coolidge - Fire - Behind 247 Mackenzie	1380	2119															3499
	2012	Replace Poles & Reconductor - Pemb W & Renfrew St	5882	2093			3592.34												11567.34
	2012	Replace 44 KV Pole - Angus Campbell Dr	3947	1470		5091													10508
	2012	Repole 44Kv Line From Superior Elec To Quarry	27525	49690			9865.47												87080.47
	2012	Install Transformer at Mikes Garage in Killaloe					1495												1495
	2012	Killaloe Reclosure		24875															24875
	2012	Battery Packs Sub 3 & 7							1717.33										1717.33
																			0
Sub-Total System Renewal		Sub-Total System Renewal	70271	203450	0	5091	37619.08	4385	6177.33	17847.5	0			0	0	0	0	0	344840.91

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2013	Minor Capital Betterments	13709	37961			18652	2511		223.62									73056.62
	2013	Fraser St. Reconductoring		89235															89235
	2013	Maple St. Reconductoring	135																135
	2013	Martin St. Betterment	75333	16465				523											92321
	2013	Replace 3 Poles & Reconductor - Pemb W & Renfrew St		6976			2611	1388											10975
	2013	Repole 44Kv Line From Superior Elec To Quarry		6638															6638
	2013	Mackay St - 44 KV Ecress Sub #4	30107	30440	1210	9106	1008												71871
	2013	Beachburg Fire - 1888 Beachburg Rd (15 KVA Transformer)	2815	3590			1735	304											8444
	2013	Replace 3 44 KV Poles McKenzie St	6297	8138															14435
	2013	Substation 2							40093										40093
																			0
Sub-Total System Renewal		Sub-Total System Renewal	128396	199443	1210	9106	24006	4726	40093	223.62	0	0	0	0	0	0	0	0	407203.62

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
																			0
	2014	Minor Capital Betterments	20668.26	57015.59			22561.07	146.2	1185.94										101577.06
	2014	Fraser St - Reconductoring		52559.22															52559.22
	2014	Martin St Betterment	1477.36	82137.54			2975.91	33.86											86624.67
	2014	Replace Defective UG Riser Pole - 240 Reynolds Ave	1456.11	799.55		1259.85													3515.51
	2014	Almonte 44 KV Betterment Hwy 15 to Sub #2	28283.83	33451.51															61735.34
	2014	Robertson Rd Rebuild - Beachburg	14504.61	38207.05			5814.96	2854.45	3589.61										64970.68
	2014	Install 35" Guy Stub Pole Anchor & Transfer - 968 Reynolds A	768.28																768.28
	2014	Replace Transformer 75 Kva to 50 Kva - 386 Morris St					6018.96												6018.96
	2014	Reroute Primary - International Drive			1569.32	8122.63	4342.3		172										14206.25
	2014	Reconductor McGee St With 4/0 / 1/0 Bus		15628.09			1004.46	353.12											16985.67
	2014	Install OH 120V Secondary - Bell St		1854.46															1854.46
	2014	Replace 2 Poles & Transfer @ Cameron St	2354.97	2479.51															4834.48
	2014	Reinsulate 15 KV Line - Bennet & Julien St		8966.84															8966.84
	2014	Fraser St - 5 KV -Convert to Armless Construction		3690															3690
	2014	Install 44 KV Switches - 260 Fraser St		3575															3575
	2014	Install 2 45' Poles - John St @ Ryan St Killaloe	2818.8	1154.54															3973.34
	2014	Upgrade Secondary Conductor - Everett St		2989															2989
	2014	Sub 3 Ground Grid							10468										10468
	2014	Sub 6 Ground Grid							10468										10468
																			0
Sub-Total System Renewal		Sub-Total System Renewal	72332.22	304507.9	1569.32	9382.48	42717.66	3387.63	25883.55	0	0	0	0	0	0	0	0	0	459780.76

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2015	Scattered Pole replacement Pembroke	43000				5500												48500
	2015	Scattered Pole replacement Almonte	15000				2000												17000
	2015	Scattered Pole replacement Beachburg	4000				1000												5000
	2015	Scattered Pole replacement Killaloe	4000				1000												5000
	2015	Minor Capital Betterments Pembroke	31820	43000		30000	19000												123820
	2015	Minor Capital Betterments Almonte	24000	25000		25000	12000												86000
	2015	Minor Capital Betterments Beachburg	1500	3500		5000	3000												13000
	2015	Minor Capital Betterments Killaloe	1500	3500		5000	3000												13000
	2015	Fisher St. to Trafalgar	0																0
	2015	Sub 4 Behind Remi Auto	0						10000										10000
	2015	Sub 2 44 kV cement Pole	0																0
	2015	Pembroke Substation Condition Assessment							20000										20000
	2015																		0
	2015	Substation Testing and assesment							14500										14500
	2015	Sub 3 Replace Pole structure at station entrance	0																0
	2015	Pembroke roads			0	0	0												0
	2015	Replace cedar poles at Mackay	0																0
	2015	Replace Bell poles		0															0
	2015	Meters								49500									49500
																			0
Sub-Total System Renewal		Sub-Total System Renewal	124820	75000	0	65000	46500	0	44500	49500	0	0	0	0	0	0	0	0	405320

System Renewal		System Renewal	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2016	Pembroke Substation testing							29000										29000

	2016	Pole Replacement	46000																0
	2016	Pole Replacement - Line betterments	14200																0
	2016	Pole Replacement - Line betterments	14200																0
	2016	Pole Replacement - Line betterments	11700																0
	2016	Pole Replacement - Line betterments conductors		44500															44500
	2016	Pole replacement Bell Killaloe																	0
	2016	Transformer replacement Program					24500												24500
	2016	Pole Replacement																	0
	2016	Pole Replacement - Line betterments transformers					10000												10000
																			0
Sub-Total System Renewal		Sub-Total System Renewal	86100	44500	0	0	34500	0	29000	0	0	0	0	0	0	0	0	0	108000

2010 – 2016 System Service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. The historical years show little investment in System services other than new meters in 2011 and 2013 and replacement of porcelain surge arrestors planned for 2015. Specifics can be found in the Distribution System Plan at Ex.2/Tab 5/Sch.2

Table 2.12 at the next page presents the System Service Capital Projects for years 2010-2016

System Service		System Service		1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
1647	**2014**	Replace Collectors in Almonte With Pole Mount Colle									12215.84									12215.84
1652	**2014**	Install New Viper Mount Reclosure - Mill St Killaloe			35561.57				4875.84											40437.41
1709	**2014**	SUB 2 - Rebuild		267.13	3265.67	2834.9	68900.61	7275.92		52752										135296.23
1725	**2014**	Subs 2 & 3 - Inspection and Testing - Almonte								28828										28828
																				0
																				0
Sub-Total System Service		Sub-Total System Service		267.13	38827.24	2834.9	68900.61	7275.92	4875.84	81580	12215.84	0	0	0	0	0	0	0	0	216777.48

System Service		System Service		1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2015	Substation 3								40000									0	40000
	2015	Almonte Sub 2 & 3								30000									0	30000
	2015	Substation 6								25000									7000	32000
																				0
Sub-Total System Service		Sub-Total System Service		0	0	0	0	0	0	95000	0	0	0	0	0	0	0	0	7000	102000

System Service		System Service		1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2016	Almonte MS-2 44 kV conductor upgrades			58100															58100
	2016	Engineering Studies								86000										86000
	2016	Almonte MS-2 44 kV pole upgrades		27100																0
	2016	Almonte Feeder MS-2 (2F2) conductor upgrades																		0
	2016	Almonte Feeder Reclosing relay MS 2			24300															24300
	2016	Almonte Feeder Reclosing relay MS 3			18500															18500
	2016	Almonte MS 3 feeder cables			14300															14300
	2016	Electronic Protective relays								16500										16500
	2016	Scada upgrade																	45000	45000
	2016	Outage Management System																	78000	78000
	2016	Pembroke MS 6 Ground Grid								12000										12000
	2016	Pembroke MS 6 Ground Grid								50000										50000
	2016	Pembroke Substation MS 2										38000								38000
	2016	SCADA connections Almonte MS-1																	7000	7000
Sub-Total System Service		Sub-Total System Service		27100	115200	0	0	0	0	164500	0	38000	0	0	0	0	0	0	130000	447700

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Table 2.12 at the next page presents the General Plant Capital Projects for years 2010-2016

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2010	Building Accesibility									14386.46								14386.46
	2010	Upgrade office furniture for service department										5883							5883
	2010	Upgrade two PC's from 2003											2297						2297
	2010	Hansen Software												1050					1050
	2010	TCG Computers												2450					2450
	2010	BTS- Accpac Upgrade												1585					1585
	2010	Third Octet												7109					7109
	2010	2010 Radial Boom Line Truck													277694.84				277694.84
	2010	Miscellaneous Small Tools														2335			2335
	2010	Upgrade of radio system															5658		5658
	2010	Scada Computer and System Upgrade																64230	64230
Sub-Total General Plant		Sub-Total General Plant	0	0	0	0	0	0	0	0	14386.46	5883	2297	12194	277694.84	2335	5658	64230	384678.3
Total Capital Expenditures			117218	145587	40593	75749	100224.54	103019	166448	10436	14386.46	5883	2297	12194	277694.84	2335	5658	64230	1104625.3

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940			Total
	2011	Building Accessibility									5349								5349
	2011	New Roof									8830								8830
	2011	Renovate downstairs washroom									4428								4428
	2011	Office Chairs										2572							2572
	2011	2011 Chevrolet Pickup Truck - Almonte													28088				28088
	2011	Harris												4500					4500
	2011	Other Software												4148.02					4148.02
	2011	Miscellaneous Small Tools														5113.61			5113.61
	2011	Computer Hardware											8336.17						8336.17
																			0
Sub-Total General Plant		Sub-Total General Plant	0	0	0	0	0	0	0	0	18607	2572	8336.17	8648.02	28088	5113.61			71364.8

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808			1925	1930	1940	1955	1980	Total
	2012	Front Office Washroom									12844.2								12844.2
	2012	Heat Exchanger									7423.92								7423.92
	2012	Pave between buildings									4100								4100
	2012	New Front Entrance - Accessibility Entrance									29978.81								29978.81
	2012	Roof Repair									5813								5813
	2012	Annual PC replacement												5308					5308
	2012	Chipper													41500				41500
	2012	Backhoe													57000				57000
	2012	2012 Dodge Grand Caravan													27191				27191
	2012	Rebuild Engine 2005 International 4400 - Almonte													7585				7585
	2012	Reel Trailer													12127				12127
	2012	Miscellaneous Small Tools														12398.51			12398.51
	2012	Communication Equipment															1574.33		1574.33
	2012	Scada Equipment																4116	4116
																			0
																			0
																			0
Sub-Total General Plant		Sub-Total General Plant	0	0	0	0	0	0	0	0	60159.93			5308	145403	12398.51	1574.33	4116	228959.77

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1945	1980	Total
	2013	Doors for Garage									11963								11963
	2013	Overhead Walkway between Buildings									41323								41323
	2013	Install accessible washroom, new shower area and men'swashroom and lunch room area									40459								40459
	2013	Office Chairs										1388							1388
	2013	Computer Hardware											28127.21						28127.21
	2013	Harris - Upgrade to new version												46620					46620
	2013	2014 Dodge Ram													25170				25170
	2013	2013 Ford F150 1/2 Ton													30746				30746
	2013	2014 Double Bucket Material Handler Truck													401326				401326
	2013	Miscellaneous Small Tools														6273			6273
	2013	Measurement and Testing Equipment														12104	18090	503	30697
Sub-Total General Plant		Sub-Total General Plant	0	0	0	0	0	0	0	0	93745	1388	28127.21	46620	457242	18377	18090	503	664092.21
Total Capital Expenditures			161460	224632	2064	33860	73907	118991.84	40093	9280.22	93745	1388	28127.21	46620	457242	18377	18090	503	1374238.27

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2014	Men's Wshrm Accessability									11740.48								11740.48
	2014	Garage Work									12989.12								12989.12
	2014	Office Desk & Chairs										3337							3337
	2014	Computer Hardware: Printers, Desktops											10556.86						10556.86
	2014	Computer Software - CIS												28560					28560
	2014	Computer Software - Finance, Mapping												12406.71					12406.71
	2014	Forklift Purchase													16400				16400
	2014	Ford C-Max - Service Vehicle Purchase													28236				28236
	2014	Utility Trailer													8970				8970
	2014	Final Material for Double Bucket Truck													5273.43				5273.43
	2014	Small Tools														39977.4			39977.4
	2014	Communication Equip															2147.6		2147.6
	2014	System Supervisory Equp																611.33	611.33
																			0
Sub-Total General Plant		Sub-Total General Plant	0	0	0	0	0	0	0	0	24729.6	3337	10556.86	40966.71	58879.43	39977.4	2147.6	611.33	181205.93

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2015	Doors for Stores									10000								10000
	2015	Fire Alarm									38000								38000
	2015	Garage Roof									20000								20000
	2015	Garage floor									13000								13000
	2015	Office Furniture front office										5000							5000
	2015	PC Upgrade											10000						10000
	2015	Misc Software Upgrades												34000					34000
	2015	Office façade									25000								25000
	2015	2016 RBD downpayment													36000				36000
	2015	#28 van													25000				25000
	2015	Miscellaneous Small Tools														10000			10000
	2015	Radios															1200		1200
	2015	Scada Equipment																15500	15500
Sub-Total General Plant	2015	Sub-Total General Plant	0	0	0	0	0	0	0	0	106000	5000	10000	34000	61000	10000	1200	15500	242700
Total Capital Expenditures			154820	210000	73000	243650	187000	101000	139500	75000	106000	5000	10000	34000	61000	10000	1200	22500	1433670

General Plant		General Plant	1830	1835	1840	1845	1850	1855	1820	1860	1808	1915	1920	1925	1930	1940	1955	1980	Total
	2016	Misc Small Tools														10000			10000
	2016	Misc Software Upgrades												9000					9000
	2016	Misc Software Upgrades												10000					10000
	2016	Mobile radio															1200		1200
	2016	PC Upgrade											10000						10000
	2016	Replacement Furniture										8000							8000
	2016	Transportation Equipment													300000				300000
	2016	Transportation Equipment													28000				28000
																			0
Sub-Total General Plant		Sub-Total General Plant	0	0	0	0	0	0	0	0	0	8000	10000	19000	328000	10000	1200	0	376200

2010 – 2011: While the percentage increase in 2011 was not particularly notable, the increased dollar value reflects a new boom insert installed on bucket truck T95-1. The truck itself was actually purchased in 2012.

2011 – 2012: The 2012 General Plant expenditures increased significantly due to the purchase of a bucket truck to replace a 26 year old truck that had reached the end of its useful life. Further details can be found in the Distribution System Plan.

2012 – 2013: The 2013 General Plant expenditures increased due to the purchase of new pickup truck to replace a truck purchased in 1999. This unit was rusted and in need of considerable maintenance. Further details can be found in the Distribution System Plan.

2013 – 2014: The 2014 General Plant expenditures focused more on much needed building renovations. As indicated in the Distribution System Plan, the aluminum siding and the doors and windows were replaced and 1.5 inches of Styrofoam board was installed all around. The doors and windows in particular allowed cold air leaks to occur. These improvements, taken together, should result in significantly lower heating costs this winter.

2014 – 2015: The General Plant expenditures for the test year reflect investments in a second pickup truck and computer hardware, more specifically a new desktop at the warehouse and a new laser printer for billing.

ORPC's assets fall into two broad categories – the first is ***distribution plant***, which includes assets such as municipal substations, poles, conductors, overhead and underground electricity distribution infrastructure, transformers and meters. The second is ***general plant*** which includes assets such as: office building and service centre, office furniture, transportation equipment, communications techno9logy, computer equipment and software, general equipment and tools. Table 2.2.5 below provides details of these functions along with the associated contributed capital.

Ex.2/Tab 2/Sch.2 - Accumulated Depreciation

ORPC has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at the following link http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf.

The rates used are presented below and the Continuity Schedules of the Accumulated Depreciation are presented at the next pages.

ORPC's Accumulated Depreciation is presented in a continuity schedule at the next page. While ORPC's accumulated depreciation generally increases at the same pace as the utility capital investment, the accumulated depreciation decreased in 2015 and 2016 due to increased depreciable lives.

ORPC's depreciation expense policy and methodology are provided at Ex.2/Tab 5/Sch.3. The depreciation expenses continuity schedules are presented in Exhibit 4.

Table 2.14 below provides ORPC's depreciable lives by asset class.

Table 2.16 - Comparison of Depreciation Rates

Account	Description	CGAAP	Modified CGAAP Post 2013
1611	Computer Software (Formally known as Account 1925)	5.00	5.00
1820	Distribution Station Equipment <50 kV	30.00	55.00
1830	Poles, Towers & Fixtures	25.00	40.00
1835	Overhead Conductors & Devices	25.00	60.00
1845	Underground Conductors & Devices	25.00	35.00
1850	Line Transformers	25.00	40.00
1855	Services (Overhead & Underground)	25.00	40.00
1860	Meters	25.00	25.00
1860	Meters (Smart Meters)	25.00	15.00
1915	Office Furniture & Equipment (10 years)	10.00	10.00
1920	Computer Equipment - Hardware	5.00	5.00
1935	Stores Equipment	10.00	10.00
1940	Tools, Shop & Garage Equipment	10.00	10.00
1945	Measurement & Testing Equipment	10.00	10.00

1995	Contributions & Grants	25.00	40.00

Allowance for Working Capital

Ex.2/Tab 3/Sch.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 3, 2015 where the OEB set 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 split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. The derivation of the Cost of Power can be found at Exhibit 9. Table 2.15 presented below show ORPC's calculations in determining its Allowance for Working Capital.

Table 2.17 - Allowance for Working Capital

Expenses for Working Capital	**2016**
Eligible Distribution Expenses:	
3500-Distribution Expenses - Operation	630,467
3550-Distribution Expenses - Maintenance	802,123
3650-Billing and Collecting	733,000
3700-Community Relations	67,000
3800-Administrative and General Expenses	1,062,375
6105-Taxes other than Income Taxes	-
6205-Sub-account LEAP Funding	-
Total Eligible Distribution Expenses	3,294,964
3350-Power Supply Expenses	23,602,740,
Total Expenses for Working Capital	26,897,704
Working Capital factor	7.50%
Total Working Capital	**2,017,328**

Table 2.18 - Working Capital Trend

Expenses for Working Capital	Last Board Approved	2010	2011	2012	2013	2014	2015	2016
Eligible Distribution Expenses:								
3500-Distribution Expenses - Operation	360,476	388,095	548,028	562,813	595,899	589,388	617,080	630,467
3550-Distribution Expenses - Maintenance	705,409	491,364	721,496	693,882	840,521	707,406	766,322	802,123
3650-Billing and Collecting	616,443	600,482	528,100	533,838	577,268	634,033	710,315	733,000
3700-Community Relations	58,624	41,451	53,320	47,391	52,864	55,452	61,000	67,000
3800-Administrative and General Expenses	859,815	821,877	833,118	817,920	1,026,994	915,963	969,266	1,062,375
6105-Taxes other than Income Taxes	-	-	-	-	-	-	-	-
6205-Sub-account LEAP Funding	-	-	-	-	-	-	-	-
Total Eligible Distribution Expenses	2,600,768	2,343,269	2,684,062	2,655,844	3,093,547	2,902,242	3,123,984	3,294,964
3350-Power Supply Expenses	16,212,879	15,149,079	15,968,092	17,687,620	19,362,954	20,413,375	19,632,374	23,602,740
Total Expenses for Working Capital	18,813,647	17,492,348	18,652,154	20,343,464	22,456,500	23,315,618	22,756,358	26,897,704
Working Capital factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Total Working Capital	**2,822,047**	**2,623,852**	**2,797,823**	**3,051,520**	**3,368,475**	**3,497,343**	**3,413,454**	**2,017,328**

The Working Capital Allowance ("WCA") remained stable between the years of 2010 Board Approved and 2012. The WCA increased proportionally with the OM&A and Cost of Power. In 2016, the WCA dropped as a result of the OEB reducing the rate from 13% to 7.5%.

Ex.2/Tab 3/Sch.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 April 12, 2012 letter providing two approaches for the calculation of the allowance for working capital:

(1) The 7.5% allowance approach; or

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

In addition, ORPC has not previously been directed by the Board to undertake a lead/lag study.

Smart Meter Deployment and Stranded Meters

Ex.2/Tab 4/Sch.1 - Disposition of Smart Meters

Introduction:

Ottawa River Power Corporation (ORPC) is seeking recovery of costs incurred while implementing the Province of Ontario's Smart Meter Initiative.

As of December 31, 2012, 100% of ORPC's residential and general service less than 50 kW customer base had conventional meters replaced with smart meters. The total Smart Meter Initiative costs claimed in this application are $1,841,170 as indicated in Table 2.19 below. These costs can be offset by the disposition of the Smart Meter Funding Adder ("SMFA"). The SMFA was introduced by the Board in ORPC's 2006 rates and continued until April 30, 2012. Ottawa River Power Corporation's 2012, 2013 and 2014 rates do not include the SMFA or any other rates associated with the Smart Meter Initiative.

Table 2.19 - Summary of Cost Claim

Smart Meter – Capital Costs	$1,743,787
Smart Meter – O&M Costs	$ 97,383
Total Smart Meter Costs	$1,841,170

The costs of the Smart Meter Initiative (to December 31, 2012) are partially offset by the SMFA, in the amount $559,000. This includes accumulated interest.

ORPC is proposing to follow the allocation methodology applied by the Board in the Smart Meter Initiative proceedings of other distributors.
The resulting rate riders being proposed are displayed in Table 2.20 below.

Table 2.20 - Summary of Cost Claim

Rate Rider	Residential	GS<50 kW
Smart Meter Disposition Rate Rider (SMDR)	$2.46	$7.18

According to the Board's Guideline, the Smart Meter Disposition Rider ("SMDR") recovers, over a specified time period, the variance between: 1) the deferred revenue requirement for the Smart Meter Initiative up to the time of disposition, and 2) the SMFA revenues collected from May 2006 through April 2012 and associated carrying charges until May 1, 2015.

The Applicant's costs of the Smart Meter Initiative were $167.58 average capital cost per meter and $176.93 average total cost per meter as set out in Tables 2.21 and 2.22 below.

The Board's report, "Sector Smart Meter Audit Review Report", dated March 31, 2010, indicates a sector average capital cost of $186.76 per meter and an average total cost of $207.37 per meter (capital plus OM&A). The review was based on 3,053,931 meters (64% complete) with capital costs of $570,339,200 and a total cost of $633,294,140 as at September 30, 2009. The review period was January 1, 2006 to September 30, 2009.

Table 2.21 - Average Capital Cost per Meter

Smart Meter Capital Costs (Including Costs Exceeding Minimum Functionality)	$1,743,787
Smart Meter Capital Costs Exceeding Minimum Functionality	$0
Smart Meter Capital Costs Excluding Costs Exceeding Minimum Functionality	$1,743,787
Number of Meters Installed	10,406
Average Cost per Meter (Excluding Costs Exceeding Minimum Functionality)	$167.58

Table 2.22 - Average Total Cost per Meter

Smart Meter Capital Costs (Including Costs Exceeding Minimum Functionality)	$1,743,787
Smart Meter Capital Costs Exceeding Minimum Functionality	$0
Smart Meter OM&A Costs Including OM&A Cost Exceeding Minimum Functionality	$97,383
Smart Meter OM&A Costs Excluding Costs Exceeding Minimum Functionality	$0
Total Smart Meter Costs Excluding All Costs Exceeding Minimum Functionality	$1,841,170
Number of Meters Installed	10,406
Average Cost per Meter (Excluding Costs Exceeding Minimum Functionality)	$176.93

As illustrated in Table 2.23, the Applicant was able to implement the Smart Meter Initiative below the provincial average. Consequently, ORPC's customers will pay approximately 17.2% less for their smart meters, than the Board's benchmark for the industry. This was due in large part to the partnering of four local utilities namely: Hydro 2000 Inc., Co-Operative Embrun, Renfrew Hydro Inc. and Ottawa River Power Corporation. Together they operated as one under the London RFP and to this day they continue to share software and computer hardware.

Table 2.23 - Comparison with Sector Averages

	Ottawa River Power Corporation	Ontario	Variance $	Variance %
Average Capital Cost	$167.58	$186.76	($19.18)	(11.44%)
Average Total Cost	$176.93	$207.37	($30.44)	(17.20%)

Ottawa River Power Corporation is not seeking recovery at this time for any costs that exceed minimum functionality required by the Province of Ontario. The Board's Guideline, section 3.4, described beyond minimum functionality as incremental smart meter technical capabilities, deployment to larger customers and Time-of-Use ("TOU") implementation costs such as CIS system upgrades, web presentation, integration with the Province's MDM/R, etc. While these are foreseeable costs associated with the Smart Meter Initiative, they are subject to separate regulatory treatment.

As the Board is aware, ORPC has already implemented TOU pricing, including CIS system upgrades, a web presentation service with a third party, and integration with the Province's MDM/R. This application is specific to the Smart Meter Initiative costs and recovery.

Procurement and London RFP:

Ottawa River Power Corporation purchased its smart meters through the London Hydro Request for Proposals ("RFP"). The process enabled dozens of distributors, including ORPC, to benefit from collective expertise and buying power.

The sufficiency of the process was recognized by the Province of Ontario which, through O. Reg. 427/08, authorized the distributors that participated in the London Hydro RFP to proceed with the Smart Meter Initiative. ORPC was among those authorized distributors.

Ottawa River Power Corporation had previously taken part in a Smart Meter Pilot Project as part of the third tranche CD&M that had been approved by the Ontario Energy Board in 2007. During this pilot project approximately 450 REX1 smart meters were installed in customer's premises.
As part of the London Hydro RFP, ORPC attempted to contact and do business with the proponent in the London Hydro RFP that received the best score based on the ORPC's criteria in accordance with the prescribed process. After this failed, ORPC contacted the Fairness Commissioner. Approval to purchase the smart meter infrastructure from its second proponent, Elster Metering was received in February 2009. A copy of this correspondence is attached.

The Applicant retained the services of an in-house Project Manager for the management of the Smart Meter Initiative.

After a competitive process for supporting services, ORPC awarded contracts to: Green-port Environmental for meter disposal and Elster Metering as the installation service provider.

Table 2.24 - Smart Meter Installations by Year and by Rate Class

Year	Smart Meters Installed			% Converted in Year	% Converted to Date
	Residential	GS < 50 kW	Total		
2007	490		490	4.7%	4.7%
2008	155		155	1.5%	6.2%
2009	2905	159	3064	29.4%	35.6%
2010	5365	811	6176	59.3%	94.9%
2011	113	286	399	3.9%	98.8%
2012	25	97	122	1.2%	100%
Total	9053	1353	10406	100%	100%

Ottawa River Power Corporation installed a total of 10,406 smart meters as at December 31, 2012, which represented 100% of its Residential and 100% of its GS < 50 rate classes.

ORPC has not included any 2013 installations of smart meters attributable to growth of Residential and GS<50 customers. Neither the capital cost nor the operating cost of these smart meters is included for recovery sought in this application. For 2013 and beyond, the capital and operating costs for growth related smart meters have been included in the rate base. Those incremental smart meters are being and will continue to be treated as Account 1860 meters.

Cost:

The Board's Guideline, section 3.5, states that, "The Board expects the majority (i.e. 90% or more) of the total program costs for which the distributor is seeking recovery will be audited." Ottawa River Power Corporation has included costs up to and including those captured in its audited financial statements as at December 31, 2012. As such, all of the costs for which ORPC is seeking recovery were incurred in years for which an external financial audit has been completed and thus exceeds the 90% threshold set in the Board's Guideline.

In this application, the ORPC is seeking recovery for the minimum functionality costs of the Smart Meter Initiative as at December 31, 2012. The costs of the post 2012 smart meters and beyond minimum functionality costs are not included in this application. Full details of the various cost components by year are shown in Sheet 2 of the Smart Meter Model attached as Appendix H. Table 2.25 below provides an intermediate-level break down of the costs.

Table 2.25 - Smart Meter Costs Claimed for Recovery

Cost	Cost Sub-Element		Total Costs
Capital	1.1	Advanced Metering Communications Devices (AMCD)	$1,551,545
	1.2	Advanced Metering Regional Collector (AMRC) (Includes	$31,551
	1.3	Advanced Metering Control Computer (AMCC)	$92,693
	1.4	Wide Area Network (WAN)	$0
	1.5	Other AMI Capital Costs Related to Minimum Functionality	$67,998
	1.6	Capital Costs Beyond Minimum Functionality	$0
	Total Smart Meter Capital Costs		$1,743,787
OM&A	2.1	Incremental AMCD OM&A Costs	$18,044
	2.2	Incremental AMRC OM&A Costs	$0
	2.3	Incremental AMCC OM&A Costs	$64,122
	2.4	Incremental AMRC OM&A Costs	$0
	2.5	Other AMI OM&A Costs Related to Minimum Functionality	$15,217
	2.6	OM&A Costs Beyond Minimum Functionality	$0
	Total Smart Meter OM&A Costs		$97,383
Total	**Total Smart Meter Costs**		**$1,841,170**

As presented in Tables 2.21 and 2.22 and 2.23 and discussed in the introduction, all costs incurred in completing the Smart Meter Initiative have been prudently incurred as is evidenced by a $167.58 average capital cost per meter and a $176.93 average total cost per meter. These costs are lower than the Ontario benchmarks of $186.76 average capital cost per meter and $207.37 average total cost per meter.

This is the first application by ORPC for recovery of Smart Meter Initiative costs and therefore the variance analysis against prior recovery is not applicable in this case.

Ottawa River Power Corporation has completed the Smart Meter Initiative as prescribed by provincial regulation. ORPC is not at this time seeking recovery for costs beyond minimum functionality.

Rate Riders:
(SMFA)

In the Board's 2006 Decision (RP-2005-0020, EB-2005-0403) setting ORPC's 2006 rates, a $0.25 SMFA was applied to all metered customers namely residential, less than 50 KW and greater than 50 KW customers. The $0.25 SMFA amount continued to be embedded in ORPC's metered customers' rates until the Board's 2009 Decision and Order (EB-2008-0206). In that Decision, the Board increased the SMFA to $1.00 per metered customer per month effective May 1, 2009. The SMFA of $1.00 continued until May 1, 2012. Since that date, no SMFA has been charged.

In EB-2011-0128, the Board stated: "The Board directs PowerStream to allocate the smart meter adder amounts collected from the GS > 50 and Large Use customer classes evenly to the Residential and GS < 50 classes when calculating the true-up for the SMDR." Ottawa River Power Corporation has complied with the methodology approved in the PowerStream Decision and provided for in the Board's 2016 Smart Meter Model v5.0. Table 2.26 below shows the SMFA re-allocation. The other class revenue is re-allocated evenly to the Residential and GS < 50 rate classes and presented in Table 2.26. Details are included in the Smart Meter Model attached as Appendix H.

Table 2.26 - Smart Meter Funding Adder Revenue Allocation

Rate Class	SMFA ($)	SMFA (%)	SMFA Other Distributed	SMFA
Residential	$488,253	87.4%	$3,018	$491,272
GS<50	$64,546	11.5%	$3,018	$67,564
GS >50	$6,037	1.1%	-	-
Total	**$558,836**	**100%**	**$6,037**	**$558,836**

Rate Riders:

(SMDR)

Ottawa River Power Corporation is seeking Board approval for a Smart Meter Disposition Rate Rider in the amount of $2.46 per Residential customer per month and $7.18 per GS< 50 customer per month, for the two year period May 1, 2015 to April 30, 2017. The calculation was made utilizing the Board's Smart Meter Model v6.0 (Appendix H).

ORPC has presented the Weighted Average Cost of Capital ("WACC") and Tax Rates reflected in its Smart Meter Model in Table 2.27 below. The WACC and Tax Rates agree to those approved in each year's respective approved rates for 2006 through 2014.

Table 2.27 - WACC and Tax Rate Inputs

Year	2006 IRM	2007 IRM	2008 IRM	2009 COS	2010 IRM	2011 IRM	2012 IRM	2013 IRM	2014 IRM
WACC	8.13%	8.13%	8.07%	8.01%	8.08%	8.08%	8.08%	8.08%	8.08%
Tax Rates	18.62%	18.62%	18.62%	18.62%	16.00%	16.00%	16.00%	16.00%	16.00 %

The value of the SMDR is based on the net amount resulting from:

- Deferred and forecasted Smart Meter Incremental Revenue Requirement from 2008 to December 31, 2014

  Plus

- Interest on deferred and forecasted OM&A and amortization expenses 2008 to December 31, 2014

  Less

- SMFA revenues collected from May 1, 2006 to April 30, 2012 and carrying charges from May 1, 2006 to April 30, 2015.

Tables 2.28, 2.29 and 2.30 below show the calculation of the SMDR for each rate class, including the cost allocation between the rate classes.

Table 2-28 - Smart Meter Disposition Rate (SMDR)

Component of Revenue Requirement	Residential	GS < 50	Total
Return, Amortization and Related Interest	$944,000	$281,974	$1,225,974
OM&A	$85,739	$12,814	$98,553
PILs	$43,017	$12,315	$55,331
Total Revenue Requirement	$1,072,756	$307,103	$1,379,858
SMFA Revenue including Carrying Charges	$537,598	$73,934	$611,532
Net Deferred Revenue Requirement	$535,158	$233,169	$768,326
Number of Metered Customers	9,053	1,353	10,406
Calculation of Smart Meter Disposition Rider	$2.46	$7.18	$9.64

Table 2.29 – Smart Meter Revenue Requirement Calcs.

Component	Allocator		Return	Amortization	Interest	OM&A	PILs	Total	Residential	GS < 50	Total
Return Amortization Interest	Capital costs of the meters installed of each class	%							77.00%	23.00%	100.00%
OM&A Interest	# Meters installed for each class	$	$556,775	$643,244	$25,955			$1,225,974	$944,000	$281,974	$1,225,974
		%							87.00%	13.00%	100.00%
		$			$1,170	$97,383		$98,553	$85,739	$12,814	$98,553
Revenue Requirement Before PILs Allocation								$1,324,527	$1,029,739	$294,788	$1,324,527
PILs	Revenue Requirement allocated to	$							$1,029,739	$294,788	$1,324,527
	each class before PILs (A+B)	%							77.74%	22.26%	100.00%
		$					$55,331	$55,331	$43,017	$12,314	$55,331
Total Revenue Requirement		**$**	**$556,775**	**$643,244**	**$27,125**	**$97,383**	**$55,331**	**$1,379,858**	**$1,072,756**	**$307,102**	**1,379,858**
		%							77.74%	22.26%	100.00%

Table 2.30 - SMDR Backup - Allocation Costs

Allocator		Residential	GS < 50	Total
Capital costs of Meters Installed - AMCD 1.1	$	$1,342,716	$401,071	$1,743,787
	%	**77.0%**	**23.0%**	**100.0%**

# Meters installed	#	9,053	1,353	10,406
	%	**87.0%**	**13.0%**	**100.0%**
Total Revenue Requirement	$	$1,072,756	$307,102	$1,379,858
	%	**77.74%**	**22.26%**	**100.0%**

It is respectfully submitted that the costs for smart metering requested for recovery in this application have been prudently incurred to fulfill the Applicant’s obligations under the Provincially-mandated Smart Meter Initiative and have been prudently incurred in accordance with Board’s guidelines. Moreover, the proposed rate riders are just and reasonable and the associated customer bill impacts are reasonable. It is therefore appropriate that the Board approve the proposed rate riders for implementation effective May 1, 2016.

Of importance, the Applicant implemented the provincial policy in a manner that resulted in average total costs per meter lower than the provincial benchmark.

Ex.2/Tab 4/Sch.2 - Treatment of Stranded Meters

In the Minimum Filing Requirements, the Board states that the Smart Meter Funding and Cost Recovery (G-2008-0002) provides two options regarding the accounting treatment for Stranded Meters related to the installation of smart meters:

- Option A: transfer the Stranded Meter costs to "Sub-account Stranded Meter Costs" of Account 1555; or
- Option B: continue to record Stranded Meter costs in Account 1860.

Ottawa River Power has acted in accordance with Option A; effective as of 2010 the net book value of Ottawa River Power's Stranded Meters had been transferred to the "Sub-account Stranded Meter Costs" of Account 1555. The table below (excerpt from Appendix 2-R of the Board's Appendices) shows the net book value of Ottawa River Power's stranded smart meters.

Table 2.30a) - Summary of Proposed Charge Parameters

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2009		$314,616.63	$157,835.55	$0.00	$156,781.08	$0.00	$156,781.08
2010		$902,723.88	$514,836.59	$0.00	$387,887.29	$0.00	$387,887.29
2011		$942,455.57	$543,491.16	$0.00	$398,964.41	$0.00	$398,964.41
2012		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix 2-S requests that utilities complete the following information relating to the treatment of the utility's stranded meters.

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes. Thus far, stranded meters were included in account 1860 and therefore were treated in accordance with CGAAP with the same accounting rules as standard meters.

   a. Ottawa River Power transferred $2.16 M stranded meter costs out of account 1860.

2. The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2010.
   a. The amount of pooled residual net book value as of December 31st, 2012 is in the amount of $398,964.

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2012.
   a. The Stranded meter amount, after its removal from Account 1860, was not depreciated.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2012.
   a. The depreciation amount would have been for the period from the time that meters became stranded to December 31, 2012 would have been $85K.

5. The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.
   a. The net residual amount at the end of 2012 was $398K.

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.
    a. The applicant intends to recover the cost of the Stranded Meters through a Rate Rider. The proposed recovery period is 2 years. Calculations of the proposed rate rider are presented at Table 1 below.

Table 2.30b) - Stranded Meter Rate Rider

Customer Class Name	**Net Book Value**	**% share**	**Annual $**	**Customer**	**Rate**	**per month**
Residential	$187,513.27	47.00%	62504.42	9384	$6.66	$0.56
General Service < 50 kW	$95,751.46	24.00%	31917.15	1300	$24.56	$2.05
General Service > 50 to 4999 kW	$115,699.68	29.00%	38566.56	146	$264.15	$22.01
	TOTAL	100.00%				

Total for Recovery			**398,964**
Recovery Period (years)		**3**	
Annual Recovery			**132,988**

Capital Expenditures

Ex.2/Tab 5/Sch.1 - Planning

The RRFE Report of the Board concluded that an integrated approach to planning is preferred. With this in mind Ottawa River Power consolidated all categories of system investments its capital expenditure plan, including investments to renew and expand the distribution system, investments identified in a regional planning process, and investments to accommodate the connection of renewable generation or to implement a smart grid. These requirements are discussed in the DSP at Ex.2/Tab 5/Sch.2

Ex.2/Tab 5/Sch.2 - Distribution System Plan

Ottawa River Power Corporation

Distribution System Plan

Developed in accordance with
"Ontario Energy Board – Filing Requirements for Electricity Transmission and Distribution Applications"
Chapter 5

Consolidated System Plan Filing Requirements

For the Period

2015 to 2019

Date: November 2014

Prepared by: Denis Montgomery

Edited by: Christine Mitchell

Reviewed by: James Buckingham (P.Eng)

With Support by: CHEC LDC Inc.,

Table of Contents

5.0 Introduction

Ottawa River Power Corporation (herein ORPC) has organized its Distribution System Plan (DS Plan) according to the suggested format contained within the March 28, 2013 "Chapter 5 Consolidated Distribution System Plan Filing Requirements Guide." Additional subsections have been added to expand on relevant topics of discussion to support the new work plan, as well as for ease of reference. This is ORPC's first DS Plan, and as such there are no available comparisons to any previously filed DS Plans.

This document outlines the ORPC DS Plan covering the historical period of 2009-2014 and the projected period of 2015-2019. The report also identifies recommendations to improve on the available asset data and the potential to implement a more structured and analytical asset management strategy. This report focuses on:

1. Asset inspection and maintenance
2. Capital expenditure planning
3. The required supporting information management systems
4. The effect of renewable generation on ORPC distribution system

In developing the DS Plan, the following factors were considered:

1. Available asset inventory
2. Asset condition based on the current inspection processes
3. Current and proposed FIT and micro FIT projects
4. Current capital expense programs, as identified by ORPC staff

5.1 General and Administrative Matters

ORPC is an embedded distributor within Hydro One's service territory and is connected to the Hydro One Distribution System. ORPC is located in and around the City of Pembroke. Other municipalities served by ORPC are: 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). The ORPC distribution system is connected to five points of the HONI distribution system.

Transformer Substation Owner	Feeder Name	Community Served within **ORPC** service territory
Hydro One Networks Almonte TS (NAL20)	Almonte TS 20M25	Almonte
Hydro One Networks Cobden TS 23M2 Beachburg DS (QM2334)	Beachburg DS 34 F1 feeder	Beachburg
Hydro One Networks Pembroke TS (Q6)	Pembroke TS 6M1 Feeder Pembroke TS 6M2 Feeder	Pembroke
Hydro One Networks Cobden TS 23M6 Killaloe DS (QM28) Alternate Wallace TS 16M6	Killaloe DS 28F2	Killaloe

As an embedded utility, ORPC is billed monthly by Hydro One for all Transmission related charges. Transmission and Low Voltages charges are passed through to ORPC's customers.

ORPC is a municipally owned local distribution company originally serving the residents and customers of the City of Pembroke and the Villages of Beachburg, Almonte and Killaloe. ORPC is currently licensed to distribute electricity within the confines of the boundaries as described herein.

ORPC is a regulated electricity distribution company whose principal activity is delivering electricity to over 10,718 residential, General Service, Street Lighting, Sentinel Light and Unmetered Scattered Load customers/connections, commercial, and industrial customers in the City of Pembroke and the municipalities of Beachburg, Almonte and Killaloe.

ORPC is licensed to distribute electricity within the boundaries of the City of Pembroke and the Villages of Beachburg, Almonte and Killaloe. The outlying service territory is serviced by Hydro One Networks Inc. (HONI).

When combined, ORPC has a service area of 35 square kilometres, a municipal population as provided by the communities of 20,200 and a customer base of approximately 10,700. ORPC's system consists of over 270 kilometres of primary conductor, both overhead and underground and more than 1,900 distribution transformers. The ORPC service area is mature, possessing a customer density less than 40 customers per km of line.

ORPC's service area consists of 44kV, 12kV, and 4kV high voltage systems. The ORPC system operates three primary voltages, these are a 44kV sub transmission circuit which feeds eleven (11) MS stations owned and

operated by ORPC, and these stations provide 4.16kV and 12/7.20kV to the feeder circuits. The company operates the municipal substations with 44kV oil circuit breakers located in Pembroke only.
The 4.16kV system in Pembroke is being replaced with 12kV; voltage conversion began in the 1970s with the new additions of substations in Pembroke and is ongoing with the plan to convert the distribution system connected to Substation 5.

Almonte Ward contains (3) three DS stations owned and operated by ORPC. These stations provide 4.16kV power to multiple feeders. A new substation (MS-1) was installed in 2010 in conjunction with the Mississippi River Power Corporation while upgrades were being completed on their generating station.

ORPC operates its distribution system from the City of Pembroke and from Almonte Ward which represents the bulk of its service area and customer base. Pembroke staff travel to Beachburg and Killaloe to complete preventive maintenance, renewals, connections and responding to power outages.

ORPC is embedded within the HONI system. ORPC does not host any utilities; however, we have embedded generators within the service area:

- Brookfield is a 10.5 MW generation facility connected to the Pembroke 44 kV system via ORPC's Substation 4 and Substation 1
- Mississippi River Power is a 4.6 MW generation facility connected to the Almonte 44 kV system at Almonte MS-1
- Enerdu is a 300kw generation facility connected to the 4.16 kV system in Almonte MS-1

The current ORPC system was created by the amalgamation of the distribution systems of City of Pembroke and the municipalities of Beachburg, Almonte and Killaloe. These distribution systems operate independently and are not directly connected to one another.

ORPC's distribution system in Pembroke was designed and constructed since the 1900s. Since this time, parts of the distribution system were converted from a 2400 Volt feeder system to a 7200 Volt feeder system.

ORPC's distribution system in Almonte was designed and constructed since the 1900's and the distribution system contains a 2400 Volt feeder system. It is also important to note that ORPC also owns and operates three individual transformer stations in Almonte that are located throughout the town. Two substations will require upgrading in the next 10 years and the addition of a new substation is planned for future growth beyond 2020. From a replacement cost perspective, the new transformer station may represent approximately 5% of ORPC's entire asset.

Beachburg and Killaloe consist of circuits that are connected to the Hydro One Cobden DS.

ORPC owns and operates a very well-built, reliable, safe and efficient electrical distribution system. Due to the entire system redundancy, ORPC's mode of operation has been to repair equipment following failure for the last few decades. Over the 2014 to 2020 planning horizon, ORPC is transitioning out of this mode into a predictive maintenance mode and a subsequent capital rebuild mode, as needed. The transition will be driven

by the results of the recently adopted systems for asset management and capital planning processes, which will give ORPC improved oversight and understanding of the state of its distribution system.
In 2012, ORPC contracted BDO Group to perform an IFRS conversion program and at the same time inventory the assets of distribution system. Details and data resulting from the analysis will be quoted throughout the DSP.

An analysis of load flow and load loss was completed in the 2005-2007 period. The analysis provided a system load study of which concluded that:

- Marginal implications were required to rebalance the system by changing individual load phase connections; and
- No additional options for loss reduction need be considered (e.g. increasing conductor size).

ORPC's distribution station assets include:

- Eight distribution stations that step voltage from 44kV down to 12kv and 4kV for distribution within the City of Pembroke; and
- Three distribution stations that steps voltage from 44kV down to 4kV for distribution within Almonte Ward (within the Township of Mississippi Mills).

Recently, ORPC has become a member of the CHEC Association. The Cornerstone Hydro Electric Concepts Association (CHEC) developed out of the Organized Power Group. CHEC, as an association of small LDCs, is focused on assisting Member LDCs meet these regulatory and service requirements in the most effective manner. Through the collaborative nature of the Association, LDCs have access to resources to assist them to meet the regulatory requirements while continuing to focus on providing excellent services to their customers.

The CHEC Mission and Vision is in support of Ottawa River Power's focus on serving customers in the communities of Pembroke, Beachburg, Killaloe, and Almonte. CHEC, as a not for profit corporation, is focused on providing a collaborative environment where LDCs can gain benefits from working together with other like-minded LDCs to continue to meet the needs of their customers.

The aim of CHEC as written in its mission statement is: "To be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources." The Association is led by a Board of Directors, all from Member LDCs, which share the challenges faced within the sector. The Association, through committees, working groups, training, shared models and shared documents support the efforts of the individual LDC. The ability to reach out and share information and best practices is enhanced through the working relationships developed within the network of the Association.

Participation in CHEC helps each LDC to:

- Maintain Local Control;
- Maintain Local Ownership;
- Increase Efficiencies; and
- Lower impact of new costs.

CHEC members have clearly stated the value of membership to be in excess of one full time equivalent position. A review of membership in CHEC by a third party consultant summarized the benefits as indicated by Members to include:

- Collaboration, security and best business practices;
- Provides "peace of mind" – simplified services, someone else is on it, one less thing on the collective TO DO list, support and knowledge that you are not alone;
- Compliance issues addressed through single provider, consistency in deliverables and messaging to OEB and OPA with the efficiency of a single submission; and
- Validation and clarity on emerging business pressures.

Pembroke

ORPC receives power from two Hydro One 44kV circuits for the City of Pembroke. The two circuits originate from the HONI owned Pembroke TS. These 44kV circuits are used to supply our distribution assets described above. Electricity is then distributed through ORPC's service area of **31** square kilometers through the company's 170 km of overhead primary conductors and 25 km of underground cable.

Almonte

ORPC receives power from one Hydro One 44kV circuit, at the HONI owned Arnprior TS that connects to the Almonte DS. These 44kV circuits are used to supply our distribution assets described above. Electricity is then distributed through ORPC's service area of **4** square kilometers through the company's 57 km of overhead conductors and 9.3 km of underground cable.

Transformers

The distribution voltage of 12kV and 4kV is stepped down by approximately 1,900 transformers, both overhead and pad mounted, to the service voltage provided to our customers.

Control Room

ORPC monitors its distribution system using a station monitoring system at its main office building in Pembroke. A planned contingency/continuity back-up monitoring system located at a different location should be completed in the fall of 2014.

Underground versus Overhead Distribution Plant

The majority of ORPC's distribution system consists of overhead conductor affixed to wood poles. Underground conductors are primarily found in newer developments, as well as at larger three-phase customer installations. Several years ago, ORPC undertook a significant effort to map out the dimensions and properties of its distribution system in a GIS system. The results of the mapping exercise state that ORPC owns and operates:

Type of Primary Power Line	Length	Units
Three Phase OH Primary Power Lines	112.87	km
Single Phase OH Primary Power Lines	157.2	km
Three Phase UG Primary Power Lines	3.35	km
Two Phase UG Primary Power Lines	1.88	km
Single Phase UG Primary Power Lines	19.8	km
Total	296	km

Metering

ORPC owns and maintains approximately 10,650 smart meters installed on its customers' premises for the purpose of measuring energy consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW demand and kVA, as well as hourly interval data. On June 25, 2008, Ontario Regulation 235/08 was filed by the Ontario Provincial Government giving ORPC authorization to proceed with its first phase of Smart Meter installation. ORPC completed the installation of all of its Residential and General Service <50kW Smart Meters by 2012 as part of the Province of Ontario's Smart Meter initiative.

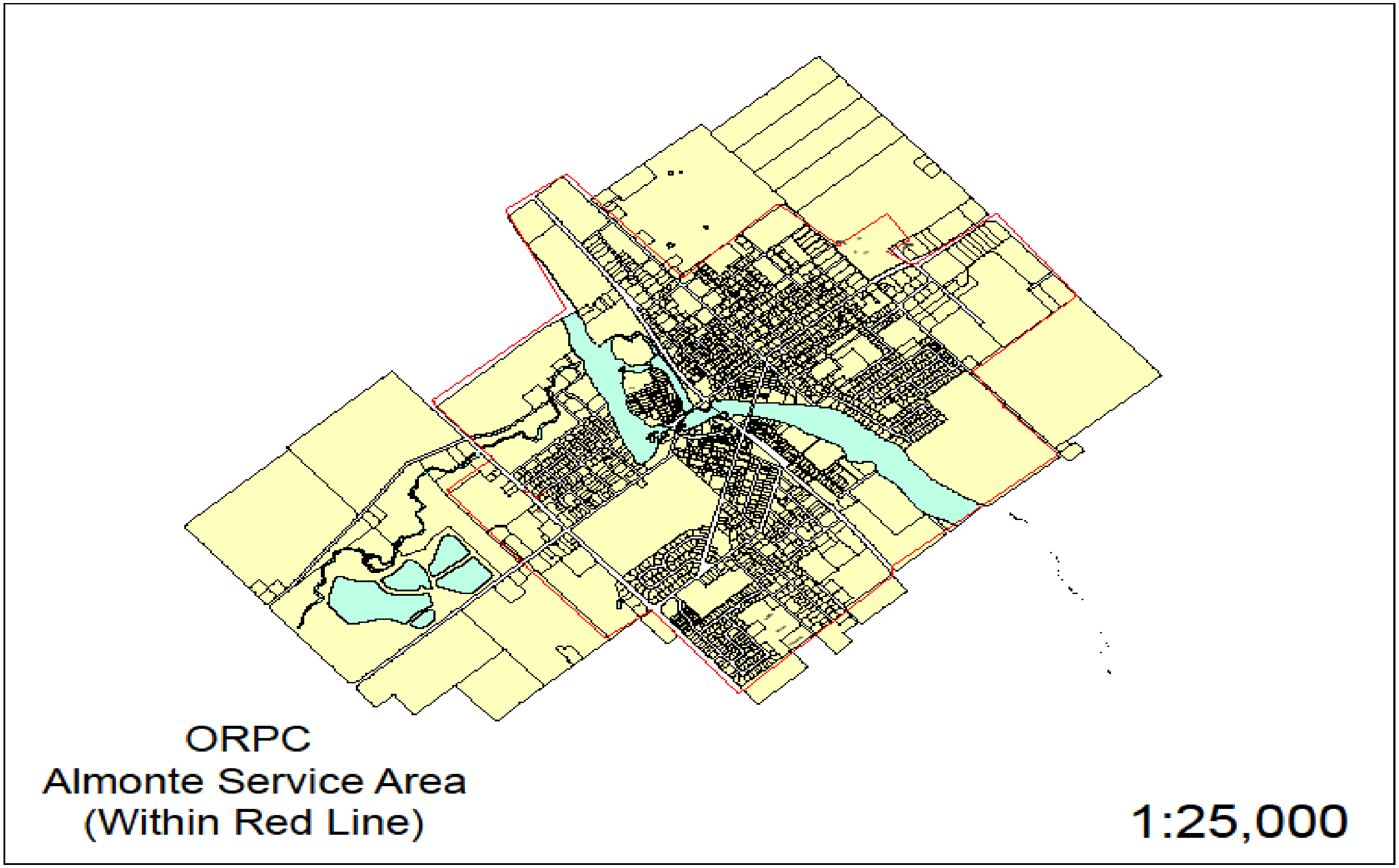
In managing its distribution system assets, ORPC's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and worker safety and customer service requirements.

In addition to the capital needs of the network, ORPC provides for maintenance planning for the assets. ORPC's assets fall into two broad categories:

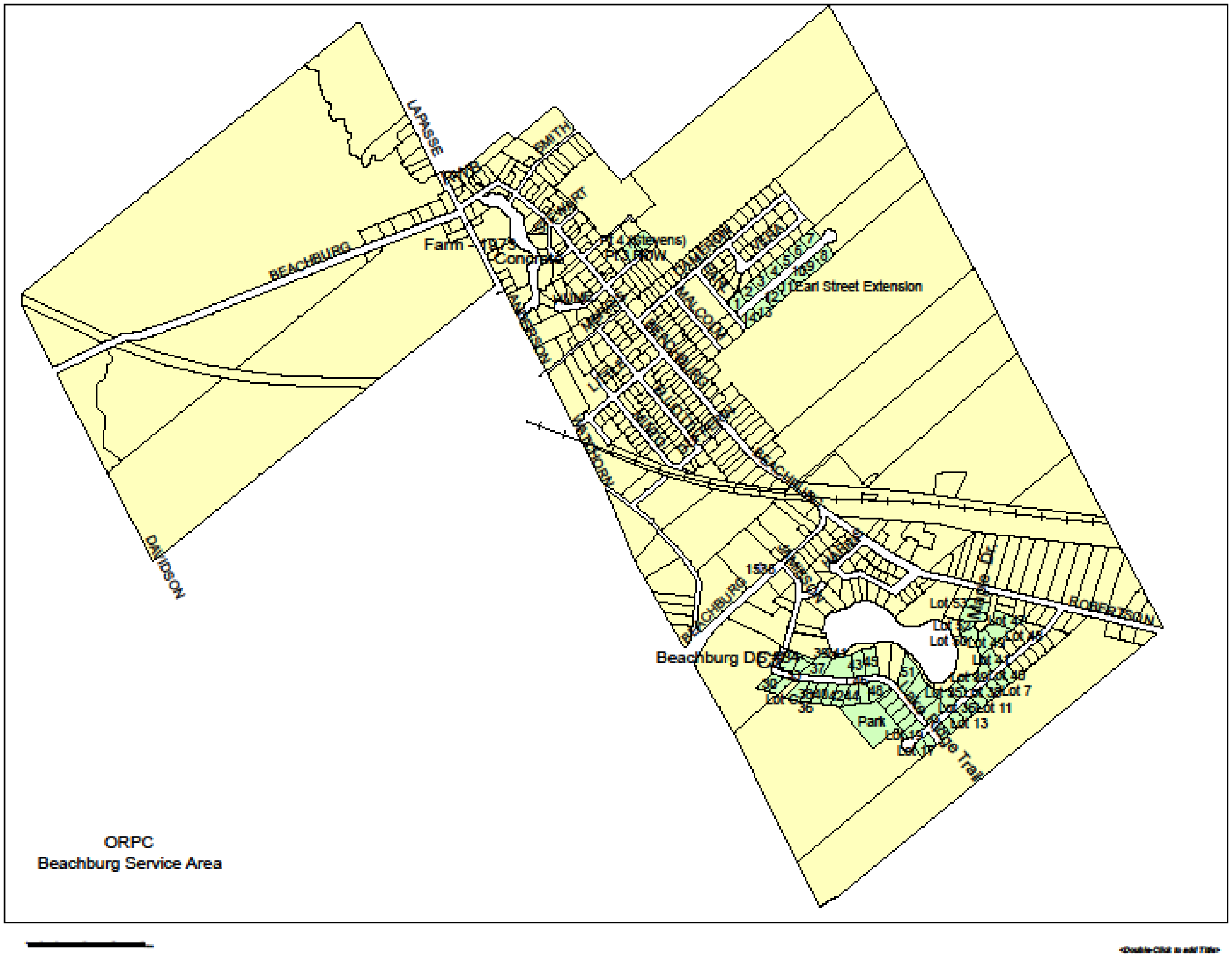
- Distribution plant which includes assets such as substation building, wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and
- General plant which includes assets such as, office building and service center, computer equipment and software. General Plant also includes the company's fleet of 31 vehicles, trailers and stores equipment. Vehicles in Almonte include 2 bucket trucks and 1 pick-up truck. Vehicles in Pembroke include 3 bucket trucks, 2 pick-up trucks, and four service vans.

Below are ORPC service area maps and single-line diagrams:

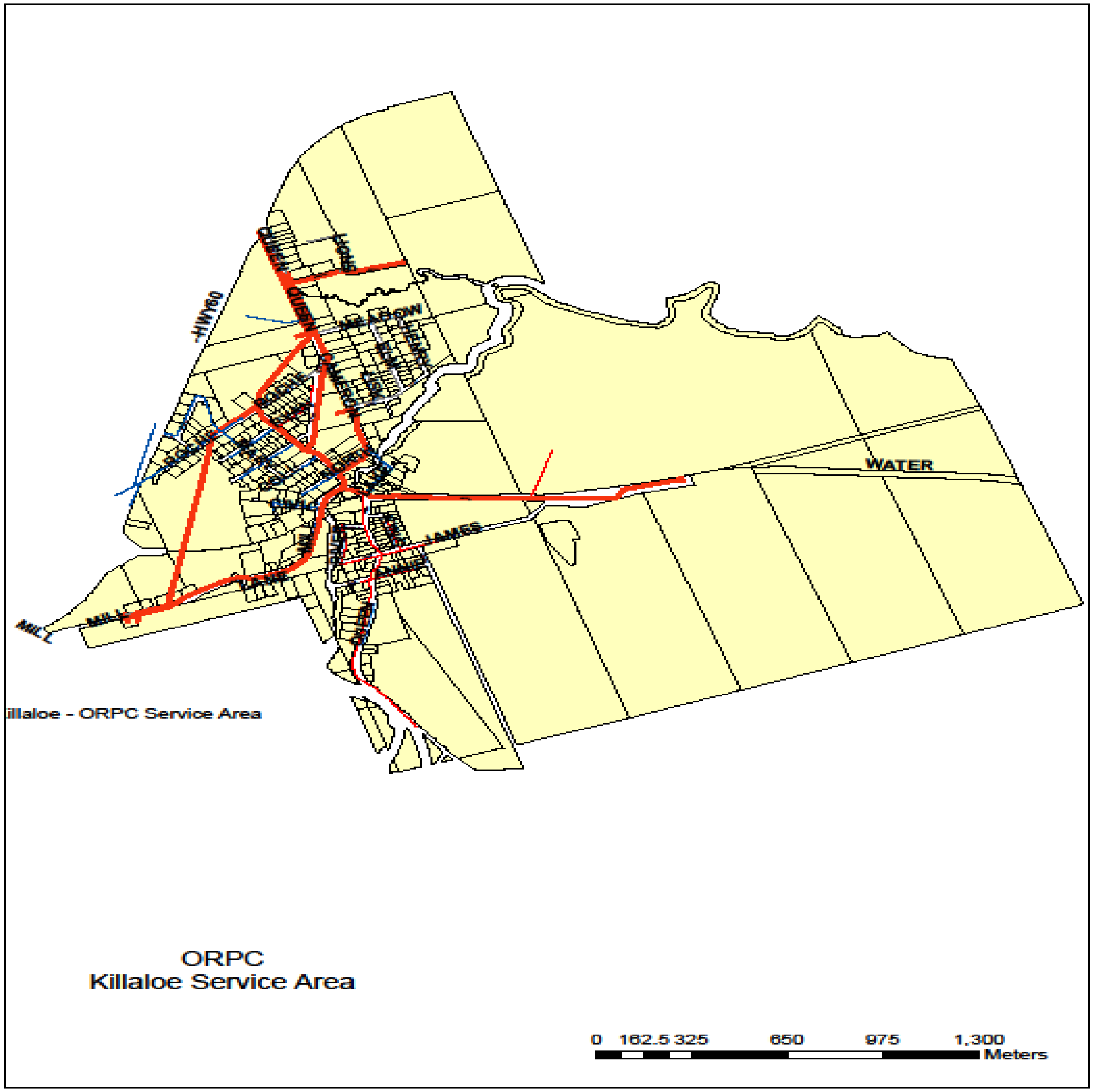
ORPC Service Territory Map – Almonte



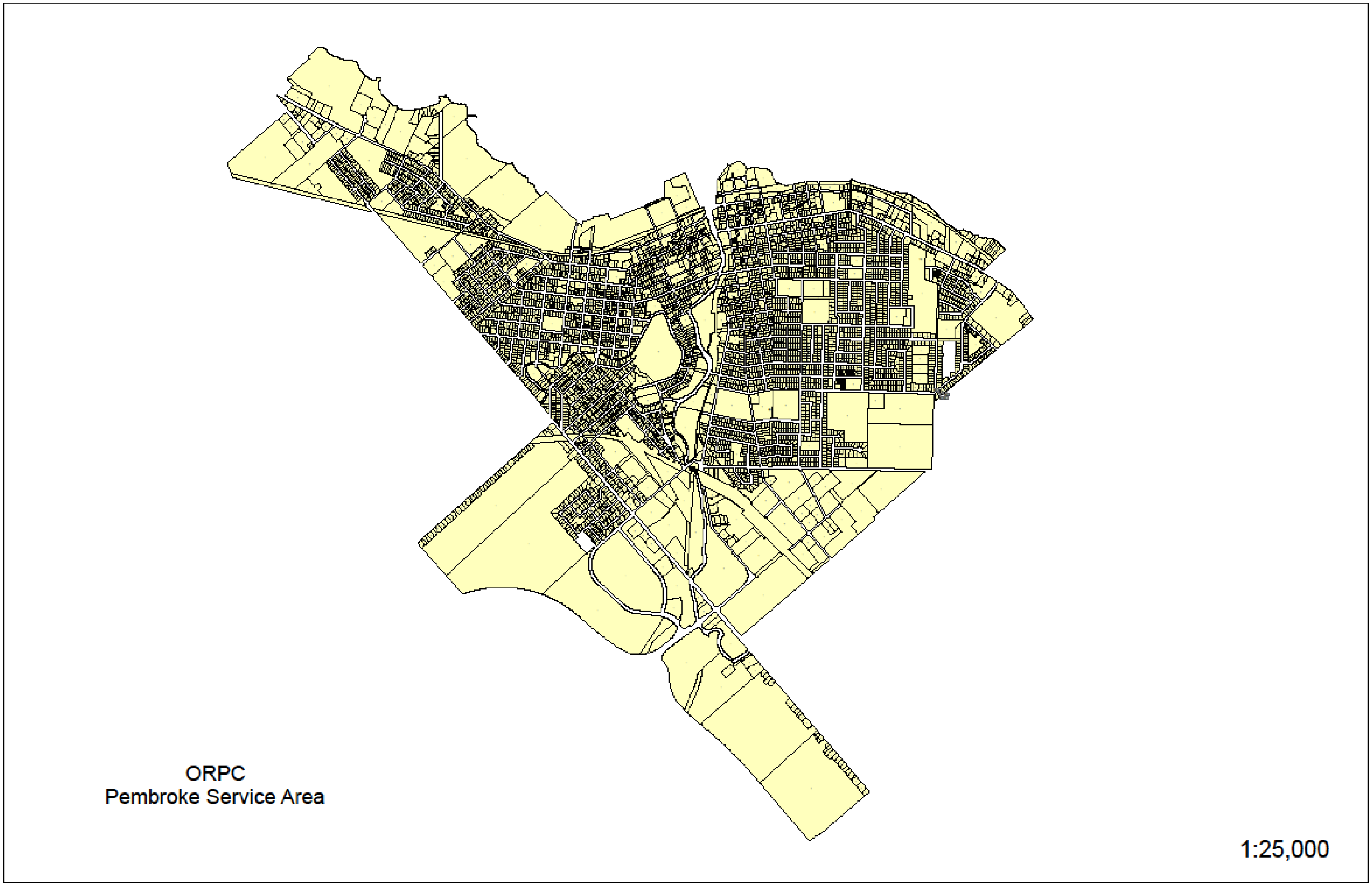
ORPC Service Territory Map – Beachburg



ORPC Service Territory Map – Killaloe



ORPC Service Territory Map – City of Pembroke



Customer Statistics

The Table below shows the most recent three-year customer statistics. The customer base is stable, but slowly growing. Over the past three years, ORPC has experienced:

- Customer numbers trend;
- Overall consumption patterns; and
- Summer or winter peaking.

All data included in this report is accurate as of 31/12/2014 unless otherwise specified.

General Statistics	For the year ended December 31, 2012	For the year ended December 31, 2013	For the year ended December 31, 2014
Population Served	20,200	20,200	20,200
Municipal Population	20,200	20,200	20,200
Seasonal Population	-	-	-
Residential	9,136	9,250	9,298
General Service (<50 kW)	1,351	1,322	1,316
General Service (50-4999 kW)	146	146	146
Large User (>5000 kW)	-	-	-
Sub Transmission	-	-	-
Total Customers	**10,633**	**10,718**	**10,791**
Rural Service Area (sq. km)	-	-	-
Urban Service Area (sq. km)	35	35	35
Total Service Area (sq. km)	**35**	**35**	**35**
Overhead km of Primary Line		270	270
Underground km of Primary Line		25	25
Total km of Line		**295**	**295**
Total kWh Delivered (excluding losses)	188,134,284	188,547,051	186,751,366
Total Distribution Losses (kWh)	4,896,238	12,469,321	7,794,424
Total kWh Purchased	**193,030,522**	**201,016,372**	**194,545,791**
Winter Peak (kW)	35,963	36,856	43,158
Summer Peak (kW)	33,570	29,294	33,756
Average Peak (kW)	29,443	26,575	31,681
Capital Additions in 2012	$ 822,268	$ 1,336,555	$ 1,198,235
Full time equivalent number of employees	28	28	27

The life of a community is rarely confined to its political borders and urban development in Pembroke has spilled over to the neighbouring rural townships in the County of Renfrew. The affinity with the rural hinterland is a contributing factor to the demand for city services by rural residents.

The City of Pembroke's population has experienced modest growth over the past two census periods, with approximately 3% growth in both the 2006 and 2011 censuses. This growth has returned population levels to those previous to the 2001 census, which saw a sharp decrease of 4.8% during the 1996-2001 period. Persons per household figures continue to decline at a rate of approximately 0.02 persons per year, which is consistent with the overall provincial trend of decreasing household size.

The institutional sector in particular has seen significant increases over the past five years, including the construction of a new 50,000 square foot medical centre in 2009, the construction of the new Algonquin College Waterfront Campus in 2011, and the current construction of a new 22,000 square foot Ontario Provincial Police headquarters.

In consideration of historic population and building trends, the population of the City of Pembroke has been projected to grow at a rate of just under 0.5% per annum, reaching approximately 16,006 people by the year 2034.

Population projections are as follows:

- Total new residential construction in the planning period is expected to be approximately 38 units per year.
- Low density housing is expected to continue to account for the majority (60%) of housing completions. The demographic shifts anticipated in the population profile (aging of population), along with the natural pace of urban growth, suggest a gradual continued shift toward higher density housing demand in the City of Pembroke over the next three decades. It is expected that medium and high density housing will account for about 40% of the total residential construction in the future.

The available inventory of residential land can accommodate the projected population growth, which is based on projected demand for housing over the 20-year planning period. The inventory of approved and potential new residential lots includes some 2,267 units (March 2014) encompassing a full range of housing types. This inventory is sufficient to accommodate any potential influxes in population that may result from personnel changes at major federal government employers including Garrison Petawawa and Chalk River Laboratories.

The non-residential (ICI) supply is also substantial. There is a minimum twenty year supply.

Planning for new development shall include consideration for adequate capacity of all services and the cost-efficient routing of utilities and coordination in the design and installation of facilities as part of the approval and construction process. Preference will be given to the installation of underground services for new development.

5.2 Distribution System Plans

5.2.1 Distribution System Plan Overview

Ottawa River Power Corporation in a glance at year end 2014

	2014
System Peak (kW)	43,158
Service Area (sq. km)	35
Total Customers	10,790
GS > 50	1,315
GS < 50	146
Residential	9,298
Generation	0
Unmetered Scattered Load	69
Sentinel Lights	206
Street Lighting	2,794
Smart Meters (to date)	10712
Wholesale Meter Points	10
Poles	4299 (w) + 45 (c) = 4344
Primary Lines (km)	295
Overhead	270
Underground	25
Transformers (units)	1892
OH	1583
UG	309

ORPC's Plan is a systematic approach to optimize the operation and maintenance expenditures and capital investments for the distribution system and the general plant. ORPC operates the distribution system with the objective of balancing necessary distribution system maintenance and reinvestment, while providing customers with a safe and reliable supply of electricity at the lowest possible rates. ORPC intends to adopt a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner, as they approach their high probability of failure zone of their lifecycle. ORPC's strategy is to replace end-of-life assets under planned and coordinated circumstances, as opposed to under emergency or after hour's circumstances which add unnecessary risk and expense.

ORPC plans to expend significant effort in quantifying and characterizing its distribution system and general plant with the assistance of a Geographic Information System (GIS). ORPC has created an asset register that contains both quantitative data such as the age of individual assets. It is anticipated that we will enhance the asset register with key qualitative data, such as inspection and condition testing results including detailed asset information in the next two years. This enhancement will enable ORPC to project when individual assets are expected to reach the end of their useful service life, at which time the assets have a high probability of failure.

The GIS system will become one of ORPC's most relied upon day-to-day core business systems. The GIS database will be utilized to update our Harris database and our DESS engineering software. ORPC's DSP is built on the foundation of data contained within the GIS tool. This tool will allow ORPC to transition from planning projects based on failure to pin-pointing individual assets throughout the distribution system. As such, ORPC's budgets will be driven by the needs of individual assets, their lifecycle and replacement cost.

ORPC has also incorporated the OEB's principles for good planning with a focus of achieving performance outcomes as per the renewed regulatory framework for electricity. ORPC is committed to Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. ORPC aims to demonstrate the functionality of its asset management and capital planning processes that deliver value to customers.

ORPC's planning objectives are to deliver on the following performance outcomes over the 2015 to 2019 planning horizon and beyond:

Customer Focus

- To provide services in alignment with customer preferences and needs

Operational Effectiveness

- Keep pace with distribution system deterioration through reinvestments as determined by ORPC's asset management process
- Minimize future rate instability by smoothing the age profile of distribution asset classes/groups
- Support the achievement of customer and regulatory reliability & service quality expectations
- Support the achievement of performance measures contained in the OEB's Distributor Scorecard
- Support future objectives of Regional Planning (unknown at this time with the exception of Almonte)

Support Public Policy Objectives:

- Support the connection of renewable generation to our distribution system
- Support the deployment of a smart grid and the achievement of associated objectives
- Support the achievement of conservation and demand management targets

Financial Performance:

- To ensure that financial viability is maintained in consideration of operating with the mandated return on equity

5.2.2 Coordinated Planning with Third Parties

Regional Planning Consultations

At the time of preparing this DS Plan, the Regional Infrastructure Planning initiative is still in the early stages of development and as such many of the elements of the planning process have not yet been implemented. As per the "Integrated Planning Requirements - Part 1: Regional Infrastructure Planning", the transition and implementation to Regional Infrastructure Planning (RIP) is expected to take four (4) years.

For planning purposes, Ontario has been divided into 21 regions by electrical topography. Regional plans for these 21 regions have been divided into three groups: Active (Group 1), Upcoming (Group 2) and Future (Group 3). It is worth noting, that ORPC's licensed service territory is geographically located in "Future - Group 3", with some embedded in Group 1. Refer to Appendix A for a map of the regions, as well as for a listing of electrical distributors within them.

Almonte is part of Group 1 which includes the Ottawa East sub region. To date, joint regional planning meetings involving ORPC, OPA, Regional Transmitter and other stakeholders have been completed for the Ottawa area. Future meetings are planned for the Renfrew area in late 2015 which will involve Pembroke, Beachburg and Killaloe.

ORPC has solicited feedback from stakeholders including the Ontario Power Authority, regionally interconnected transmitters/distributor, municipal planning office, customers and the general public for the purpose of developing this DS Plan, as well as to fulfill rate application filing requirements. ORPC has incorporated stakeholder feedback and has attempted to align future service offerings and investments with the needs and priorities of all stakeholders, including consumers.

Appendix A: Map of Ontario's Planning Regions

Consultations with the Ontario Power Authority

ORPC submitted a formal "Request for Letter of Comment" to the OPA along with supporting documentation as per the criteria contained in Sections 5.1.4.1 and 5.1.4.2 of the revised OEB Chapter 5 Filing Requirements. The submission also included: a system capability assessment for renewable generation; smart grid deployment information; and regional planning and consultation activities. The OPA found that ORPC's plan is consistent with its information regarding renewable generation applications to date.

The OPA's November 25th, 2014 Letter of Comment is included as Appendix B of this submission.
Ottawa River Power Corporations System Capability Assessment for Renewable Energy Generation is included as Appendix C of this submission.

Appendix B: OPA's letter of Comment dated November 25th, 2014
Appendix C: ORPC's System Capability Assessment for Renewable Energy Generation

Consultations with Regionally Interconnected Distributors and Transmitters

ORPC also submitted a formal "Request for Letter of Comment" to HONI. Under the new regional planning process that has been developed by the Process Planning Working Group, ORPC expects to receive either a Needs Assessment Report, if ORPC involvement is not required in the RIP and/or IRRP process, or alternately a Regional Planning Status Letter, if ORPC involvement is required in RIP and/or IRRP process. ORPC also welcomed any general feedback or comments for consideration.

On November 3, 2014 ORPC received a Regional Planning Status Letter in response to ORPC's request for a Letter of Comment. The letter, which was send electronically, confirmed that ORPC's licensed distribution service territory belongs to "Group 3", which is the Renfrew Region, "however, it notes that some of our facilities are embedded LDCs that fall within Greater Ottawa Region which is in Group 1". This letter is available as Appendix D.

Appendix D: November 3rd letter from HONI

Consultations with Customers

Customer focus is considered to be an important outcome of the OEB's newly released Renewed Regulatory Framework for Electricity. ORPC has incorporated customer feedback in developing its five-year DS Plan and beyond. Customer feedback is also a key input into ORPC's asset management process.   Information gathered from Town Hall forums were used to align ORPC's planned service offerings and planned expenditures with customer preferences and priorities.

ORPC plans to conduct customer surveys in September of 2015 to solicit customer feedback.

ORPC will also be launching annual customer education campaigns, which focus on topics consumers are most interested in learning more about. ORPC's believes its customers want to learn more about the following topics in the following order: Conservation, Renewable Generation, Smart Meters, Smart Grid, Understanding Your Bill, Demand Management and Time-of-Use Rates.

ORPC uses and intends to continue to utilize Town Hall Meetings, trade shows and standard advertising outlets such as newspapers and bill inserts.

ORPC is also very proactively involved with one on one customer service and care. We take great pride in our staff's ability to converse with customers on a regular basis. We have an open door philosophy and still use the telephone as a key tool to communicate with our customers.

An example of the presentations we give to our shareholders at municipal council forums and to the general public at large is available as Appendix E.

Appendix E: Copy of the PowerPoint Presentation used at Town Hall forums

Consultations with Municipal Planning Office

Since ORPC is owned by four municipal shareholders, we enjoy a mutually open working partnership. With the municipal planning office, ORPC has historically worked very closely with this department, in regards to coordinating planning efforts that are conducted throughout the community. An example of our consultation; ORPC provides feedback on all applications that are circulated to stakeholders from the municipal Committee of Adjustment. Comments are often solicited in regards to the impact of zoning changes, coordination of land utility services (electric, water, gas, sewer, communication), requests for relief from by-law requirements, easements etc. ORPC also uses the opportunity to advise applicants of their requirements under ORPC's Conditions of Service, as well as to inform applicants of relevant industry programs such as the "New Construction" CDM program offering.

ORPC is currently aware of two significant development projects being coordinated through the Planning Office of Pembroke and Almonte for the 2015 planning horizon. See Appendix F which demonstrates Ottawa River Power Corporation's participation on the County of Renfrew Coordinating Committee.

Appendix F: Copy of the minutes of County of Renfrew Coordinating Committee, dated April 8, 2014

Pembroke Emergency Planning exercises

ORPC is also an active member of the Pembroke Emergency Planning group. The group performs emergency management table top exercises in preparation for real life community emergencies that may occur. Recent exercise scenarios included an ice storm, emergency evacuation due to an industrial site disaster, as well other natural disasters. The group also coordinates and conducts emergency management training for all members (key contacts) such as Incident Management Training (IMS). The table top emergency exercises are a good opportunity for members to review and critique their emergency plan.

Current members include ORPC, Ontario Provincial Police, Canadian Red Cross, Ambulance Services, City of Pembroke, Local Radio Station, Local Health Unit, Critical Incident Stress Management Team (C.I.S.M.),

In recent history, this working group has stimulated ORPC to proactively prepare itself for emergency situations. ORPC invested in a back-up generator for its main office, such that essential services can remain operational including communications, building heat and lighting. In developing a Disaster Recovery Center, ORPC plans to complete the installation of the back-up equipment of its operations centre including a backup generator, to also allow for essential services to remain operational such as communications, SCADA control, GIS, CIS and IT infrastructure.

ORPC has several immaterial initiatives planned over the 2015 to 2019 planning horizon that are driven from this consultation, such as staff education and awareness training; however, the costs are expected to be immaterial.

Impact Summary of Third Party Consultations on DS Plan

The following is a summary of material impacts on ORPC's 2015 to 2019 DS Plan, as a result of third party and stakeholder consultations:

Regional Planning Consultations

- Currently there are two confirmed subdivisions identified for 2015.
- Potential Transmission projects for the Almonte TS may impact ORPC DS Plan, but at this point in time the potential impact cannot be quantified.

Consultation with OPA

The ORPC advised OPA of thermal constraints which affects continued FIT uptake in ORPC's service territory over the planning period.

Customer Engagement - Customer Satisfaction

- Customers find that investing in a Mass Customer contact system will be of value to their needs.
- ORPC believes that its customers support investing in transitioning customer billing to true calendar month billing
    - ORPC planning on deploying true calendar monthly billing in 2015
        - Estimated Operational Cost $7,500
- Customers may find that investing in offering a choice of receiving a paper or electronic bill will be of value to their needs
    - ORPC planning on deploying paper or electronic billing choice in 2015
        - Estimated Operational Cost $10,000
- Customers may find that investing in technology to enable them to access their electronic consumption data and billing information through the internet is of value to their needs
    - ORPC recognizes that this is a mandated directive, and as such ORPC will continue with offering online access to consumption and billing data with Lowfoot
- Outage Communication is an identified area of improvement, ORPC plans to deploy an Outage Management System (OMS) that will enable proactive notification of localized customer outages, as well as assist with customer communication and interaction regarding planned or unplanned outages
    - ORPC planning to deploy an OMS in the planning period 2015 to 2017
        - Estimated Capital Cost $15,000

5.2.3 Performance Measurement for Continuous Improvement

ORPC's mission is to deliver safe and reliable electricity to its customers, at the lowest possible sustainable rates. ORPC has attempted to align its performance measures with the July 2014 version of Board Staff's Recommended ORPC scorecard. ORPC currently does not use all of the recommended measures, and as such, ORPC does not have a history of data for newly introduced measures. ORPC plans to adopt any new measures contained in the finalized scorecard.

The following summary illustrates ORPC's Unitized Statistics and Service Quality Requirements history based on RRR reporting, for the period 2009 to 2013.

Scorecard - Ottawa River Power Corporation

9/24/2014

Performance Outcomes	Performance Categories	Measures	2009	2010	2011	2012	2013	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	98.60%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time	99.40%	99.80%	99.80%	99.90%	99.90%		65.00%	
	Customer Satisfaction	First Contact Resolution								
		Billing Accuracy								
		Customer Satisfaction Survey Results								
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]								
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	2.66	0.71	2.39	1.69	0.91			at least within 0.71 - 2.66
		Average Number of Times that Power to a Customer is Interrupted	2.10	0.79	1.43	1.08	0.81			at least within 0.79 - 2.10
	Asset Management	Distribution System Plan Implementation Progress								
	Cost Control	Efficiency Assessment				3	3			
		Total Cost per Customer [1]	$452	$449	$487	$470	$505			
		Total Cost per Km of Line [1]	$32,146	$31,795	$34,703	$33,773	$32,410			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			13.00%	13.00%	10.70%			1.61MW
		Net Cumulative Energy Savings (Percent of target achieved)			34.00%	60.00%	77.50%			8.97GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time								
		New Micro-embedded Generation Facilities Connected On Time					100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	3.65	3.29	2.70	2.32	1.54			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.74	0.74	0.73	0.72	0.73			
		Profitability: Regulatory Return on Equity – Deemed (included in rates)			9.85%	9.85%	9.85%			
		Profitability: Regulatory Return on Equity – Achieved			10.58%	11.60%	5.90%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Legend: up; down; flat; target met; target not met

5.2.3.1 Service Quality and Reliability Performance

In January each year, Ottawa River Power Corporation annually reports its service quality and service reliability metrics; that is, its service quality indicators to the Ontario Energy Board. The Service Quality Indicators are defined in Chapter 7 of the Distribution System Code. OPRC has met the minimum standards for all service quality indicators and reliability metrics every year.

The following table shows Ottawa River Power Corporation's annual results:

Service Quality Indicator	Minimum Standard	2009	2010	2011	2012	2013	2014
Connection of New Services – Low Voltage	90% or better	100	100	100	100	100	200
Connection of New Service – High Voltage	90% or better	n/a	n/a	n/a	n/a	n/a	n/a
Appointment Scheduling	90% or better	100	100	100	100	100	100
Appointments Met	90% or better	100	100	100	100	100	100
Appointments Rescheduled	100	n/a	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65% or better	99.4	99.8	99.8	99.9	99.9	99.9
Telephone Call Abandon Rate	10% or less	0.6	0	0	0	0	0
Written Response to Enquires	80% or better	100	100	100	100	100	100
Emergency Response – Urban	80% or better	100	100	100	100	100	100
Emergency Response – Rural	80% or better	n/a	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85% or better	n/a	n/a	100	100	100	100
Reliability Metrics – All Interruptions							
SAIDI (System Average Interruption Duration Index)	Within the range of performance over the previous 3 years	3.2	1.21	10.69	3.31	3.97	1.740
SAIFI (System Average Interruption Frequency Index)	Within the range of performance over the previous 3 years	2.87	1.40	6.01	2.25	3.04	3.99
CAIDI (Customer Average Interruption Duration Index)	Within the range of performance over the previous 3 years	1.11	.86	1.78	1.47	1.30	.044
Reliability Metrics – Excluding Loss of Supply							
SAIDI (System Average Interruption Duration Index)	Within the range of performance over the previous 3 years	2.66	.71	2.39	1.69	.91	1.240
SAIFI (System Average Interruption Frequency Index)	Within the range of performance over the previous 3 years	2.1	.79	1.43	1.08	.81	0.790
CAIDI (Customer Average Interruption Duration Index)	Within the range of performance over the previous 3 years	1.27	.89	1.67	1.57	1.13	1.57

5.2.3.2 Maintenance and Inspection program

ORPC has developed an extensive maintenance inspection program to meet the requirements of Ontario Regulation 22/04 Section 4 “Safety Standards”, section 5 “When Safety Standards Met” and of the Ontario Energy Board’s Distribution System Code Appendix C, “Minimum Inspection Requirements”. The inspection program covers the following items:

- Refer to Appendix G for ORPC’s complete Maintenance Inspection Program.

5.2.3.3 Customer Satisfaction

Ottawa River Power Corporation will be conducting a customer satisfaction survey in September 2015. We will purchase and use an online survey that other utilities such as, Hydro Hawkesbury have used. The scope of this survey will offer us the data that we need to affirm our levels of client satisfaction and our client’s key concerns.

Methods of customer communication

ORPC utilizes a number of media platforms and sources to communicate with our customers. We continually monitor and update the effectiveness of our various communication mediums.

Direct Telephone/Office Access – our offices are open daily, Monday to Friday, 8 am to 4 pm where customers can speak to a company representative about a variety of issues or concerns.

Direct Mail – Billing is done in regular cycles via traditional mail. ORPC regularly inserts updates, produced in-house (newsletter) and partner sourced material that provide our customers with information such as time of use changes, rate changes, power saving tips and opportunities, etc.

Targeted Customer Notices – For planned outages and repair work, ORPC staff contact customers directly with specific information such as duration, time and anticipated work affecting their service. Notice is also circulated in poster format for large scale outages that will affect multiple areas. Key local service locations are targets for poster distribution.

Local Media – Radio and Newspapers – For planned outages affecting large areas of our customers ORPC informs them through traditional sources such as local radio and local newspapers.

Website – ORPC has a website http://www.orpowercorp.com/. The website is an excellent source of information regarding our utility, services, and opportunities for customers to proactively reduce energy consumption. A dedicated power outage timeline page is updated as required.

Social Media – ORPC has both a business Facebook https://www.facebook.com/OttawaRiverPower/ and twitter page https://twitter.com/ORPowerCorp

These media sources allow us to communicate and exchange in real time with our customers and our partners.

Public Forums/Trade Shows/Community Events – ORPC takes part in shareholder specific activities that create the opportunity for our customers to interact with us. We set up information booths at key trade shows, participate in third party hosted learning forums, host float(s) in shareholder Christmas parades and continually make presentations to municipal council(s).

5.2.3.4 Operational Effectiveness Measures

5.2.3.4.a ESA Ontario Regulation 22/04 Compliance Audits

- Objective of Audit
- Methodology of Audit
- Safety Standards Met
- ORPC's ESA Audit History
- Equipment Approval
- Approval of plans, drawing and specifications

In early 2004, Ontario Regulation 22/04 was put in place with the objective of enhancing public safety in regards to Ontario's electrical distribution systems. The regulation affects the safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Section 13 of the regulation stipulates that distributors are required to participate in annual compliance audits as per the following:

> *13. (1) It is a condition of an approval issued to a distributor for the use of a distribution system that the distributor engage an auditor to audit on an annual basis the distributor's compliance with sections 4, 5, 6, 7 and 8 and to prepare an audit report. O. Reg. 22/04, s. 13 (1).*

As such, ORPC has participated in annual compliance audits and believes that the audit results are a good measure for assessing performance with respect to ensuring public and employee safety.

Objective and Scope of the Audit: To conduct a comprehensive review of the processes, guidelines, 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 as to avoid or reduce the possibility of electrical hazards.

Auditing Methodology Followed: The following standard audit practices were followed to assess the level of conformance to the provincial safety regulation:

1. Review of ORPC's existing processes, guidelines and standards
2. In person meeting with knowledgeable personnel
3. Site visits

ESA Safety Standards: Section 4.0 of Regulation 22/04 (Electrical Distribution Safety) requires that the distributor has processes in place to ensure that all distribution systems and the electrical installations, and electrical equipment forming part of such systems are designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to avoid/reduce the exposure to electrical safety hazards.

To meet the requirements of Section 5.0 of Regulation 22/04 (Electrical Distribution Safety), the distributor is to ensure that there are processes in place that check on an ongoing basis the installations, overhead and underground lines and distribution stations.

Section 6 of Regulation 22/04 requires the use of certified/duly approved equipment for the construction of new or the repair and extension of existing distribution systems after February 11, 2005.

Section 7.0 of Regulation 22/04 (Electrical Distribution Safety) applies to electrical installations that are, or may form part of the distribution system. This section requires that before starting, or affecting repairs, alterations, or extensions of an existing distribution system, the distributor must ensure that the installation is based on:

- Plans that have been prepared by a Professional Engineer and these have been reviewed and approved by a professional engineer or ESA; or
- The distributor's standard design drawings are assembled by a Professional Engineer or by an engineering technologist certified by OACETT, or by another competent person, and reviewed and approved by a professional engineer or by ESA.
- Moreover, prior to authorizing third party attachments, the distributor is to ensure that attachments to its distribution systems meet the safety requirements of the Regulation
- On February 11, 2005, section 8 of the Regulation came into effect requiring that before putting any new construction or repairs of the distribution systems into use, the distributor is to:
    - ensure the construction is inspected;
    - confirm that only approved equipment was utilized in the construction;
    - prepare a record of inspection; and
    - complete a Certificate

ORPC Performance History

ORPC Ontario Regulation 22/04 Compliance Audit Results					
Audit Year	**Section 4** Safety Standards	**Section 5** When Safety Standards Met	**Section 6** Equipment Approval	**Section 7** Approval of plans, drawings, and specifications for installation work	**Section 8** Construction Approval and Inspections
2009	C	C	C	C	NC
2010	C	C	C	NI	C
2011	C	C	C	C	C
2012	C	C	C	C	C
2013	C	C	C	C	C

Legend C-complies, NI- Needs Improvement Identified, NC Non-conformance fund, N/A –Not Applicable

Performance Trend & Assessment

ORPC is very pleased with its performance record and notes over the last five years only once instance of a non-conformance to regulation 22/04 was identified through the audit process. ORPC has managed to obtain a perfect score for the last three consecutive years. Compliance to O.Reg. 22/04 has not been identified as needing improvement or as a driver requiring material investments over the planning period. ORPC's objective is to maintain current performance levels.

ESA Due Diligence Inspections: In order to ensure compliance with Ontario Regulation 22/04 "Electrical Distribution Safety," the Electrical Safety Authority performs Due Diligence Inspections (DDIs) of LDCs. The inspections focus on ensuring that construction in the field is in accordance with a plan, work instruction, and/or standard designs such that no undue hazards exist to the public or LDC personnel. ORPC believes this measure to be a good measure of performance with respect to public safety and the safety of personnel.

LDCs receive an inspection report which could require LDC action in the event that significant findings were found in the inspection.

The following are ESA's definitions and instructions with respect to responding to the DDI Inspection Report:

> **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 Local Distribution Company (LDC) and a formal, written response submitted to Electrical Safety Authority (ESA).
>
> **Key Due Diligence Findings:** Key Due Diligence Findings are items that ESA requires formal, written responses within 10 working days. The Key Due Diligence Findings can be found in the "NON-COMPLIANCES TO REGULATION 22/04" and "NEEDS IMPROVEMENT" sections of the report.
>
> **Observations:** Observations are items that ESA does not require formal, written responses to, unless specifically requested. The Observations can be found in the "SAFETY RELATED OBSERVATIONS" and "MISCELLANEOUS OBSERVATIONS" sections of the report.
>
> **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 Local Distribution Company (LDC) and a formal, written response submitted to Electrical Safety Authority (ESA). For each non-compliance detailed, the LDC shall address (1) an ACTION PLAN / RESPONSE and (2) 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 Local Distribution Company (LDC) and a formal, written response submitted to Electrical Safety Authority (ESA). For each "Needs Improvement" point, the LDC shall address (1) an ACTION PLAN / RESPONSE and (2) TIMELINES (when not detailed by ESA) for addressing each point. LDC's are requested to provide comments within 10 working days.
>
> **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.

Miscellaneous Observations: The section details non-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 are non-safety related, and may or may not fall under Regulation 22/04.

ORPC Performance History

ORPC ESA Due Diligence Inspection Performance History					
Inspection Year	Imminent Fire / Shock / Explosion Hazards	Non-Compliances(s) to O.Reg. 22/04	Needs Improvement	Safety Related Observations	Miscellaneous Observations
2008	0	0	3	7	0
2009	0	0	2	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0

ORPC's Performance Trends

ORPC is very pleased with the inspection results and notes that over the last five years of inspections no hazards or non-conformances to Ontario Regulation 22/04 were found. DDI inspection 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 current performance levels.

5.2.3.4b Safe Work Environment

Safe Worked Hours & Injury Free Years:

ORPC has been tracking the performance of employee safety using the measure "Safe Worked Hours." 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 "years, months", since the last occurrence of a lost time injury.

ORPC Performance History

In 2012, ORPC had no accidents or injuries. In 2013, an employee did lose 2 days of work as a result of trauma caused by work equipment (lawn tractor) that had been altered. The equipment was repaired and the safety mechanisms reinstalled. In 2014, a journeyman suffered a minor cut to his arm while out on a job site, this resulted in a loss of 2 work days.

Performance Trend & Assessment

ORPC continues to strive to improve safety for its employees and its customers. Over the 2015 to 2019 planning horizon, ORPC is planning on expanding employee safety awareness, skills development training and continued education. ORPC believes that all work related injuries can be prevented if employees are armed with the proper continued education and training, as well as supplied with the proper tools that enable them to work safely.

5.2.3.5 System Reliability & Performance

Killaloe Outage Performance

ORPC has worked well with Hydro One Operation centers to reduce the impact of outages of the Distribution systems in our Killaloe service area. During 2013 HONI and ORPC staff were able to complete a memorandum that would have HONI employees dispatched to respond to outages in Killaloe as a priority. We identified that the employees could be dispatched from Barry's Bay and Cobden simultaneously to complete the line patrol toward Killaloe. The first employees who would arrive at Killaloe would re-energize MS in Killaloe, thus reducing the outage duration.

A Hydro One consultation was completed to determine if future improvements can be achieved. The installation of multiple remote operated switches was determined to be extremely costly and ORPC decided that the improvement not be completed at this time.

A Smart Grid recloser was installed in Killaloe. The recloser is connected to the Pembroke SCADA through a series of modems, switches and other firewall apparatus. The installation allows ORPC to monitor the power supply for Killaloe further enhancing our knowledge of the actual real time loads and power quality. On-call staff can complete an analysis of the power outage information and dispatch employees as required.

Overall System Performance

The company has completed the installation of approximately 9,320 smart meters for residential and 1,315 smart meters for small commercial (GS<50kW) customers. ORPC intends to explore the potential use of the communication capability of the Smart Meter system to further improve customer service through more advanced outage detection and outage response.

The following table demonstrates Ottawa River Power Corporation's five year system performance summary.

		2009	2010	2011	2012	2013	2014
Average Customer Count		10,413	10,430	10,549	10,615	10,729	10,783
Number of Interruptions (Include Code 2)		29,912	14,632	63,443	23,857	32,633	43,052
Total Customer Hours of Interruptions (Include Code 2)		33,271	12,613	112,773	35,087	42,567	18,739
Number of Interruptions (Exclude Code 2)		21,839	8,273	15,067	11,444	8,638	8,508
Total Customer Hours of Interruptions (Exclude Code 2)		27,719	7,394	25,192	17,965	9,736	13,378
Including loss of service from HONI (Code 2)	SAIDI	3.20	1.21	10.69	3.31	3.97	1.74
	SAIFI	2.87	1.40	6.01	2.25	3.04	3.99
	CAIDI	1.11	0.86	1.78	1.47	1.30	0.44
Excluding Loss of service from HONI (Code 2)	SAIDI	2.66	0.71	2.39	1.69	0.91	1.24
	SAIFI	2.10	0.79	1.43	1.08	0.81	0.79
	CAIDI	1.27	0.89	1.67	1.57	1.13	1.57

SAIDI

System Average Interruption Duration Index (SAIDI) represents the average outage duration per customer served by WNP. The formula is shown below this paragraph

$$SAIDI = \frac{Sum\ of\ all\ customer\ interruption\ durations}{Total\ number\ of\ customers\ served}$$

SAIFI

System Average Interruption Frequency Index (SAIFI) represents the average number of interruptions that a customer would experience in a year. The formula for calculating SAIFI is shown below this paragraph

$$SAIFI = \frac{Total\ number\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

CAIDI

Customer Average Interruption Duration Index (CAIDI) provides the average outage duration or restoration time that an average customer would experience during a one year period. CAIDI is directly related to SAIDI and SAIFI as is shown below this paragraph.

$$CAIDI = \frac{Sum\ of\ all\ customer\ interruption\ durations}{Total\ number\ of\ customer\ Interruptions} = \frac{SAIDI}{SAIFI}$$

5.2.3.6 Energy Management Performance

ORPC has divided Energy Management Performance into two categories: Conservation and Demand Management, and Connection of Renewable Generation.

5.2.3.6 a Conservation and Demand Management

Net Annual Peak Demand Savings

ORPC's target for peak demand savings for the 2011-2014 Framework was 1.6 MW; the Province's target was 1,330 MW. Percentage of target achieved for ORPC, annually, over the course of the Framework increased consistently. Achievement in the first three years, in fact, surpassed that of the Province. As there were no industrial programs/projects undertaken, the demand savings were largely attributable to the delivery of the EERI and peaksaverPLUS programs. While the EERI program are delivered in house by ORPC, the peaksaverPLUS program is available to our customers through a third party service provider (Util-Assist). ORPC also offers its >50 customers with the opportunity of energy audits or facility assessments. These services are provided by Burman Energy Services. For the customers that participated, the uptake on the EERI projects was successful.

In terms of results for 2014 (at the time of this submission, 2014 progress results were obtained from Q4 2014 CDM Status Report), a large High Performance New Construction project was not included. Demand savings of this particular project were 159 kW. The inclusion of these savings, and ultimate final results, will compare attractively to the Province's final results. ORPC had a service level agreement with Enbridge Gas for all HPNC projects. Going forward into the new Framework, Burman Energy Services will work on ORPCs HPNC projects.

ORPC Net Annual Peak Demand Savings versus Province

During the first three years of program delivery, progress made towards demand target by ORPC surpassed that of the Province on an annual basis. The Q4 2014 CDM Status Report for Ottawa River Power Corporation indicates 51% target achieved towards demand target assigned. The above noted HPNC project (demand savings of 159 kW) is not included in this result.

KWh Savings

ORPC's target for cumulative energy savings was 9 GWh; the Province's target was 6,000 GWh. Percentage of target achieved for ORPC also increased significantly over the past four years. Progress increased drastically between 2011 and 2012; largely attributable to the uptake of the Direct Install Lighting Program. Burman Energy Services delivers this program on behalf of our <50 customers. Considerable energy savings have also been reaped from our EERI projects. The Home Assistance Program savings, to date, has not been included in ORPC's progress. At the time of this submission, ORPC had achieved 91% of assigned energy target (based on the Q4 2014 CDM Status

Report for Ottawa River Power Corporation). With the anticipated EERI project completions, the HAP program results, as well as the large HPNC project noted above (600,000 kWh), ORPC expects to meet its energy target of 9 GWh. A final report is to be released in September; whereby, the excluded savings will be included.

ORPC kWh Savings versus Province

Progress towards target remained close with the Province in the first two years of program delivery. During the last two years of the four year program, ORPC still remained within 10% of the Province's progress towards target. With the anticipated Home Assistance Program results, completion of EERI projects and the inclusion of the large HPNC project, ORPC anticipates meeting its energy target with the Province.

ORPC CDM Strategy for 2015-2020

ORPC joined the CHEC (Cornerstone Hydro Electric Concepts) in the spring of 2014. Currently, there are approximately 17 utilities in its membership. The CHEC CDM group will be submitting a joint CDM Plan for 2015-2020. Currently, there is a CHEC CDM Steering Committee considering the various services of third party providers in an effort to create a complete collaborative approach to the Conservation First program delivery. The targets assigned are aggressive and the related budgets are reduced than those assigned for 2011-2014. The CDM Manager at ORPC has attended all related workshops for the 2015-2020 years and is a member of the steering committee noted. It is the consensus of the CHEC membership that all provincial programs will be delivered in the new portfolio(s). Additional pilot programs will also be seriously considered. The assigned target for ORPC is 8.72 GWh, with an assigned budget of $2.3 million.

5.2.3.6 b Connection of Renewable Generation

ORPC relies on 295 kilometers of primary circuits to deliver 190,000,000 kWh of energy and 37,000 kW of winter peak power to approximately 10,780 customers in our service area. The primary circuits can be broken down into roughly 270 km of overhead lines and 25 km of underground conductor.

ORPC's service territory is surrounded by Hydro One Networks Inc. in all of its four service areas: Pembroke, Killaloe, Beachburg and Almonte. Ottawa River Power is directly connected to Hydro One's Distribution system at 44KV and is an embedded LDC that takes delivery of electricity from another LDC.

ORPC distributes power to its customers, which are comprised of primarily urban customers, through its municipally owned distribution substations.

Since the introduction of the Feed-in-Tariff (FIT) program, Ottawa River Power Corporation has been able to accommodate the connection of all micro FIT applications that have been received. ORPC has had 79 requests to connect micro FIT projects of which 47 have been cancelled or denied due to various reasons not related to connection constraints. ORPC has had 4 (four) requests to connect FIT projects which have been denied due to HONI constraints. The FIT projects mentioned were never registered with the OPA.

The generator connection application process for ORPC customers' requires the involvement of HONI. The application process includes an internal review of applications by operations, engineering and metering departments. ORPC also requires approval from HONI for projects greater than 10kW for connection capacity, as HONI is the Host Distributor. This process should become streamlined; ORPC will complete the approval process in parallel with HONI's approval process. ORPC is aware of upstream capacity constraints at the HONI owned Pembroke TS and the Cobden TS, relating to the Pembroke, Beachburg and Killaloe supply feeders.

ORPC has limited penetration of its feeders to 10% of peak load for new generation. This limit is based on the 'Technical Review of Hydro One's Anti-Islanding Criteria for micro FIT PV Generators' prepared by Kinectrics. At this time ORPC is benchmarking the available generation capacity at 10% of the peak loading of each feeder.

The distribution system has been unaffected by the micro FIT projects connected thus far. The number of connections has continued at a steady pace. ORPC settles sixteen (16) contracts at the initial rate of 80.2 cents, five (5) at 54.9 cents and the remainder at the current OPA price of 39.6 cents. It is likely that the rate of connections will decrease slightly due to the decrease in the contract pricing offered by the Ontario Power Authority and the overall lack of interest in the service territory.

Overall, ORPC's distribution system has been determined to be adequate to accept the renewable generation that is anticipated. There are no known barriers within ORPC's distribution system for projects that are serviced by its own municipal substations.

All of ORPC's feeders still have remaining capacity for FIT and micro FIT installations. 4.16kV circuits are designed for smaller local loads which limits their ability to connect REG installation to smaller mFIT units such as those found on rooftops.

Based on the fact that there are no known barriers to renewable generation related to matters under the control of Ottawa River Power, the utility does not propose any material investments in renewable infrastructure. ORPC does not anticipate reaching photovoltaic generation connection limits on several of its distribution feeders over the 2015 to 2019 planning period.

Anticipated Renewable Generation Connection Request

Given the level of interest expressed by Ottawa River Power Corporation's customers' to-date, the forecasted of Micro-FIT applications is presented in the table below. These numbers provided are speculative in nature, but they are based on experience dealing with customers over the past several years. 2014 has been forecasted higher than the following years. This year the largest shareholding municipality put micro-Fit projects on a number of their facilities. This will not repeat itself in the future.

Application Type	2014	2015	2016	2017	2018
Forecast micro FIT Connections	7-10	4-5	4-5	4-5	4-5

With respect to large scale projects, Ottawa River Power Corporation currently has no Fit connections. ORPC anticipates large scale fit projects connected in the Almonte area. In the event these projects do materialize, the utility generally has sufficient lead time to allow for an appropriate response by itself and Hydro One.

In conclusion, based on the anticipated uptake of the program and an assessment of the systems capacities, ORPC is forecasting sufficient capacity to accommodate the anticipated connections with the need to prioritize the projects.

Consultation with Affected Transmitter: Being an embedded utility, Ottawa River Power Corporation must consult with Hydro One on each connection request for projects greater than 10 kW. ORPC must complete a Connection Impact Assessment (CIA) for each project and this gives Hydro One an opportunity to assess and address capacity issues within its service territory. ORPC will continue to work co-operatively with Hydro One as new connections are added to the system.

Planned Development to accommodate Renewable Generation

As noted, throughout this Renewable Energy Generation Plan, Ottawa River Power Corporation has not proposed any development or expansions of its distribution system in order to accommodate Renewable Generation.

Larger FIT projects will typically be installed by commercial and industrial customers with a large rooftop footprint. Therefore, applications received or expected within five years, will typically displace customer load at the host site and are not expected to be significant net-exporters of energy into the distribution system.

For further information refer to Appendix C, ORPC's System Capability Assessment for Renewable Energy Generation.

5.2.3.7 Financial Performance Measures

The table below shows ORPC's summary of OM&A Recoverable Expenses from 2010-2016

	Board Approved	2010	2011	2012	2013	2014	2015	2016
Operations	$353,033	$388,095	$548,028	$562,813	$595,899	$589,388	$601,296	$616,000
Maintenance	$705,409	$491,364	$721,496	$693,882	$840,521	$707,406	$853,533	$805,000
Billing and Collecting	$616,443	$600,482	$528,100	$533,838	$577,268	$634,033	$690,315	$738,000
Community Relations	$58,624	$41,451	$53,320	$47,391	$52,864	$55,452	$67,273	$65,000
Administrative and General	$859,815	$821,877	$833,118	$817,920	$1,026,994	$915,963	$1,020,753	$1,062,514
Total	**$2,593,325**	**$2,343,269**	**$2,684,062**	**$2,655,844**	**$3,093,547**	**$2,902,242**	**$3,233,171**	**$3,286,514**
%Change (year over year)		-9.6%	14.5%	-1.1%	16.5%	-6.2%	21.7%	6.2%

	Board Approved	2010	Variance	2011	Variance	2012	Variance	2013	Variance
Operations	$353,033	$388,095	-$35,062	$548,028	$159,933	$562,813	$14,785	$595,899	$33,086
Maintenance	$705,409	$491,364	$214,045	$721,496	$230,132	$693,882	-$27,614	$840,521	$146,639
Billing and Collecting	$616,443	$600,482	$15,961	$528,100	-$72,382	$533,838	$5,738	$577,268	$43,430
Community Relations	$58,624	$41,451	$17,173	$53,320	$11,869	$47,391	-$5,929	$52,864	$5,473
Administrative and General	$859,815	$821,877	$37,939	$833,118	$11,241	$817,920	-$15,198	$1,026,994	$209,074
Total OM&A Expenses	$2,593,325	$2,343,269	$250,056	$2,684,062	$340,792	$2,655,844	-$28,217	$3,093,547	$437,703
Adjustments for Total non-recoverable items									
Total Recoverable OM&A Expenses	$2,593,325	$2,343,269	$250,056	$2,684,062	$340,792	$2,655,844	-$28,217	$3,093,547	$437,703
Variance from previous year				$340,792		-$28,217		$437,703	
Percent change (year over year)				15%		-1%		16%	
Percent Change: Test year vs. Most Current Actual						23.75%			
Simple average of % variance for all years						40.25%			
Compound Annual Growth Rate for all years									
Compound Growth Rate (2012 vs. 2014 Actuals)						13.34%			

	2014	Variance	2015	Variance	2016	Variance
Operations	$589,388	$26,575	$601,296	$5,397	$616,000	$14,704
Maintenance	$707,406	$13,524	$853,533	$13,012	$805,000	-$48,533
Billing and Collecting	$634,033	$100,195	$690,315	$113,047	$738,000	$47,685
Community Relations	$55,452	$8,061	$67,273	$14,410	$65,000	-$2,273
Administrative and General	$915,963	$98,043	$1,020,753	-$6,241	$1,062,514	$41,760
Total OM&A Expenses	$2,902,242	$246,398	$3,233,171	$139,624	$3,286,514	$53,343
Adjustments for Total non-recoverable items						
Total Recoverable OM&A Expenses	$2,902,242	$246,398	$3,233,171	$139,624	$3,286,514	$53,343
Variance from previous year	-$191,304		$330,928		$53,343	
Percent change (year over year)	-6%		11%		2%	
Percent Change: Test year vs. Most Current Actual						
Simple average of % variance for all years						8%
Compound Annual Growth Rate for all years						1466.5%

OM&A per Customer

Ottawa River Power Corporations' cost per customer was $452 in 2009 and is $505 in 2013. This shows a per customer increase of $53 over a five year period.

OM&A per Circuit km of line

Ottawa River Power Corporations' cost per km was $32,146 in 2009 and is $32,410 in 2013. This shows a per km increase of $264 over a five year period.

5.3 Asset Management Process

Asset knowledge, combined with the integration of inspection and condition testing process, will enable ORPC to adopt an asset specific approach to asset management. ORPC will have oversight of virtually every individual asset, with insight into its age, overall health, operating conditions, projected failure date, impact of failure and replacement cost within the planning period. The maintenance inspection process and condition testing process offer insight into the health of every asset. An asset's health is based on its relative age compared to industry established life expectancies (Kinetric's Report), as well as information that quantifies its operating capacity. Assessing age and operating load allow for the probability of failure to be assigned. Based on this approach, ORPC will develop a profile of the order in which assets are expected to fail, categorized by asset type. The year during which an asset is expected to fail due to exceeding its failure risk tolerance is called its "Adjusted End-of-Life" (AEOL). The AEOL profile of assets drives ORPC's pace of capital reinvestment needs for sustainment or development activities (also referred to as asset lifecycle management).

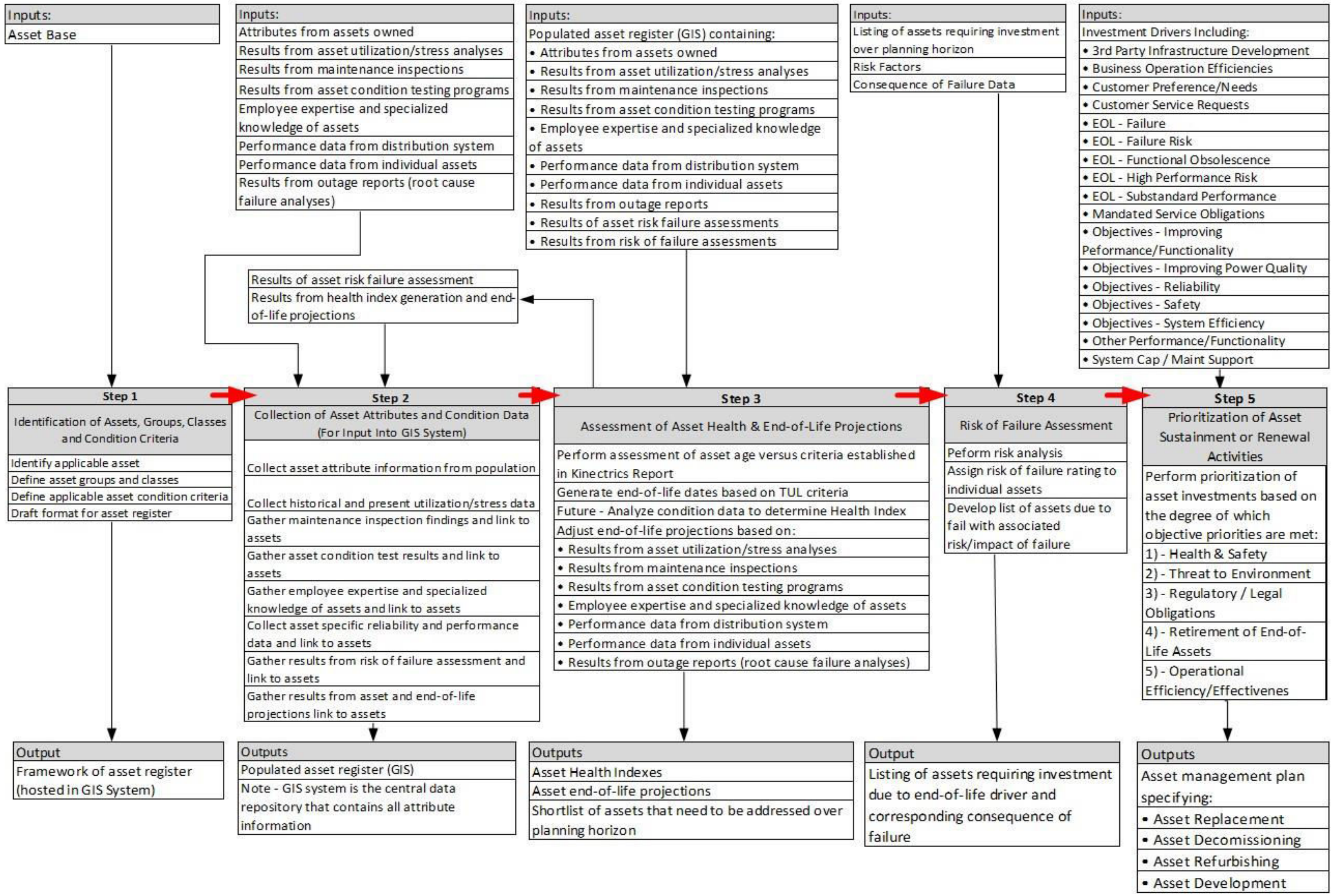
As an example, switchgear that has been well-maintained may need additional upkeep or upgrades. Factors include the availability of spare parts, reliability and the cost of ongoing maintenance. There may also be the need to increase the equipment's fault or continuous current rating.

Prior to purchasing new equipment, ORPC takes into account the initial equipment cost as well as the potential disruption to the facility's processes and workflow during the course of changing out the equipment.

The asset data contained in the GIS system combined with ORPC's maintenance program (inspections and condition testing), are the heart of the Asset Management Process. In summation, the asset management process can be boiled down to two main modules that complement one another:

1. Process for Managing Asset Sustainment and Development Activities
2. Process for Managing the Operation and Maintenance Activities

Asset Management Process Flow Chart for Sustainment and Development Activities



5.3.1 Asset Management Process Overview

ORPC's approach to managing the sustainment and development of its assets can be broken down into five logical steps.

Step 1
Identification of Assets, Groups, Classes and Condition Criteria
Identify applicable assets
Define asset groups and classes
Define applicable asset condition criteria
Draft format for asset register
Inputs:
Asset Base
Output
Framework of asset register (hosted in GIS System)

Step 1 - Identification of Assets, Groups, Classes and Condition Data

ORPC's first step towards implementing an asset management process was to identify and quantify the assets that are within ORPC's scope to manage. Once the assets were quantified, ORPC developed a listing of key asset attributes, by asset type, to establish the data sets required to support data driven asset management decisions. ORPC's asset data sets can be broken into two categories; physical attribute data and condition data.

For example, typical physical attribute data includes; the type of asset (equipment type); its location; age; rating; or configuration. Arguably the most important attribute from this data set with respect to asset management is the "age" of the asset. The basic knowledge of the age profile of assets is a very good high level tool for estimating future expenditure requirements. The age profile of assets is a fundamental driver of investments and is a good starting point for prioritizing investments.

This step essentially creates the framework of the asset register that is required to be populated. It should be noted that ORPC is working towards having all asset attribute and condition data linked to the assets themselves within the GIS system. For example, for a typical pole ORPC now has the pole properties stored in the GIS such as it height, class, location, replacement cost and age, as well as condition data has been linked to it, such as the results of the last "hammer test" for structural integrity or of the last general inspection findings. In future iterations of the DS Plan, ORPC, also plans to link risk ratings, health indexes and consequence of failure data to all individual assets.

Step 2
Collection of Asset Attributes and Condition Data (For Input Into GIS System)
Collect asset attribute information from population
Collect historical and present utilization/stress data and link to assets
Gather maintenance inspection findings and link to assets
Gather asset condition test results and link to assets
Gather employee expertise and specialized knowledge of assets and link to assets
Collect asset specific reliability and performance data and link to assets
Gather results from risk of failure assessment and link to assets
Gather results from asset end-of-life projections and link to assets
Inputs:
Attributes from assets owned
Results from asset utilization/stress analyses
Results from maintenance inspections
Results from asset condition testing programs
Employee expertise and specialized knowledge of assets
Performance data from distribution system
Performance data from individual assets
Results from outage reports (root cause failure analyses)
Inputs From Step 3
Results of asset risk failure assessment
Results from health index generation and end-of-life projections
Outputs
Populated asset register (GIS)
Note - GIS system is the central data repository that contains all attribute and condition information

Step 2 - Collection of Asset Attributes and Condition Data

Once the framework for necessary data required to manage assets has been established, the next logical step is to compile a listing of the population of assets owned, and to gather corresponding asset attribute information including condition and performance data. This step essentially generates a populated asset register.

ORPC will compile a listing of typical replacement costs for most common asset types and "replacement cost" will be an available attribute contained within the GIS based asset register.

Assets deteriorate as a function of time, as a function of their operating conditions and as a function of their physical environment. As such, ORPC's approach to asset management utilizes asset age, complimented by asset condition data. ORPC uses condition data to try and understand the operating conditions and environment of assets. This enables more accurate predictions of when assets will reach the end of their useful life, based on how quickly they are deteriorating. ORPC's key sources of condition data are the results from its maintenance inspection program, as well as the results from condition testing programs. In addition to this, ORPC also utilizes available performance data and the results from outage root cause failure reports.

The output of this step is a populated asset register that contains all pertinent attribute and condition data. The populated asset register enables data analysis to be performed on individual assets or on asset groups or classes.

Step 3 Assessment of Asset Health & End-of-Life Projections
Perform assessment of asset age versus criteria established in Kinectrics Report
Generate end-of-life dates based on TUL criteria
Analyze condition data to determine Health Index
Adjust end-of-life projections based on:
• Results from asset utilization/stress analyses
• Results from maintenance inspections
• Results from asset condition testing programs
• Employee expertise and specialized knowledge of assets
• Performance data from distribution system
• Performance data from individual assets
• Results from outage reports (root cause failure analyses)
Inputs:
Populated asset register (GIS) containing:
• Attributes from assets owned
• Results from asset utilization/stress analyses
• Results from maintenance inspections
• Results from asset condition testing programs
• Employee expertise and specialized knowledge of assets
• Performance data from distribution system
• Performance data from individual assets
• Results from outage reports
• Results of asset risk failure assessments
• Results from risk of failure assessments
Outputs
Asset Health Indexes
Asset end-of-life projections
Shortlist of assets that need to be addressed over planning horizon

<u>Step 3 - Assessment of Asset Health & End-of-Life Projections</u>

ORPC performs an analysis on all of its asset types by comparing the age of assets relative to the “Typical-Useful-Life” (TUL) standards established in the July 8, 2010 “Kinectrics Asset Depreciation Study for the Ontario Energy Board” (“Kinectrics Report”). ORPC then performs further analyses to determine how available asset condition data affects the longevity of individual assets. Condition data sources include inspection results, condition testing results, asset performance data, employee expertise, root cause failure data from outage reports and known manufacturer defect information.

Utilizing these inputs, ORPC adjusts the “Typical-Useful-Life” expectancy of individual assets based on assessing the health of individual assets. Favourable condition data extends the life expectancy of assets and unfavourable condition data decreases the life expectancy, relative to the normal TUL’s established in the Kinectrics Report. The resulting end-of-life estimations are referred to as “Adjusted End-of-Life” (AEOL) projections. The AEOL value profile for asset classes essentially generates a listing that reflects ORPC’s best guess as to the order in which assets will fail.

The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. ORPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

The AEOL profile for each asset class is updated annually to incorporate the latest available inspection, condition testing and performance data results. The end-of-life profile of assets allows ORPC to focus on the portion of assets that require special attention over the planning horizon. In other words, it allows ORPC to focus its attention on the assets that demand attention.

With ORPC’s replacement cost data available at the asset level, ORPC is able to quickly and easily generate high level cost projections for long range planning purposes.

Step 4
Risk of Failure Assessment
Perform risk analysis
Assign risk of failure rating to individual assets
Develop list of assets due to fail with associated risk/impact of failure
Inputs:
Listing of assets requiring investment over planning horizon
Risk Factors
Consequence of Failure Data
Output
Listing of assets requiring investment due to end-of-life driver and corresponding consequence of failure

Step 4 - Risk of Failure Assessment

After establishing end-of-life projections for individual assets, the next step is to assign a criticality of failure to the assets that are projected to fail over the planning horizon. In future iterations of the DS Plan, ORPC will assign a criticality rating to all of individual assets, not just those projected to fail over the planning horizon. ORPC uses the following risk factors when performing its failure assessment: impact on the health and safety of employees and the public; number of customers affected; location; accessibility; environmental impact; impact on reliability; cost of failure. The output of this step provides management with a listing of projected asset failures (high probability of failure) over the planning horizon, and an understanding of the impact

Steps 1 through 4 systematically identify assets that are at the end of their service life, have failed, are due to fail (have a high risk of failure) or are operating with substandard performance. These factors only represent a portion of drivers that need to be considered for capital planning. Steps 1 to 4 essentially encompass the management of asset lifecycles, which typically represents upwards of 70% of all capital expenditure requirements.

Step 5 (see table below) evaluates the impact of all investment drivers (not just lifecycle management) that ORPC must address as well including: customer service requests; other 3rd party infrastructure development requirements; mandated service obligations (accomplishment of regulatory requirements); expected changes in load or customer growth; achievement of corporate or strategic goals; achieving customer needs or expectations; and the achievement of regional planning activities.

The output of this step is a long range capital plan that specifies asset replacement, decommissioning, refurbishing and development projects to meet ORPC's business objectives.

Step 5
Prioritization of Asset Sustainment or Renewal Activities
Perform prioritization of asset investments based on the degree of which objective priorities are met:
1) - Health & Safety
2) - Threat to Environment
3) - Regulatory / Legal Obligations
4) - Retirement of End-of-Life Assets
5) - Operational Efficiency/Effectiveness
Inputs:
Investment Drivers Including:
• 3rd Party Infrastructure Development
• Business Operation Efficiencies
• Customer Preference/Needs
• Customer Service Requests
• EOL - Failure
• EOL - Failure Risk
• EOL - Functional Obsolescence
• EOL - High Performance Risk
• EOL - Substandard Performance
• Mandated Service Obligations
• Objectives - Improving Performance/Functionality
• Objectives - Improving Power Quality
• Objectives - Reliability
• Objectives - Safety
• Objectives - System Efficiency
• Other Performance/Functionality
• System Capital / Maintenance Support
Outputs
Asset management plan specifying:
• Asset Replacement Projects
• Asset Decommissioning Projects
• Asset Refurbishing Projects
• Asset Development Projects

<u>Step 5 - Prioritization of Asset Sustainment or Renewal Activities</u>

This step is essentially the decision making engine or capital expenditure planning process, for the purpose of prioritizing long range investments and linking investment drivers to planned expenditures. The linking and prioritizing of investments essentially generates the foundation of a long range capital plan.

ORPC prioritizes investments or projects to the degree with which the following objectives are satisfied:

1. Ensuring that the health and safety of employees and the public is maintained
2. Eliminate or mitigate threats to the environment
3. Ensuring compliance to regulatory and legal obligations
4. Meeting the needs and preference of customers
5. Retiring assets that are at the end of their useful life
6. Improving operational efficiency and effectiveness

Asset Management Process for Managing Maintenance Activities

ORPC's asset management process for managing maintenance activities can be broken down into the following four main programs:

1. Maintenance Inspection Program (OP 7-6)
    - Includes asset condition testing program
2. Transformer Station Preventative Maintenance Program
    - Includes asset condition testing & analysis
3. Vegetation Management Program
4. Power System Studies, Including Short Circuit Analysis, Coordination, Load Forecast, Arc Flash and Ground Grid

The Maintenance Inspection Program and Transformer Station Preventative Maintenance Program provide key inputs for Step 2 - "Collection of Asset Attributes and Condition Data" of ORPC's Asset Management Process for Sustainment and Development Activities. The programs essentially provide asset specific condition data that is used to assess asset end-of-life projections.

Maintenance Inspection Program:

ORPC has developed an extensive maintenance inspection program to meet the requirements of Ontario Regulation 22/04 Section 4 "Safety Standards", section 5 "When Safety Standards Met" and of the Ontario Energy Board's Distribution System Code Appendix C, "Minimum Inspection Requirements." Refer to Appendix G for ORPC's complete Maintenance Inspection Program.

Transformer Station Preventative Maintenance Program:

ORPC has retained the services of an independent third party contractor to perform annual maintenance inspections and asset condition testing of all major station components. All major components have been assigned to a three year maintenance schedule and asset condition assessments are performed annually due to the criticality of the station.

The following maintenance, testing and inspection schedule has been applied as per the recommendation NETA:

Year 1 Inspection, Maintenance & Condition Analysis:

- OCB testing
- Relay testing
- Battery banks testing
- Yearly oil sampling (all assets containing oil)

Year 2 Inspection, Maintenance & Condition Analysis:

- Transformer and associated equipment (tap changer, arrestors), 5 kV Breakers
- Battery banks testing
- Yearly oil sampling (all assets containing oil-)

Year 3 Inspection, Maintenance & Condition Analysis:

- Transformer and associated equipment (tap changer, arrestor), 15 kV Breakers
- Battery banks testing
- Yearly oil sampling ()

ORPC'S Asset Register

Over the planning horizon, approximately 15% of all planned capital investments are driven by "system renewal," specifically due to assets reaching their end-of-useful service life. ORPC's asset management process will project the end of service lives for individual assets and to quantify the corresponding impact/risk associated with failure. Informed decisions in the future can be made to prioritize asset replacements based on other variables than impact of failure.

ORPC performs detailed inspections, as well as proposed condition tests, on all major asset categories where practical. Refer to Appendix G "Maintenance Inspection Program" for details. The results of inspections and condition tests are used to quantify the amount of asset deterioration. As such, the degree of asset deterioration is a key input to projecting equipment longevity as well as the expected date of failure. The date on which an asset is predicted to fail is termed as an asset's "Adjusted End-of-Life" (AEOL) date, as per ORPC's asset management process. By default AEOL's are aligned with TUL values according to the "Kinectrics Report". Favourable inspection and condition testing results will extend an asset's AEOL date beyond the TUL and alternately unfavourable inspection and condition testing results will shorten an asset's AEOL with respect to its TUL. It is important to note that adjusted end-of-life projections are more meaningful as assets approach their TUL, as opposed during their early years of service. The TUL stage of an assets lifecycle is the critical time at which investment decisions must be made. The decision could be to do nothing, replace, refurbish, decommission or develop the asset.

ORPC's Adjusted End-of-Life profiles essentially govern lifecycle related investments. ORPC's long term goal is to normalize unevenly distributed asset populations, thereby smoothing future expenditure requirements, while at the same time replacing assets proactively just before reaching their point of failure. ORPC's "just in time" proactive asset replacement strategy allows for replacements to be conducted in a coordinated and planned manner, as opposed to under emergency repair circumstances. Emergency repair circumstances often add significant unnecessary expense such as overtime rates of pay or minimum crew callout durations, as well as they often require the use of more expensive equipment such as vacuum trucks to complete the job safely.

ORPC has also aligned the life cycles of various asset classes such that multiple asset classes can be changed at the same time.

Furthermore, ORPC has adopted several Maximum Useful Life values as per the "Kinectrics Report" for various asset classes, as the longer service life better reflects ORPC operating conditions and environment. For example, ORPC has adopted the Maximum Useful Life of 20 years for Trucks and Buckets, 70 years for power transformers, Smart meters 15 years, and pole and pad mount 60 years.

ORPC owns and operates all electrical distribution assets necessary to distribute electricity to its customers throughout its licensed distribution service territory.

ORPC has organized its asset groupings according to the "Kinectrics Asset Depreciation Study for the Ontario Energy Board" ("Kinectrics Report"). The following table summarizes all of the significant assets managed by ORPC:

ORPC Summary of Assets Owned											
		Asset Details			ORPC Assets			Kinectrics Useful Life			Refurbishment Considered?
Parent*	#	Category| Component | Type			Count	Units	Average Age	MIN UL	TUL	MAX UL	Yes/No
OH	1	Fully Dressed Wood Poles	Overall		4299	Each	21.79	35	45	75	yes
			Cross Arm	Wood	N/A			20	40	55	n/a
				Steel	N/A			30	70	95	n/a
	2	Fully Dressed Concrete Poles	Overall		45			50	60	80	
			Cross Arm	Wood	N/A			20	40	55	
				Steel	N/A			30	70	95	
	3	Fully Dressed Steel Poles	Overall		N/A			60	60	80	
			Cross Arm	Wood	N/A			20	40	55	
				Steel	N/A			30	70	95	
	4	OH Line Switch (Expressed as sets of 3 Phase Switches)				Each		30	45	55	yes
	5	OH Line Switch Motor			N/A			15	25	25	
	6	OH Line Switch RTU			N/A			15	20	20	
	7	OH Integral Switches			N/A			35	45	60	
	8	OH Conductors	Primary Conductor		224.2	km		50	60	75	no
			Secondary Conductor		114.8	km		25	35	40	no
	9	OH Transformers				Each		30	40	60	no
	10	OH Shunt Capacitor Banks			N/A			25	30	40	
	11	Reclosers			2		5	25	40	55	

ORPC Summary of Assets Owned										
		Asset Details		ORPC Assets			Kinectrics Useful Life			Refurbishment Considered?
Parent*	#	Category | Component | Type		Count	Units	Average Age	MIN UL	TUL	MAX UL	Yes/No
TS & MS	12	Power Transformers	Overall		Each		30	45	60	yes
			Bushing		Each		10	20	30	yes
			Tap Changer		Each		20	30	60	yes
	13	Station Service Transformer			Each		30	45	55	no
	14	Station Grounding Transformer		N/A	Each		30	40	40	
	15	Station DC System	Overall		Each		10	20	30	yes
			Battery Bank		Each		10	15	15	yes
			Charger		Each	23	20	20	30	yes
	16	Station Metal Clad Switchgear	Overall		Each	45	30	40	60	yes
			Removable Breake		Each	45	25	40	60	yes
	17	Station Independent Breakers			Each	67	35	45	65	yes
	18	Station Switch			Each	41	30	50	60	yes
	19	Electromechanical Relays			Each	36	25	35	50	no
	20	Solid State Relays		N/A	Each		10	30	45	
	21	Digital & Numeric Relays		8	Each	1.5	15	20	20	no
	22	Rigid Busbars		3	Each	36	30	55	60	no
	23	Steel Structure		1	Each	36	35	50	90	yes
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		N/A			60	65	75	
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		N/A			20	25	25	
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		N/A			20	25	30	
	27	Primary Non-TR XLPE Cables in Duct		N/A			20	25	30	
	28	Primary TR XLPE Cables Direct Buried		N/A			25	30	35	
	29	Primary TR XLPE Cables in Duct			km	27.07	35	40	55	yes
	30	Secondary PILC Cables		N/A			70	75	80	
	31	Secondary Cables Direct Buried			km	28	25	35	40	no
	32	Secondary Cables in Duct		N/A			35	40	60	
	33	Network Transformers	Overall	N/A			20	35	50	
			Protector	N/A			20	35	40	
	34	Pad-Mounted Transformers	Single Phase		Each	27.7	25	40	45	no
			Three Phase		Each	20.05	25	40	45	yes
	35	Submersible/Vault Transformers		N/A			25	35	45	
	36	UG Foundation			Each	27.52	35	55	70	no
	37	UG Vaults	Overall	N/A			40	60	80	
			Roof	N/A			20	30	45	
	38	UG Vault Switches		N/A			20	35	50	
	39	Pad-Mounted Switchgear		N/A			20	30	45	
	40	Ducts			km	27.95	30	50	85	no
	41	Concrete Encased Duct Banks			km	33.46	35	55	80	no
	42	Cable Chambers			Each	20.4	50	60	80	no
S	43	Remote SCADA					15	20	30	

ORPC Summary of Assets Owned											
		Asset Details		**ORPC Assets**			**Kinectrics Useful Life**			**Refurbishment Considered?**
Parent*	**#**	**Category | Component | Type**		**Count**	**Units**	**Average Age**	**MIN UL**	**TUL**	**MAX UL**	**Yes/No**
General Plant	1	Office Equipment		Various	Each	Various	5	10	15	yes
	2	Vehicles	Trucks & Buckets		Each	8	5	10	15	yes
			Trailers		Each	26	5	12.5	20	yes
			Vans				5	7.5	10	yes
	3	Administrative Buildings			Each	45	50	62.5	75	yes
	4	Leasehold Improvements (Generator)			Each	5	20	20	20	
	5	Station Buildings	Station Buildings		Each	39	50	62.5	75	yes
			Parking		Each	24	25	27.5	30	yes
			Fence		Each	42	25	42.5	60	yes
			Roof		Each	39	30	30	30	yes
	6	Computer Equipment	Hardware	Various	Each	Various	3	4	5	no
			Software	Various	Each	Various	2	3.5	5	no
	7	Equipment	Power Operated	Various	Each	Various	5	7.5	10	no
			Stores	N/A			5	7.5	10	no
			Tools, Shop, Garag	Various	Each	Various	5	7.5	10	yes
			Measurement & Testing Equip	Various	Each	Various	5	7.5	10	no
	8	Communication	Towers	1			60	65	70	no
			Wireless	Various	Each	Various	2	6	10	no
	9	Residential Energy Meters		N/A			25	30	35	
	10	Industrial/Commercial Energy Meters		N/A			25	30	35	
	11	Wholesale Energy Meters			Each	5	15	22.5	30	no
	12	Current & Potential Transformer (CT & PT)			Each	Various	35	42.5	50	no
	13	Smart Meters			Each	4.92	5	10	15	no
	14	Repeaters - Smart Metering		N/A			10	12.5	15	
	15	Data Collectors - Smart Metering			Each	5	15	17.5	20	yes

Note: For General Plant where TULs were not specified, ORPC has designated the midpoint between the Min UL and Max UL.

5.3.2 Overview of Assets Managed

Substations and Feeders

ORPC owns and operates eleven municipal sub-stations. The station data is summarized below in Table 6. The substations are located within the City of Pembroke and the town of Almonte. Each station is controlled by appropriately rated load break and/or airbrake switches. A brief description of each station is provided in the subsections below.

City of Pembroke and Almonte Ward Substations

Summary of Pembroke's substations:

- 1917 – Substation 1 was built, it currently consists of three 1500KVA 2500 – 2300Volt single phase, air cooled transformers. In 1962, the current air blast switchgear was added.
- 1950-1951 – Substation 2 was built with a 3750KVA in place until and a new 5000KVA transformer was added in 1957 -1958. In 1968 a 6000KVA was added to replace the existing.
- 1957 – Substation 3 was built and completed in 1958 with a 5000KVA transformer.
- 1965 – Substation 4 was built with a 6000 KVA transformer and a secondary voltage of 4160.
- 1969 – Substation 5 was built and includes a 3000KVA transformer with a voltage of 4160.
- 1976 – Substation 6 was built with a 10,000KVA transformer and a voltage of 44Kv / 12.4KV.
- 1976 – Substation 7 was built with a 10,000KVA transformer and a voltage of 44KV / 12.4KV and is at the same physical address as Substation #3.
- 1985 – Substation 8 was built with a 10,000KVA transformer and a voltage of 44KV / 12.4KV.

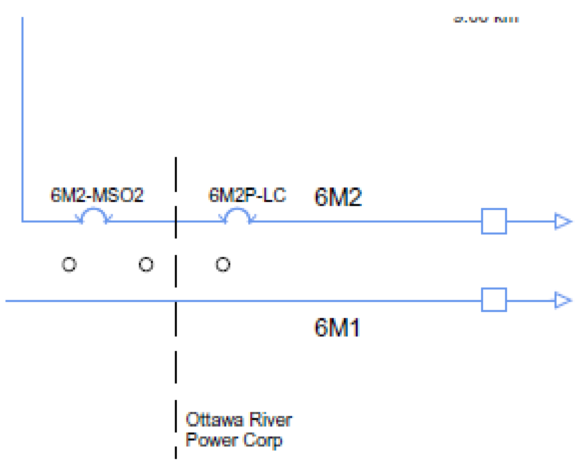


Figure: HONI 44 kV supply to Pembroke Substation #4

Substation 1 Pembroke

MS1	Land	150 sq. m	1962
Lake St.	Building	Room in Building	
	HV Gear	Power Fuses (Breaker Yard for 44kV	
	Transformers	Three single 2500KVA, 44000/2400 volt	
	Secondary Gear	Five 15 KV Metal Clad Breakers	
	Feeder Cables		

In 1917, Substation 1 was built, it consisted of three 1500KVA 2500 – 2300 Volt single phase, air cooled transformers. In 1955, these transformers were updated to 2500KVA single phase air cooled transformers. In 1960, the current Westinghouse Oil Circuit Breakers (OCB) were added. The switch gear is Westinghouse metal clad 1200amp. The OC relays are Westinghouse style no. 1875275, model #CO-8. The reclosing relays are Westinghouse style #71B78A09 Type DRC set with 4 operations to lockout.

In October 2009, the following maintenance was completed on the 44KV OCB:

a. Breaker A3 – Breaker oil flushed and mechanical checks made by Les Services Electrotechniques Inc. Breaker counter was left at 227.
b. Breaker A2 – Breaker oil flushed and mechanical checks made by Les Services Electrotechniques Inc. Contact resistance was high. Breaker drained and tank lowered. Contacts were adjusted to correct the resistance. Trip free relay was not working properly and required an adjustment on the TF coil. The problem was corrected and tested.

Transformer oil samples are sent to the Rondar Laboratory every second year for testing. Two samples are taken from the bottom of the transformer one for water content and one for dissolved gas. To test for dissolved gas requires that you take the oil sample with a syringe that is provided by the test laboratory. The laboratory will provide a detail analysis of the oil and gases and provide recommendations based on history of the oil samples.

Oil samples for T1, T2 and T3 tested in 2012, oil is 1 ppm above normal in T1. T2 and T3 are within normal operating limits. Lab test suggest Furan analysis on all 3 transformers to assess paper condition. Furan test should be included in 2014 test samples.

Monthly maintenance is provided on the station battery bank; this includes voltage tests, inspection of battery cell structure and specific gravity of battery acid. Battery chargers are checked as well for charging rate and output to the battery bank Batteries are change as required.

Known Deficiencies of Substation 1:

1. Aging transformers
2. Mechanical protective relays
3. Oil Circuit Breaker

Substation 2 Pembroke

MS2	Land	900 sq. m, fenced yard	1952
Fraser St.	Building	Steel building for MC	
	HV Gear	44 KV Fused A/B	
	Transformers	6000 KVA, 44000/4160	
	Secondary Gear	Four 5 KV Metalclad Breakers	
	Feeder Cables		

In 1950-1951, Substation 2 was built with a 3750KVA in place until and a new 5000KVA transformer was added in 1957-1958. In 1968, a 6000kVA transformer was installed.

This station is in the 2014 budget for new feeder cables. A new ground grid and fencing will be installed at the same time. The existing 6000KVA transformer will remain in place.

Known Deficiencies of Substation 2:

1. Aging transformers
2. Mechanical protective relays
3. Ground Grid deficiencies
4. Building ageing
5. PILC Feeder cables
6. Original 48 VDC Batteries

Substation 3 Pembroke

MS3	Land	560 Sq. meter fenced yard	1957
Fischer Ave.	Building	Steel building for MC	
	HV Gear	44 kV AB and fuses	
	Transformers	6000 KVA, 6000 KVA, 44000/4160	
	Secondary Gear	Five cell metalclad breakers	
	Feeder Cables		

In 1957, Substation 3 was built and completed in 1958 with a 5000KVA transformer. The unit was originally built by English Electric in 1957 serial number 261103 in Y-Δ and rebuilt by Ferranti Packard Electric Ltd. in 1967 to Δ-Δ/Y.

In November 2007, we replaced all the station insulators to new polymer station insulators.
In September 2011 the following maintenance was completed on feeder 3-1 and 3-2:

a. New 3/0 15KV XLPE cable was installed on feeder 3-1 and 3-2 feeders, this replaced the old lead cable and pothead. New 15KV switches were installed at the same time.
b. Breakers were removed from their cells and repaired and cleaned, testing was completed and the breakers were put back into service.

In February 2012, a new battery bank was installed in Substation 7 and a 48 DC volt supply was provided to Substation 3 from the new battery bank.

Known Deficiencies of Substation 3:

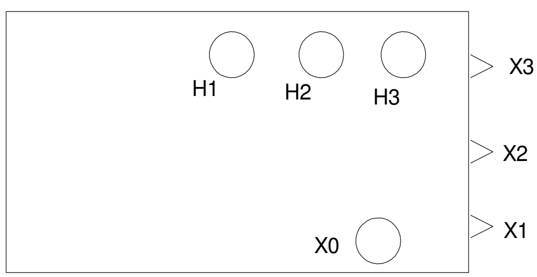
1. Phasing of power transformers
2. Mechanical protective relays
3. Ground grid and fencing
4. 44 kV incoming pole structure

Substation 3 – Nameplate Data on 44,000 – 4160 Bank

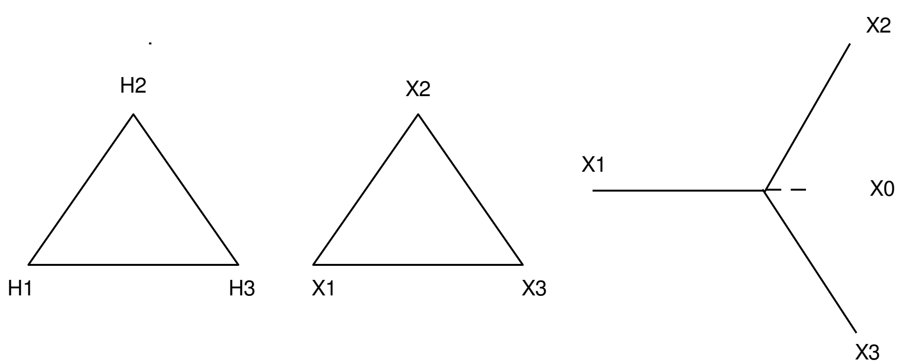
<u>Ferranti Packard Name Plate</u>
HV Taps: 47150, 46000, 44860, 43700, & 42500
Secondary; 4160/2400 V Y or 2400 V Delta
5000 KVA at 55^{o} C ONS
Impedance 5.52% @ 75^{o} C
HV BIL 200kV
LV BIL 75kV

<u>Weights</u>

Core/Coil	25990
Tank	6000
Oil	13650 (1600 gal)
Total	35580



<u>Winding Configuration</u>



Substation 4 Pembroke

MS4	Land	900 sq. m	1964
	Building	Steel building for MC	
	HV Gear	AB and HV Fuses	
	Transformers	6000 KVA, 44000/4160	
	Secondary Gear	Five cell metalclad breakers	
	Feeder Cables		

In 1963, Substation 4 was built and consists of a 5,000KVA transformer. Substation 4 is a main switching yard for two 44KV HV supplies from Hydro One Networks and a 44KV supply from Brookfield Power.

There are a total of five 44KV oil circuit breaks in this yard, four of which belong to ORPC and one that belongs to Pontiac Hydro. The switch gear is Westinghouse metal clad 1200amp. The OC relays are Westinghouse style no. 1875275, model #CO-8. The reclosing relays are Westinghouse style #71B78A09 Type DRC set with 4 operations to lockout.

In October 2009, the following maintenance was completed on the 44KV OCB:

a. Feeder Cable on 4-3 cable failed and was removed from the duct, two phases were damaged. New cable (single conductor 500 mcm Cu 15 kV, shielded XLPE was installed from the breaker to the riser pole. The duct bank at the rear of the sub building was found to be sheared due to frost or settlement. Duct was exposed and moved back into position and interior sleeve was inserted.

b. Breaker B2 – Breaker failed on June 24 with the load side center bushing blowing apart. Two bushings replaced with used units obtained from Hydro Pontiac. Bushings tested, oil filtered and tank flushed by Les Services Electrotechniques Inc. Travel test and alignment was not done inasmuch as the top plug could not be removed to gain access.

c. Breaker 6M2P – Breaker oil flushed and mechanical checks made by Les Services Electrotechniques Inc. Bushing test was poor and oil level was found low and corrected.

d. Breaker B3 - Breaker oil flushed and mechanical checks made by Les Services Electrotechniques Inc. Breaker was found to be in good shape.

e. 44 kV Potential transformers- checked and oil added to one PT. The secondary connections off the PT's was replaced with new flex cable and re-wired in a weather proof box. The PT's were scraped and re-painted at the same time. The connection plate on the rear of the PT's was sealed with outdoor caulking as well.

f. The neutral frequency transformer was removed from the back of the secondary incoming cell in Sub #4 at the same time. The neutral conductors were connected directly to the neutral bus.

Note: Breaker 6M1P was not maintained due to not being able to get protection from HONI for the work. We will need to complete a PC1 and send to HONI for approval, this will require 4-6 weeks' notice to HONI for them to complete the request.

In 2006, a new battery bank was installed. In 2011, new S&C power fuses were installed on transformer, and in 2013 new in-line switches were installed on riser pole 4-1 and 4-2.

Known Deficiencies of Substation 4

1. Aging transformer
2. Mechanical protective relays
3. Oil Circuit Breaker Maintenance and replacement as required
4. 44 kv PT <3 meter clearance to ground
5. Building

Substation 5 Pembroke

MS5	Land	650 sq. m	1969
	Building	Masonry building	
	HV Gear	HV Fuses only	
	Transformers	3000 KVA, 44000/4160	
	Secondary Gear	Four cell metalclad breakers	
	Feeder Cables		

In March 2011, Breaker 5-1 and 5-2 performed full maintenance on breaker including operation and installed copper all on HV contacts. The batteries were addressed in 2009.

More recently in January 2014, ORPC installed a new "Keep Dry" oil dryer on the power transformer. During our regular oil sampling it was recognized that the water content in the transformer was increasing over the years. In 2007, we had contracted a company to re-circulate the oil and remove the water down to an acceptable amount. Since then it has steadily increased to a point where we decided to try a procedure to remove the water while keeping the transformer in service.

Known Deficiencies of Substation 5

1. Mechanical protective relays and recloser
2. LAs
3. Batteries 2009 Gel Maintenance free

Substation 6 Pembroke

MS6	Land	3700 sq. m	1976
	Building	Masonry building	
	HV Gear	HV Fuses only	
	Transformer T1	10MVA 44000/12400 volt	
	Transformer T2	10MVA 44000/12400 volt	
	Secondary Gear	Four cell metalclad breakers	
	Feeder Cables		

In March 2007, ORPC replaced all porcelain insulators on Air Break switch B-26. In June 2011, ORPC replaced arc snuffer on 44KV a-26, and in October 2011, ORPC replaced secondary buss on transformer T-1 and installed new 15KV shrink tubing. More recently, in July 2013, ORPC repaired battery charger diodes, and in July 2014 the 44KV lightning arrestor on transformer T-1 was replaced.

Known Deficiencies of Substation 6

1. Building foundation
2. Mechanical protective relays and recloser
3. LAs
4. Batteries 1990

Substation 7 Pembroke

MS7	Land	Same site as MS3	1974
	Building	Steel building	
	HV Gear	HV Fuses only	
	Transformers	10000 KVA, 44000/12400	
	Secondary Gear	Two 15kV cell metalclad breakers	
	Feeder Cables		

In 2012, ORPC removed breakers from cells and performed complete maintenance on breakers, and installed new batteries as well. In 2013, the battery charger was replaced and ORPC installed new capacitors and potentiometer.

Known Deficiencies of Substation 7

1. Building, foundation
2. Mechanical protective relays and recloser
3. Lightning arresters
4. Ground Grid and fencing

Substation 8 Pembroke

MS8	Land	560 sq. m	1991
	Building	Masonry building	
	HV Gear	HV AB and Fuses	
	Transformers	10,000 KVA, 44000/12400	
	Secondary Gear	Two cell metalclad breakers	
	Feeder Cables		

In July 2004, the transformer was re-levelled and ORPC checked secondary buss connections to switch gear. Previously, in May 2009, ORPC removed pillar caps and replaced with new cement caps.

Known Deficiencies of Substation 8

1. Transformer foundation
2. Mechanical protective relays
3. Structure for fuse and LAs, proximity to ground
4. Proximity of adjacent Building and property to Transformer
5. Batteries – 1989

Pembroke Substation Data Summary Table

Station	Year	Voltage	Transformer Size	No. of Feeders
MS1	1955	44 - 4.16 kV	3*2.5 MVA single phase	4
MS2	1952	44-4.16 kV	5.0 MVA	4
MS3	1957	44-4.16 kV	6.0 MVA	5
MS4	1964	44-4.16 kV	6.0 MVA	5
MS5	1969	44-4.16 kV	3.0 MVA	4
MS6	1976	44-12.400kV	10.0 MVA	2
MS6	1976	44-12.400kV	10.0 MVA	2
MS7	1974	44-12.400kV	10.0 MVA	2
MS8	1991	44-12.400kV	10.0 MVA	2

Substation 1 Almonte

MS1	Land	Owned by MRPC	
Almonte	Building	Masonry building (owned by MRPC)	
	HV Gear	HV AB and Fuses	2010
	Transformers	5000 KVA, 44000/4160	
	Secondary Gear	Three Viper Reclosures & S&C Vista	
	Feeder Cables		

Substation 1 in Almonte was re-built in 2010 when a new transformer was installed along with new riser cables, state of the art Viper switch gear, and SEL Protective Relays.

Substation 2 Almonte

MS2	Land		1975
Victoria Street	Building	Steel Building	
	HV Gear	HV AB and Fuses	
	Transformers	5000 KVA, 44000/4160	
	Secondary Gear	Three cell metalclad breakers	
	Feeder Cables		

	Nomen	Manu/Model	Rating	
Switch	MS2T1-L	CLM, PH40, Cat No PH1Hc15	600A, 46kV, 250 kV BIL	
Fuse Holder	A01T1L-X	S&C/ SMD 1A	200 A	
Fuse		S&C / SMD 1A 445075R1	75 A 153-1	
Arrestor		GE L9A2H Type RW Cat GEH2901		

Transformers Device #	Rating	Voltage	Imp	Taps
C01T1	5000KVA,	44000-4160/2400	5.6% at 75 C	Off load, 2 ½,5 +/- set at tap 3
Manu.	Winding Conf.	S/N	Wt./Gal of Oil	
CGE	delta/grd wye	288606	27600lb/675g	

Comments:

- db. level is high (fence erected to lessen impact on neighbors), Open fence yard with walk in metalclad
- Oil tested in 1997 and 2014, PCB 34ppm, Provision for fan cooling to increase capacity to 6667 kVA
- Station Service; 10KVA 120/240 dry core

Low Voltage Switchgear/Fuses

Device	Manuf/Model	Rating	Settings	Comments
F1 (Harold St)	CGE/M26 Magneblast	2000A, 60 KV BIL, 250MVA, 40,000 A momentary	Tap 8 TD 1.5 (480 Amps)	300:5 CT
F2 (St James N&W to Martin)	CGE/M26 Magneblast	2000A, 60 KV BIL, 250MVA, 40,000 A momentary	Tap 6 TD 1.5 (360 A)	300:5 CT
F3 (Ottawa St to MS1)	CGE/M26 Magneblast	2000A, 60 KV BIL, 250MVA, 40,000 A momentary	Tap 8 (pick up 7.5) (450 A) TD 1.5	300:5 CT

Comments: tested relays in 2014

<u>Relay Settings</u>

F1: CGE IAC Inverse, 4-16 amps, 20-80, Time dial 1.5, Tap 8

F2: CGE IAC Inverse, 4-16 amps, 20-80, Time dial 1.5, Tap 6

F3: CGE IAC Inverse, 4-16 amps, 20-80, Time dial 1.5/1.5/1.8, Tap 8

Known Deficiencies and findings of Substation 2 in Almonte

1. Building Fence
2. Mechanical protective relays
3. Las
4. Porcelain Insulators
5. SCADA (fibre cable exists in Station)
6. Potable water station in proximity; No Oil Containment

Substation 3 Almonte

MS3	Land		
King St.	Building	Metacald Aisle Type MC	
	HV Gear	HV AB and Fuses	
	Transformers	3000 KVA, 44000/4160	
	Secondary Gear	Two cell metalclad breakers	
	Feeder Cables		

	Nomen	Manu/Model	Rating	Age	
Switch	C01T1-L			1965	
Fuse Holder		S&C/ SMD 1A	200 A	1965	
Fuse		SMD 1A	65 Amp		Curve 153-1
Arrestor		CLM Line Type F	50 KV	1965	

Transformers

Device #	Rating	Voltage	Imp	Taps
	3000KVA, ONS	44000-4160/2400	5.6% at 75 C	Off load, +2 ½,-2 ½, -5, -7.5 - set at tap 2
Manu.	Winding Conf.	S/N	Date	Wt/Oil
Ferranti Packard	delta/grd wye	1-2505	1965	23200lb/915 gal

Low Voltage Switchgear/Fuses

Device	Manuf/Model	Rating	Settings	Comments
F1 (Gemmill, Perth St, Hwy29)	CLM/AE	1200A, 150MVA, 25000A Sym	6 A trip (360A) Inst 22 A (1320A)	Capacitor trip, 300:5 CT, Feeder 3/0 Cu 1/3 capacity 5kV
F2 (Country St & Bridge St)	CLM/AE	1200A, 150MVA, 25000A Sym	6 A trip (360A) Inst 22 A (1320A)	Capacitor trip, 300:5 CT, Feeder 3/0 Cu 1/3 capacity 5kV
Incoming Cell				1200:5 CT 20:1 PT

Auxiliary Equipment: SCADA
Building: Open fence yard with walk in metalclad
Station Service; 10 KVA 120/240

<u>Relay Settings</u>
F1: CGE IAC Inverse, 4-16 amps, 10-40, Time dial 1.5, Tap 6, Inst 24
F2: CGE IAC Inverse, 4-16 amps, 10-40, Time dial 1.5, Tap 6, Inst 24

Known Deficiencies and findings of Substation 3 in Almonte

1. Building fencing and Ground grid
2. Mechanical protective relays
3. LAs
4. Porcelain Insulators
5. SCADA (fiber cable exists in Station)
6. Radial 44 kV feeder

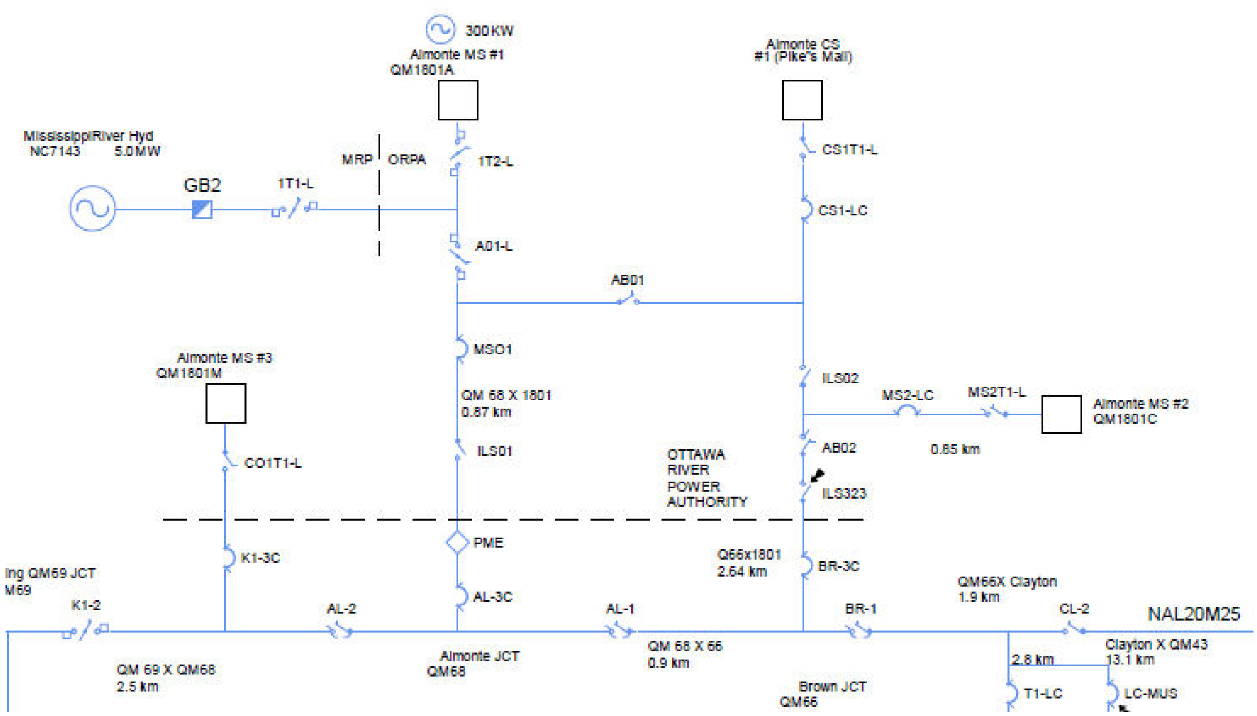
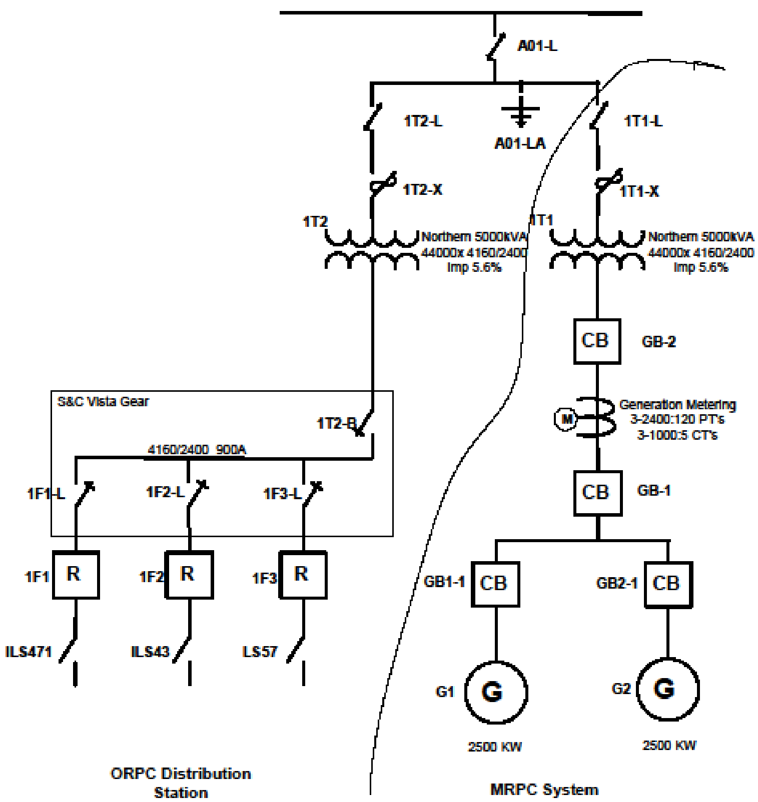
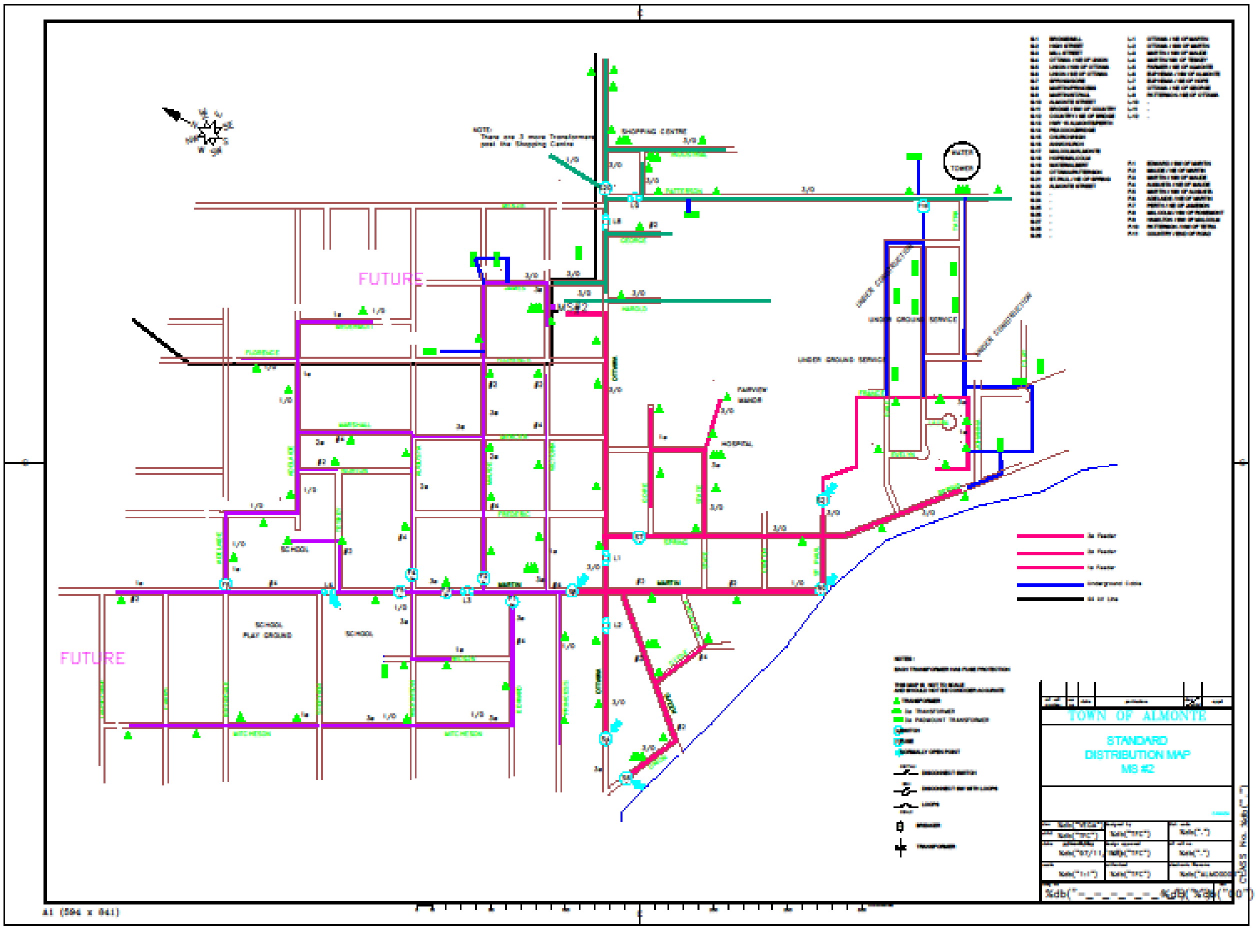


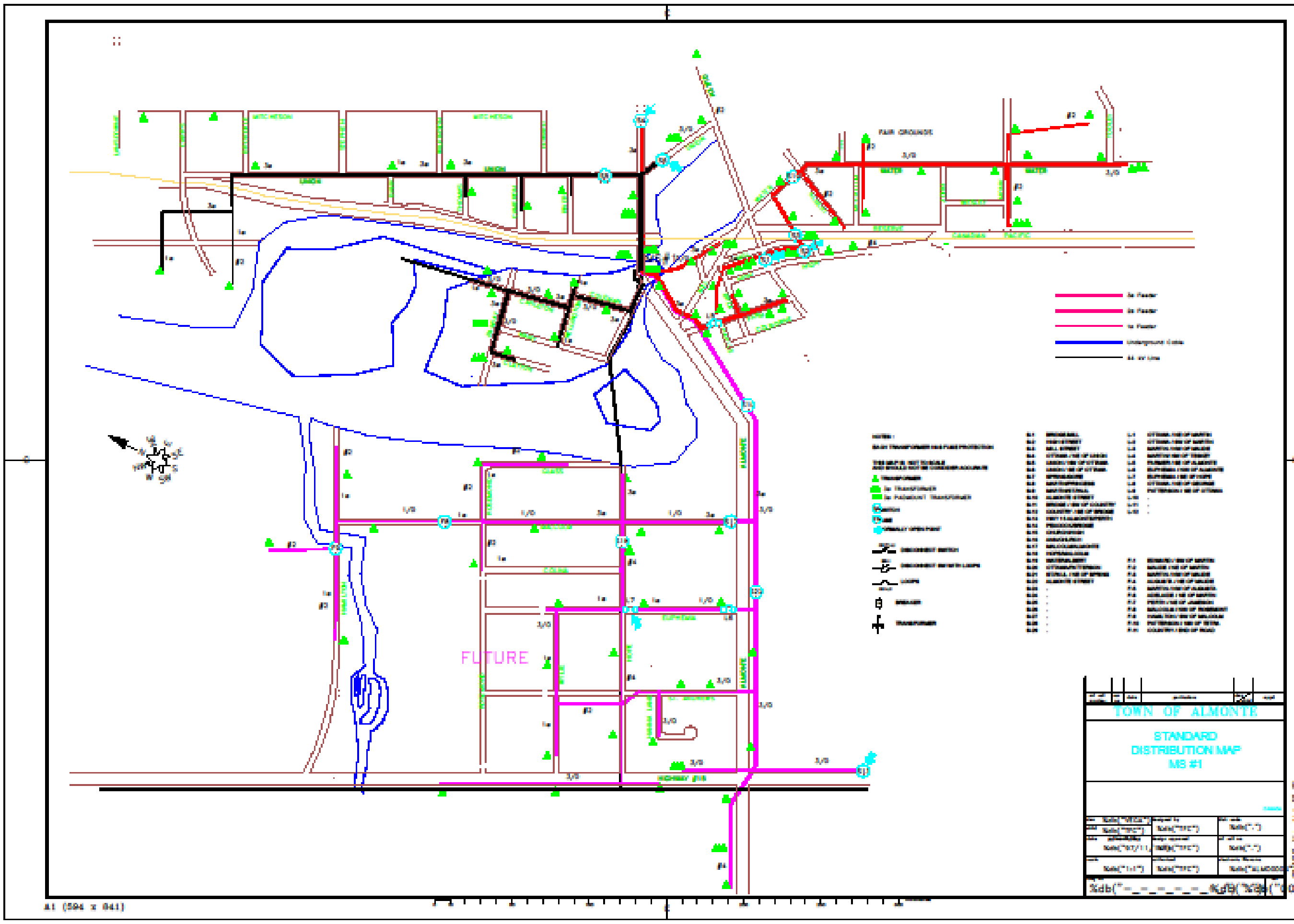
Figure: HONI 44 kV feeders to Almonte

ORPC Almonte MS1 & MRPC Sub
Ottawa Street, Almonte





TOWN OF ALMONTE
STANDARD DISTRIBUTION MAP MS #2
FUTURE
SHOPPING CENTRE
WATER TOWER
UNDER GROUND SERVICE
UNDER CONSTRUCTION
FAIRVIEW MANOR
HOSPITAL
SCHOOL
SCHOOL PLAY GROUND
A1 (594 x 841)

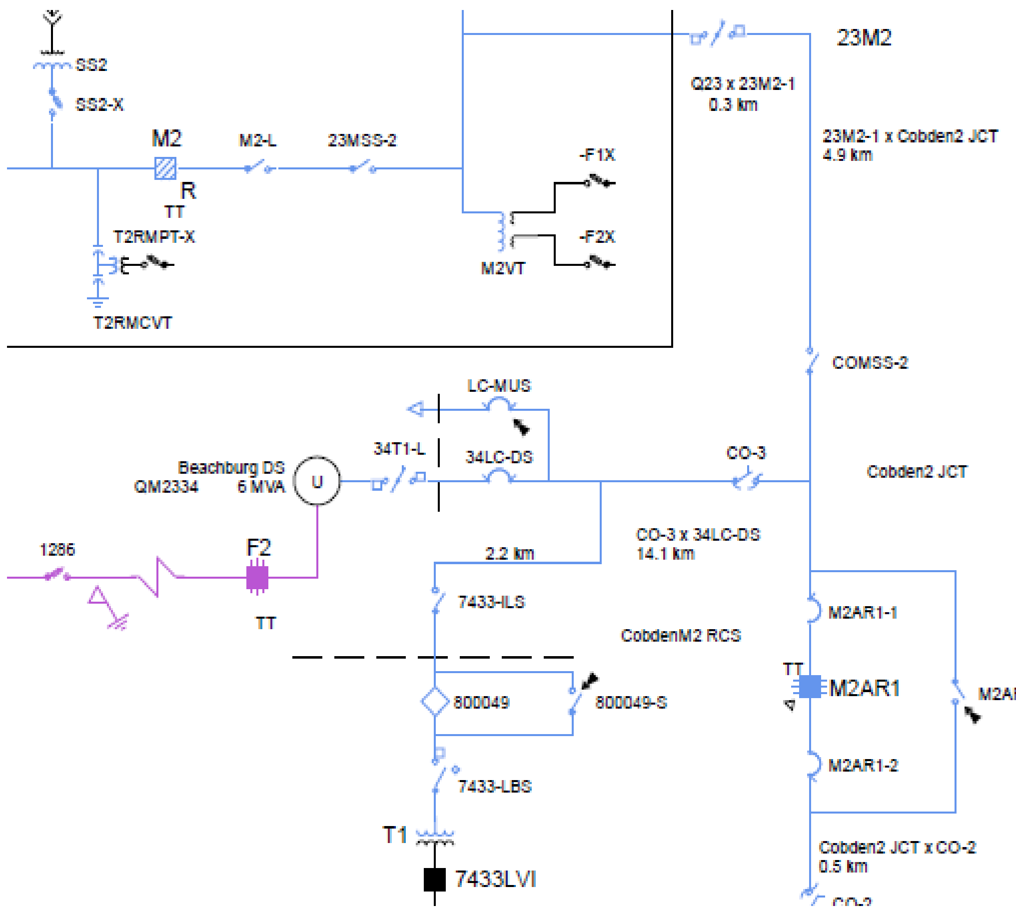


Almonte Substation Data Summary Table

Station	Year	Voltage	Transformer Size	No. of Feeders
MS1 - Almonte	2010	44-4.16 kV	5.0 MVA	4
MS2 - Almonte	1975	44-4.16 kV	5.0 MVA/6667	3
MS3 - Almonte	1965	44-4.16 kV	3.0 MVA	2

Beachburg

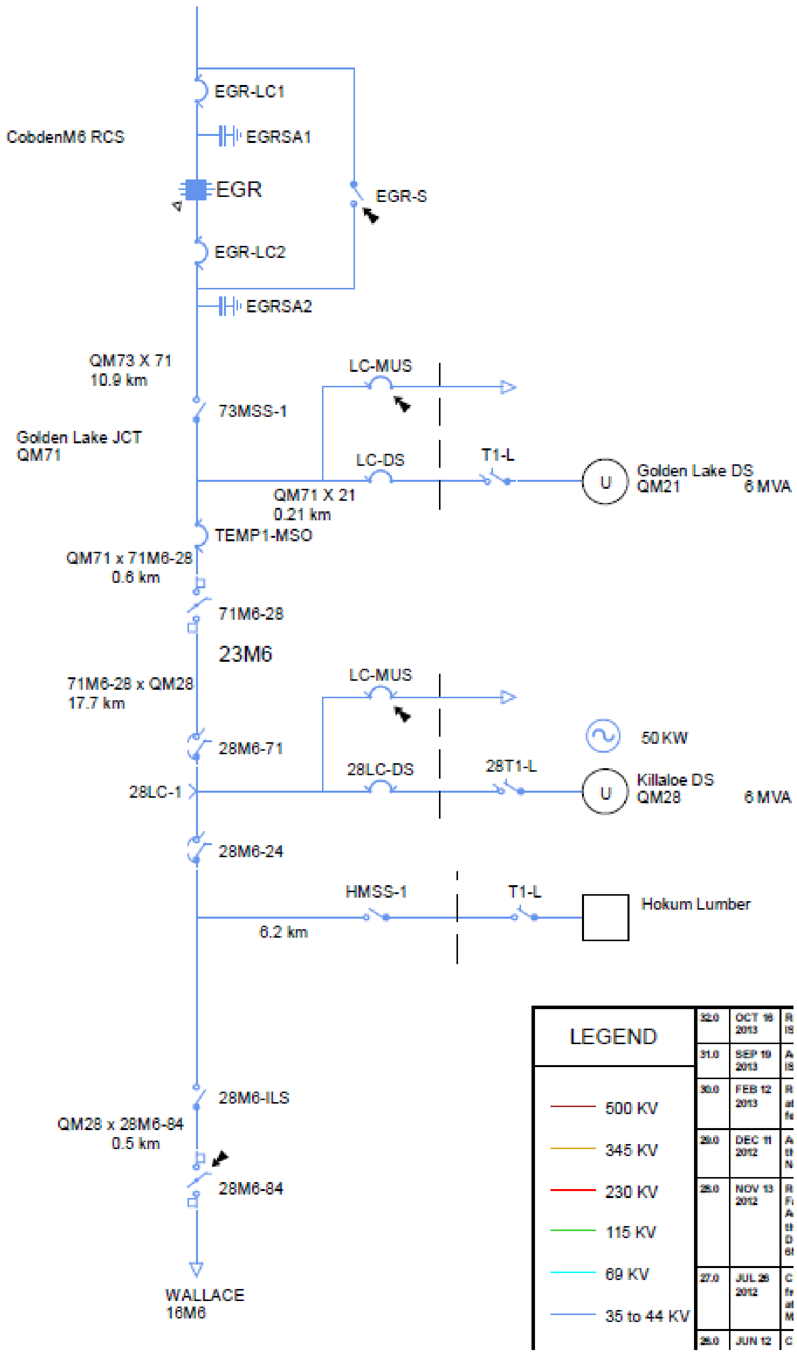
Beachburg is supplied by HONI with an M-class feeder supplying 44kV. The feeder is fed directly from HONI by 23M2 from Cobden TS. This feeder is a radial supply from Cobden 2 Jct. to Beachburg DS, approximately 20 km away. This means the Village of Beachburg does not have a redundant supply, which can result in longer power outages, which ORPC customers may experience during an ice storm and wind storms. In order to improve system reliability, ORPC will participate in regional planning with HONI to investigate the options available to increase reliability and future capacity in Beachburg.



Figure; HONI Cobden TS, feeder to Beachburg DS

Killaloe

Killaloe is supplied by HONI with an M-class feeder supplying 44kV. The feeder is fed directly from HONI by 23M6 from Cobden TS. The Killaloe DS is connected and located between the Cobden TS approximately 50 km away and the Wallace TS. The Killaloe DS may also be connected to the Wallace during extended power outages which means the Town of Killaloe has a redundant supply which can result in shorter power outages durations.



Substation Inspections

ORPC owns and operates 11 substations, which are patrolled once a month in Maintenance Procedures. Patrols at substations require the use of the Patrol Deficiency Record to record any defects or areas of concern which are identified during the visual inspection. Monthly visual inspections for station equipment include the following:

Transformers

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map
- Leaking oil and oil levels
- Flashed or Cracked Insulators
- Contamination/discoloration of bushings
- Ground lead attachments
- Winding and oil temperatures

Switches and Protective Devices

- Bent, broken bushings and cutouts
- Damaged lightning arresters
- Ground wire on arresters unattached

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wire unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Switchgear

- Paint condition and corrosion
- Placement on pad or vault
- Check for locks
- Grading changes
- Feeder Loads

Battery Systems

Vegetation

- Accessibility compromised
- Grade changes that could expose cable
- Leaning or broken “danger” trees in proximity of station
- Growth into line of “climbing” trees
- Vines or brush growth interference (line or fence clearance)
- Bird or animal nests

Major Station Maintenance

Preventive station maintenance is conducted periodically according to the ORPC Inspection and Maintenance Procedures and includes the following:

- Testing of Substation Transformers
- Arrester testing
- Breaker Testing and Maintenance
- Protection Relay Testing and Maintenance
- General station maintenance

Distribution Station Components				
Asset Detail	Useful Life			Significant
	Minimum	Typical	Maximum	
Power Transformers - Overall	30	45	60	Y
Power Transformers - Bushing	10	20	30	N
Power Transformers - Tap Changer	20	30	60	N/A
Station Service Transformers	30	45	55	N
Station Grounding Transformers	30	40	40	N/A
Station DC System - Overall	10	20	30	Y
Station DC System - Battery Bank	10	15	15	N
Station DC System - Charger	20	20	30	N
Station Metal Clad Switchgear - Overall	30	40	60	N
Station Metal Clad Switchgear - Removable Breaker	25	40	60	N
Station Independent Breakers	35	45	65	Y
Station Switch	35	50	60	N
Reclosers	25	40	55	Y
Electromechanical Relays	25	35	50	N
Solid State Relays	10	30	45	N
Digital & Numerical Relays	15	20	20	N/A
Rigid Bus bars	30	55	60	N/A
Steel Structure	35	50	90	N/A

Summary table of ORPC'S Substations by year and service length

Substation	Year put in Service	Years in service
MS1	1955	59
MS2	1952	62
MS3	1957	57
MS4	1964	50
MS5	1969	45
MS6	1976	38
MS7	1976	38
MS8	1991	23
MS1 - Almonte	2010	4
MS2 - Almonte	1975	39
MS3 - Almonte	1965	49

Power Transformers

Station transformers are critical assets operating within ORPC's distribution system. They provide voltage transformation from transmission line voltage to a lower voltage to distribute throughout the service area.

Station transformers are unique assets due to a number of factors including replacement costs ranging from $300,000 to $900,000. A failure will have major consequence on our system reliability and a replacement is a six to twenty-four months project cycle.

In addition, station transformer replacements may require additional upgrades such as oil containment, ground grid upgrades, cable replacement, and protection & control upgrades. In some cases a full substation upgrade (switchgear and transformers) may be triggered by a transformer replacement.

Degradation Mechanism: Transformers operate under many extreme conditions and both normal and abnormal conditions affect their aging and breakdown. Transformers are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures; through-faults can cause displacement of coils and insulation; and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. It is not cost effective, in most applications, to change the paper and pressboard insulation (i.e.: rewind). The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the rate of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Transformer bushings are major components of the power transformer. Bushings are subject to aging from both electrical and thermal stresses.

ORPC performs monthly inspections and conducts annual oil testing (condition analysis) to determine the health of the transformers. The power transformers are found to be in good condition relative to their age. The following list identifies known deficiencies and future planning activities:

1. Pembroke's Substation #5 transformer has high moisture content and an oil dryer has been installed in early 2014. Continual monitoring and changing the gaskets will be required.
2. Pembroke's Substation #3 transformer phasing will not allow paralleling of feeders.
3. Almonte MS-2 has no Oil containment and may be too close to potable water source.
4. Future testing of the transformers will include Power Factor, turns ratio, winding tests and bushing tests.

Given current operating conditions and maintenance practices, all units are expected to achieve or exceed their maximum useful life of 60 years. The adjusted end-of-life dates have been set as outlined below. The robust design of the Pembroke distribution system ensures that a failure of a transformer will not seriously impact the reliability of power to customers. ORPC's replacement policy is to replace transformers with a standard capacity rating that is rated equal or greater than the existing capacity rating. Note that ORPC's Capacity Plan will be consulted to determine if an upgraded capacity rating is required. The average cost per transformer replaced in projects is provided by TX size; 5MVA - $450k and 10MVA - $900k.

ORPC's station transformer purchasing standard will include designs of new transformers with the ability to have reversed current flow and ability to dispatch varying load flow through the transformer as required for Renewable Generation connections. This will reduce restrictions due to thermal overloading of transformers.

Considerations for a voltage conversion will be reviewed as an alternative to replacing the transformer.

The installation of a fan kit on the Almonte MS-2 power transformer will provide additional supply for the feeders and extend the life of the transformer.

Station	Year	Voltage	Transformer Size	EOL
MS1	1955	44 - 4.16 kV	3*2.5 MVA single phase	2025
MS2	1968	44-4.16 kV	5.0 MVA	2020
MS3	1967	44-4.16 kV	5.0 MVA	2022
MS4	1963	44-4.16 kV	5.0 MVA	2024
MS5	1968	44-4.16 kV	3.0 MVA	2029
MS6	1976	44-12.400kV	10.0 MVA	2036
MS6	1976	44-12.400kV	10.0 MVA	2036
MS7	1974	44-12.400kV	10.0 MVA	2034
MS8	1991	44-12.400kV	10.0 MVA	2051

Power Transformer Bushings: The majority of the bushings of the station transformers have exceeded the maximum useful life established in the Kinectrics report. The bushings are also inspected annually and are found to be in good health with no sign of physical deterioration. Although the bushings have exceeded their maximum useful life, ORPC does not plan on replacing them over the rate horizon, given the favourable condition test results. ORPC will continue to closely monitor the health of all bushings and look for signs of deterioration. ORPC does not plan on incurring any significant expenses in this category for years 2015 to 2019.

Station Service Transformers: The station service transformer provides power to the auxiliary equipment, such as fans, heating, or lighting, in the distribution station. Small power transformers are configured to provide this requirement.

The station service transformer is also original to the construction of the transformer stations. Condition test results have not found any signs of premature failure, and as such, the transformers are expected to achieve or exceed their maximum-useful-life of 55 years. ORPC does not plan on incurring any significant expenses in this category.

Station DC System: Station direct current (DC) systems are the critical supply for station protection and control equipment and other auxiliary devices such as transformer cooling. This asset category has been componentized into batteries, chargers and other DC distribution equipment. Maintaining batteries in a condition capable of delivering the necessary energy as required is essential.

Batteries consist of multiple individual cells. For the purposes of this report, these are lead-acid battery banks. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the battery banks.

The transformer stations have separate DC systems installed to supply power to key station protection components, as well as to emergency lights. The systems are inspected on a monthly basis to ensure their proper operation. ORPC also conducts annual condition tests on each battery cell to assess whether replacement in needed. The inspection and condition tests have found systems to be in good overall working condition relative to their age. ORPC will complete the replacement of batteries in the Pembroke Substation 2 in 2014. ORPC plans to continue with its annual replacement of deteriorated battery cells throughout the period 2015 to 2019, and has budgeted $2,000 per year accordingly.

Station Metal Clad Switchgear: Station Metal Clad Switchgear comprises the metal enclosure, the circuit breakers and the associated protection and control devices. Station switchgears are commonly employed at substations to provide protection for electrical equipment, and to allow control and isolation during faults and planned maintenance activities. Station switchgears have a direct impact on the reliability of electricity supply to customers. Station switchgear failure will have reliability, safety and environmental consequences. The station switchgear replacement program targets the planned replacement of switchgears based on their age and qualitative information to maintain system reliability and safety in the most cost-effective manner.

The transformer stations have main metal clad switchgear lineups. Some of the switchgear was originally manufactured as stand-alone outdoor switchgear but have since been covered by station buildings to house the batteries and associated SCADA equipment. The switchgear was installed with the stations in most cases. Under ORPC's preventative maintenance program, all breakers are thoroughly inspected and condition tested on a three year cycle. Any maintenance issues identified are also addressed at that time. The latest condition assessments and inspections found all breakers and switchgear to be in good overall condition, relative to their age. ORPC plans to complete the detailed inspections and condition assessments (by external consultants) of the Almonte stations in late 2014 and the Pembroke stations in 2015. Some of the breakers have surpassed their TUL of 40 to 45 years. However, given their current operating condition and environment, ORPC expects them to achieve their maximum useful service life of 60 years. Parts availability is a known issue and as such, an unexpected breaker failure could result in a breaker replacement, rather than a refurbishment. In the short term, ORPC does not plan on incurring any significant expense in this category.

ORPC's overhead distribution switch and recloser asset class consists of all pole mounted load break switches, reclosers, fuse cut-outs and inline switches, with a primary voltage rating as high as 44kV. Equipment belonging to this asset class serves the main purpose of providing a means to isolate or re-route a section of overhead line due to a fault condition or planned work. Overhead switches and reclosers of varying size and type are located within all geographic areas covered by ORPC's service territory and are found on all distribution feeders. The overhead switch and recloser program is typically a run-to-failure strategy, unless a technical or health and safety issue has been identified.

ORPC has grouped its overhead distribution assets according to the classifications contained in the "Kinectrics Report." ORPC does not have any assets in the following categories, and as such they have been omitted: Fully Dressed Steel Poles; Line Switch RTU; and Overhead Shunt Capacitor Banks.

Station Switches: ORPC Distribution system has many three phase switches, some motorised, which allow for the isolation of various stations including Substation Transformers as well as the Oil filled Circuit breakers that protect the stations. ORPC has utilized planned loss of supply opportunities to inspect the units, as well as to perform condition tests. ORPC also used these opportunities to perform maintenance work including testing insulators and realigning switch linkages. All units are found to be in good working condition relative to their age, with no signs of excess deterioration. Given current operating conditions and continued maintenance practices, ORPC expects the units to surpass their maximum useful service life of 60 years. ORPC will assign an adjusted end-of-life date to align with the end of useful service life with that of the station as a whole.

Overhead distribution switches are used to isolate sections of the system for planned work or restoring customers from an interruption. They provide a means of protecting major system equipment as well as allowing circuits to be available for backup supply. The number of failures per year within this asset class is very minimal and as such, ORPC employs a run-to-failure strategy for overhead switches. As an exception, there are porcelain switches procured and installed in the 1990's which have been identified as reaching end-of-life or defective and are presenting a safety concern.

Distribution System Reclosers: Reclosers are considered to be a part of the Overhead Lines asset grouping. The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect arc suppression devices as well as the contacts, and the oil condition. The degradation of these devices depends on the available fault current, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism malfunction. For deterioration, exposure to weather is a potentially significant degradation process.

The Beachburg recloser was installed in 2003 and ORPC expects the recloser to achieve is typical useful life of 40 years. ORPC will implement an outage management system and Smart grid devices during the next few years. These tools will allow ORPC to monitor the frequency of operations and the severity of the faults that the recloser has to interrupt. The end of life may need to be assessed during the next 10-20 years.

The Killaloe recloser was installed in 2013-2014 and ORPC expects the recloser to achieve is typical useful life of 40 years. A new Vista recloser, SEL digital relay and wireless modem communication to the Pembroke SCADA have been installed. These tools will allow ORPC to monitor the frequency of operations and the severity of the faults that the recloser has to interrupt.

Station Independent Breaker: ORPC performs annual inspections and oil condition testing on its station breakers that protects the transformer station and distribution system as a whole. The oil filled circuit breakers (OCB) have surpassed their typical useful life of 45 years, as they were manufactured in 1959. Recent inspections and condition test results indicate that the OCB is in good working condition relative to its age. Sourcing replacement parts for the OCBs is also a known issue. A failure of a bushing in 2008 was repaired by sourcing used parts from the local generating station. Our consultants have advised ORPC that the OCBs should be replaced, and as such ORPC has assigned an adjusted end-of-life date of 2018. ORPC plans to replace one of the OCBs in 2018 at an estimated cost of $150,000. The replaced OCB will be refurbished and kept as a spare unit, if possible. The remaining breakers will be replaced within the next 10 to 15 years. The following picture depicts the oil filled circuit breaker.

Electromechanical Relays: Protection relays work to detect faults and isolate the system by triggering the opening and closing of the circuit breakers. This asset class includes the older designs of protective relays which had primarily electromechanical mechanisms.

The degradation of electromechanical relays is primarily related to the wear and seizing of the mechanical mechanisms. For instance, relay contacts age due to the following factors:

1. Contact oxidation
2. Contact welding or pitting due to excessive current
3. Chemical corrosion

In the case of degradation of relay moving parts, such as wear of moving parts like spring/armature, the major contributing factor is the wear after numerous switching cycles.

Degradation on relay coils is mainly a thermal aging issue due to continuous energization or elevated cabinet temperatures. Excessive heat generated by coil or associated components may cause the coil to burn out or adversely affect other nearby components or components within the relay or nearby (e.g. chemical breakdown of varnishes causing contact contamination, or change in component dimensions).

As a consequence, the failure mode of an electromechanical relay can be:

1. Failure to actuate when commanded
2. Actuates without command
3. Does not make or break current
4. Failure to carry current
5. High contact resistance
6. Set-point shift
7. Time delay shift

Protection technology is offered by using single function electromechanical relays. As such, the transformer stations are equipped entirely with single function electromechanical relays. In 2015, ORPC plans to convert the first lineup of single function electromechanical relays with modern processor based multifunction relays, in order to accommodate the Smart Grid initiative. The electromechanical relays that have not yet been converted have a UL of 35 years. Under ORPC's preventative maintenance program all relays are inspected, calibrated and condition tested on a three year rotation. The relays are expected to achieve or exceed their maximum useful life of 50 years under current operating conditions and maintenance practices. As discussed Solid state relays will allow for: reliability monitoring (statistics) of individual feeders, reverse power flow, automatic logging and time-stamping of events or data, remote annunciation of incidents or failures, broadcasting of operating data and conditions to ORPC and other regional stakeholders.

Digital & Numeric Relays: In 2010, ORPC had installed digital multifunction protection relays in the more recent substation in Almonte (MS-1). In 2013-2014, ORPC installed a digital relay in combination with the Killaloe re-closer that is fed from HONI Killaloe DS. As previously discussed, the driver for these replacements was to accommodate Smart Grid improvements and asset replacement as was the case for the new Almonte substation. ORPC will continue with its preventative maintenance practices of inspecting and performing condition analysis of these relays on a three year rotation. ORPC has adopted the Kinectrics TUL for Digital & Numeric relays of 20 years. ORPC will assess whether or not the relays are on track for a 20 year useful life in future iterations of condition testing. ORPC plans on continuing with the upgrades from electromechanical relays to digital multifunction protection relays. ORPC is planning to continue to deploying "Schweitzer Engineering Laboratories (SEL) 751 and 351" relays.

Steel Structures: ORPC has various structures in the Steel Structure category. The structures were erected during the station construction and they are found to be in good condition relative to their age. Inspection and condition testing results have not identified any excessive deterioration. Under current operating conditions and maintenance practices, ORPC expects that the structures will surpass their TUL of fifty (50) years, as per the "Kinectrics Report." ORPC has set its adjusted end-of-life and at which time the structure will be replaced with concrete poles. ORPC does not expect to incur any significant expenses in this category over the period 2015 to 2020.

Station Buildings: The majority of the substation buildings are Butler buildings that were constructed over top of outdoor metalclad switchgear. The structures have poor foundations, or built on cement slabs, and have mould and rot. The structures will be replaced with prefab buildings to house the SCADA, batteries and switchgear control cabinets.

Load and Load Balancing

ORPC relies on the SCADA system to monitor feeder loads and for determining how ORPC's load from its transformer station is distributed among its feeders.

ORPC uses DESS software to simulate the distribution system load losses, loading, etc. The data (conductor size, transformer size and connections, etc.) for DESS is extracted from our GIS data. Updates to our GIS including conductor sizes and feeder connections will be completed during the next two years which will enhance the DESS results.

ORPC is planning to develop a project in early 2015 that will provide real-time load data for the feeders and associated downstream transformers including transformer secondary loads. ORPC's overhead distribution system has an overall ampacity constraint of 300 Amps on each feeder, based on conductor size limitations. This constraint is much higher than other underlying constraints, and as such ORPC does not expect to encounter feeder capacity constraints, given the current load profile of its customer base. ORPC also does not anticipate significant customer growth.

As such, overhead distribution system capacity constraints are not identified as investment drivers for the period 2015 to 2019 with the exception of Almonte feeders.

ORPC will update feeder information for the Almonte distribution system in early 2015. Currently, we are upgrading the feeder conductors to allow for paralleling of feeders.

Station Metering and Monitoring

Currently mechanical protective relays and instrument transducers are in service for the feeder monitoring and protection. Typically three single phase O/C mechanical protective relays are used. The transducers provide a signal to the SCADA derived from the voltage and current instruments. We plan to replace the protective relays with one unit that will provide solid state protective functions as well as power monitoring and power quality functions.

Poles

All of ORPC'S overhead pole lines are constructed using treated wood poles with the exception of 45 concrete poles. The overhead distribution system is supported by a system of poles and fixtures. The reliability and safety of the overhead distribution is contingent on the performance of these poles and fixtures.

The pole replacement program replaces wood poles, and pole fixtures, on the overhead distribution system that are aged or in poor condition. Existing concrete poles in general are in good condition and will not require replacement.

Poles and fixtures will be replaced with an equivalent pole on a like-for-like basis. New poles are fully treated western red cedar. ORPC's current practice is to replace porcelain insulators with polymer insulators. The conductor will not typically be replaced at the same time as the pole as experience has shown very little failure rates resulting from conductors.

Under specific circumstances, a wood pole may be replaced with a new composite pole. Composite poles are of a fiber-reinforced material and are used in areas that have a high probability of woodpecker damage or when installed in high moisture soil conditions.

		Asset Details			ORPC Assets			Kinectrics Useful Life		
	#	Category| Component | Type			Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL
OH	1	Fully Dressed Wood Poles	Overall		4299	Each	27.45	35	45	75
			Cross Arm	Wood				20	40	55
				Steel				30	70	95
	2	Fully Dressed Concrete Poles	Overall		45	Each	44	50	60	80
			Cross Arm	Wood				20	40	55
				Steel				30	70	95
	3	Fully Dressed Steel Poles	Overall					60	60	80
			Cross Arm	Wood				20	40	55
				Steel				30	70	95
	4	OH Line Switch (Expressed as sets of 3 Phase Swit				Each		30	45	55
	5	OH Line Switch Motor						15	25	25
	6	OH Line Switch RTU						15	20	20
	7	OH Integral Switches						35	45	60
	8	OH Conductors	Primary Conductor		270	km	45.1	50	60	75
			Secondary Conductor		96	km	11	25	35	40
	9	OH Transformers			1583	Each	25.8	30	40	60
	10	OH Shunt Capacitor Banks						25	30	40
	11	Reclosers			2		2	25	40	55

ORPC Poles					
	Pembroke	Almonte	Killaloe	Beachburg	Total
Wood	3102	1037	316	465	**4920**
Less Bell	380	142	99		**621**
Total Wood	2722	895	217	465	**4299**
Concrete	45				**45**

Wood poles installed 50 years ago during the expansion and electrification across Pembroke service area are now approaching end of life. Approximately 35% of the poles installed exceed the TUL as mentioned in the Kinectrics report. To help ensure reliability and public safety, ORPC plans to replace 50 wood poles in 2015.

ORPC Pole Age and Height Estimates								
	Height	**1960**	**1970**	**1980**	**1990**	**2000**	**2010**	**Total**
Wood	30	20	40	17				77
	35	15	225	225	200	80	23	903
	40	500	500	450	156	100	20	1726
	45		50	160	500	500	80	1290
	50		10	20	30	20	3	83
	55	15	20	60	40	10	2	147
	60		2	18	15	7	1	43
	65		2	6	9			17
	70		1	4	4	3	1	13
Subtotal Wood		**685**	**850**	**960**	**954**	**720**	**130**	**4299**
Concrete	45			20				20
	55	25						25
Sub Total Concrete		25		20				**45**

ORPC would have to replace 685 poles installed in the 1960's to keep pace with the lifecycle of wood poles. ORPC has identified that at least 980 poles may need to be replaced due to a minimum height requirement of 40 feet to comply with new ESA guidelines.

ORPC has identified public safety issues due to the lack of replacements being completed by the owners of Joint use poles and estimate that approximately 10% of the pole population should be replaced or new ORPC poles installed adjacent to the existing poles.

Poles which are deemed to be at the end of their useful service life due to excessive deterioration have been estimated at approximately 25 poles per year. It is also important to note that wood poles frequently (on average five per year) fail prematurely, due to sudden devastating damage incurred by external influence such as wood peckers, snow ploughs or pole fires.

Pole Inspection

Line patrols, conducted in accordance with the ORPC Procedures, include a visual inspection of poles for the following:

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Rotting utility poles can present a serious reliability. Decay is usually not easily identified since 90% of utility pole failure is caused by interior rotting at or just below ground level. The Resistograph pole testing methodology is the most reliable technique for testing pole integrity in areas not visible by the eye.

As a regular part of our preventative maintenance program, ORPC will test for pole deterioration by boring a 1.5 mm to 3.0 mm diameter needle drill at a 45 degree angle to a boring depth of approximately 38 mm using specialized Resistograph® equipment.

ORPC's pole testing can also identify less common internal rot or damage to the exposed portion of the pole. A complete written report is completed including graphical representation of the internal cross-section of every pole tested.

The needle drill resistance method of testing greatly enhances the predictability of utility pole failure, which will prevent the unnecessary exchange of poles and save you time and money. Although utility pole testing can only provide definite analysis information for the specific testing area of the pole, our services will improve the efficiency of your preventative maintenance program.

With 4300 poles in our distribution system, more than 1,500 poles will need to be replaced in the next 10 years. The Typical Useful Life of a wood pole is approximately 45 years. ORPC recommends a replacement rate on average of 125 poles a year in to keep pace, which represents 2.90% of the entire population of distribution poles. Increase in the amount of poles replaced will reduce the risk of having poles in a critical or poor condition.

Description	Year	Acct	Labour	Material	O/SCont	Truck	Notes
Pole Replacement	2015	1830	$18,000	$23,000	$2,000	$3,000	Scattered pole replacement
Pole Replacemt-Line Work	2015	1830	$10,000	$3,000	$0	$1,200	Fisher Street to Trafalgar Related line betterments
Pole Replacemt-Line Work	2015	1830	$10,000	$3,000	$0	$1,200	Sub 4 behind Remi auto Related line betterments
Pole Replacemt-Line Work	2015	1830	$10,000	$3,000	$0	$1,200	misc Related line betterments
Poles	2015	1830	$8,000	$8,000	$1,000	$500	Eight poles Residential Development
Poles	2015	1830	$2,500	$2,500	$1,000	$1,000	Commerical Development Commerical Development
44 kV Structure	2015	1830	$4,000	$5,000	$0	$750	Replace South pole structure
Poles HONE/Brookfield	2015	1830	$10,000	$10,000	$0	$4,270	Replace Cedar Poles on 44 Line McKay St Betterment
Pembroke Sub 2 Station Yard	2015	1830	$2,500	$5,000	$0	$200	Sub 2 Concrete Pole and 44 kv cable
Pole Replacement-Line Work	2015	1835	$10,000	$3,000	$0	$1,200	Conductors Related to line betterments

Pole Maintenance

The stress placed on a pole is important when considering its lifespan; generally the greater the stress the shorter the lifespan. The stress increases with equipment, such as transformers or utilization, such as dead ended or line angle installations. It is therefore important that they be more closely monitored. ORPC will be completing a detailed three dimension (3D) stress analysis of all new pole installations as part of new Regulatory requirements expected to become in effect in 2015. These analyses should ensure that proper poles are installed. ORPC anticipates that the majority of new poles will be Class 3.

Pole Capital

The above pole inspection process has identified the need to replace a sufficient number of poles on an annual basis, such that over the course of their expected life, all poles will be replaced.

The results of the inspections and condition tests are used to project the date when the pole is expected to be at the end of its useful service life due to deterioration herein referred as the "Adjusted End-of-Life" (AEOL) date. Favorable inspection and condition testing results extend an asset's AEOL date beyond its TUL and alternately, unfavorable inspection and condition testing results will shorten an asset's AEOL date, with respect to its original TUL date assigned. It is important to note that adjusted

AEOL projections are more meaningful as assets approach their TUL, as opposed during their early years of service. The timeframe when assets approach their TUL is the critical time at which investment and planning decisions must be made. ORPC's long term planning strategy is to establish and maintain evenly distributed asset populations. Due to wood poles failures posing a hazard to employees, the general public as well as undermining the structural integrity of the overhead distribution system, ORPC's strategy is to replace them just prior to their deemed failure. Just in time proactive replacements allows for the replacement to be conducted in a coordinated and planned manner, as opposed to under emergency repair circumstances, which often add unnecessary risk and expense.

ORPC Pole replacement schedule	
2011	25
2012	25
2013	25
2014	25
2015	100
2016	100
2017	100
2018	100
2019	100
2020	100

ORPC estimates that it may require approximately 500 poles replaced to sustain the existing population of 4,299 over the current planning cycle. Wood pole replacements have been identified as having a significant impact on the DS Plan.

The age distribution of the population of 4,299 wood poles is fairly evenly distributed over one lifecycle period beginning in 2015. The population is therefore not skewed, and as such, approximately the same number of assets will require replacement over the first and second half of the lifecycle. ORPC adopted a UL of 45 years, and based on the average age of 17 years for the population.

Transformers

The ORPC distribution system consists of 309 pad mount and 1,583 pole mount transformers, for a total number of transformers of 1892. The following table shows a summary of the overhead and underground transformers by age.

	Overhead Transformers											Pad Mounted Transformers								
Size (kVA)	Unkn	1940	1950	1960	1970	1980	1990	2000	2010	?	Total	1950	1960	1970	1980	1990	2000	2010	Total	Total Transformers
Unknown	5		5	5	3					8	**26**									**26**
3	3		3								**6**									**6**
5	13		7	7						1	**28**									**28**
7.5	4			4							**8**									**8**
10	36		15	17	9	1	4			2	**84**									**84**
15	13		12	14	5		2				**46**									**46**
25	51		25	37	37	32	35	11	3	8	**239**			1		1			**2**	**241**
37	66		36	45	50	29	12			2	**240**			2					**2**	**242**
50	88	3	30	52	120	70	82	29	4	4	**482**				2	18	51	20	**91**	**573**
75	18		5	10	25	26	19	11	1	1	**116**				5				**5**	**121**
100	36			22	85	129	20	14		2	**308**			54	32	194			**109**	**417**
112														2			1		**3**	**3**
150												3		5	2	1	2	1	**14**	**14**
167														3	3				**6**	**6**
225														1			1		**2**	**2**
300														3	11	5	4		**23**	**23**
500														8	13	6	4	3	**34**	**34**
750														5		2			**7**	**7**
1000															1	3	4		**8**	**8**
1500																1	2		**3**	**3**
Total	**333**	**3**	**138**	**213**	**334**	**287**	**174**	**65**	**8**	**28**	**1583**	**3**	**0**	**84**	**69**	**56**	**73**	**24**	**309**	**1892**

Pad-Mounted Transformers

Pad-mounted transformers represent a minor portion of ORPC's overall asset base with respect to replacement cost. ORPC's pad-mounted transformers have been installed proportionately over the last 40 years which will enable ORPC to replace these assets equitably as they approach their UL of 40 years. ORPC currently owns and operates 1583 single phase and 309 three phase pad-mounted transformers.

The underground transformer replacement program replaces pad-mounted transformers connected to the underground cable network. These transformers are assessed based on their age which has a correlation to their condition. The exception is submersible transformers which are inspected for corrosion leading to leaking of oil due to their small population.

Underground transformers are replaced for numerous reasons including: asset failure, leaking oil, voltage conversion, and insulator degradation identified by infrared scans, and in conjunction with cable replacement. The transformers that experience failure are replaced with a like-for-like transformer in order to provide electricity to the customer in a timely manner. Replacement completed during other projects will generally be like-for-like as well, however, the loading is assessed and there is the possibility for a smaller or larger capacity transformer to be used for economic or environmental benefits.

In addition, it is ORPC's standard to replace live front transformers with dead front transformers due to the safety benefits associated with having the cables insulated through the use of elbows. Pad-mounted transformers and their concrete base have the potential to sink below grade and this poses a risk of flooding. The sinking transformers are flagged and remediated immediately to proactively avoid a failure.

ORPC performs detailed inspections of pad-mounted transformers on an annual basis. The results of the inspections are used to assess the overall health of transformers with respect to age. Physical defects, such as oil leaks or cracked bushings, indicate that a transformer is very near to the end of its useful life having a high probability of failure. It is important to note that the adjusted end-of-life values are of higher importance as assets approach their TUL, as opposed to during their earlier years.

ORPC is also currently working on recording the relationship of transformers to customers, which will allow for analysis of electrical loading from smart meter data. Smart meter data will essentially give ORPC insight into individual transformer utilization (loading). Electrical loading is a large contributor of transformer degradation, and as such, being able to quantify it will greatly enhance ORPC's ability of predicting transformer failures.

Overhead (Pole-Mount) Transformers

ORPC has adopted a TUL of 40 years for overhead transformers as per the "Kinectrics Report." ORPC calculates that 670 of its overhead transformers will exceed TUL by 2020. As such, the majority of transformers will have surpassed the end of their useful service life, implying a high risk of failure. ORPC recognizes that it must ramp up its transformer replacements. Currently, the average age is 25.8 years.

The overhead/pole mounted distribution transformer replacement program focuses on the optimal the time to replace an asset just before it fails. Inspections help identify the condition of the transformers so that they can be prioritized and replaced.

ORPC is also currently working on recording the relationship of transformers to customers, which will allow for analysis of electrical loading from smart meter data. Smart meter data will essentially give ORPC insight into individual transformer utilization (loading). Electrical loading is a large contributor of transformer degradation, and as such, being able to quantify it will greatly enhance ORPC's ability of predicting transformer failures.

Overhead transformers are replaced for numerous reasons including; asset failure, leaking oil, voltage conversion, and insulator degradation, identified by IR scans, in conjunction with pole replacement. The transformers that experience failure are replaced with a like-for-like transformer in order to provide electricity to the customer in a timely manner. Replacement completed during other projects will generally be like-for-like as well, however, the loading is assessed and there is the possibility for a smaller or larger capacity transformer to be used for economic or environmental benefits.

Transformer Inspection

A significant portion of ORPC's asset base is overhead transformers. ORPC distribution system consists of 1583 single phase units. It is worth mentioning that three phase customers who are supplied from overhead transformers, require three individual single phase transformers that are arranged as a three phase setting (which is an industry standard).

ORPC visually inspects transformers every three years under the Overhead Visual Inspection and Underground Visual Inspection Programs and Record and follow-up on any complaints received from customers. The inspection of transformers includes:

Pole Mount Transformers:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map
- Leaking oil
- Flashed or cracked insulators
- Contamination/discoloration of bushings
- Ground lead attachments
- Damaged disconnect switches or lightning arresters
- Ground wire on arresters unattached

Pad- Mount Transformers:

- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage
- Grading changes
- Access changes (shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid Damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General Condition

Transformer Maintenance

ORPC performs maintenance on any transformers which are identified by either visual or infrared inspection as needing work. This work may include replacement of connections if found to be hot, painting or replacement of unit if leaking.

PCB oil sampling was completed in 2013 and 2014, and 474 transformers were tested. The remaining transformers will be sampled within the planning period.

Transformer Capital

ORPC performs detailed inspections of overhead transformers on a three year cycle. The results of the inspections are used to assess the overall health of transformers with respect to age. Physical defects such as oil leaks or cracked bushing indicate that a transformer is very near to the end of its useful service life, with a high probability of failure. ORPC has assigned AEOL dates to individual transformers using ORPC's asset management process. It is important to note that the AEOL values are of higher importance as assets approach their TUL, as opposed to in their earlier years.

ORPC is also currently working on recording the relationship of transformers to customers, which will allow for analysis of electrical loading from smart meter data. Smart meter data will essentially give ORPC insight into individual transformer utilization (electrical loading profile) as electrical loading is a large contributor of transformer degradation, and as such, being able to quantify it will greatly enhance ORPC's ability in predicting transformer failure.

The age distribution of the population of the 1583 pole mounted transformers is not evenly distributed. The population has high positive skew, and as such, approximately 61% (972 transformers) will require replacement over the first half of the lifecycle period (over the next 20 years).

Switches and Cutouts

ORPC currently utilizes three types of overhead line switches that are grouped into this category. ORPC has manual gang operated sectionalizing switches, inline paralleling switches, as well as inline fused switches, all of which are three phase switch settings. ORPC performs routine inspections of all overhead switches according to its overhead plant inspection process. The most common identified deficiency is insulator degradation. ORPC believes that it is worthwhile to extend the life of switches with minor refurbishments such as insulator replacements, as they are easy to do, as well as inexpensive.

Conductor

Over the course of history, ORPC's distribution system was re-conductored over very short periods of time. Exact dates of individual overhead conductor runs are not known; however, the type of conductor used and property records allowed ORPC to estimate their vintage. In recent history, there has been a need for ORPC to undertake feeder re-conductoring and overhead expansions activities. The main trunks of the feeders are mostly three-phase circuits, with a combined ampacity limit corresponding to approximately 5 MW. ORPC has recorded the properties of individual primary overhead conductor runs, such as their length, type of conductor and wire gauge. ORPC has also started to record the properties of its secondary overhead conductor runs; however, the available data is limited to the conductor runs along distribution pole lines. As such, individual lengths of secondary conductor from the distribution transformer to individual customer premises are not completely accurate.

ORPC is planning on continuing with its GIS mapping updates initiative, and hopes to have all secondary conductor runs assessed by 2018.

Historically, the cable replacement analysis is based on inspection information taken from known aged and problem areas in the system which may have biased the results. ORPC will continue to do distributed inspections throughout the system to get a complete picture of the underground cable condition demographics.

ORPC recommends that a high amount of cable replacement be completed to reduce the fault levels. The estimated yearly cost of the proposed cable replacement program is excessive. Until confidence levels are more in-line, no annual budget will be spent replacing underground cable.

Underground versus Overhead Distribution Plant: The majority of ORPC's distribution system consists of overhead conductor runs affixed to wood poles. Underground conductors are primarily found in newer developments, as well as at larger three-phase customer installations. Several years ago, ORPC undertook a significant effort to map out the dimensions and properties of its distribution system in a GIS system. The results of the mapping exercise state that ORPC owns and operates:

Type of Primary Power Line	Length in km	Units
Three Phase OH Primary Power Lines	112.87	km
Single Phase OH Primary Power Lines	157.2	km
Three Phase UG Primary Power Lines	3.35	km
Two Phase UG Primary Power Lines	1.88	km
Single Phase UG Primary Power Lines	19.8	km
Total	296	km

Primary Lines

ORPC's underground primary conductor is used to connect feeders to the transformer station, in newer subdivisions in place of overhead lines, as well as to connect the distribution system to pad-mounted transformers.

ORPC has adopted the TUL of 40 years as per the "Kinectrics Report". ORPC has divided the conductor runs into Single Phase, Two Phase and Three Phase Circuits and lastly into Overall Conductor Length. The following tables and graphs illustrate the age distribution of Single Phase, Two Phase, Three Phase Circuits, as well as Overall Conductor Length with respect to a TUL of 40 years.

Overhead Primary Lines and Bus (meters)

	Pembroke	Almonte	Killaloe	Beachburg	Total
1 Ph OH	26,708	11,316	8,986	5,055	**52,065**
2 PH OH	533	-	-	-	**533**
3 PH OH	61,987	22,478	3,892	6,084	**94,441**
44KV	15,686	2,735	-	-	**18,421**
Spun Bus	460	9,966	-	992	**11,418**
Open Bus	67,022	10,795	8,012	7,352	**93,181**
Total	**172,396**	**57,290**	**20,890**	**19,483**	**270,059**

	1940	1950	1960	1970	1980	1990	2000	2010	Total
	0.2%	11.3%	17.4%	27.3%	23.5%	14.2%	5.3%	0.7%	**100.0%**
1 Ph OH	128	5,880	9,075	14,231	12,228	7,414	2,769	341	**52,065**
2 PH OH	1	60	93	146	125	76	28	3	**533**
3 PH OH	232	10,665	16,461	25,813	22,180	13,447	5,023	618	**94,441**
44KV	45	2,080	3,211	5,035	4,326	2,623	980	121	**18,421**
Spun Bus	28	1,289	1,990	3,121	2,682	1,626	607	75	**11,418**
Open Bus	229	10,523	16,242	25,468	21,885	13,268	4,956	610	**93,181**
Total	**663**	**30,498**	**47,072**	**73,813**	**63,426**	**38,454**	**14,365**	**1,768**	**270,059**

Under ground Primary Lines (meters)

	Pembroke	Almonte	Killaloe	Beachburg	Total
1 Ph UG	13,306	6,449	-	40	**19,795**
2 Ph UG	1,131	749	-	-	**1,880**
3 PH UG	1,201	2,072	-	77	**3,350**
Total	**15,638**	**9,270**	**-**	**117**	**25,025**

Age and Length Estimates

	1940	1950	1960	1970	1980	1990	2000	2010
	0.0%	1.0%	0.0%	27.2%	22.3%	18.1%	23.6%	7.8%
1 Ph UG	-	192	-	5,381	4,420	3,587	4,676	1,537
2 Ph UG	-	18	-	511	420	341	444	146
3 PH UG	-	33	-	911	748	607	791	260

Secondary Lines

Secondary Cables (meteres)					
	Pembroke	**Almonte**	**Killaloe**	**Beachburg**	**Total**
OH Services (meters)					
1 PH OH	60,326	23,594	4,998	6,188	**95,106**
3 PH OH	132	608	-	-	**740**
UG Services (meters)					
1 PH UG	42,479	19,985	1,744	5,448	**69,656**
3 PH UG	911	386	-	19	**1,316**

	1940	**1950**	**1960**	**1970**	**1980**	**1990**	**2000**	**2010**	**Total**
OH Services (meters)									
1 PH OH	233	10,740	16,577	25,995	22,337	13,542	5,059	623	**95,106**
3 PH OH	2	84	129	202	174	105	39	5	**740**
UG Services (meters)									
1 PH UG	-	676	-	18,936	15,554	12,624	19,161	2,705	**69,656**
3 PH UG	-	13	-	358	294	238	362	51	**1,316**

Secondary Cables Direct Buried: Average age 21

ORPC has mapped and recorded the dimension of individual underground secondary cable runs. The mapping and collection of this dimensional data will be re-completed over the next several years, as part of ORPC's GIS expansion effort. As such, ORPC estimates that it has approximately 71 km of secondary cables (at the time ORPC estimated having 10,700 customers). Direct buried secondary cables are mostly found in newer subdivisions throughout the community.

ORPC performs inspections and condition assessments on the portions of buried secondary cables that are exposed above ground and are accessible via cable vaults or pad-mounted transformer enclosures. The inspection and condition assessments are part of ORPC's maintenance inspection program, which is conducted annually. ORPC has adopted a TUL of 35 years for direct buried secondary cables, as per the "Kinectrics Report." The age profile of individual secondary cables buried is not known at this time however the average remaining UL is 15 years.

Conductor Inspection

ORPC also performs detailed inspections of its overhead conductors on a three year cycle. The results of the inspections may trigger condition testing if deterioration is observed. To date, ORPC's inspections have not triggered the need for condition testing. ORPC anticipates that the conductors will achieve or surpass their UL of 60 years. ORPC has set the adjusted useful life dates to correspond to a 60 year TUL. ORPC does not expect to incur any re-conducting expenses for primary conductor over the 2014 to 2020 planning period.

Line Patrols

Line patrols are conducted annually in accordance with ORPC's Procedures. The line patrols include a visual inspection of the following:

Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

General Conditions and Vegetation

- Leaning or broken "danger" trees
- Growth into line of "climbing" plants
- Accessibility compromised
- Vines or bush growth interference (line clearance)
- Bird or animal nests

Vegetation and Right of Way

- Accessibility compromised
- Grade changes that could expose cable
- Excessive vegetation on right of way

Overhead System – Tree-Trimming

ORPC's policy relating to line inspection and tree trimming is to follow a schedule of cycle maintenance. Tree trimming takes place from late December to early April.

Cycle 1 – The Town of Killaloe and the centre of the City of Pembroke from the Muskrat River to Trafalgar Rd. The Town of Almonte east of the Mississippi River to the most easterly boundary of Almonte.

Cycle 2 - The City of Pembroke from Trafalgar Rd. to the most westerly part of the City of Pembroke boundary. In the town of Almonte; west of the Mississippi River to the most westerly boundary of Almonte.

Cycle 3 – The Village of Beachburg and the City of Pembroke from the most easterly boundary of the City of Pembroke to the Muskrat River.

Year	Line Clearing Inspection Rotation
2014	Cycle 3 Schedule
2015	Cycle 1 Schedule
2016	Cycle 2 Schedule
2017	Cycle 3 Schedule
2018	Cycle 1 Schedule
2019	Cycle 2 Schedule
The following schedule will be applied for the period 2015 to 2019	

Conductor Capital

ORPC also performs detailed inspections of its overhead conductors on a three year cycle. The results of the inspections may trigger condition testing if deterioration is observed. To date, ORPC's inspections have not triggered the need for condition testing. ORPC anticipates that some of the conductors will achieve or surpass their UL of 60 years. ORPC has set the adjusted useful life dates to correspond to a 60 year TUL. ORPC does not expect to incur any re-conductoring expenses for primary conductor over the planning period. ORPC does plan to complete the installation of a tie between the Almonte MS-2 and MS-3 stations.

ORPC's underground distribution assets consist mainly of Pad-Mounted Transformer settings and Underground Cable installations. All of ORPC's recently installed primary underground cables are ducted, where some of the ducts are cement encased for additional protection. ORPC's total conductor length of underground primary cable is 30.7 km (includes the length of conductor that is above ground which is required to connect the shielded cables to the distribution feeders via dip poles).

Pad-Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. All of the pad mounted switchgear currently employs air-insulated gang operated load-break switches. None of the switchgear is submerged, hence no risk of failure due to flooding.

The pad-mounted switchgear replacement program targets the planned replacement of air-insulated pad-mounted switchgear and pedestal switches to maintain system reliability and safety in the most cost-effective manner.

Metering and Monitoring

ORPC has completed the installation of approximately 9,320 smart meters for residential and 1,315 smart meters for small commercial (GS<50kW) customers. ORPC intends to explore the potential use of the communication capability of the Smart Meter system to further improve customer service through more advanced outage detection and outage response.

Wholesale Metering

ORPC's system contains 10 wholesale metering points.

Locates and Connections

Four Year Locate and Connection Summary

	2011	2012	2013	2014
Average Customer Count	10,549	10,615	10,729	10,783
Number of Customers per km² of Service Area	301	303	306	308
Number of Customers per km of Line	35.76	35.98	36.37	36.55
Number of Locates	651	956	1441	2099
Number of New LV Connections	146	115	130	120
Number of New HV Connections	3	4	0	3

Smart Meters

As per the provincial smart meter mandate, ORPC replaced its entire meter population with smart meters during the years 2007 to 2012 including Computer Hardware cost of $25,493 and Computer Software cost of $67,200.

ORPC began billing its customers monthly, on a calendar bill cycle as of January 1st 2015.

Year	2007	2008	2009	2010	2011	2012	2013	2014	Totals
Installed Residential	490	155	2905	5364	113	25	20	62	9,134
Installed General service			159	811	286	87	7	8	1,358
Total annual meters installed	**490**	**155**	**3064**	**6175**	**399**	**112**	**28**	**70**	**10,493**

The useful life of the smart meters is governed by Measurement Canada, as it has the authority to govern meter seal periods. ORPC has engaged a Meter Service Provider to complete the pre-sampling requirements outlined in the Measurement Canada Bulletin E-26 Rev5 "Reverification Periods for Electricity Meters and Metering Installations."

All of ORPC's smart meters installed have a 10 year seal. The "Kinectrics Report" established a useful life range of 5 to 15 years. For the purpose of this application ORPC has assigned an Adjusted End-of-Life value of 15 years to its smart meter population. This is aligned with ORPC's depreciation. If however, a group of smart meters fail testing; ORPC will be forced to replace its entire sampling group. The reduced life expectancy would increase ORPC's average annual replacement cost for Smart Meters.

ORPC may install remote disconnect meters over the 2016 to 2020 time period. This project will provide the capability to turn power on and off at the service point remotely reducing the requirement to send a meter technician to the premise to disconnect as well as reconnect the meter when required. This will also eliminate the need to install power limiters based on timer functionality for non-payment during the winter months.

Smart Meters Qualified for a Lengthened Initial Re-verification Period

	QTY	2014	2015	2016	2017	2018	2019	2020
200	366				100			
202	97							
205	3254	125		250			250	
210	270	15			100		100	
215	52							
220	5720		250			250		250
225	351		100			100		100
230	59							
235	55							
240	94							
245	68							
250	38							
255	34							
BLANK	220							
Total		**140**	**350**	**250**	**200**	**350**	**350**	**350**

Smart Meter Age Profile Relative to Maximum Useful Life:

The following table illustrates ORPC's smart meter age profile relative to the 15 year maximum useful life established in the "Kinectrics Report." It is again important to note that the best of ORPC's knowledge meter seals expire after 10 years as per current Measurement Canada requirements.

In Service Year	Age	End-of-Life (Based on 15 Year Max UL)	Single Phase
2007	7	2022	490
2008	6	2023	155
2009	5	2024	3064
2010	4	2025	6175
2011	3	2026	399
2012	2	2027	112

Smart Meter Adjusted End-of-Life Projections:

ORPC has adopted a Maximum Useful Life of 15 years for its smart meter population, as per the "Kinectrics Report". ORPC has aligned it Adjusted End-of-Life dates accordingly. It is again important to note that Measurement Canada seal periods expire after 10 years, and if the group sample fails all of the meters in the group will need to be replaced and would have an Adjusted End-of-Life of 10 years.

MIST Meter

Metering Inside the Settlement Timeframe (MIST) – reference EB2013-0311, requirement for ORPC to install interval meters for customers with a monthly average peak demand of 50kW during a calendar year but less than or equal to 500kW. ORPC is compliant with this requirement.

Data Collectors - Smart Meters

ORPC's Elster Energy Axis Smart Metering System, utilizes Data Collectors to backhaul smart meter data back to its central server called the Master Application Server (MAS). ORPC requires the use of seventeen active Data Collectors, to administer its smart meter network throughout its entire licensed distribution service territory. ORPC collectors failed to communicate for an extended period in the fall of 2013 which required extensive efforts and time to troubleshoot while the meters were failing to communicate. The collectors communicate via hard wired telephone lines. Initially Bell Canada stated that the circuits were operating correctly, however they found problems and they were unaware that another group was making changes to hardware located in Renfrew, Ontario. Also, Bell Canada was charging long distance charges for the dropped calls and ORPC could not convince Bell to reverse the charges nor provide a credit. ORPC decided that the collectors were critical assets and ORPC could not incur significant expenses in dealing with dropped long distance in the future. ORPC decided recently to use wireless modem and Ethernet collectors that were more reliable and not susceptible to dealing with Bell. The wireless devices will also be used as part of our Smart Grid initiatives.

ORPC has adopted the Maximum Useful Life of 20 years for these units, as per the "Kinectrics Report." ORPC performs routine inspections of the units, and services them upon notification of error codes, which imply improper operation. ORPC plans on incurring material expenses in this category during the 2015 to 2020 period updating the remaining collectors to wireless modem units.

Meter Inspection and Maintenance

All maintenance activities related to meters follow the requirements of Measurement Canada guidelines including the group sampling and reseal program.

			ORPC Gatekeepers			
	Meter #	Phone #	Serial #	Address	Gatekeeper Type	Comm Type
O	ORPC20430	Removed	07290255			
	ORPC20431	613-629-5011	07290256	115 Noik Dr. (Pembroke)	Socket Base, metered	Phone Line
	ORPC20432	spare- in shop	07290257			
	ORPC20433	613-582-7492	07290258	1823 Beachburg Rd. (B-burg)	Socket Base, metered	Phone Line
	ORPC20434	613-757-0230	07290259	177 Queen St. (Killaloe)	Socket Base, metered	Phone Line
	ORPC20435	spare- in shop	07290260			
	ORPC20436	spare- in shop	07290261			
	ORPC20437	Removed	07290262			
	ORPC20438	spare- in shop	07290263			
	ORPC20439	613-629-5010	07290264	613 Miller St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC23985	613-629-5208	10288263	331 Isabella St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC23986	Removed	10288264			
	ORPC23987	613-629-5259	10288265	547 Cecelia St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC23988	Removed	10288266			
	ORPC23989	Removed	10288267			
	ORPC23990	Removed	10288268			
	ORPC23991	Removed	10288269			
	ORPC23992	Removed	10288270			
	ORPC23993	Removed	10288271			
	ORPC23994	613-629-5253	10288272	498 Julien St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC29981	spare- in shop	12008959			
	ORPC29982	613-629-5209	12008960	174 John St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC29983	613-629-5311	12008961	529 Herbert St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC29984	spare- in shop	12008962			
	ORPC29985	Removed	12008963			
	ORPC31622	spare- in shop	13766706			
	ORPC31623	spare- in shop	13766707			
	ORPC31624	Removed	13766708			
	ORPC31625	spare- in shop	13766709			
	ORPC31626	613-629-5231	13766710	174 Mud Lake Rd. (Pembroke)	Socket Base, metered	Phone Line
	ORPC31708	Removed	14126308			
	ORPC31709	613-629-5312	14126309	815 Mackay St. (Pembroke)	Socket Base, metered	Phone Line
	ORPC31710	613-629-5252	14126310	1050 Bronx St. (Pembroke	Socket Base, metered	Phone Line
	ORPC31711	613-582-7490	14126311	1624 Beachburg Rd. (B-burg)	Socket Base, metered	Phone Line
	ORPC31757	184.151.57.6:11	17056777	In front of 301 Hope St. (Almonte)	Pole-Mount, non-metered	Ethernet
	ORPC31758	184.151.58.162:1	17342048	In front of 93 Queen St. (Almonte)	Pole-Mount, non-metered	Ethernet
	ORPC31759	184.151.56.38:11	17342049	In front of 310 Ottawa St. (Almonte)	Pole-Mount, non-metered	Ethernet
	ORPC31760	184.151.58.196:1	17342050	In front of 308 St. George St. (Almonte)	Pole-Mount, non-metered	Ethernet
	ORPC31761	spare- in shop	17342051			

Equipment

ORPC owns a significant amount of assets that are grouped under the parent group, “General Plant.” The most significant assets are contained under the categories Vehicles, Administrative Buildings, Station Buildings. ORPC is currently working on gathering detailed asset information for the Computer Equipment, Equipment, and Communication categories, such that age and condition profiles can be generated; however, at this time the information is not available.

For General Plant assets, ORPC has only identified material capital reinvestment requirements for the asset group “Vehicles,” over the planning period.

This category fulfills the requirements of the office structure, office equipment, stores, major tools, measurement and testing equipment plus any miscellaneous equipment. In order to reduce failure risk or safety issues, the administration and operations manager prepare a review of aging, obsolete and necessity to update equipment to current standards in these areas of the business. The review is completed on a yearly basis during the budgeting process. In the event that there are no foreseen concerns or known failures, a contingency amount will be set out in the budget in order to have funds set aside.

Transportation Equipment

ORPC owns and operates a fleet of trucks and trailers that support all maintenance, operations and capital activities. It is very important to ORPC’s overall operation that all vehicles remain in good working condition, as ORPC does not have redundant units to rely upon.

The vehicle replacement program is based on annual condition surveys and life cycle planning. New vehicles and equipment support productivity through innovation, improve crew response time, reduce fuel costs, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

Consideration is given to the amount of mileage on the vehicle, body shape and if there are costly repairs prior to replacement. Allowing for the historical usage and track record of the previous fleet types of vehicles, the following replacement schedule is used as a guide:

Small Trucks – 8 Years
Medium Trucks – 12 Years
Large Trucks – 15 Years

Vehicles under 3 tons: Investigate and price suitable vehicles from the selection of dealerships in the immediate area.

Vehicles over 3 tons: Ensure vehicles meet functional requirements to perform meet the near term and expected long term requirements. In order to achieve a lower cost, explore the following:

- Initially investigate the known manufacturers that meet the specifications and requirements that may have an existing used or demonstration vehicle in their inventory.
- If no suitable vehicle is available; prepare a specification list and proceed with a request for quotes.

ORPC believes in replacing vehicles before they become costly to repair, uneconomic and unsafe to operate. ORPC's replacement schedule for vehicles has been reviewed and revised in 2014.

VEHICLE ID#		Division	YEAR	DESCRIPTION	ORIGINAL PRICE	Additions	Replacement cost	max ul	Kinectrics replacement date	Proposed Replacement Date
1	HT	Almonte	1994	FREIGHTLINER -RBD LINE TRUCK			$ 300,000.00	15	2009	2016
3	HT	Almonte	2005	INTERNATIONAL 4400	$193,037.11		$ 193,037.11	15	2020	2019
14	LT	Almonte	2011	CHEVROLET PICK UP TRUCK	$ 28,000.00		$ 28,000.00	10	2021	2020
24	T	Almonte	2008	POLE/UTILITY TRAILER	$ 9,020.79		$ 9,020.79	20	2028	2028
23	O	Almonte	2000	FORKLIFT	$ 25,000.00		$ 25,000.00	30	2030	2025
30	T	Almonte	2010	Trailer	$ 9,020.79		$ 9,020.79	20	2030	2030

VEHICLE ID#		Division	YEAR	DESCRIPTION	ORIGINAL PRICE	Additions	Replacement cost	max ul	Kinectrics replacement date	Proposed Replacement Date
11	HT	Pembroke	1997	INTERNATIONAL, MODEL 6 X 4, MODEL SF267	$314,035.45	21075	$ 335,110.10	15	2012	2017
8	HT	Pembroke	2008	INT'L MODEL 4400 4X2 LINE	$277,601.92		$ 277,601.92	15	2023	2022
9	HT	Pembroke	2010	International 4400 SBA			$ 300,000.00	15	2025	2023
31	HT	Pembroke	2014	INT'L MODEL 70S	$396,307.00		$ 396,307.00	15	2029	2027
5	LT	Pembroke	2013	FORD F150 1/2 TON	$ 27,000.00		$ 27,000.00	10	2023	2019
6	LT	Pembroke	2014	Dodge Ram 1500	$ 25,170.00		$ 25,170.00	10	2024	2021
25	O	Pembroke	1985	LAWNTRACTOR	$ 5,000.00		$ 5,000.00	20	2005	2014
21	O	Pembroke	1960	FORK LIFT	$ 25,000.00		$ 25,000.00	30	1990	2025
22	O	Pembroke	2014	FORK LIFT	$ 25,000.00		$ 25,000.00	30	2044	2034
15	O	Pembroke	2007	JOHN DEERE BACKHOE	$ 65,000.00		$ 65,000.00	30	2037	2037
4	PV	Pembroke	2003	CHEV ASTRO VAN	$ 25,266.32	2493.3	$ 27,759.62	10	2013	2014
28	PV	Pembroke	2007	DODGE CARAVAN C/V	$ 22,099.66		$ 22,099.66	10	2017	2017
10	PV	Pembroke	2008	Dodge Caravan	$ 22,318.58		$ 22,318.58	10	2018	2018
7	PV	Pembroke	2012	DODGE GRAND CARAVAN	$ 27,000.01		$ 27,000.01	10	2022	2022
16	T	Pembroke	1981	HAVELOCK DUMP TRAILER	$ 7,372.26		$ 7,372.26	20	2001	2014
13	T	Pembroke	1979	KING POLE TRAILER H3CPT	$ 9,020.79		$ 9,020.79	20	1999	2015
27	T	Pembroke	2005	UTILITY (BOX) TRAILER	$ 9,020.79		$ 3,023.10	20	2025	2015
17	T	Pembroke	1986	CUSTOM REEL TRAILER	$ 3,116.94		$ 3,116.94	20	2006	2016
18	T	Pembroke	1986	CUSTOM REEL TRAILER	$ 3,116.94		$ 3,116.94	20	2006	2016
19	T	Pembroke	1990	TIMBERLINE TENSIONER/PULLER	$ 41,678.59	3240	$ 44,918.59	20	2010	2017
20	T	Pembroke	1990	TIMBERLINE TENSIONER/PULLER	$ 41,678.59	6821.1	$ 48,499.69	20	2010	2017
12	T	Pembroke	1981	CASE DH4 TRENCHER	$ 29,185.23		$ 29,185.23	20	2001	2025
29	T	Pembroke	2007	Splicing Trailer	$ 9,020.79		$ 4,505.76	20	2027	2027
26	T	Pembroke	2008	MULTI REEL TRACTOR	$ 9,020.79		$ 9,020.79	20	2028	2028
2	T	Pembroke	2012	VERMEER BRUSH CHIPPER BC120	$ 46,830.00		$ 46,830.00	20	2032	2032

Vehicles Age Profile Relative to Useful Life Period:

ORPC has adopted the Maximum Useful Life of 15 years for its Trucks & Buckets, and the Maximum Useful Life of 20 years for its trailers, as per the "Kinectrics Report." As previously mentioned, the Vehicles under General Plant require material capital reinvestment over the planning period.

Vehicles Adjusted End-of-Life Profile Relative to Adjusted End-of-Life Projections:
ORPC performs routine inspections on all of its fleet vehicles, as well as any necessary maintenance is performed annually, during the mechanical, dielectric, and emissions inspection and testing processes.

As previously discussed, ORPC's core fleet vehicles are all parked indoors and out of the elements when not in use. As such, the fleet vehicles are expected to remain reliable, and safe for use up to their recommended maximum useful life. ORPC has assigned Adjusted End-of-Life values corresponding to the Maximum Useful Life values contained in the "Kinectrics Report". As such, Trucks & Buckets are expected to have a useful life of 15 years, and trailers are expected to have a useful life of 20 years. The Previous table illustrates ORPC's anticipated replacement schedule. Note that large fleet vehicles, such as double bucket trucks, have a typically delivery time in excess of one year. As such, they are planned and budgeted for one year in advance to ensure that they are received in a timely manner.

The average total annual reinvestment cost is $61,000 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by ORPC's adopted useful life.

IT – Computer Hardware/Software/GIS

Computer hardware is used by all departments of the utility and is a major element in customer service, finance, improving reliability and reducing costs. ORPC currently owns ten computer stations that are located in either the main office or operations centre in Almonte. ORPC has adopted the maximum useful life of 5 years for these stations. All stations are setup with base software such as Virus Protection, and core office programs such as Microsoft Office. Some stations are then loaded with additional functionality such as GIS or access to Customer Service Software depending on the user. ORPC also owns various other computing hardware such as printers, network hubs and docking stations. ORPC owns several higher value business software solutions such as its GIS system and DESS. ORPC plans to keep its computing hardware and software up to date over the planning period and as such has annual planned investments. However the combined total of all investments in this category are far below the materiality threshold.

ORPC's computer purchase and deployment mandate:

- Cyber Security and Business Continuity;
- Upgrades are based on business software requirements. With the constant upgrades to business specific software, ORPC may maintain the standard computer configuration required by software vendors. Upgrade to maintain customer service levels, in order to maintain prompt response to customer inquiries and billing creation, it is often necessary to increase processing level of hardware primarily used for customer service.
- Replace obsolete equipment; as equipment ages it loses the ability to run required operating systems and standard software applications. PC deployment is based on user specific requirements. CPUs are to be deployed based solely on the business need. Deployment is dependent upon the level of processing power each user requires to efficiently manage the business need, not based on user perception of requirements or perceived obsolescence of equipment. The deployment scheme assures WNP that assets are maintained for the maximum length of time and as importantly, each computer deployment is based specifically on user needs.

- Benefits of new equipment reduces the dependence on IT and support of older hardware, taking advantage of new technologies, empowering employee productivity with right equipment to complete their jobs efficiently, improved access to data and information, adhering to best practices and allowing for growth.
- Maintenance and updates of the GIS is required to collect and display information. A review must be conducted annually to determine any GIS upgrades or add-ons in order to keep the system current. The yearly operational budget includes the annual licensing and provides funding for hardware replacements.

Remote SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

There are many factors that contribute to the end-of-life of RTUs. ORPC will upgrade or replace the older units that are no longer supported by vendors or where spare parts are no longer available. Over the past year, there have been several hardware failures which clearly indicate that the assets are approaching the end of their useful life and should be replaced.

Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

New DNP protocol is required to communicate with the new devices that are installed and for future Smart grid devices.

ORPC is planning on deploying an Outage Management System on the SCADA system over the 2015 to 2020 planning period as part the improvements planned for our Almonte and Pembroke locations.

ORPC is planning to connect convert the copper co-axial loop communication system with Fiber optics.

5.3.3 Asset Lifecycle and Optimization Policies and Practices

Potential Asset Refurbishment Summary:

ORPC evaluates the feasibility of refurbishing assets on an asset specific basis depending on circumstances. Only a portion of ORPC's asset base is conducive to being refurbished or partially refurbished. Some asset classes however, must be outright replaced in their entirety. The following table summarizes whether or not particular asset groups are conducive to refurbishment in ORPC's experience. A detailed explanation of the rationale follows the table.

ORPC Asset Refurbishment Summary Table				
Assorted Category	**Asset Details**			**Refurbishment Considered?**
Parent*	**Category | Component | Type**			**Yes/No**
OH	Fully Dressed Wood Poles	Overall		yes
		Cross Arm	Wood	n/a
			Steel	n/a
	OH Line Switch (Expressed as sets of 3 Phase Switches)			yes
	OH Conductors	Primary Conductor		no
		Secondary Conductor		no
	OH Transformers			no
TS & MS	Power Transformers	Overall		yes
		Bushing		yes
		Tap Changer		yes
	Station Service Transformer			no
	Station DC System	Overall		yes
		Battery Bank		yes
		Charger		yes
	Station Metal Clad Switchgear	Overall		yes
		Removable Breaker		yes
	Station Independent Breakers			yes
	Station Switch			yes
	Electromechanical Relays			no
	Digital & Numeric Relays			no
	Rigid Busbars			no
	Steel Structure			yes
UG	Primary TR XLPE Cables in Duct			yes
	Secondary Cables Direct Buried			no
	Pad-Mounted Transformers	Single Phase		no
		Three Phase		yes
	UG Foundation			no
	Ducts			no
	Concrete Encased Duct Banks			no
	Cable Chambers			no

ORPC Asset Refurbishment Summary Table			
Assorted Category	**Asset Details**		**Refurbishment Considered?**
Parent*	**Category | Component | Type**		**Yes/No**
General Plant	Office Equipment		yes
	Vehicles	Trucks & Buckets	yes
		Trailers	yes
		Vans	yes
	Administrative Buildings		yes
	Station Buildings	Station Buildings	yes
		Parking	yes
		Fence	yes
		Roof	yes
	Computer Equipment	Hardware	no
		Software	no
	Equipment	Power Operated	no
		Stores	no
		Tools, Shop, Garage Equip.	yes
		Measurement & Testing Equip	no
	Communication	Towers	no
		Wireless	no
	Wholesale Energy Meters		no
	Current & Potential Transformer (CT & PT)		no
	Smart Meters		no
	Data Collectors - Smart Metering		yes

Prioritization of Individual Asset Replacements or Refurbishments:

ORPC uses the following priority tree to determine the importance of individual assets, for the purpose of ranking the importance of necessary individual asset replacements or refurbishments.

1. Asset failure poses imminent shock or safety hazard to the general public or to employees
2. Asset failure impacts entire distribution system
3. Asset failure impacts one or more feeders
4. Asset failure impacts large section of feeder
5. Asset failure impacts essential services
6. Asset failure impacts critical customers
7. Asset failure impacts multiple residential units or businesses
8. Asset failure impacts single residential unit or business
9. Asset failure does not impact customers

Overhead Distribution Assets Optimization Policies and Practices

Fully Dressed Wood Poles: ORPC replaces wood poles individually as per the findings of ORPC's overhead plant inspection and condition testing process, which is an integral part of ORPC's asset management process. As such, ORPC continually focuses on replacing the worst poles, as opposed to replacing sections of feeders where some poles would still be relatively good health. As part of the replacement process, ORPC inspects all components to see if any are fit for reuse. As ORPC has experienced considerable premature failures of wood poles due to flaws in the manufacturers treatment process, ORPC has been able to avoid unnecessary expense through the reuse of "like new" components. The most common components fit for reuse are the metal standoff brackets which are expected to last more than two full lifecycles of the wood poles to which they are affixed. It is important to note; however, that in order for any minor component to be deemed fit for reuse, it must be inspected thoroughly to ensure that no defects exist. Furthermore, any major component must also be condition tested to verify that it is fit for reuse.

Overhead Line Switches: ORPC currently utilizes three types of overhead line switches that are grouped into this category. ORPC has manual gang operated sectionalizing switches, inline paralleling switches, as well as inline fused switches, all of which are three phase switch settings. ORPC performs routine inspections of all overhead switches according to its overhead plant inspection process. The most common identified deficiency is insulator degradation. ORPC believes that it is worthwhile to extend the life of switches with minor refurbishments such as insulator replacements, as they are easy to do, as well as inexpensive.

Overhead Conductors: ORPC is not aware of any practical way in which overhead primary or secondary conductors can be refurbished. For jacketed cables, silicon injection technology allows for refurbishment; however, the practical application would be for underground primary cables. ORPC performs routine inspections of all of its overhead conductors according to its maintenance inspection process. Any small deficiencies such as excess sag or poor terminations are repaired under ORPC's maintenance process.

Overhead Transformers: ORPC does not refurbish overhead transformers and generally speaking transformers do not require maintenance. Historically transformers were run to failure, or alternately, were replaced in poorly accessible areas (back lot construction) at the same time that the wood poles to which they were mounted to were replaced. ORPC's new asset management approach is to transition to a just-in-time replacement approach, such that replacements are conducted under planned and coordinated circumstances, as opposed to under emergency repair circumstances. Factors that influence transformer replacements include the relative health of the transformer as determined by ORPC's asset management process, as well as the impact of failure. ORPC must ramp up its replacement program, beginning with replacements that are found to have the lowest health and highest impact of failure. ORPC's asset management process is utilized to prioritize the order in which individual transformers require replacing.

Transformer Station Lifecycle Optimization Policies and Practices

ORPC plans on sustaining its transformer stations such that they will achieve, or possibly surpass, the maximum useful life as dictated by core station components. As per the "Kinectrics Report", the majority of major station components such as Power Transformers, Metal Clad Switchgear and Station Switches, all have a maximum useful service life of 60 years. The availability of replacement parts has become a known issue for some components, as the types of assets are no longer commonly used in the industry.

ORPC will perform annual maintenance inspections and asset condition testing of all major station components. All major components have been assigned to a three year maintenance schedule and asset condition assessments are performed annually, due to the criticality of the station.

The following maintenance, testing and inspection schedule has been:

Year 1 Inspection, Maintenance & Condition Analysis:

- OCB testing
- Relay testing
- Battery banks testing
- Yearly oil sampling (all assets containing)

Year 2 Inspection, Maintenance & Condition Analysis:

- Pembroke Transformers and associated equipment (tap changer, arrestors), 15 kV Breakers
- Battery banks testing
- Yearly oil sampling (all assets containing oil)

Year 3 Inspection, Maintenance & Condition Analysis:

- Almonte Transformers and associated equipment (tap changer, arrestor), 15 kV Breakers
- Battery banks testing
- Yearly oil sampling (all - T1, T2 & OCB's)

Year	Asset Management Schedule
2014	Year 3 Schedule
2015	Year 2 Schedule
2016	Year 1 Schedule
2017	Year 3 Schedule
2018	Year 2 Schedule
2019	Year 1 Schedule
The following schedule will be applied for the period 2015 to 2019	

Power Transformers: Power transformers by nature require ongoing maintenance and are conducive to being partially refurbished. Over the last few years, ORPC has replaced and repaired components that have a shorter lifecycle relative to the transformer core. For example, ORPC has replaced all lightning arrestors. ORPC has also reconditioned the oil, installed an online oil drier and performed major maintenance repairs such as replacing the cooling fin gaskets. As previously mentioned, ORPC's strategy is to continue with necessary ongoing maintenance activities, as well as necessary refurbishments of smaller components, such that all of the power transformers will achieve their maximum suggested service life of 60 years. Overall, the past maintenance inspection and condition testing program did not find any items of immediate concern. However detailed inspections and testing will be completed in fall 2014 and 2015.

Station Service Transformer: The station service transformer is not conducive to being refurbished, and as such will be monitored for signs of fatigue. When the transformer is deemed to be close to failure, it will be replaced. ORPC expects to achieve a useful service life of 45 years.

Station DC System: The Station DC Systems require ongoing maintenance, as well as ongoing refurbishments in order for them to reach their maximum useful service life. ORPC performs annual battery cell testing to determine which cells no longer hold an acceptable charge and replaces them as required. This approach ensures that the system as a whole operates at acceptable performance levels. In the event of a premature charger failure, it is worthwhile repairing or replacing the charger and not necessarily replacing the battery banks.

Metal Clad Switchgear: ORPC's metal clad switch gear is inspected and condition tested on a three year rotation according to ORPC's maintenance inspection program. The switchgear is original to the stations. ORPC's strategy is to sustain the life of switchgear until the transformer station as a whole reaches the end of its useful service life. The switchgear is currently found to be in good health with respect to age, not requiring any significant sustained investments at this time. As such, ORPC's inspection and condition testing program will be relied upon to drive future maintenance and sustainment activities.

Station Independent Breaker: ORPC's station independent breakers have been identified as a major station component that is not expected to be sustainable until the station as a whole is planned to be decommissioned. The main reason for this is due to the fact that the oil circuit breakers (OCB's) were manufactured and purchased in 1957. The OCB's have surpassed their maximum useful life of 65 years and cannot be refurbished as parts have become obsolete. The most recent inspections and condition tests have found the OCB's to be in good working condition, with no immediate signs of failure. The purpose of the OCB's is to protect the entire station from sustaining damage in the event of a fault. ORPC has therefore determined to closely monitor the health of the OCB's until their planned replacements.

Station Switches: The station switches are also original to the station, and as such are of early 1970's vintage. The life expectancy of these switches aligns with the life expectancy of other core station components, and as such, ORPC's strategy is to refurbish the switches as required until their anticipated decommissioning along with the station as a whole in 2034. The switches are expected to reach their maximum useful service life of 60 years. The most common refurbishment of these switches is insulator replacements. ORPC's 2013-2014 annual inspection and condition testing did not identify any defects, and as such the switches are found to be in overall good health.

Electromechanical Relays and Digital & Numeric Relays: Electromechanical relays have been become obsolete with the availability of low cost microprocessor based digital relays. Modern day relays offer considerably more functionality and require less maintenance compared to older single function electromechanical relays. ORPC's strategy is therefore not to refurbish electromechanical relays but rather replace them with modern day technology in the event of failure.

Steel Structure: ORPC expects that the useful service life of the steel structure will outlast the useful service of the station as a whole. The steel structure generally does not require any maintenance or sustainment activities. ORPC has not had issues with acidic rain or road salt spray causing excessive deterioration. The structures are inspected annually for defects but to date none have been identified. ORPC's strategy is to sustain the steel structures as long as possible with the intent of replacing the structures with a cement pole.

Underground Plant Lifecycle Optimization Policies and Practices

Primary TR XLPE Cable Duct: ORPC's underground primary conductor is used to connect feeders to the transformer station, in newer subdivisions in place of overhead lines as well as to connect the distribution system to pad-mounted transformers. The age distribution of ORPC's underground cables is not evenly distributed and as such large portions of assets are approaching their end of service life during relatively narrow timeframes. It is not feasible or practical for ORPC to replace all cable runs as they reach their ideal end of their service life. As such, ORPC has staggered the planned cable replacements over a longer timeframe.

As underground cables cannot be inspected, ORPC plans on starting a cable condition testing program in 2015. The purpose of the program will be to determine the degree of cable jacket deterioration, from which replacement or sustainment activities will be identified and prioritized. ORPC plans on smoothing out the age profile of cable runs through the utilization of cable sustainment investments. ORPC must also be mindful that cable replacements cannot practically be performed during the winter months.

Secondary Cables Direct Buried: ORPC does plan on replacing the cables according to ORPC's asset management plan. ORPC plans on replacing the cables using a "just in time" proactive approach, such that the replacements can be conducted under planned and coordinated circumstances as opposed to under emergency circumstances. Unplanned failures during the winter months require that temporary overhead services be installed, as well as that the underground service be replaced the following spring. Winter failures add considerable unnecessary expense and should be avoided.

Pad-Mounted Transformers: ORPC does not refurbish pad-mounted transformers and generally speaking, transformers require little maintenance. ORPC's asset management approach is to perform just-in-time replacements, such that replacements are conducted under planned and coordinated circumstances as opposed to under emergency repair circumstances. Factors that influence transformer replacements include their relative health index as determined by ORPC's asset management process, as well as, the impact of failure. ORPC's asset management process is utilized to prioritize the order in which individual transformers require replacing.

ORPC is currently working on mapping out transformer to smart meter relationships such that transformer load profiles can be established. ORPC intends to use the loading data to refine Adjusted End-of-Life values, as there is a direct correlation between transformer loading and transformer longevity. The data will essentially give insight into how hard transformers are working and it will also allow for optimum transformer sizing as the units are replaced ORPC's fleet of spare transformers is currently not sized for increased transformer failure rates and as such it is important to proactively acquire transformers over the planning period.

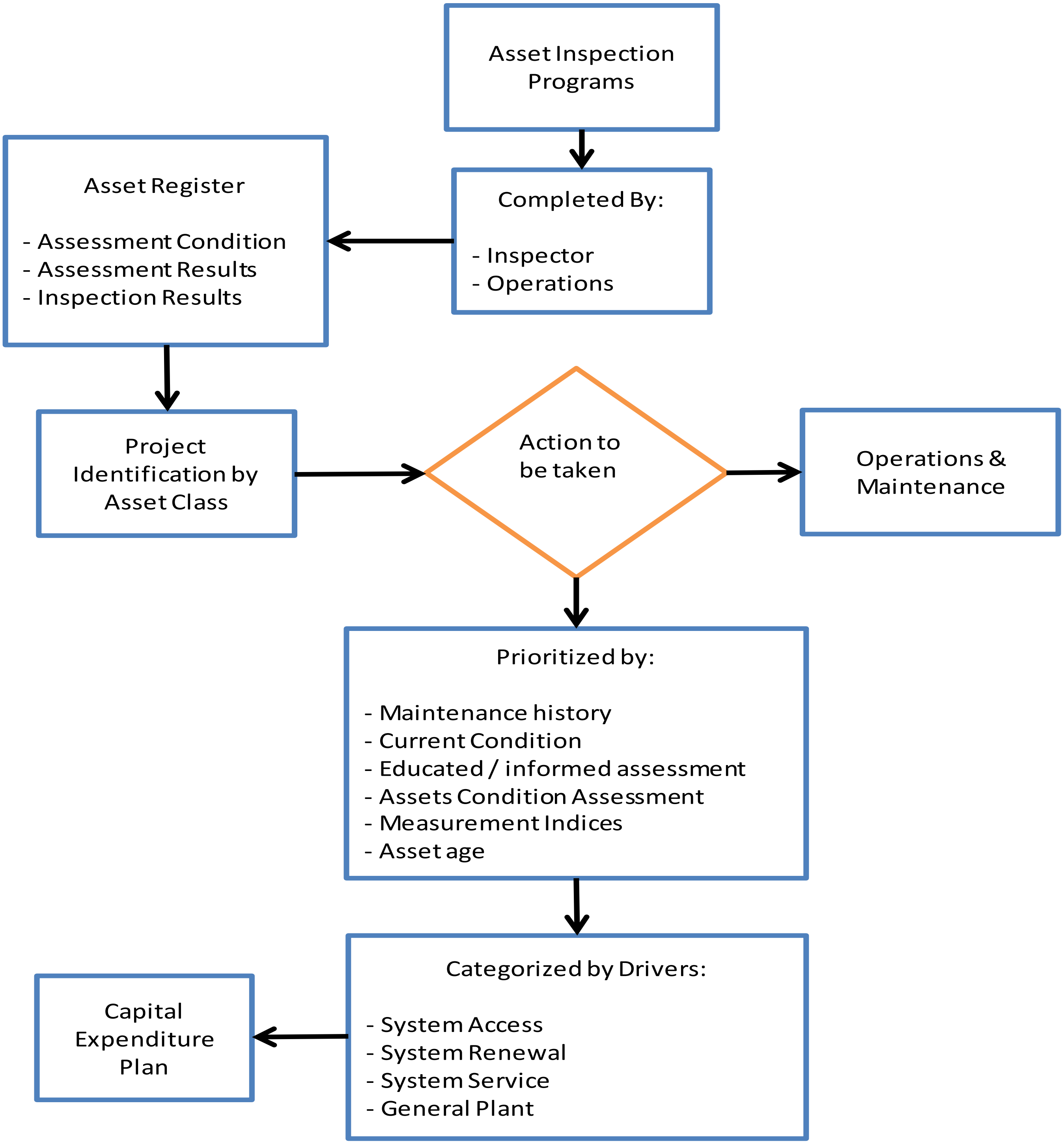
UG Foundations: Underground foundations generally do not require any maintenance and their refurbishment is not very practical. ORPC's strategy is to try to align two lifecycles of pad-mounted transformers for every one lifecycle of the underground foundation. As such, ORPC expects to replace underground foundations on an 80 year cycle. The underground foundations are also inspected annually as part of ORPC's maintenance inspection program, and any identified deficiencies are addressed accordingly. In recent history, inspections have only identified deficiencies related to transformer base tilting.

Ducts: Ducts generally do not require any maintenance and their refurbishment is not practical. Given that ducts are buried, they are also not conducive to maintenance inspections. ORPC's strategy is to align one lifecycle of ducts with two lifecycles of cable replacements. As such, ORPC expects to replace ducts on an 80 year lifecycle. This will save unnecessary excavation, landscaping, labour and material costs.

Concrete Encased Ducts: Concrete encased ducts generally do not require any maintenance and their refurbishment is not practical. Given that concrete encased ducts are buried, they are also not conducive to maintenance inspections. ORPC's strategy is to align one lifecycle of concrete encased ducts with a minimum of two lifecycles of cable replacements. As such, ORPC expects to replace ducts on a minimum 80 year lifecycle.

Cable Chambers: Cable chambers require very little maintenance and their refurbishment is not practical. ORPC performs minor maintenance such as cleaning or exterior painting of the chambers. The chambers are also inspected annually as part of ORPC's underground plant inspections program. Inspections typically focus on ensuring no animal intrusions have occurred and that the cable terminations they house are in good condition.

Asset Management Process Overview Flowchart



5.4 Capital Expenditure Plan (2015-2019)

The following table summarizes all of ORPC's planned capital expenditures over the 2015 to 2019 forecast period.

Capital Expenses as per OEB Categories 2015-2019

DESCRIPTION	2015	2016	2017	2018	2019
System Access	$500,850	$500,850	$452,200	$392,700	$392,700
System Renewal	$449,820	$194,100	$248,750	$193,200	$193,200
System Service	$270,800	$474,800	$345,849	$573,650	$293,200
General Plant	$212,200	$376,200	$255,200	$116,200	$134,200
TOTAL	**$1,433,670**	**$1,545,950**	**$1,301,999**	**$1,275,5700**	**$1,013,300**

5.4.1 Capital Expenditure Plan Summary

Capital Expenditures Planning Process Overview

ORPC has developed this DS Plan with a focus of delivering value for money and to achieve the four performance outcomes established in the OEB's renewed regulatory framework for electricity (Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance). ORPC's GIS system has been an invaluable tool, enabling improved asset oversight, identifying individual assets that are approaching the end of their useful service life due to their high risk of failure.

The following investment drivers have had a material impact on the DS Plan planning period: Mandated Service Obligations; Asset Failure and Risk of Failure; Asset End-of-Life High Performance Risk; Customer Preference; Reliability Objectives; Safety Objectives; necessary Non-System Physical Plant; Business Operational Efficiency and Performance Improvements; and System Capital/Maintenance Support.

Linking Investment Categories to Planning Process Outcomes:

Planned System Access investments are dedicated towards the upgrade of infrastructure for new customer connections. ORPC has planned for customer growth over the forecast period and as such, has allocated capital expenditures towards customer driven load expansions. A total of $ 500k has been allocated towards System Access expenditures, representing 45% of the total planned capital expenditures over the 2015 forecast period.

System Renewal is by far the most dominant investment category demanding capital reinvestment. ORPC has to upgrade obsolete transformer station equipment and protection and historically has operated in a "Maintenance Mode". As such, ORPC required relatively low levels of capital reinvestments as most distribution assets had sufficient back-up. A portion of ORPC's asset base is approaching the end of its useful service life over the planning period, posing a high risk of failure. The outcomes of the asset management process have resulted in ORPC shifting from its current maintenance mode to a capital reinvestment mode going forward. The overall level of investment towards System Renewal will be increased according to ORPC's asset management process, in preparation for the large volume of assets predicted to fail in the near future. The Poles, Towers & Fixtures and Line Transformers categories reinvestments combined, account for 40% of all planned System Renewal expenditures. ORPC has committed $130k for Poles Tower & Fixtures and $60k towards line transformers (overhead and underground combined). Approximately 45% of all planned capital expenditures over the 2015 forecast period are towards System Renewal.

System Service expenditures are largely driven by ORPC's desire to achieve operational objectives including; customer preference; maintaining/improving service reliability; and the elimination of potential safety hazards. Over the 2015 forecast period ORPC has committed a total of $270k towards the System Service category, which represents approximately 25% of total planned capital expenditures. Significant planned activities under this category include the installation of a fire barrier in 2017, a $15k Outage Management System in 2015, a total of $120k towards operational reliability improvements, and $115k towards eliminating safety hazards. The Outage Management System (OMS) will enable ORPC to respond to outages proactively, assist in pin-pointing equipment failures, offer improved oversight of the performance of ORPC's distribution system, as well as improve customer communication regarding outages. The elimination of identified safety hazards as well as strategic reliability improvements projects are also included in this category.

General Plant investments are necessary in order for ORPC to support and improve the efficiency of day to day business and operational activities. Over the 2015 forecast period, ORPC has committed $211k towards General Plant, which represents approximately 18% of the total planned capital expenditures. ORPC is planning to invest $61K annually into its rolling stock due to vehicles, as well as trailers, reaching or surpassing their maximum useful service life. ORPC also has various smaller initiatives planned, such as business efficiency improvement initiatives, computer replacements and software updates.

5.4.2 Capital Expenditure Planning Process Overview

ORPC Capital Expenditure Strategy

Ottawa River Power Corporation implemented accounting changes on January 1, 2013 that were consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report*,* and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* ("APH").

Ottawa River Power changed its depreciation rates to reflect the typical useful life of its capital assets as set out in the Kinectrics report. The change that implementation of this policy caused was in the extension of the useful lives of certain distribution assets.

This in turn caused a decrease in overall depreciation expense which was recorded in account 1576 Accounting Changes under CGAAP, as stipulated by the Board. At the same time ORPC also reviewed its overhead costs and found that they were consistent with overhead rates under International Financial Reporting Standards and that no changes were required.

POLICY: It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital projects that enhance or improve the efficiency of the Company's assets. Capital Assets include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

A "betterment" is a cost which enhances the service potential of a capital asset and is therefore capitalized. A "betterment" includes increasing the capacity of the asset, lowering associated operating costs, improving the quality of output or extending the asset useful life. This enhancement can result in an increase in physical output or service capacity, a decrease to operating costs, extension of the useful life of the asset, or improvement in the quality of the asset's output. Service potential may be enhanced when there is an increase in physical output or service capacity, associated operating costs are lowered, the useful life is extended, or the quality of output is improved. For example a refurbished transformer in which the service potential has been enhanced should be capitalized. Further, if during an underground fault repair, the work results in a reconfiguration of the asset that will clearly benefit future periods, there may be an argument to capitalize the work.

REPAIR: A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

MATERIALITY: The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary cost incurred to place a capital asset into its intended state of operation. Assets that are expected to provide future economic benefit greater than one year will be capitalized.

Individual items such as the following:

- New plant providing services over the value of $1,000.
- Rebuilding of facilities or vehicles when the value is over $2,000 and when the life of this equipment or facility will be extended.
- Equipment over the value of $500.

CAPITAL SPARES: Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

AMORTIZATION: As stated above, capital assets are amortized based on a method and life set by the OEB, currently following the Kinetrics Report, which is considered a suitable indicator of estimated useful life for the electrical distribution industry. The half year rule is utilized for amortization purposes, with a half year of amortization being recorded in the year of acquisition and a half year being recorded in the year of disposal.

DISPOSALS AND WRITE-OFFS: For assets taken out of service, the asset cost and the related accumulated amortization is removed from the records. Any difference between the proceeds and the unamortized asset cost including removal costs are recorded as a gain or loss in the year of disposal.

Justifying Capital Expenditures

With ORPCs' new approach to identifying, prioritizing and categorizing system renewal projects driven by assets reaching the end of their useful service life. ORPC plans to develop and implement a formalized asset management and capital planning process in 2015.

ORPC will also subject its General Plant assets to these processes, to determine which assets require replacement or refurbishments, similar to what is planned for the distribution system assets. In the past, distribution system renewal projects were typically performed on a Region or Zone Basis; however, with availability of asset specific dimensional and condition data, ORPC will transition to an asset class investment approach based on the results of the asset management and capital planning processes. Using this approach, ORPC will limit replacements to the "worst in class" assets and does not replace assets that are in the same "zone" which may still have significant useful life remaining.

ORPC will take this approach for all significant asset classes that are populated in the GIS system including: Fully Dressed Wood Poles; OH Line Switches; OH Conductors; OH Transformers; Primary TR XLPE Cables in Duct; Secondary Cables Direct Buried; Single Phase Pad-Mounted Transformers; Three Phase Pad-Mounted Transformers; Trucks & Buckets; Smart Meters; Data Collectors; and Wholesale Energy Meters.

Transformer station assets are made up of a relatively small number of high cost assets such as Power Transformers and Station Metal Clad Switchgear. System renewal investments are typically "lumpy", as they are very periodic in nature and not conducive to being spread over longer periods of time. ORPC has also grouped system renewal transformer station related capital projects by asset class.

ORPC will develop this DS Plan with a focus on achieving the performance outcomes established for electricity distributors under the Renewed Regulatory Framework for Electricity, in regards to Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.

Customer Focus

ORPC is dedicated to providing services in a manner that responds to customer preferences. ORPC invited the community to a presentation of our planned Capital spending. Future surveys and town hall meetings will help to shape our capital expenditures and to devote operational resources over the planning period, to align service offerings with the needs of our customer base.

A growing portion of customers would like to receive electronic bills via email. In response to this request, as well as in support of the smart grid deployment objectives, ORPC is planning to deploy e-billing in early 2015. The expected capital rollout costs are $7k

A portion of customers also expressed an interest in being able to access their consumption data and billing data online. ORPC is planning on offering customer access to this data in parallel to the e-billing rollout, and as such the service will be offered in early 2015. ORPC has allocated $5K towards capital expenditures.

It is important to note that a large elderly population who prefer traditional business communication methods, as most are not computer literate and as such do not utilize the internet or emails. ORPC's business strategy is to offer its consumers a choice of paper bills versus electronic bills, as well as preferred means of communication.

ORPC also plans to invest in an outage management system (OMS). These investments will enable ORPC to improve its ability to manage outages, as well as improve ORPC's ability to communicate directly with customers regarding important events such as outages. ORPC has begun to communicate the outages to its customers through social media such as Facebook and Twitter. Emails are also distributed; however ORPC has not accumulated a large amount of email accounts to date. With the help of this OMS customer communication will be conducted in an efficient and effective manner.

Operational Effectiveness

ORPC has a long history of utilizing technology and employee innovation to improve on its operational efficiency and effectiveness. The existing asset management and the new capital planning processes will enable ORPC to realize sustainable long term saving through improved asset lifecycle management, long term planning capabilities and data driven decision making.

Public Policy Responsiveness

ORPC is committed to delivering on its mandated service obligations. At the time of preparing this DS Plan, the following mandated service obligations impact the plan: to support the Connection of Renewable Generation; to provide monthly billing: to facilitate the implementation of a Smart Grid; and to achieve the mandated CDM Targets through the delivery of CDM Programs.

Over the past few years, ORPC conducted a system wide analysis to assess the capability of connecting renewable generation onto its distribution feeders. No constraints were identified that will limit the overall generation connections that ORPC's distribution system can accommodate. However, constraints (both thermal and short circuit) do limit the connection of all generation >10kW.

ORPC will develop a plan towards the implementation of Renewable Enabling Improvements that will guarantee the potential renewable generation capacity. Constraints will be set to error on the side of caution.

ORPC currently does have planned investments specific to achieving Smart Grid objectives and other planned investments such as the Renewable Generation Enabling Improvements which achieve many of Smart Grid priorities. The proposed improvements will support Smart Grid objectives under the Power System Flexibility, Customer Control and Adaptive Infrastructure categories. The improvements will also allow for the sharing of information with regional stakeholders.

Financial Performance

ORPC operates under a rate minimization philosophy with the objective of balancing investment needs, with providing customers with a safe and reliable supply of electricity at the lowest possible rates. ORPC will adopt a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner as they approach their high probability of failure zone in their lifecycle, as established by ORPC's asset management and capital planning processes.

ORPC's strategy is to pace investments according to the rate at which its asset base is deteriorating, so as to maintain long term perpetual viability. This ensures that the asset base as a whole is not driven to failure (end-of-life), at which time enormous reinvestment would be required. The DS Plan has been built on this premise, and as such the investments contained within it are essential to maintain ORPC's long term viability. ORPC's asset management and capital planning processes are instrumental in ensuring that savings from operational effectiveness are sustainable

ORPC has a good track record of wise spending, and has kept its cost base to a bare minimum in the interest of ratepayers. Over the period 2010 to 2014 ORPC's average annual percentage OM&A increase was 21.9%. ORPC credits its staff and service providers for enduring significantly intensified short term workloads, which were necessary to implement the multitude of sector changes.

The current level of effort exerted by ORPC's staff is not sustainable, and as such ORPC is realigning its revenue requirement to fund additional resources such as membership in CHEC as well as more necessary services from third party service providers including Human Resources, Engineering and IT expertise.

Future savings should be gained following the implementation of the asset management and capital planning processes. The processes will give ORPC improved oversight of its entire asset base managed, at the individual asset level, thereby enabling precise data driven decision making and long range planning. Improved decision making will result in optimizing investment needs to support the right investments at the right time.

5.4.3 System Capability Assessment for Renewable Energy Generation

Smart Grid

Background

In 2009, the *Green Energy and Green Economy Act, 2009* ("*GEA*") established an additional objective for the Board, namely, "to facilitate the implementation of a smart grid in Ontario". The *GEA* defined smart grid (by way of amendment to the *Electricity Act2*) as follows:

> For the purposes of this Act, the smart grid means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,
> (a) Enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;
> (b) Expanding opportunities to provide demand response, price information and load control to electricity customers;
> (c) Accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or
> (d) Supporting other objectives that may be prescribed by regulation. 2009, c. 12, Sched. B, s. 1 (5).

The Minister's Directive was issued pursuant to the authority provided by the *GEA* (by way of an amendment to the OEBA) and set out a number of objectives for the Board to consider in providing guidance on smart grid implementation, namely: customer control, power system flexibility and adaptive infrastructure. The Minister's Directive also set out a number of policy objectives to guide the Board's development of criteria for evaluating regulated entities' plans.

Seven main components of the Smart Grid include;

1. Self-healing system from power disturbance events,
2. Enable active participation by customers through engagement and education,
3. Operating resiliency against physical and cyber-attack,
4. Provide customer access to consumption data in an electronic format,
5. Accommodating all generation and storage options,
6. Enabling new products, services and markets,
7. Optimizing assets and operating efficiently.

The OEB Supplemental report on Smart Grid (EB-2011-0004) indicates that the internal and external motivators for different groups vary significantly between those customers that feel engaged and those that do not.

The report states that there's a significant amount of consumer benefits derived directly from consumer engagement, education and behavior. The study helps stakeholders unlock those benefits for consumers and tailor messaging that invokes engagement around the smart grid.

Programs must be simple to enroll in and participate in, and the benefits, such as saving money, must be clearly communicated. The OEB recommends designing programs and technologies that are easy-to-use and convenient and centering messaging around these opportunities.

Smart grid development and implementation

Under the renewed regulatory framework, smart grid development is expected to be integral to distribution system plans, a central focus of grid-enhancing innovation, and implemented on a coordinated regional basis to achieve economies of scope and scale. These filing requirements therefore include DS Plan information regarding, where appropriate:

- the activities a distributor has undertaken in order to understand their customers' preferences (e.g., data access and visibility, participating in distributed generation, and load management) and how they have addressed those preferences;
- the options a distributor has considered for facilitating customer access to consumption data in an electronic format;
- the mechanisms that facilitate "real-time" data access and "behind the meter" services and applications that a distributor has considered for the purpose of providing customers with the ability to make decisions affecting their electricity costs;
- the consideration a distributor has given to the investments necessary to facilitate the integration of distributed generation and more complex loads (e.g., customers with self-generation and/or storage capability);
- the technology-enabling opportunities a distributor has considered regarding operational efficiencies and improved asset management; and
- the distributor's awareness and adoption of innovative processes, services, business models, and technologies.

In the case of ORPC, a Smart Grid should be tailored to ORPC's relatively small and separate service territories. Design criteria should be based on system characteristics including distribution feeder dimensions and topography, as well as consideration of transformer station functionality.

As technology changes both the way people consume electricity and the way electricity is supplied to consumers, society will rely more and more on the Smart Grid to manage and maintain that reliable supply. The Smart Grid will allow remote balancing of supply and demand, which will get even more complicated as more homeowners seek opportunities to generate electricity for their own use, as well as to sell to the "Grid".

The Smart Grid already allows us to remotely restore service in some outage situations, by using our advanced SCADA (Supervisory Control and Data Acquisition) System to reroute supply.

Another important element of the Smart Grid is the Smart Meter. Smart Meters measure when and how much electricity you use throughout the day; that information allows the customer to make changes, for example running the dishwasher after 7pm, to take advantage of lower "Time-of-Use" rate periods.

There is a need for the addition of enhanced power quality monitoring due to ORPC's distribution system and that ORPC does have large scale generators connections.

Cyber security

ORPC has invested in cyber security by adopting best practices in both day to day system operations and staff training as well as investing in industry standard security hardware/software for their network. Data encryption policies are in effect on all customer data stores. Customer privacy and network security are always a focus when implementing new systems and integrating smart grid technologies. By utilizing multiple layers of security both with hardware and software ORPC is committed to preventing network attacks and access to customer data.

OPA PEAKSAVER

Peaksaver has the potential to reduce customer energy usage while at the same time shedding load during peak hours and allowing ORPC to meet its conservations goals. ORPC deploys Aztec IHD devices as part of its program. The Aztec IHD gives customer a visual indication as to what period they are in as well as cost per kWh based on live consumption data reported by their meter. Historical data is also logged in the device allowing the customer to review consumption without accessing the internet. Together the Peaksaver program and IHD's have encouraged responsible energy usage amongst ORPC customers who have enrolled. In many cases customers have had peak time usage visibly drop with the use of IHD's.

LOWFOOT

ORPC has approached web presentment with a focus on value for the customer. By utilizing Lowfoot ORPC has been able to provide rich web presentment capabilities to its customers without any additional costs. Because the adoption rate of this service encompasses a small portion of the customer base ORPC felt it was important to provide an effective solution to those that need it while not incurring costs to rate payers who do not. By using Lowfoot ORPC accomplished this goal while still providing a great user experience for customers.

Engineering Analysis

The smart grid is intended to be self-healing where problem areas are isolated efficiently while impacting as few customers as possible. ORPC will continue to implement designs that ensure a robust system will allow for multiple feeds to customer service locations. Re-closures and fault locating devices will be located in strategic areas of the distribution system that will allow for quicker location and clearing of faults. Electronic protective relays will be installed in the substations.

Asset Management System (GIS) Implementation

The existing ESRI system software will be upgraded and revised in 2015. These upgrades will provide a solid platform to connect to our smart meters and collectors, engineering software, etc. to allow for the deployment of Smart Grid functions planned during the next five years.

SCADA

ORPC Utilizes Survalent as the SCADA which will be the main device to enable the expansion of the "Smart Grid" and requires DNP protocol upgrade from Quindar system.

The existing SCADA system:

- Connects all station IED's together, enabling local/remote device control through a Human Machine Interface (HMI)
- Provides standard data management
- Performs logic functions for system automation
- Provides remote access, with security to ORPC and authorized regional stakeholders
- Provides single point engineering access to connected IED's

ORPC's definition of a smart grid within the Distribution System includes:

- Fully automated system to maintain power flow under all possible circumstances (under automated supervisory control)
- Automatic annunciation of problems, feeder trips etc., to ORPC personnel
- Remote operation and monitoring of all devices within the transformer station by ORPC or other authorized regional stakeholders
- Local and remote real time metering and logging of data for station mains and feeders
- Data acquisition and storage of basic metering functions for historical trending
- Fault data storage for trending and analysis

ORPC currently has planned investments specific to achieving Smart Grid objectives; however, other planned investments, such as the previously discussed, achieve many of Smart Grid objectives as per the Minister's Directive and subsequent OEB Supplemental Report on Smart Grid.

According to this plan, in 2015 ORPC will begin,

- Installing the SEL, or equivalent, protective relays.
- Line Fault indicators
- Automatic feeder restoration which will include the installation of special hardware and software that support more effective feeder restoration.
- Connection of NET metering solar generators and EV charging stations will allow ORPC to identify the grid impact and customer use patterns.
- ORPC will develop a transformer load tool, which will use smart meter data, to forecast and optimize asset utilization and identify over/under loaded transformers.
- Outage Management System and Reliability improvements

Because customers and their expectations are always changing, ORPC will apply social media to its system for improving customer communications for major events and many other applications in day-to-day utility operations, including vegetation management and work closure.

ORPC may adopt a Situational Analysis Tool that will combine internal and external information onto a single platform. Information includes:

- Outage restoration times
- Customers impacted
- Grid and external crew GPS locations
- Community liaison locations and contact information
- Company and logistics facility locations
- Weather data including wind speeds and flood zones
- Critical customer locations (hospitals and schools).

Demonstration Projects

At this time ORPC does not have any planned expenditures towards grid demonstration projects.

The staggering response to FIT and Micro FIT raises the stakes for improvements to the grid. For further information on Ottawa River Power Corporation's capacity for renewable energy generation, refer to Appendix C, ORPC's system Capability Assessment for Renewable Energy Generation.

5.4.4 Capital Expenditure Summary

Criteria for Prioritizing Capital Projects

ORPC's commitment is to deliver value to customers while pacing and prioritizing capital investments

Detailed project information is provided herein for all capital projects over $50,000.

Capital Project Name	2014	2015	2016	2017	2018	2019	Total
Fully Dressed Wood Pole Replacement Program	$34,000	$64,500	$64,500	$64,500	$64,500	$64,500	$322,500
Overhead & Pad-Mounted Transformer Replacement Program	$59,600	$59,500	$103,300	$103,300	$103,300	$103,300	$472,700
Conductors	$220,359	$60,200	$44,500	$14,000	$14,000	$14,000	$146,700
Fleet Vehicle Replacement Program	$49,066	$61,000	$300,000	$60,000	$60,000	-	$481,000
Scada		$18,000	$45,000	$45,000		$45,000	$153,000
Transformer Station – Power Transformer Fire Barrier				$65,000			$65,000
Information System	$35,425	$10,000			$26,000	$47,000	$83,000
Transformer Station - 44kV Breaker Replacement				$108,000		$108,000	$216,000
Engineering Studies			$86,000				$86,000
Outage Management System			$78,000				$78,000
44 KV tie Line Almonte				$100,000			$100,000
Substation upgrades	$84,000				$228,000		$228,000
Almonte Substation					$280,000		$280,000
Substation Design	$74,600				$73,000	$115,000	$188,000
Scattered Residential and Subdivisions	$203,500	$400,850	$400,850	$290,700	$290,700	$290,700	$1,673,800
Commercial	$108,370	$100,500	$100,500	$161,500	$91,500	$91,500	$545,500
2015 Misc. Small Capital Projects		$285,250					$285,250
2016 Misc. Small Capital Projects			$424,100				$424,100
2017 Misc. Small Capital Projects				$219,700			$219,700
2018 Misc. Small Capital Projects					$226,550		$226,550
2019 Misc. Small Capital Projects						$222,900	$222,900

The following tables show ORPC's summary of OM&A Recoverable Expenses from 2010-2016

Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	NEWGAAP	NEWGAAP
	Board Approved	2010	2011	2012	2013	2014	2015	2016
Operations	$360,476	$388,095	$548,028	$562,813	$595,899	$589,388	$617,080	$630,467
Maintenance	$705,409	$491,364	$721,496	$693,882	$840,521	$707,406	$766,322	$802,123
SubTotal	**$1,065,885**	**$879,459**	**$1,269,524**	**$1,256,695**	**$1,436,420**	**$1,296,794**	**$1,383,402**	**$1,432,589**
%Change (year over year)		-17.5%	44.4%	-1.0%	14.3%	-9.7%	6.7%	10.5%
%Change (Test Year vs Last Rebasing Year - Actual)							29.8%	62.9%
Billing and Collecting	$616,443	$600,482	$528,100	$533,838	$577,268	$634,033	$710,315	$733,000
Community Relations	$58,624	$41,451	$53,320	$47,391	$52,864	$55,452	$61,000	$67,000
Administrative and General+LEAP	$859,815	$821,877	$833,118	$817,920	$1,026,994	$915,963	$969,266	$1,062,375
SubTotal	**$1,534,883**	**$1,463,810**	**$1,414,538**	**$1,399,149**	**$1,657,126**	**$1,605,448**	**$1,740,581**	**$1,862,375**
%Change (year over year)		-43.7%	-3.4%	-1.1%	18.4%	-3.1%	8.4%	16.0%
%Change (Test Year vs Last Rebasing Year - Actual)							-33.1%	21.3%
Total	**$2,600,768**	**$2,343,269**	**$2,684,062**	**$2,655,844**	**$3,093,547**	**$2,902,242**	**$3,123,984**	**$3,294,964**
%Change (year over year)			14.5%	-1.1%	16.5%	-6.2%	17.6%	26.7%

	Board Approved	2010	2011	2012	2013	2014	2015	2016
Operations	$360,476	$388,095	$548,028	$562,813	$595,899	$589,388	$617,080	$630,467
Maintenance	$705,409	$491,364	$721,496	$693,882	$840,521	$707,406	$766,322	$802,123
Billing and Collecting	$616,443	$600,482	$528,100	$533,838	$577,268	$634,033	$710,315	$733,000
Community Relations	$58,624	$41,451	$53,320	$47,391	$52,864	$55,452	$61,000	$67,000
Administrative and General	$859,815	$821,877	$833,118	$817,920	$1,026,994	$915,963	$969,266	$1,062,375
Total	**$2,600,768**	**$2,343,269**	**$2,684,062**	**$2,655,844**	**$3,093,547**	**$2,902,242**	**$3,123,984**	**$3,294,964**
%Change (year over year)		-9.9%	14.5%	-1.1%	16.5%	-6.2%	17.6%	6.5%

	Board Approved	2010	Variance	2011	Variance	2012	Variance	2013	Variance	2014	Variance	2015	Variance	2016	Variance
Operations	$360,476	$388,095	-$27,619	$548,028	$159,933	$562,813	$14,785	$595,899	$33,086	$589,388	$26,575	$617,080	$21,181	$630,467	$13,386
Maintenance	$705,409	$491,364	$214,045	$721,496	$230,132	$693,882	-$27,614	$840,521	$146,639	$707,406	$13,524	$766,322	-$74,199	$802,123	$35,800
Billing and Collecting	$616,443	$600,482	$15,961	$528,100	-$72,382	$533,838	$5,738	$577,268	$43,430	$634,033	$100,195	$710,315	$133,047	$733,000	$22,685
Community Relations	$58,624	$41,451	$17,173	$53,320	$11,869	$47,391	-$5,929	$52,864	$5,473	$55,452	$8,061	$61,000	$8,136	$67,000	$6,000
Administrative and General	$859,815	$821,877	$37,939	$833,118	$11,241	$817,920	-$15,198	$1,026,994	$209,074	$915,963	$98,043	$969,266	-$57,728	$1,062,375	$93,109
Total OM&A Expenses	$2,600,768	$2,343,269	$257,499	$2,684,062	$340,792	$2,655,844	-$28,217	$3,093,547	$437,703	$2,902,242	$246,398	$3,123,984	$30,437	$3,294,964	$170,980
Adjustments for Total non-recoverable items															
Total Recoverable OM&A Expenses	$2,600,768	$2,343,269	$257,499	$2,684,062	$340,792	$2,655,844	-$28,217	$3,093,547	$437,703	$2,902,242	$246,398	$3,123,984	$30,437	$3,294,964	$170,980
Variance from previous year				$340,792		-$28,217		$437,703		-$191,304		$221,741		$170,980	
Percent change (year over year)				15%		-1%		16%		-6%		8%		5%	
Percent Change: Test year vs. Most Current Actual						24.06%									
Simple average of % variance for all years						40.61%									9%
Compound Annual Growth Rate for all years															1469.3%
Compound Growth Rate (2012 vs. 2014 Actuals)						13.34%									

Ottawa River Power Corporation has the following historical capital spending allocations for these sectors:

	Ottawa River Power Corporation									
	Historical Capital Additions									
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Average 10 Yrs**	**Average 4 Yrs**
180600	Land Rights									
180870	Building	14,386.46	18,607.45	60,159.83	93,745.12	24,730.00	106,000.00	38,000.00	32,583.33	49,310.60
182000	Mun. Trans. Stn - <50kv	166,447.78	90,612.98	6,177.55	40,093.00	107,464.00	139,500.00	193,500.00	94,384.68	61,086.88
183000	Poles Towers Fixtures	117,217.95	70,411.71	88,303.45	161,461.54	74,730.00	154,820.00	137,700.00	108,528.63	98,726.68
183500	O/H Conductors, Devices	145,586.40	121,026.95	239,543.24	224,632.63	344,599.00	210,000.00	191,200.00	225,339.39	232,450.46
184000	Distribution lines u/g	40,593.95	58,881.17	3,645.29	2,063.78	43,881.00	73,000.00		34,796.34	27,117.81
184500	Undergd Conductor/Dev	75,748.73	99,504.28	43,959.29	33,859.51	176,031.00	243,650.00	163,650.00	64,770.52	88,338.52
185000	Distributrion Transformers	60,897.34	129,496.48	119,724.00	119,765.48	158,090.00	187,000.00	172,000.00	116,155.63	131,768.99
185503	Customer services	103,018.64	95,629.83	50,079.08	118,991.56	80,284.00	101,000.00	101,000.00	101,468.83	86,246.12
186000	Meters	10,435.96	11,289.35	24,596.00	9,278.00	31,949.00	75,000.00	42,700.00	15,981.72	19,278.09
191500	Office equipment	5,883.38	2,572.20		1,387.96	3,337.00	5,000.00	8,000.00	3,295.14	2,432.39
192000	Computer Hardware	2,296.70	8,336.17	5,307.82	28,127.21	10,557.00	10,000.00	10,000.00	15,141.31	13,082.05
192501	Computer Software	12,193.75	8,648.02		46,620.00	40,967.00	34,000.00	19,000.00	54,708.63	32,078.34
193000	Rolling Stock and equipment	277,694.84	28,088.01	145,403.06	457,242.29	58,879.00	61,000.00	328,000.00	130,574.78	172,403.09
194000	Miscellaneous Tools & Equipment	2,334.90	5,113.61	12,398.51	6,273.28	39,977.00	10,000.00	10,000.00	11,075.70	15,940.60
194500	Measurement Equipment				18,090.00				18,090.00	18,090.00
195500	Communication Equipment	5,658.09		1,574.33		2,148.00	1200	1200	2,376.27	1,861.17
196000	Miscellaneous Equipment				12,104.00				12,104.00	12,104.00
198000	System Supervisory Equipment	64,229.68		4,116.00	503.27	611.00	22,500.00	130,000.00	12,455.86	1,743.42
	Contributed Capital	(125,255.00)	(254,011.00)	(347,304.00)	(35,217.00)	(148,792.00)	(324,000.00)	(300,000.00)	(169,246.40)	(196,331.00)
		979,369.55	**494,207.21**	**457,683.45**	**1,339,021.63**	**1,049,442.00**	**1,109,670.00**	**1,245,950.00**	**852,001.02**	**818,417.59**

The following tables show the 5 year historical spending and 5 year projected spending for each sector

DESCRIPTION	2010	2011	2012	2013	2014
System Access	$206,026	$369,429	$231,185	$302,943	$340,430
System Renewal	$513,921	$307,425	$344,841	$407,204	$459,780
System Service	$0	$0	$0	$0	$216,819
General Plant	$384,678	$71,365	$228,960	$664,092	$181,206
TOTAL	**$1,104,625**	**$748,219**	**$804,986**	**$1,374,239**	**$1,198,235**

DESCRIPTION	2015	2016	2017	2018	2019
System Access	$500,850	$500,850	$452,200	$392,700	$392,700
System Renewal	$449,820	$194,100	$248,750	$193,200	$193,200
System Service	$270,800	$474,800	$345,849	$573,650	$293,200
General Plant	$212,200	$376,200	$255,200	$116,200	$134,200
TOTAL	**$1,433,670**	**$1,545,950**	**$1,301,999**	**$1,275,700**	**$1,013,300**

Historical summaries of these projects (2010-2014) are detailed by description and year below

	2014	
	Investment Description	**Total**
General Plant	Men's Wshrm Accessability	$11,740
	Garage Work	$12,989
	Office Desk & Chairs	$3,337
	Computer Hardware: Printers, Desktops	$10,557
	Computer Software - CIS	$28,560
	Computer Software - Finance, Mapping	$12,407
	Forklift Purchase	$16,400
	Ford C-Max - Service Vehicle Purchase	$28,236
	Utility Trailer	$8,970
	Final Material for Double Bucket Truck	$5,273
	Small Tools	$39,977
	Communication Equip	$2,148
	System Supervisory Equp	$611
		$181,206
System Access	New Services - Capital	$87,181
	Micro Fit Connections	$1,984
	Anne St Townhouse s	$2,250
	Noik Drive - 12 unit Apt	$1,333
	Seigel Dev - Bell & Patricia St	$5,714
	OPP Detachment - Install UG Primary XLPE Cable	$47,249
	Watchorn U/G Line Extension - Load Transfer	$46,032
	Mill Run - Phase 1 B Developement	$102,940
	U/G Services - Townhouses - 329-339 Matheson Dr	$3,111
	New Gas Station - Almonte	$15,119
	Almonte - New Transformer Bank - Spring St Pumping Station	$16,174
	Install Transformer Bank - Stinson Paul Martin Drive	$8,060
	Rd Crossing - McKenzie St Development	$1,551
	Construct Line - Loadtransfer Cust. @ 68 Watchorn Rd	$1,733
		$340,430
System Renewal	Minor Capital Betterments	$101,577
	Fraser St - Reconductoring	$52,270
	Martin St Betterment	$86,914
	Replace Defective UG Riser Pole - 240 Reynolds Ave	$3,516
	Almonte 44 KV Betterment Hwy 15 to Sub #2	$61,735
	Robertson Rd Rebuild - Beachburg	$64,971
	Install 35" Guy Stub Pole Anchor & Transfer - 968 Reynolds A	$768
	Replace Transformer 75 Kva to 50 Kva - 386 Morris St	$6,019
	Reroute Primary - International Drive	$14,206
	Reconductor McGee St With 4/0 / 1/0 Bus	$16,986
	Install OH 120V Secondary - Bell St	$1,854
	Replace 2 Poles & Transfer @ Cameron St	$4,834
	Reinsulate 15 KV Line - Bennet & Julien St	$8,967
	Fraser St - 5 KV -Convert to Armless Construction	$3,690
	Install 44 KV Switches - 260 Fraser St	$3,575
	Install 2 45' Poles - John St @ Ryan St Killaloe	$3,973
	Upgrade Secondary Conductor - Everett St	$2,989
	Sub 3 Ground Grid	$10,468
	Sub 6 Ground Grid	$10,468
		$459,780
System Service	Replace Collectors in Almonte With Pole Mount Colle	$12,216
	Install New Viper Mount Reclosure - Mill St Killaloe	$40,437
	SUB 2 - Rebuild	$135,338
	Subs 2 & 3 - Inspection and Testing - Almonte	$28,828
		$216,819
	Sub Total	$1,198,235
	Contributed Capital	-$148,792
	Total 2014	**$1,049,443**

	2013	
	Investment Description	**Total**
General Plant	Doors for Garage	$11,963
	Overhead Walkway between Buildings	$41,323
	Install accessible washroom, new shower area and men's washroom and lunch room area	$40,459
	Office Chairs	$1,388
	Computer Hardware	$28,127
	Harris - Upgrade to new version	$46,620
	2014 Dodge Ram	$25,170
	2013 Ford F150 1/2 Ton	$30,746
	2014 Double Bucket Material Handler Truck	$401,326
	Miscellaneous Small Tools	$6,273
	Measurement and Testing Equipment	$30,697.00
		$664,092
System Access	New Services	$43,112
	Almonte Mews - Anne St - Townhouse project	$4,908
	Seigel Developement - Bell & Patricia St	$92,905
	Reginal Homes - Mill Run Phase 1A ,	$62,547
	Creek Side Towns - Novatech Engineering	$7,793
	Everett St - 3 Unit Townhouse.	$340
	Watchorn Drive Line Extension	$34,122
	Vera Cres; Install 2 Polls - Jeff Johnson	$5,209
	Lowe Court - Beachburg	$6,150
	Transformer	45858
		$302,943
System Renewal	Minor Capital Betterments	$73,057
	Fraser St. Reconductoring	$89,235
	Maple St. Reconductoring	$135
	Martin St. Betterment	$92,321
	Replace 3 Poles & Reconductor - Pemb W & Renfrew St	$10,975
	Repole 44Kv Line From Superior Elec To Quarry	$6,638
	Mackay St - 44 KV Ecress Sub #4	$71,871
	Beachburg Fire - 1888 Beachburg Rd (15 KVA Transformer)	$8,444
	Replace 3 44 KV Poles McKenzie St	$14,435
	Substation 2	$40,093
		$407,204
	Sub Total	$1,374,238
	Contributed Capital	-$35,217
	Total 2013	**$1,339,021**

2012		
	Investment Description	**Total**
General Plant	Front Office Washroom	$12,844
	Heat Exchanger	$7,424
	Pave between buildings	$4,100
	New Front Entrance - Accessibility Entrance	$29,979
	Roof Repair	$5,813
	Annual PC replacement	$5,308
	Chipper	$41,500
	Backhoe	$57,000
	2012 Dodge Grand Caravan	$27,191
	Rebuild Engine 2005 International 4400 - Almonte	$7,585
	Reel Trailer	$12,127
	Miscellaneous Small Tools	$12,399
	Communication Equipment	$1,574
	Scada Equipment	$4,116
		$228,960
System Access	New Services	$48,033
	Beachburg Line Extension	$1,870
	Almonte Mews - Anne St - Townhouse project	$1,096
	Noik @ Bell St - 12 Townhouses - Ken Siegel	$3,078
	New Algonquin College	$19,235
	Frank Neighbour Street Extension	$3,465
	Hyde Park Condominium - Jamieson St.	$33,144
	Rondeau Electric Mackay St	$18,558
	Crozier Electric.	$4,825
	Holiday Inn Suites - Good Night Hotel Inc	$7,318
	LCBO - 1050 Pembroke St E - MARNAC Developement	$12,267
	Lakeridge Trail Phase Ph 2 Poleline Extension	$18,761
	CW Homes - 559 Nelson St - Townhomes	$1,210
	Poleline Extension - Fern Gulley Lane	$6,352
	Seigel Developement - Bell & Patricia St	$4,969
	Reginal Homes - Mill Run Phase 1A	$11,731
	Mill Run	$18,227
	Transformers	$17,048
		$231,185
System Renewal	Minor Capital Betterments	$133,915
	Energy Retrofit at Substation 1	$4,460
	Fraser St. Reconductoring	$307
	Maple St. Reconductoring	$65,353
	Martin St. Betterment	$64
	Pole Replacement on Coolidge - Fire - Behind 247 Mackenzie	$3,499
	Replace Poles & Reconductor - Pemb W & Renfrew St	$11,567
	Replace 44 KV Pole - Angus Campbell Dr	$10,508
	Repole 44Kv Line From Superior Elec To Quarry	$87,080
	Install Transformer at Mikes Garage in Killaloe	$1,495
	Killaloe Reclosure	$24,875
	Battery Packs Sub 3 & 7	$1,717
		$344,841
	Sub Total	$804,985
	Contributed Capital	-$347,304
	Total 2012	**$457,681**

2011		
	Investment Description	**Total**
General Plant	Building Accessibility	$5,349
	New Roof	$8,830
	Renovate downstairs washroom	$4,428
	Office Chairs	$2,572
	2011 Chevrolet Pickup Truck - Almonte	$28,088
	Harris	$4,500
	Other Software	$4,148
	Miscellaneous Small Tools	$5,114
	Computer Hardware	$8,336
		$71,365
System Access	New Services	$38,124
	MicroFit Connections	$1,224
	Enerdu Apartment	$13,959
	Ottawa Street	$78,197
	Patterson St - Line Extension	$27,821
	Equators Grind	$13,562
	Almonte Mews - Anne St - Townhouse project	$34,006
	Noik @ Bell St - 12 Townhouses - Ken Siegel	$4,979
	375 Country St, - 18 Unit Apt.	$1,329
	New Algonquin College	$56,370
	Hyde Park Condominium - Jamieson St.	$8,026
	Rondeau Electric Mackay St	$8,369
	Crozier Electric.	$7,764
	Transformers	$75,699
		$369,429
System Renewal	Minor Capital Betterments	$38,367
	Ottawa Street	$23,776
	Alexander St Rebuild	$62,486
	Beachburg Road Line Upgrade	$59,798
	Line Upgrade - Laurier Ave	$15,759
	Ellis Avenue Line Upgrade	$13,734
	Replace Feeder Cables in Substation #3	$20,479
	Cassidy's Transfer Service Upgrade Warehouse 1001 Mackay St	$1,332
	Substation 4 Storage Building	$27,438
	Substation 7 - New Batteries	$10,250
	Substation 1 in Almonte - Completion	$34,006
		$307,425
	Sub Total	$748,219
	Contributed Capital	-$254,011
	Total 2011	**$494,208**

2010		
	Investment Description	**Total**
General Plant	Building Accesibility	$14,386
	Upgrade office furniture for service department	$5,883
	Upgrade two PC's from 2003	$2,297
	Hansen Software	$1,050
	TCG Computers	$2,450
	BTS- Accpac Upgrade	$1,585
	Third Octet	$7,109
	2010 Radial Boom Line Truck	$277,695
	Miscellaneous Small Tools	$2,335
	Upgrade of radio system	$5,658
	Scada Computer and System Upgrade	$64,230
		$384,678
System Access	New Services	$60,456
	Logan Subdivision - Ketch Construction	$7,240
	New Service on Minto St. - Beachburg	$2,372
	Line Extension 3 Fern Gully Lane Beachburg	$3,871
	351 Matheson Dr - Townhouses	$3,880
	Blakely St Townhouses - Ryan Habraken Carpentry	$4,128
	Integrated Health Centre	$639
	Microfit Connection	$786
	Hydro One Networks - Walmart Tap	$43,897
	Enerdu - APT Service	$7,424
	Transformers	$60,897
	Meters	$10,436
		$206,026
System Renewal	Minor Capital Betterments	$40,487
	Farm St @ Almonte Lane Relocation	$10,242
	Ottawa Street	$41,856
	Sub-Station 1 in Almonte Rebuild	$135,131
	River Road - Bus Betterment	$599
	Replace Poles/Secondary Transformer - Craig St	$8,388
	Remove Lines - Bell St. and Angus Campbell Drive	$120,941
	Morris St - Extension	$7,100
	Quarry Road - City Yard	$7,861
	Replace Pole & Transfer Backlot - 498 Cecelia St	$724
	Install Transformer - 40 Watchorn Rd Beachburg	$3,428
	Florence St. 44KV Airbrake Switch	$35,692
	Replace NRTC 35' with ORPC 40' Pole - 59 Robertson Rd	$1,908
	Moffat St. Betterment 623 to 698	$34,863
	Alexander St. Rebuild	$9,242
	Beachburg Road Line Upgrade	$24,142
	Substation 4 -Pole Storage Building	$31,317
		$513,921
	Sub Total	$1,104,625
	Contributed Capital	-$125,255
	Total 2010	**$979,370**

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		206,026	--		369,429	--		231,185	--		302,943	--		340,430	--	500,850	500,850	452,200	392,700	392,700
System Renewal		513,921	--		307,425	--		344,841	--		407,204	--		459,780	--	449,820	194,100	248,750	193,200	193,200
System Service		-	--		-	--		-	--		-	--		216,819	--	270,800	474,800	345,849	573,650	293,200
General Plant		384,678	--		71,365	--		228,960	--		664,092	--		181,206	--	212,200	376,200	255,200	116,200	134,200
TOTAL EXPENDITURE	-	1,104,625	--	-	748,219	--	-	804,986	--	-	1,374,239	--	-	1,198,235	--	1,433,670	1,545,950	1,301,999	1,275,750	1,013,300
System O&M			--			--			--			--			--					

5.4.5 Justifying Capital Expenditures

5.4.5.1 Overall Plan

Ottawa River Power Corporation as stated in section 5.4.2 ORPC has develop this DS Plan with a focus on achieving the performance outcomes established for electricity distributors under the Renewed Regulatory Framework for Electricity, in regards to **Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.** Consideration for each outcome was detailed in the previous sub category.

Customer Focus

- To provide services in alignment with customer preferences and needs

Operational Effectiveness

- Keep pace with distribution system deterioration through reinvestments as determined by ORPC's asset management process
- Minimize future rate instability by smoothing the age profile of distribution asset classes/groups
- Support the achievement of customer and regulatory reliability & service quality expectations
- Support the achievement of performance measures contained in the OEB's Distributor Scorecard
- Support future objectives of Regional Planning (unknown at this time with the exception of Almonte.

Support Public Policy Objectives:

- Support the connection of renewable generation to our distribution system
- Support the deployment of a smart grid and the achievement of associated objectives
- Support the achievement of conservation and demand management targets

Financial Performance:

- To ensure that financial viability is maintained in consideration of operating with the mandated return on equity

5.4.5.2 Material Investments

Ottawa River Power Corporation’s material threshold is $50,000. The following sections and descriptions further detail on a project by project basis the considerations, cost and projected benefits.

Wood Poles Replacement Program

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2015
Project Title: Fully Dressed Wood Poles Replacement Program		**Project End Date:** Dec. 31, 2019
Asset Category(s): Fully Dressed Wood Pole		**Project Driver(s)**: End-of-Life, Risk of Failure & Failure
USoA Account: 1830 - Poles, Tower & Fixtures		**Ave Annual Cap. Cost:** $64,500

General information on the Project/Activity

ORPC’s asset management process annually identifies wood poles that are at the end of their useful service life based on an age and inspection and will be enhanced with future condition testing analysis. The process targets individual poles that have a high risk of failure. ORPC will annually select the poles that are most likely to fail due to deterioration. Additional pole replacements have also been allocated for unplanned circumstances which may arise due to sudden failures caused by external influences such as motor vehicles or pole fires. Deteriorated wood poles pose a serious threat to customer and employee safety, as well as they undermine distribution system reliability and structural integrity. In the future, ORPC’s annual pole condition testing will ensure that poles deemed to have reached or exceeded the end of their useful service life will be replaced. Premature failures have also occurred frequently over the course of history due to manufacturing flaws in the wood treatment process. Among other factors, ORPC is guided in its pole assessment process by Clause 8.3.1.3 of Canadian Standards Association (“CSA”) Standard C22.3 No. 1-10, which states that: *“when the strength of a structure has deteriorated to 60% of the required capacity, the structure shall be reinforced or replaced”.*

Other considerations include pole condition information such as rot, decay, splitting, and insect infestation, bending, and leaning. ORPC believes that the replacement of poles exhibiting poor (or worse) condition is non-discretionary in view of compliance with the CSA code, as well as considerations for safety of the public and for workers operating in, on, or around the poles and their associated equipment. Poles that are being installed on a go forward basis are expected to last forty-five years. This investment is viewed as a core business reinvestment and as such is treated as non-discretionary.

The following table highlights some of the proposed activity for the year 2015. As our asset characteristics are defined, we will ensure that the poles are replaced based on our process versus the current methods.

Description	Year	Acct	Labour	Material	O/S Cont	Truck	Notes
Pole Replacement	2015	1830	$18,000	$23,000	$2,000	$3,000	Scattered pole replacement
Pole Replacement-Line Work	2015	1830	$10,000	$3,000	$0	$1,200	Fisher Street to Trafalgar Related line betterments
Pole Replacement-Line Work	2015	1830	$10,000	$3,000	$0	$1,200	Sub 4 behind Remi auto Related line betterments
Pole Replacement-Line Work	2015	1830	$10,000	$3,000	$0	$1,200	Misc. Related line betterments
Poles	2015	1830	$8,000	$8,000	$1,000	$500	Eight poles Residential Development
Poles	2015	1830	$2,500	$2,500	$1,000	$1,000	Commercial Development
44 kV Structure	2015	1830	$4,000	$5,000	$0	$750	Replace South pole structure
Poles HONI/Brookfield	2015	1830	$10,000	$10,000	$0	$4,270	Replace Cedar Poles on 44 Line McKay St Betterment
Pembroke Sub 2 Station Yard	2015	1830	$2,500	$5,000	$0	$200	Sub 2 Concrete Pole and 44 kv cable

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

ORPC's strategy is also to replace End-of-Life poles under planned and coordinated conditions, as opposed to under emergency or afterhours conditions, which add unnecessary risk and expense. Capital reinvestments into wood poles are essential to sustain ORPC's ability to safely, efficiently, reliably and cost-effectively distribute electricity to its customers. When wood poles are replaced, pole hardware inspections are performed on major components to assess whether or not they are suitable for reuse. Typically hardware such as metal stand-off brackets are suitable for reuse, as they are expected to outlast two lifecycles of the wood poles to which they are affixed.

2. Safety

The new poles will be designed and constructed to current standards. This will provide a much safer work environment for field crews. This investment will eliminate potential safety hazards to both the general public and ORPC employees. The replacements will also reduce the likelihood of sustaining storm related damage, which often pose safety hazards to the general public and employees.

3. Co-ordination, Interoperability

ORPC constructs its wood pole framing according to USF Construction Standards, which are commonly used amongst LDC's throughout Ontario. When replacing poles, ORPC is also mindful of the future needs of other stakeholders including Third Party Attachments.

4. Economic Development

Essentially all material will be purchased through local or regional suppliers, who utilize many Ontario manufacturers. ORPC's labour force and fleet vehicles will be utilized to complete the replacements. Additional support services as required will be supplied by local service providers, such as vacuum excavation or trenching. This project will benefit both the local and provincial economy.

5. Environmental Benefits

ORPC is committed to conducting its business in an environmentally responsible manner. ORPC's reuse of pole line hardware practices also minimize the amount of waste that is generated. Wood poles require deforestation (each pole is a tree), and requires chemical treatment in order achieve appropriate service life. By contrast, composite poles are manufactured from inert materials, preserving trees, and eliminating any leaching of preserving chemicals. They also result in lower emissions due to reduced transportation requirements.

With these benefits and potential savings and only moderate increase in direct capital costs, it is recommended that ORPC consider the possibility of increasing the proportion of composite pole installations. While this will increase the capital costs in the short term, it will reduce overall program costs in the long term, while decreasing ORPC's environmental footprint.

Category-specific requirements for each project/activity

System Renewal: ORPC's Fully Dressed Wood Pole replacement project is categorized as System Renewal. ORPC has adopted the expectation that wood poles will achieve a useful service life of forty-five years as per the TUL values established in the "Kinectrics Report". Wood poles are subjected to the harsh climate which accelerates deterioration. Catastrophic pole failures have a high probability of impacting a significant number of customers in all classes and they have the potential of disrupting the service of entire feeder sections. Maintaining the structural integrity of wood poles is also crucial to support public and employee safety as well as the overall reliability of the distributions system. Wood poles fail when the mechanical stress they are subjected to is greater than their structural integrity, which are often put to the test during events of extreme weather. Failures often occur during storms or under extreme weather conditions such as high winds or snow loads. Hardening of the system will be achieved by maintaining the vegetation plan, analyse new standards and complete engineering analysis of critical locations. The probability of suffering storm damage and associated interruptions from high winds are greatly reduced when the weakest links conducive to failure are eliminated.

This investment will therefore support maintaining current distribution system performance levels, ensuring that they will continue to meet or exceed regulatory requirements and customer expectations. Furthermore, this investment will benefit all customers across all rate classes.

Overhead & Pad-Mounted Transformer Replacement Program

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2015
Project Title: Overhead & Pad-Mounted Transformer Replacement Program		**Project End Date:** Dec. 31, 2019
Asset Category(s): OH & UG Transformers		**Project Driver(s)**: End-of-Life
USoA Account: 1850 - Line Transformers		**Ave Annual Cap. Cost:** $94,540

General information on the Project/Activity

ORPC's asset management process has identified overhead and pad-mounted transformers that will be at the end of their useful service life based on risk analysis utilizing age, inspection and available condition test results, over the 2015 to 2019 planning period. The process targets individual transformers that have a high risk of failure and prioritizes replacements based the impact of failure. ORPC's has identified that six-hundred eighty (680) overhead, and eighty four (84) pad-mounted transformers will either reach or surpass their UL value of forty five (45) years, as established in the "Kinectrics Report", over the planning period. The replacement strategy is to begin replacing transformers while completing betterment projects followed by completing the replacement of high risk transformers with significant impact of failure, and to attempt to smooth the asset population by utilizing ORPC's asset management process. It is also important to note that an additional 144 transformers will reach their UL over the next five year planning period and 360 transformers will reach their UL over the period of 2019 to 2023. This underscores the importance that the transformer replacement program be significantly intensified. ORPC is currently working on developing a tool to analyze transformer loading across its entire asset base, which will further enhance prioritizing replacements. This investment is viewed as a core business reinvestment and as such is treated as non-discretionary.

The current plan (highlighted in the below Table) will be modified as explained herein to ensure the reliability of our system. The plan will be increased by $44k in future years.

ORPC's Overhead Transformer Replacement Program								
System Renewal	**Pole Replacement**	2015	1850	$2,000.00	$7,000.00	$0.00	$500.00	$9,500
System Renewal	**Pole Replacement - Line betterments transformers**	2015	1850	$10,000.00	$27,000.00	$0.00	$0.00	$37,000
							Total	**$46,500**

ORPC has budgeted replacements based on the following:

Year	1 Phase Pad Mounted	1 Phase Pad Mounted Transformer Replacement Cost	3 Phase Pad Mounted	3 Phase Pad Mounted Transformer Replacement Cost	Pole Mounted Transformers	Pole Mounted Transformer Replacement Cost	Spare	Spare Transformer Replacement Cost	Total #	Total Cost
2015	1	$12,000	0	$-	4	$19,200	4	$28,400	**9**	**$59,600**
2016	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**
2017	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**
2018	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**
2019	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger for this project is assets reaching the end of their useful service life posing a high risk of failure. Transformers are not changed simply because they are in a zone that is being rebuilt due to many assets within a zone coming to the end of their useful service life. This approach is very efficient as it targets the weakest links throughout ORPC's entire service territory, thereby strengthening the integrity of the distribution system as a whole. ORPC's strategy is also to replace transformers under planned and coordinated conditions, as opposed to under emergency or afterhours conditions, which add unnecessary risk and expense. Capital reinvestments into transformers are essential to sustain ORPC's ability to safely, efficiently, reliably and cost-effectively distribute electricity to its customers. ORPC has aligned the lifecycles of pad-mounted transformer foundations, such that the foundations are changed at an eighty (80) year interval that corresponds to two forty (40) year lifecycles of pad-mounted transformers. As such, ORPC is not planning on replacing any underground foundations during the planning period, as it is not necessary.

2. Safety

This investment will eliminate potential safety hazards to both the general public and ORPC employees. Public safety will be improved as the new transformers will have no rust or holes that pose a risk to the public. ORPC crews performing maintenance will benefit from the safety of these new transformers.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

ORPC constructs its transformer stations according to USF Construction Standards, which are commonly used amongst LDC's throughout Ontario. ORPC offers its customers standard voltage offerings that have allowed ORPC to also standardize its transformer fleet.

5. Economic Development

Essentially all material will be purchased from Ontario manufacturers through local or regional suppliers. ORPC's labour force and fleet vehicles will be utilized to complete the project. Additional support services will be supplied by local service providers, such as vacuum excavations and trenching. This project will benefit both the local and provincial economy.

6. Environmental Benefits

ORPC is committed to conducting its business in an environmentally responsible manner. This project will reduce the overall risk of possible environmental incidents associated with transformer failures. The reduced risk of oil leaks will benefit the local environment.

Category-specific requirements for each project/activity

System Renewal: ORPC's Overhead and Pad-Mounted Transformer Replacement project is categorized as System Renewal. Due to the relatively narrow window during which ORPC's entire distribution system rebuild and voltage conversion occurred, the age distribution of transformers is not evenly distributed but heavily skewed. ORPC has adopted that transformers will achieve a useful service life of forty years, as per the TUL values established in the "Kinectrics Report". ORPC has identified that a disproportionately large percentage of all transformers will reach or surpass their UL over the next ten years. The evaluation has given ORPC the foresight to intensify its transformer replacement program beginning in 2016, to control projected failure rates, as well as to smooth capital expenditures necessary to replace the assets. Planned replacements are prioritized by risk of failure and the associated impact of failure. ORPC is currently developing transformer loading profiles based on its GIS system and the smart meter data available from the AMI system. This asset management system process improvement will assist in assessing risk of failure, from which AEOL projections are derived. The quantity and selection summary of transformer replacements will be based on ORPC's asset management process.

Conductors

Investment Category: System Renewal		Project Start Date: Jan.1, 2015
Project Title: Cable Replacement Program		**Project End Date:** Dec. 31, 2019
Asset Category(s): Cables in Duct		**Project Driver(s)**: End-of-Life, Risk of Failure
USoA Account: 1845 - UG Conductor and Devices		**Ave Annual Cap. Cost:** $45,000

General information on the Project/Activity

ORPC's asset management process annually identifies primary underground TR XLPE cable runs that are at the end of their useful service life based on an age, inspection and condition testing analysis. ORPC's underground distribution system is fed using underground circuits running from distribution stations to overhead lines and from overhead lines to transformers and switches. This system is configured and connected through the use of underground cable. Distribution underground cables are used mainly in urban and newer residential areas where it is not feasible to build overhead lines due to aesthetic, legal, environmental or safety issues. The reliability of the overhead and underground distribution systems is contingent on the performance of this underground cable.

Underground cable is replaced on a like-for-like basis and is run-to-failure. The current standard is to bury the cable encased in a Poly Vinyl Chloride (PVC) duct in non-roadway applications and for roadway applications, concrete encased PVC duct is used to reduce risk of physical factors such as dig-ins and vehicle weight. The process targets individual cable runs that have a high risk of failure. The pace at which the conductors reach the end of their useful service life is a function of their age, physical environment and operating conditions, such as electrical loading. Due to the extremely cold and long winters, primary underground cables can practically only be replaced from the end of May to the end of October, which is roughly during half of the calendar year. As such, ORPC's strategy will be to replace primary underground cables on a proactive basis, when they have a high probability of failure. Cable replacements are prioritized based on their impact of failure. Historically, cable replacements have been prioritized based on the number of faults, or the number of customer interruptions due to cable faults.

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger of this project and its activities is assets reaching the end of their useful service life, posing a high risk of failure. ORPC's asset management process by nature targets individual assets (cable runs) that are most likely to fail. As such, cables are not changed simply because they are in a zone that is being rebuilt due to many assets within a zone coming to the end of their useful service life. The lifecycles of underground cable ducts have been adjusted to align with two lifecycles of the cables that they house. The planned cable replacements and rejuvenations are not expected to require underground ducting to be replaced, and as such the cost of the replacement is kept to a minimum.

This project will benefit the overall reliability of the distribution system at the feeder level, as many of the cable runs are utilized to connect distribution feeders to the distribution station. As such, the investment will be of benefit to all customers, and is deemed non-discretionary as it underpins overall distribution system reliability and performance.

2. Safety

Installing cables in direct buried or concrete encased ducts to current standards will help reduce accidental contact with energized conductors. Not applicable.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

Not Applicable.

5. Economic Development

Essentially all material will be sourced through local or regional suppliers. ORPC's labour force and fleet vehicles will be utilized to complete the project. This project will benefit both the local and provincial economy.

6. Environmental Benefits

ORPC is committed to conducting its business in an environmentally responsible manner. This project will reduce the overall risk of environmental incidents occurring in emergency situations as a result of underground cable failures.

Category-specific requirements for each project/activity

System Renewal: ORPC's Primary UG Cable Replacement project is categorized as System Renewal. ORPC has adopted that underground Primary TR XLPE Cables in Duct will achieve a useful service life of forty years, as per the TUL values established in the "Kinectrics Report". A large percentage of underground primary conductor runs will reach or surpass their UL over the next twenty years. The evaluation has given ORPC the foresight to intensify its replacement and refurbishing program beginning in 2015, to control projected failure rates, as well as to smooth capital expenditures necessary to replace the assets. Planned replacements are prioritized by risk of failure and the associated impact of failure. The quantity and selection summary of cable replacements is based on ORPC's asset management process.

Transformer Station

Investment Category: System Service		Project Start Date: Jan.1, 2015
Project Title: Transformer Station Improvements		Project End Date: Dec. 31, 2019
Asset Category(s):		Project Driver(s): Safety
USoA Account: 1820		Ave Annual Cap. Cost: $139,500

General information on the Project/Activity

ORPC is planning to modernize the 1970's protection and control system of its Transformer Stations. The ground grid and station fencing require urgent attention. Other current limitations include the inability to accommodate reverse power flows at any level at the station. The final objective of this multiyear project will be for the transformer station to be able to provide power quality data as well as the deployment of a fully operational Remote SCADA system. The improvements will allow ORPC to monitor the performance of core station components, as well as of individual feeders, which will support several Smart Grid Mandate objectives. The improved protection and station oversight will also significantly increase the connection capacity for renewable generation.

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The planned investments are triggered by the mandate to provide employee and public safety features. Secondary drivers include the accomplishment of many Smart Grid Mandate objectives under the Customer Control, Power System Flexibility and Adaptive Infrastructure categories. This investment will satisfy priorities 2 and 3 of ORPC's capital Investment Priorities which are: ensuring compliance to regulatory and legal obligations; and meeting the needs and preference of customers. As such, this project is ranked higher than the majority of capital investments that are planned for replacing, sustaining or retiring assets that are at the end of their useful service life.

2. Safety

This investment will ensure that the transformer station is not accessible to unqualified persons since contact with energized equipment can potentially lead to injury or even death of ORPC employees and the public. ORPC's standard is to incorporate 2.0 meter fencing and engineered ground grid systems.

3. Cyber-security, Privacy

ORPC will ensure that its communication network and the IED's are configured according to best industry practices and in compliance with corporate security and privacy policies.

4. Co-ordination, Interoperability

The equipment selected to modernize the transformer station protection and controls is commonly used throughout North America. Supervisory control system and IED data will be made available for interested stakeholders, such as Regional Transmitters or the IESO, through industry standard communication protocols and platforms.

5. Economic Development

Essentially all material will be purchased through local or regional suppliers. Local and regional labour forces will also be used to install and configure the communication network and IED's. This project will support Ontario's economic growth and job creation.

6. Environmental Benefits

This investment will increase the connection capacity of renewable generation to ORPC's distribution system.

Category-specific requirements for each project/activity

System Renewal: ORPC plans to smooth out expenditures over a seven year horizon for rate stability purposes. ORPC believes that this approach aligns with the OEB's objective of "pacing and prioritizing capital investments to promote predictability in rates and affordability for customers." The installation of transformer station protection equipment requires the expertise of third-party service providers. ORPC has to rely on external service providers to perform this type of specialized work. ORPC has taken measures to minimize the overall cost of these planned expenditures, by coordinating the installation of SCADA enabling improvements to follow regularly scheduled annual maintenance work that is also outsourced to the same external service provider.

Fleet Vehicle Replacement Program

Investment Category: General Plant		**Project Start Date:** Jan.1, 2015
Project Title: Fleet Vehicle Replacement Program		**Project End Date:** Dec. 31, 2019
Asset Category(s): Vehicles		**Project Driver(s)**: Maint. & Capital Support, Non System Physical Plant
USoA Account: 1930 - Transportation Equip.	**Tot. 2015 - 2019 Cap. Cost:**	**Ave Annual Cap. Cost:** $61,000

General information on the Project/Activity

Vehicles are an essential component in providing efficient and reliable service to customers through the quick restoration of power, the efficient construction and maintenance of the distribution system and the safety of employees. ORPC's asset management process governs the life of distribution plant assets, as well as fleet vehicles (transportation equipment). ORPC believes in replacing vehicles before they become costly to repair, uneconomic and unsafe to operate. ORPC's replacement schedule for vehicles has been reviewed and revised in 2014. Over the planning horizon the asset management process has identified that a Double Bucket Truck, two service vehicles, a reel stringing & tensioning trailer, as well as a chipper trailer will reach or surpass their Maximum Useful service life as established in the "Kinectrics Report".

Small Trucks – 8 Years
Medium Trucks – 12 Years
Large Trucks – 15 Years

ORPC has adopted a maximum target life expectancy of fifteen (15) years for trucks & buckets, and twenty (20) years for trailers.

Support vehicles are crucial in allowing employees to work safely and efficiently. Maintaining a reliable fleet is very important to business efficiency as ORPC does not have fleet vehicle redundancy. Without fleet vehicle redundancy a vehicle breakdown could result in considerable job site delays. ORPC's fleet vehicle replacements have been planned around core distribution plant asset replacements to smooth annual capital budget requirements.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USOA Account	Primary Investment Driver
2015	General Plant		2008 Service Van	$28,000		Replace end of life crew service/support vehicle	1930	Non System Physical
2016	General Plant		Replace 1994 Freightliner RBD	$300,000		Replace end of life RBD, to support maintenance, capital and operational activities	1930	Non System Physical
2019	General Plant		Replace 1990 Timberline Tension Trailer	$60,000		Replace end of life trailer to support maintenance, capital and operational activities	1930	Non System Physical
2019	General Plant		Replace 1990 Timberline Tension Trailer	$60,000		Replace end of life trailer to support maintenance, capital and operational activities	1930	Non System Physical

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

ORPC's asset management process and capital planning process have triggered planning for these fleet vehicle replacements, as they are approaching the end of their useful service life. It is worth noting that ORPC's fleet vehicles are replaced according the Maximum useful life criteria established by the Kinectrics Report, representing best industry practices. Fleet vehicle replacements are planned around core distribution system asset replacements, in order to smooth annual budget requirements. Maintaining a healthy vehicle fleet supports public and employee safety, and ensures that capital, maintenance and operational jobs are conducted efficiently.

2. Safety

Replacing aging fleet vehicles supports the overall safety of employees and the general public. New Safety features in newer models also improve workplace safety for employees and public.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

ORPC's fleet vehicles are suitable for facilitating distribution line-work on both ORPC's distribution system and on that owned by neighbouring distributors. As such, ORPC's fleet vehicles are available for emergency mutual assistance support to all neighbouring distributors.

5. Economic Development

Fleet vehicles are sourced mainly through Ontario suppliers, who often utilize Ontario manufacturers. Any necessary repairs or maintenance work to fleet vehicles is performed locally. As such, this investment will support the local and provincial economy.

6. Environmental Benefits

The replacement of aging fleet vehicles will reduce overall gas emissions, as new vehicle designs offer improved emission control systems, reduce fuel costs, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

Category-specific requirements for each project/activity

General Plant: Traditional work practices involved manual climbing of poles, and handling of pole line hardware. Fleet vehicles allow employees to utilize more efficient and safe work practices when constructing, maintaining or operating distribution systems. ORPC views fleet vehicles as essential tools that allow employees to work in a safe and efficient manner. All fleet vehicles are carefully selected to ensure that they meet the needs of the local distribution environment. All customers across all customer classes will benefit from these investments.

Transformer Station #8 - Power Transformer Fire Barrier

Investment Category: System Service		**Project Start Date:** Jan.1, 2017
Project Title: Transformer Station - Power Transformer Fire Barrier		**Project End Date:** Dec. 31, 2017
Asset Category(s): Station Buildings		**Project Driver(s)**: Business Objective - Reliability
USoA Account: 1808		USoA Cost Allocation: 1808 - $65,000

General information on the Project/Activity

ORPC has a power transformer at its Pembroke transformer station #8 which is in close proximity to an adjacent property. Recent discussions with its insurance carrier have identified that the transformers have the potential of causing structural damage in the event of a catastrophic failure, such as a fire. The main concerns are with containing a potential transformer fire, as well as containing propelled airborne debris. It has been recommended that a custom fire and blast retaining structure be built to isolate the units from one another. Although the probability of a critical failure is very low, the resulting impact of failure is very high.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USOA Account	Primary Investment Driver
2016	System Service		Transformer Fire Barrier	$62,000		Install fire and blast barrier between power transformer and adjacent building	1808	Obj - Reliability

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability
The main trigger of this project is to ensure that the overall long term reliability of ORPC's electrical distribution system maintained and due to the potential impact on customer and employee safety.

2. Safety
This project improves the protection of ORPC's transformer station equipment, which are relied upon to support the health, safety and well-being of all customers and employees.

3. Co-ordination, Interoperability
ORPC plans to implement a similar solution found at other LDC stations to resolve the potential hazard.

4. Economic Development
ORPC will rely on local material suppliers and contractors to construct the custom fire and blast retaining structure. This project will support both the local and provincial economy.

5. Environmental Benefits
This project is designed to contain a catastrophic failure of an oil filled power transformer. The nature of the project is to minimize the impact associated with a potential failure to its surroundings, which include the environment.

Category-specific requirements for each project/activity

System Service: The benefit of this project to customers is that it greatly reduces the probability of a catastrophic equipment failure from impacting the reliability of electricity distributed to them. The investment is essentially an insurance measure in support of the reliability of ORPC's distribution system as a whole. The nature of this project does not involve the deployment of advanced technology. The planning and coordinating of this project is estimated to take up to six months, which aligns its practical implementation with the summer of 2016.

The construction of a fire and blast retaining structure is by far the lowest cost solution to isolate the power transformers from the building. It is not practical to relocate the transformer or to alter the arrangement of existing equipment in the transformer station yard. As previously mentioned, this investment is a due diligence investment to reduce the probability of suffering extensive damage to transformer station property, neighbouring buildings and plant and equipment.

Station Independent Breaker Replacement

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2017
Project Title: Breaker Replacement		**Project End Date:** Dec. 31, 2019
Asset Category(s): Breakers		**Project Driver(s)**: End of Service Life - Failure Risk
USoA Account: 1820		USoA Cost Allocation: 1820 - $108,000

General information on the Project/Activity

ORPC owns and operates several distribution substations. The asset management process has identified the stations main Oil Filled Circuit Breakers (OCB) have surpassed their Maximum Useful Life of 65 years, as established in the Kinectrics Report. As the breaker is responsible for protecting the entire station in the event of a critical failure (fault), it has a high impact of failure. Condition tests indicate that the unit is operating at an acceptable level; however, expert advice recommends that the device be replaced by 2017.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USOA Account	Primary Investment Driver
2017	System Renewal		1947 OCB Replacements	$108,000		Replace end of life station independent breaker at Transformer Station	1815	EOL- Failure Risk
2019	System Renewal		1947 OCB Replacements	$108,000		Replace end of life station independent breaker at Transformer Station	1815	EOL- Failure Risk

Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger for this project revealed the unit has surpassed its maximum suggested service life, as established by the “Kinectrics Report”. The device is not conducive to running to failure, as that would compromise the protection of the entire transformer station. As the device ensures the overall safety of transformer station property, plant, equipment and personnel, it has been assigned replacement priority for 2018 capital projects. The investment will support ORPC’s ability to safely, reliably and efficiently distribute electricity to all of its customers. As such, all customers in all customer classes will benefit from this investment.

2. Safety

This investment ensures that the safety of transformer station property, plant, equipment and personnel are maintained.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

Coordinating the breaker replacement will involve joint planning with the regional transmitter HONI, as well as with IESO. All regional stakeholders will be involved in the replacement planning process to ensure proper interoperability.

5. Economic Development

This investment will utilize local and regional labour, as well as all material will be sourced through local or regional suppliers. As such, this project will benefit both the local and provincial economy.

6. Environmental Benefits

This project will reduce the risk of environmental incidents associated with equipment failures at the transformer station.

Category-specific requirements for each project/activity

System Renewal: The OCB's are not conducive to running to failure as their failure compromises the overall wellbeing of the transformer station it is designed to protect. ORPC's asset management process has revealed that the unit has surpassed its maximum useful life of 65 years, and therefore poses a high risk of failure. Expert advice suggests that the unit be replaced by 2017, and as such ORPC has planned accordingly. The device has the potential of impacting the performance of ORPC's entire distribution system and is therefore by nature very important. Planning for the replacement is expected to require at least one year.

System Access - Residential

Investment Category: System Access		Project Start Date: Jan.1, 2015
Project Title: Various Subdivisions		**Project End Date:** Dec. 31, 2019
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. 2015 - 2019 Cap. Cost:** $1.673,800	USoA Cost Allocation: Various

General Information on the Project/Activity

ORPC is obligated under the DSC to connect new customer services that are funded through contributed capital. This includes **new subdivision developments.**

Evaluation criteria and information requirements for each Project/Activity

ORPC will energize new developments and connect services as the houses are constructed; Property Townhomes and other multi resident buildings. Also, ORPC will connect services for previously energized subdivisions.

1. Efficiency, Customer Value, Reliability
The infrastructure for these developments will be installed in a joint use trench during the construction of this development. This allows for reduced installation costs to the developer and all joint use trench parties.

2. Safety
The design and equipment installed for this project meet current standards.

3. Economic Development
The assets installed in this project will service the existing development as well as future developments in the area.

4. Environmental Benefits
By installing new customers onto the 12kV system, the line losses are reduced on the primary distribution system as compared to connecting customers to our legacy 4kV infrastructure.

Category-specific requirements for each Project/Activity

ORPC is obligated under the DSC to connect new customer services that are funded through contributed capital.

System Access - Commercial

Investment Category: System Access		**Project Start Date:** Jan.1, 2015	
Project Title: Various Commercial		**Project End Date:** Dec. 31, 2019	
Asset Category(s): Various		**Project Driver(s)**: Various	
USoA Account: Various	**Tot. 2015 - 2019 Cap. Cost:** $545,500	USoA Cost Allocation: Various	

General Information on the Project/Activity

ORPC is obligated under the DSC to connect new customer services that are funded through contributed capital. This includes **new commercial developments.**

Evaluation criteria and information requirements for each Project/Activity

ORPC will energize new commercial facilities and connect services as the facilities are constructed

1. Efficiency, Customer Value, Reliability
The infrastructure for these developments will be installed in a joint use trench during the construction of this development. This allows for reduced installation costs to the developer and all joint use trench parties.

2. Safety
The design and equipment installed for this project meet current standards.

3. Economic Development
The assets installed in this project will service the existing development as well as future developments in the area.

4. Environmental Benefits
By installing new customers onto the 12kV system, the line losses are reduced on the primary distribution system as compared to connecting customers to our legacy 4kV infrastructure.

Category-specific requirements for each Project/Activity

ORPC is obligated under the DSC to connect new customer services that are funded through contributed capital.

Misc. Small Capital Projects

General information on the Project/Activity

ORPC's asset management process annually identifies assets that are at the end of their useful service life based on an age, inspection and condition testing analyses. Most of the small capital projects listed below are driven by the need of sustaining the lifecycle of existing assets owned. Non-lifecycle related investments are driven by ORPC's capital planning process, to accomplish other business objectives such as improving business efficiency or meeting customer expectations.

The following tables summarize the planned small capital activities for 2015 – 2019.

Investment Category: Various		**Project Start Date:** Jan.1, 2015
Project Title: **2015 Misc. Small Capital Projects**		**Project End Date:** Dec. 31, 2015
Asset Category(s): General Plant Maintenance and System Service		**Project Driver(s)**: Various
USoA Account: Various	**Total Capital Cost: 285,250**	USoA Cost Allocation: Various

Investment Category	Investment Description	Account	Total	Notes
General Plant	CS Carpet	1808	$8,000	CS Carpet
General Plant	Fire Alarm	1808	$38,000	
General Plant	Garage Floor Repl	1808	$31,000	Garage Floor Replacement
General Plant	Garage roof	1808	$7,000	Garage roof
General Plant	Misc Small Tools	1940	$10,000	
General Plant	Misc Software Upgrades	1925	$9,000	
General Plant	Misc Software Upgrades	1925	$10,000	
General Plant	Mobile radio	1955	$1,200	
General Plant	Office Façade	1808	$12,000	Windows and Repaint French Balconies
General Plant	PC Upgrade	1920	$10,000	
General Plant	Replacement Furniture	1915	$5,000	Front office
General Plant	Stores Door Replacement	1808	$5,000	Stores Door
General Plant	Stores shelving	1808	$5,000	Stores shelving
			$151,200	
System Renewal	Pembroke Substation Condition assesm	1820	$12,500	Condition Assesment
System Renewal	Pembroke Substation testing	1820	$12,000	Pembroke Substations
System Renewal	Pembroke Substation #3 - 44 kV Structur	1830	$9,750	Replace South pole structure
System Renewal	Smart Meters Collectors	1860	$17,700	10 Pembroke, 2 Beachburg
System Renewal	Smart Meters Intervals	1860	$14,600	18 units to replace
			$66,550	
System Service	Electronic Protective relays	1820	$16,500	
System Service	ESRI - mobile mapping	1925	$15,000	Lakeland Power
System Service	Outage Management	1980	$8,000	Locate faults and Voltage sensing devices
System Service	Outage Management	1980	$7,500	Collect metering points (collector near recloser) to display outage info
System Service	Overhead line Fault indicators	1835	$13,500	
	SCADA connections Almonte MS-1	1980	$7,000	Almonte MS-1
			$67,500	
		Total	**$285,250**	

Investment Category: Various		**Project Start Date:** Jan.1, 2016
Project Title: **2016 Misc. Small Capital Projects**		**Project End Date:** Dec. 31, 2016
Asset Category(s): Various		**Project Driver(s):** Various
USoA Account: Various	**Tot Cap. Cost:** $424,100	USoA Cost Allocation: Various

Investment Category	Investment Description	Account	Total	Notes
General Plant	Misc Small Tools	1940	$10,000	
General Plant	Misc Software Upgrades	1925	$9,000	
General Plant	Misc Software Upgrades	1925	$10,000	
General Plant	Mobile radio	1955	$1,200	
General Plant	PC Upgrade	1920	$10,000	
General Plant	Replacement Furniture	1915	$8,000	Front office
			$48,200	
System Renewal	Pembroke Substation testing	1820	$29,000	Pembroke Substations
System Renewal	Pole Replacement	1830	$46,000	Scattered pole replacement
System Renewal	Pole Replacement - Line betterments	1830	$14,200	misc Related line betterments
System Renewal	Pole Replacement - Line betterments	1830	$14,200	Fisher Street to Trafalgar Related line betterments
System Renewal	Pole Replacement - Line betterments	1830	$11,700	Sub 4 behind Remi auto Related line betterments
System Renewal	Pole Replacement - Line betterments conductors	1835	$44,500	Conductors Related to line betterments
System Renewal	Pole replacement Bell Killaloe	1835		BELL
System Renewal	Pole Replacement	1850	$9,500	transformers related to Scattered pole replacement
System Renewal	Pole Replacement - Line betterments transformers	1850	$10,000	Transformers Related to line betterments
			$179,100	
System Service	Almonte MS-2 44 kV conductor upgrades	1835	$58,100	44 kV MS-2 to river xcing
System Service	Almonte MS-2 44 kV pole upgrades	1830	$27,100	44 kV MS-2 to river xcing
System Service	Almonte Feeder MS-2 (2F2) conductor upgrades	1835	$0	MS 2 Feeder Cable 2F2
System Service	Almonte Feeder Reclosing relay MS 2	1835	$24,300	Almonte Sub 2 Feeders
System Service	Almonte Feeder Reclosing relay MS 3	1835	$18,500	Almonte Sub 3 Feeders
System Service	Almonte MS 3 feeder cables	1835	$14,300	Almonte Sub 3 Feeders
System Service	Electronic Protective relays	1820	$16,500	
System Service	Pembroke Substation MS 2	1808	$38,000	Sub 2 Control building
			$196,800	
		Total	**$424,100**	

Investment Category: Various		**Project Start Date:** Jan.1, 2017
Project Title: **2017 Misc. Small Capital Projects**		**Project End Date:** Dec. 31, 2017
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. Cap. Cost:** $219,700	USoA Cost Allocation: Various

Investment Category	Investment Description	Account	Total	Notes
General Plant	Office/Museum Paving	1908	$ 15,000	Paving under link and storm inlet
General Plant	Parking Lot Repaving	1908	$ 25,000	Parking Lot Pavement
General Plant	Office/Museum HVAC	1908	$ 15,000	Office/Museum HVAC
General Plant	PC Upgrade	1920	$ 10,000	
General Plant	Misc Software Tools	1925	$ 5,000	
General Plant	Misc Small Tools	1940	$ 10,000	
General Plant	Replacement Furniture	1915	$ 4,000	Furniture Replacement
General Plant	Mobile Radio	19550	$ 1,200	
			$ 85,200	
System Access	Smart Meters Residential	1860	$ 10,500	50 New Meters
			$ 10,500	
System Renewal	Pole Replacement -Line Work	1835	$ 14,200	Conductors Related to Line Beterments
System Renewal	Sub 6 Foundation	1808	$ 25,000	Sub 6 Building Repairs
System Renewal	UG Feeder on Melton	1845	$ 21,450	
System Renewal	Underground Cable	1845	$ -	Testing and Replacement
System Renewal	Underground Duct	1840	$ -	Replace Big O
System Renewal	Smart Meter Replacements	1860	$ 35,500	Approx 150-200 Meters
			$ 96,150	
System Service	Sub Battery	1820	$ 11,350	Sub
System Service	Electronic Protective Relays	1820	$ 16,500	
			$ 27,850	
			$ 219,700	

Investment Category: Various		**Project Start Date:** Jan.1, 2018
Project Title: **2018 Misc. Small Capital Projects**		**Project End Date:** Dec. 31, 2018
Asset Category(s): Various		**Project Driver(s):** Various
USoA Account: Various	**Tot. Cap. Cost:** $226,550	USoA Cost Allocation: Various

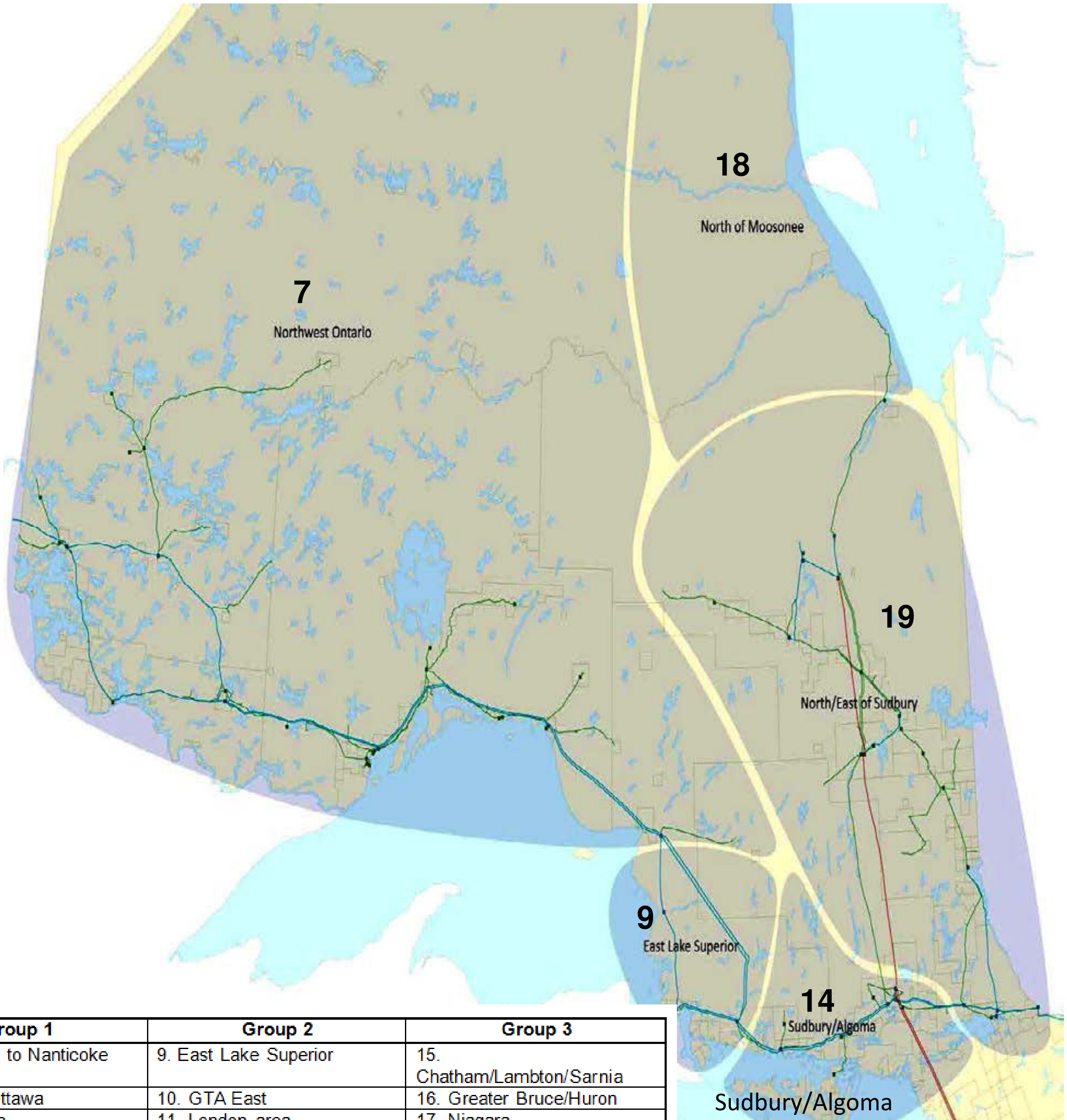
Investment Category	Investment Description	Account	Total	Notes
General Plant	PC Upgrade	1920	$10,000.00	
General Plant	Misc Software Upgrades	1925	$5,000.00	
General Plant	Misc Small Tools	1940	$10,000.00	
General Plant	Replacement Furniture	1915	$4,000.00	Furniture Replacement
General Plant	Mobile Radio	1955	$1,200.00	
			$30,200.00	
System Access	Smart Meters Residential	1860	$10,500.00	50 New Meters
			$10,500.00	
System renewal	Pole Replacement	1830	$47,500.00	Scattered pole replacement
System renewal	Pole Replacement	1830	$46,000.00	misc Related line betterments
System renewal	Pole Replacement-Line Work	1835	$14,200.00	Conductors Related to line betterments
System renewal	Smart Meter replacements	1860	$35,500.00	Approx 150-200 Meters
			$143,200.00	
System Service	Sub Battery	1820	$11,350.00	Sub
System Service	Sub 3 Vector Correction	1820	$5,800.00	Labour and contracts
System Service	Sub 4 PT	1820	$9,000.00	Re-locate PT to allow for 3 meter clearances
System Service	Electronic Protective relays	1820	$16,500.00	
			$42,650.00	
		Total	**$226,550**	

Investment Category: Various		**Project Start Date:** Jan.1, 2019
Project Title: **2019 Misc. Small Capital Projects**		**Project End Date:** Dec. 31, 2019
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. Cap. Cost:** $222,900	USoA Cost Allocation: Various

Investment Category	Investment Description	Account	Total	Notes
General Plant	PC Upgrade	1920	$10,000.00	
General Plant	Misc Software Upgrades	1925	$5,000.00	
General Plant	Harris CIS Upgrades 6.40	1925	$22,000.00	Harris +ORPC Labour
General Plant	Misc Small Tools	1940	$10,000.00	
General Plant	Replacement Furniture	1915	$4,000.00	Furniture Replacement
General Plant	Mobile Radio	19550	$1,200.00	
			$52,200.00	
System Access	Smart Meters Residential	1860	$10,500.00	50 New Meters
			$10,500.00	
System renewal	Pole Replacement	1830	$48,000.00	Scattered pole replacement
System renewal	Pole Replacement	1830	$46,000.00	misc Related line betterments
System renewal	Pole Replacement-Line Work	1835	$14,200.00	Conductors Related to line betterments
System renewal	Smart Meter replacements	1860	$35,500.00	Approx 150-200 Meters
System renewal	Transformer Replacement Program	1850	$0.00	407 pole and 129 Pad mounts
			$143,700.00	
System Service	Electronic Protective relays	1820	$16,500.00	
			$16,500.00	
		Total	**$222,900**	

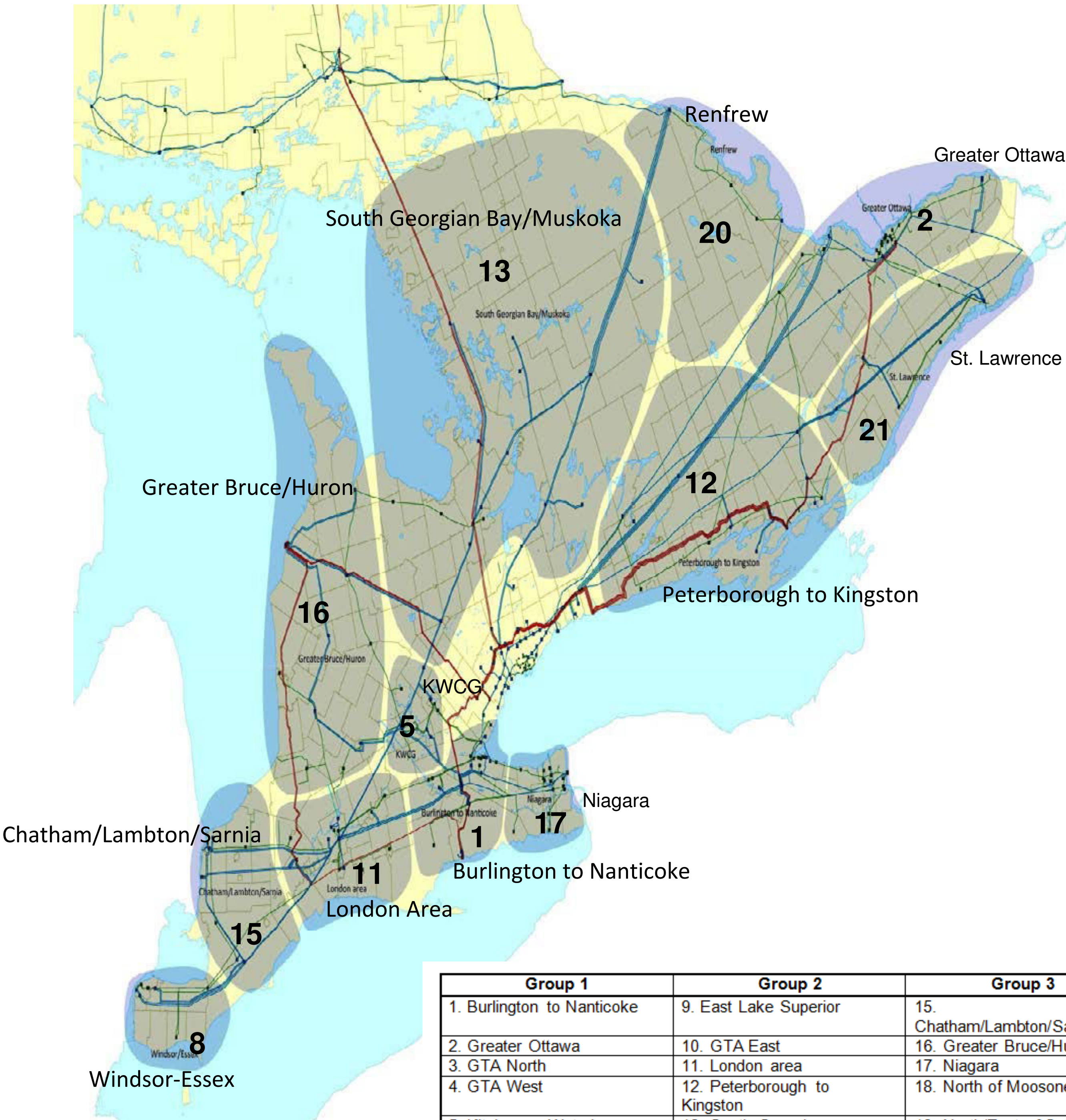
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



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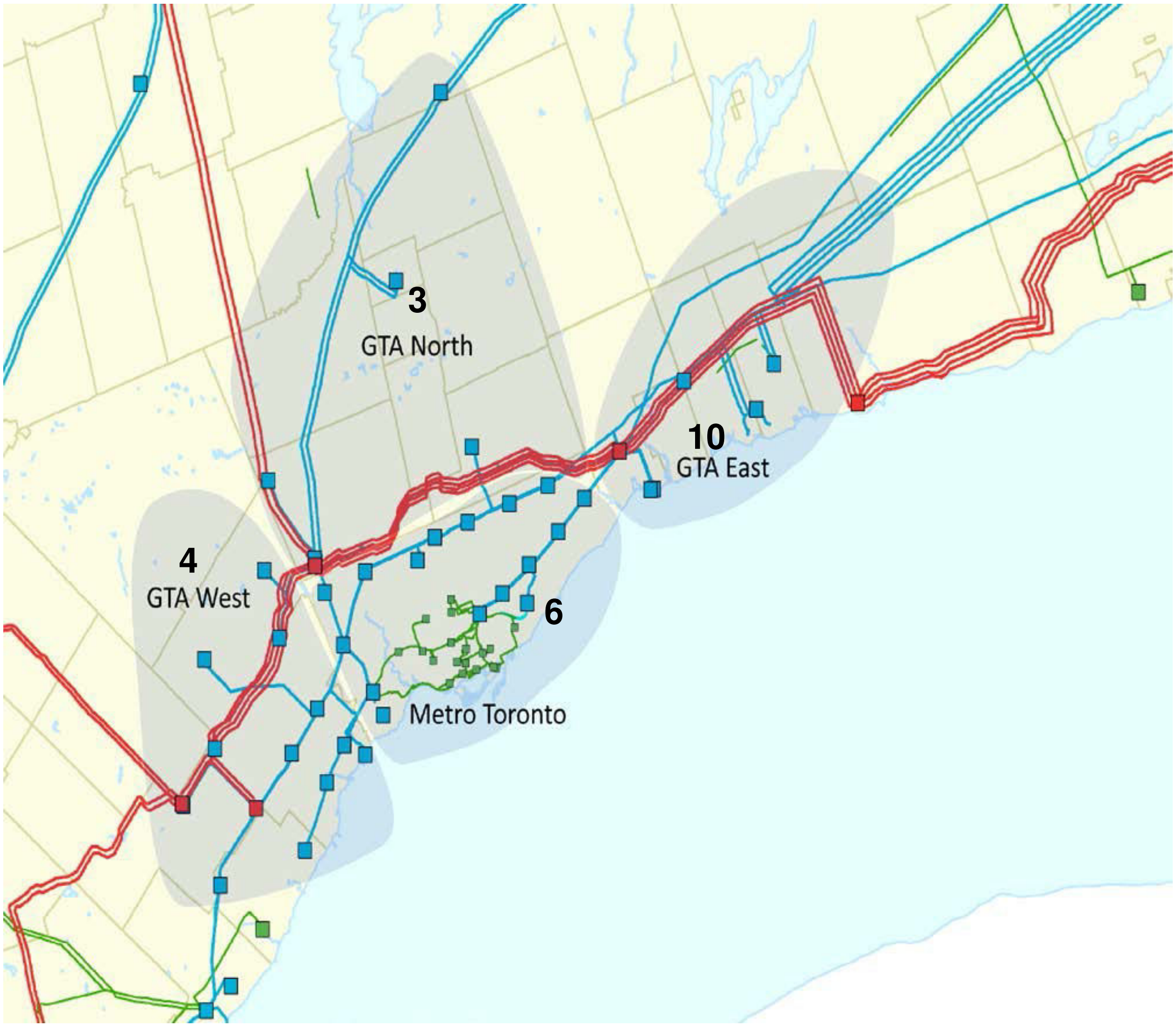
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
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6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

<u>Appendix B</u>: <u>List of LDCs for Each Region</u>

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One’s territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc*. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. *Changes to the May 17, 2013 OEB Planning Process Working Group Report.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Ottawa River Power

OPA Letter of Comment

Ottawa River Power Corporation

Renewable Energy Generation Investments Plan

November 25, 2014

ONTARIO
POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Ottawa River Power Corporation – Distribution System Plan

On October 23, 2014 Ottawa River Power Corporation ("ORPC") provided its Renewable Energy Generation Investments Plan ("Plan") to the OPA as part of its 5-year Distribution System Plan. The OPA has reviewed ORPC's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

On page 5 of its Plan, ORPC indicates that presently it has connected 28 microFIT projects, and 0 FIT projects. According to the OPA's information, as of October 2014, the OPA has offered contracts to 27 microFIT projects totalling 250 kW of capacity, and 0 FIT projects. The renewable energy generation connections information in ORPC's Plan is therefore consistent with that of the OPA.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes Ottawa River Power Corporation is part of "Group 3" and the Renfrew Region, and as an embedded distributor certain of its facilities were also considered as part of "Group 1" and the Greater Ottawa Region, specifically, the Outer Ottawa sub-region. The final Needs Screening Report was published on July 28, 2014, and the Working Group established for the Outer Ottawa sub-region identified no significant needs that impact ORPC at this time.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

On page 6 of its Plan, ORPC indicates that has been able to connect all microFIT applications received, but as an embedded distributor of HONI, it requires approval from the host distributor to connect projects greater than 10 kW. To date, ORPC indicates that it has no FIT connections and that 4 FIT requests were denied connecting to its distribution system due to upstream system constraints of HONI. These constraints were identified as upstream capacity constraints at HONI's Pembroke TS and Cobden TS related to Pembroke, Beachburg and Killaloe supply feeders. The OPA is aware of the constraints that ORPC has identified and notes that ORPC is working directly with HONI on issues related to regional planning.

Ottawa River Power Corporation states that its distribution system has been determined adequate to accept the renewable generation that is anticipated as there are no known barriers to connection renewable generation related to matters or facilities under its control. As a result, they propose no material REG investments over the 2014 to 2019 planning period.

In a regional planning status letter to ORPC dated November 3, 2014 HONI communicated that it intends to initiate planning of the Renfrew Region in either Q2 or Q3 2015.

At this time however, because neither a Regional Infrastructure Plan, nor an IRRP has commenced for ORPC's service territory that belongs to Group 3 in the Renfrew Region, the OPA has no comment on the following three items outlined in the Chapter 5 filing requirements, specifically:

- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The OPA looks forward to working with Ottawa River Power Corporation on regional planning once that process is triggered for the Renfrew area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

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Ottawa River Power Corporation

System Capability Assessment for Renewable Energy Generation

October 2014

Created and approved by: Denis Montgomery, President ORPC

Table of Contents

1 Introduction

The *Green Energy and Green Economy Act, 2009* ("the Act" or "GEA") was introduced in the Ontario legislature on February 23, 2009. Its intent was to expand renewable energy production and encourage energy conservation. Under the GEA, a number of feed-in tariff rates for different types of energy sources were created. Most notably, the microFIT program for small non-commercial systems under 10 kilowatts, and FIT, the larger commercial version which covers a number of project types with sizes into the megawatts. The objectives of the Act include the following;

- To stimulate energy conservation, through the establishment of programs and policies within the Ministry or such agencies as may be prescribed, load management and the use of renewable energy sources throughout Ontario;
- To encourage prudence in the use of energy in Ontario;
- To stimulate the planning and increase the development of infrastructure in Ontario, and
- To support planning and growth and building strong communities in Ontario.

Two other key elements of the Act include:

- To facilitate the implementation of a smart grid in Ontario; and
- To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

System capability assessment for renewable energy generation ("Assessment")

As part of the filing requirements, this section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

The herein Assessment is divided into two main sections:

- Section 1 describes the current assessment of the LDC's distribution system;

- Section 2 covers the planned development and costs to accommodate renewable generation over the next 5 years, including Renewable Enabling Improvements, such as SCADA and Smart Grid.

This Assessment provides summary information about current demands from generation, a description of the current efforts to enable renewable generation and future plans to accommodate anticipated new connections.

2 Current Assessment – Ottawa River Distribution System

Ottawa River Power Corporation (ORPC) relies on 195 KM of primary circuits to deliver 190,000,000 kWh of energy and 37,000 kW of winter peak power to approximately 10,800 customers in our service area. The primary circuits can be broken down into roughly 152 km of overhead lines and 41 km of underground conductor.

ORPC's service territory is surrounded by Hydro One Networks Inc. in all of its four service areas: Pembroke, Killaloe, Beachburg and Almonte. Ottawa River Power is directly connected to Hydro One's transmission system at 115 KV and 44KV and is not an embedded LDC that takes delivery of electricity from another LDC.

Ottawa River Power Corporation distributes power to its customers, which are comprised of primarily urban customers, through its municipally owned distribution substations.

Ottawa River Power Corporation has completed the installation of approximately 9,320 smart meters for residential and 1,315 smart meters for small commercial (GS<50kW) customers. ORPC intends to explore the potential use of the communication capability of the Smart Meter system to further improve customer service through more advanced outage detection and outage response.

Since the introduction of the Feed-in-Tariff (FIT) program, Ottawa River Power Corporation has connected a total of:

- 29 MicroFIT contracts
- 0 Fit contracts

microFIT Projects Processing	2010	2011	2012	2013	2014	Total
Total Numbers of Project Requests	17	34	3	19	3	79
Total Number of Projects connected	9	7	0	11	1	25

Two microFIT proposals are currently active for the Pembroke area.

Applicants over 10 kW

FIT Projects Processing	2010	2011	2012	2013	2014	
Total Numbers of Project Requests	1	2		1		
Total Number of Projects connected	0	0		0		

To date ORPC has been able to accommodate the connection of all microFIT applications that have been received. ORPC has had 79 requests to connect microFIT projects of which 47 have been cancelled or denied due to various reasons not related to connection constraints. ORPC has had 4 (four) requests to connect FIT projects which have been denied due to HONE constraints. The FIT projects mentioned were never registered with the OPA

The generator connection application process for ORPC customers' requires the involvement of HONI. The application process includes an internal review of applications by operations, engineering and metering departments. ORPC also requires approval from HONI for projects greater than 10kW for connection capacity, as HONI is the Host Distributor. This process should become streamlined; ORPC will complete the approval process in parallel with HONI's approval process. ORPC is aware of upstream capacity constraints at the HONI owned Pembroke TS and the Cobden TS, relating to the Pembroke, Beachburg and Killaloe supply feeders.
ORPC has limited penetration of its feeders to 10% of peak load for new generation. This is based on the 'Technical Review of Hydro One's Anti-Islanding Criteria for microFIT PV Generators' prepared by Kinectrics.
At this time ORPC is benchmarking the available generation capacity at 10% of the peak loading of each feeder.

The distribution system has been unaffected by the microFIT projects connected thus far. The number of connections has continued at a steady pace. ORPC settles sixteen (16) contracts at the initial rate of 80.2 cents, five (5) at 54.9 cents and the remainder at the current OPA price of 39.6 cents. It is likely that the rate of connections will decrease slightly due to the decrease in the contract pricing offered by the Ontario Power Authority and the overall lack of interest in the service territory.

Overall, Ottawa River Power's distribution system has been determined to be adequate to accept the renewable generation that is anticipated. There are no known barriers within ORPC's distribution system for projects that are serviced by its own municipal substations.

All of ORPCs feeders still have remaining capacity for FIT and microFIT installations.
4.16kV circuits are designed for smaller local loads which limits their ability to connect RG installation to smaller units such as those found on rooftops.

Based on the fact that there are no known barriers to renewable generation related to matters under the control of Ottawa River Power, the utility does not propose any material investments in renewable infrastructure. ORPC does not anticipate reaching photovoltaic generation connection limits on several of its distribution feeders over the 2014 to 2019 planning period.

System Limitations

The number of connections has not had any impact on the distribution system and therefore Ottawa River Power Corporation sees no apparent system limitations at this time. ORPC will continue to monitor feeder loading data to determine minimum feeder loads.

However, Regional Planning has identified Constraints that limit the connection of projects Greater than 10kW as previously mentioned and are described herein.

Capability to Accommodate Renewable Generation

- ### Hydro One Pembroke Transmission Station

ORPC is aware of upstream capacity constraints at the HONI owned Pembroke TS and the Cobden TS, relating to the Pembroke, Beachburg and Killaloe supply feeders due to Thermal Constraints.

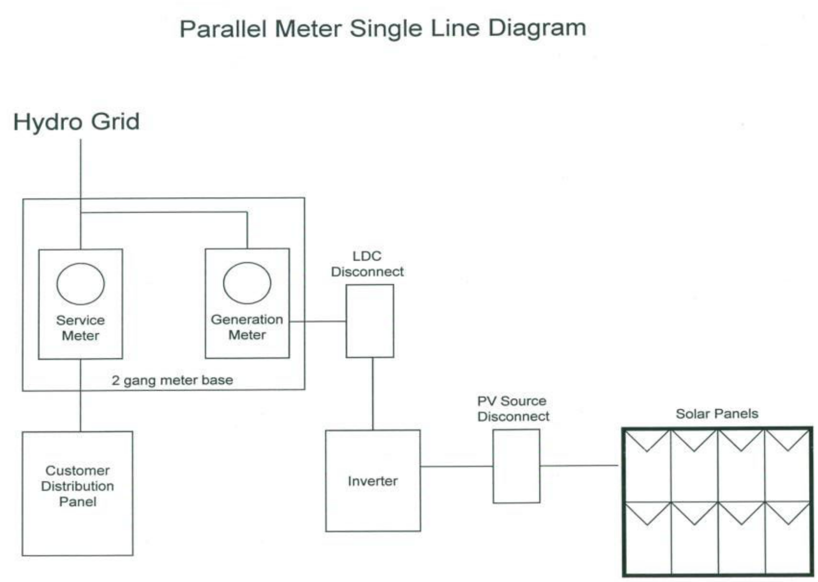
3 Anticipated Renewable Generation Connection Request

Given the level of interest expressed by Ottawa River Power Corporation's customers to-date, the forecasted of Micro-FIT applications is presented in Table 2 below. These numbers provided are speculative in nature, but they are based on experience dealing with customers over the past several years. 2014 has been forecasted higher than the following years. This year the largest shareholding municipality put micro-Fit projects on a number of their facilities. This will not repeat itself in the future.

Table 2 – Forecast of connections

Application Type	2014	2015	2016	2017	2018
Forecast microFIT Connections	7-10	4-5	4-5	4-5	4-5

Ottawa River Power Corporation expects the future micro-Fit connections to be accommodated with standard metering and connection techniques. An example is provided in the schematic below:



With respect to large scale projects, Ottawa River Power Corporation currently has no Fit connections. ORPC anticipates large scale fit projects connected in the Almonte area. In the event these projects do materialize, the utility generally has sufficient lead time to allow for an appropriate response by itself and Hydro One.

In conclusion, based on the anticipated uptake of the program and an assessment of the systems capacities, ORPC is forecasting sufficient capacity to accommodate the anticipated connections with the need to prioritize the projects.

Consultation with Affected Transmitter

Being an embedded utility, Ottawa River Power Corporation must consult with Hydro One on each connection request for projects greater than 10 kW. ORPC must complete a Connection Impact Assessment (CIA) for each project and this gives Hydro One an opportunity to assess and address capacity issues within its service territory. ORPC will continue to work co-operatively with Hydro One as new connections are added to the system.

Planned Development to accommodate Renewable Generation

As noted throughout this Renewable Energy Generation Plan, Ottawa River Power Corporation has not proposed any development or expansions of its distribution system in order to accommodate Renewable Generation.

Larger FIT projects will typically be installed by commercial and industrial customers with a large rooftop footprint. Therefore, applications received or expected within five years, will typically displace customer load at the host site and are not expected to be significant net-exporters of energy into the distribution system.

The interest in FIT and micro-FIT projects has been slow to moderate. Therefore, ORPC does not expect to reach the current available capacity for renewable generation in the near future.

Prioritization Method

Projects will be prioritized to align with the intent of the OPA FIT and microFIT programs. Prioritization of FIT projects is based on project application dates and the ongoing status of the new development. Ottawa River Power Corporation intends to prioritize and expedite renewable generation projects that are ready to connect to the distribution system.

Direct Benefits for Customers

Ottawa River Power Corporation is not proposing that any of its costs incurred to make eligible investments for the purpose of enabling the connection of renewable electricity generation be recovered from provincial ratepayers rather than solely from ORPC's ratepayers. It is therefore not necessary to calculate the direct benefits accruing to Ottawa River Power's customers.

Proposed Budget

There is no proposed budget with respect to connection of renewable generation under the FIT program. ORPC will undertake an annual review of the anticipated renewable generation connection project schedule as well as related costs.

4 Reporting

Ottawa River Power Corporation will review this document on a regular basis and will publish updates to this document as needed or required by the OEB. Once the OEB provides further direction as to the time and manner of Renewable Energy Plan reporting, indicated as pending in EB-2009-0397 (page 25), ORPC will comply with the OEB directives.

Ottawa River Power

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November 3, 2014

Denis Montgomery
President and CEO
Ottawa River Power Corporation
283 Pembroke Street West
Pembroke, Ontario, K8A 6Y6

Dear Mr. Montgomery**:**

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) Ottawa River Power Corporation (ORPC) belongs to the Renfrew Region, which is in Group 3. It is worth noting that some of your facilities as embedded LDCs may also fall within in Greater Ottawa Region which is in Group 1. A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

Group 1 – Greater Ottawa

Greater Ottawa region was divided into two sub-regions: Ottawa sub-region and Outer Ottawa sub-region. Planning activity for the Ottawa sub-region was already underway prior to the new Regional Planning (RP) process came into effect and led by the OPA. This planning process currently underway is deemed to be in the IRRP phase of the process.

The RP for the Outer Ottawa sub-region was initiated in Q1 of 2014 and the Needs Screening (NS) report (see attached Appendix C) for this sub-region. The report was published on Hydro One's Regional Planning website on July 28, 2014 in accordance with the regional planning process as set out in the OEB's Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board"[1].

ORPC is an embedded LDC in this region and did not directly participate in the planning process. The needs identified in the OPA-led IRRP process or NS led by Hydro One have not identified any significant need that may impact ORPC or result in any cost implications for ORPC.

Group 3 - Renfrew

This letter also confirms that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Renfrew region affecting the Ottawa River Power Corporation. I am expecting, as per the new process, that the regional planning for the Renfrew Region may be initiated in 2nd or 3rd

[1] Planning Process Working Group (PPWG) Report to the Board – May 17, 2013

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quarter of 2015. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

The new planning process provides flexibility during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with Ottawa River Power Corporation in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

Sincerely,
Ajay Garg, |Manager – Regional Planning Coordination|
Hydro One Networks Inc.

Cc:
Brad Colden, Manager – Key Accounts Manager

Background on Distribution Rates and 2015 Cost of Service Application

Ottawa River Power Corporation

How Does the Market Work?

Generation. Generators are the sellers in the Ontario electricity market. They communicate with the Independent Electricity System Operator (IESO) to make electricity offers.

Dispatch and settlement. The IESO forecasts how much power will be needed at a given time, and constantly monitors changes in demand. At five-minute intervals, the IESO balances supply with demand. As more electricity is demanded, more expensive offers from generators are accepted by the IESO.

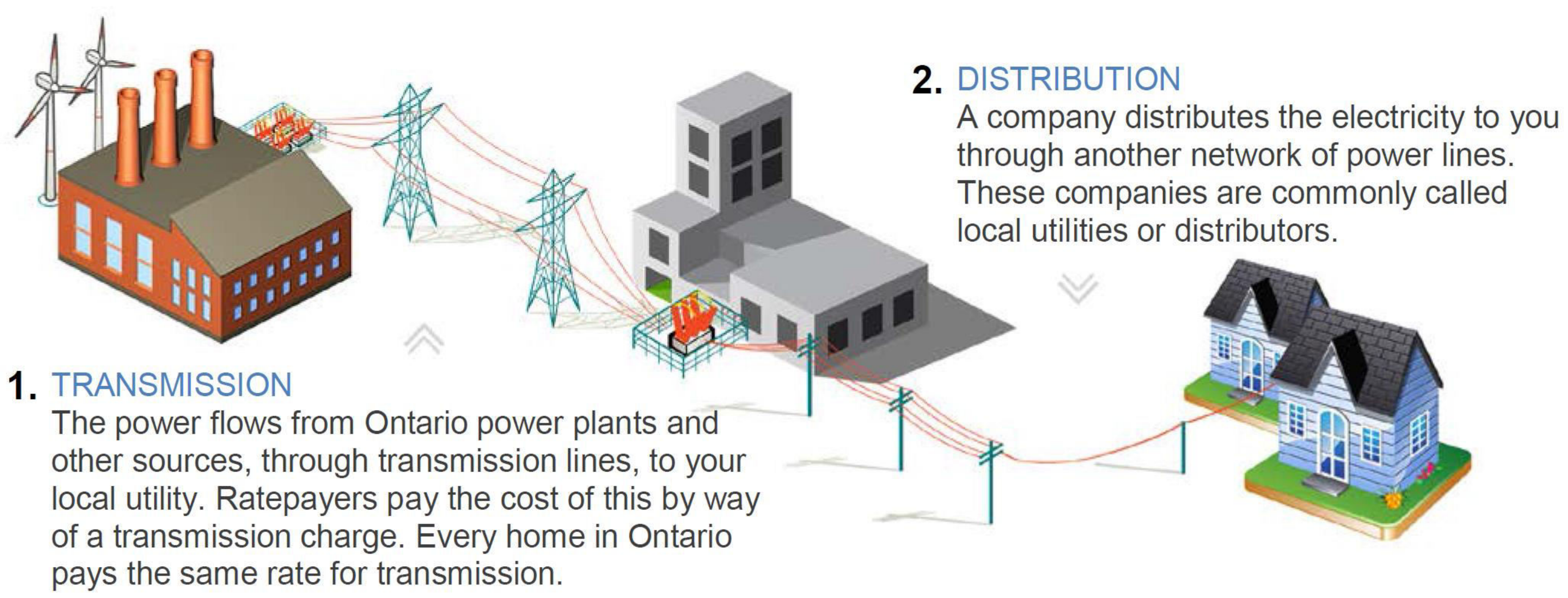
Each hour, the IESO takes the weighted average of these five-minute interval prices and sets the Ontario hourly spot price.

How Does the Market Work? (cont'd)

Flow of electricity. The physical energy is transmitted from generators to high-voltage transmission lines. Distributors then take the electricity from the transmission lines and deliver it to consumers in accordance with IESO directions.

Supply to consumers. The local distributor physically delivers the electricity and passes through the spot market price of the electricity directly to the customer. This is called Standard Supply Service (SSS, or "default service").

How Does the Market Work? (cont'd)



- The cost of both steps are added together and shown on the "Delivery" line of your electricity bill.

How Does the Market Work? (cont’d)

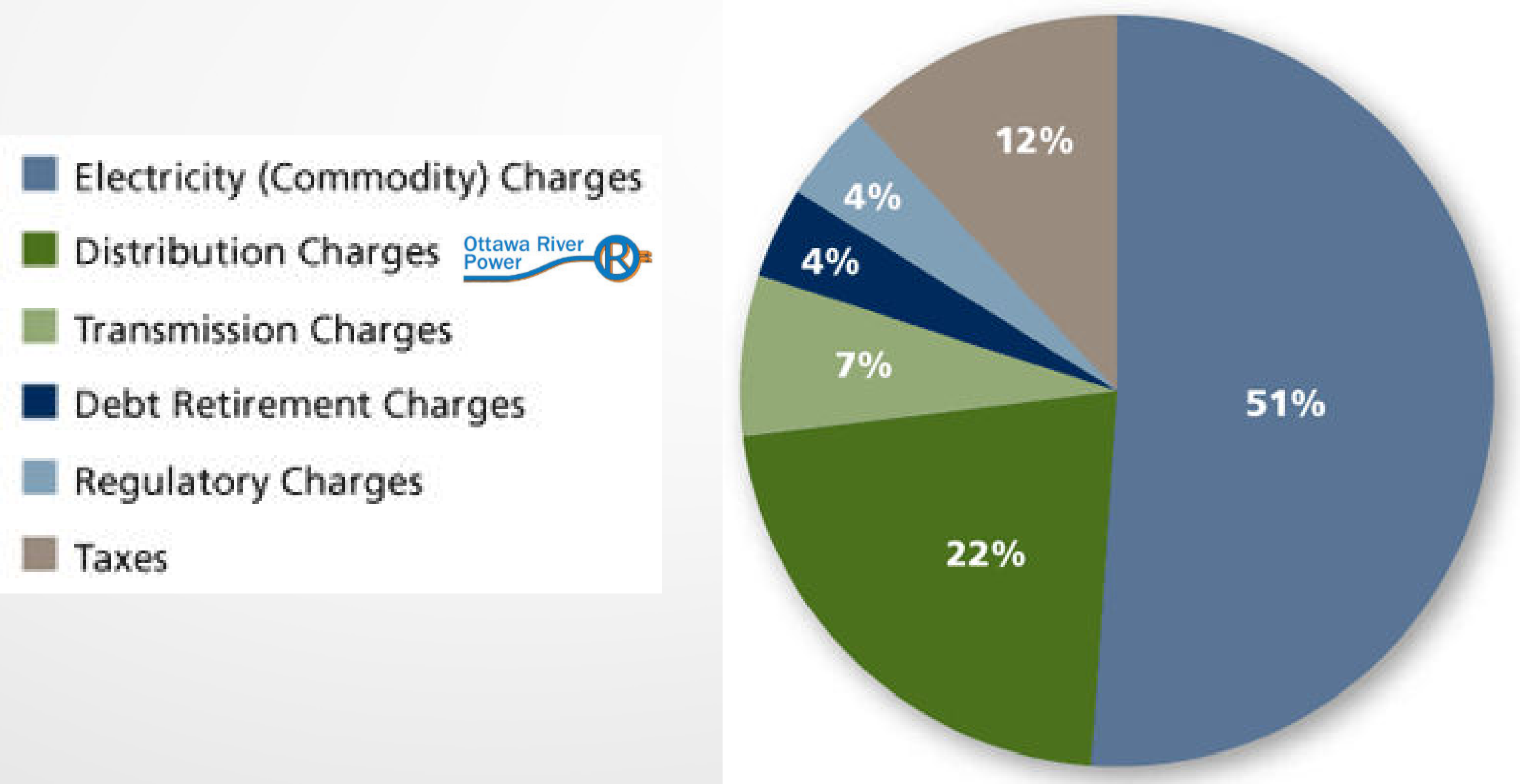
Your electricity bill is broken down into separate charges for:

- Electricity - charges related to the energy consumed;
- Delivery (Distribution+Transmission) - The cost of delivering electricity from generators to transmitters and distributors;
- Regulatory - The cost of administering the wholesale electricity system and maintaining the reliability of the provincial grid;
- Debt Retirement Charge - Set by the Ministry of Finance to pay down the residual stranded debt of the former Ontario Hydro.

The charge for the electricity commodity, which is roughly half of a customer’s bill, is a price set in the competitive market. In contrast, the charge for electricity distribution and transmission are regulated and approved by the OEB.

Understanding your electricity bill

63% of delivery goes to ORPC (or $22.99 on an average bill)



ORPC Residential Bill Calculations Over Time (800 Kwh monthly bill)

	1-May-09	1-Jan-11	1-May-13	1-May-14	Change from 2009 to 2014
Electricity	$ 49.46	$ 54.54	$ 67.14	$ 73.97	49.56%
Delivery	$ 29.78	$ 15.73	$ 34.12	$ 36.52	22.63%
Regulatory	$ 5.65	$ 3.41	$ 4.90	$ 4.99	-11.68%
Debt Retirement	$ 3.92	$ 3.92	$ 3.92	$ 3.92	0.00%
ON Clean Energy Bill		$ (8.77)	$ (12.44)	$ (13.49)	
	$ 88.81	$ 68.83	$ 97.64	$ 105.91	19.25%
HST	$ 11.55	$ 10.09	$ 14.31	$ 15.52	34.37%
Total Bill	$ 100.36	$ 78.92	$ 111.95	$ 121.43	20.99%

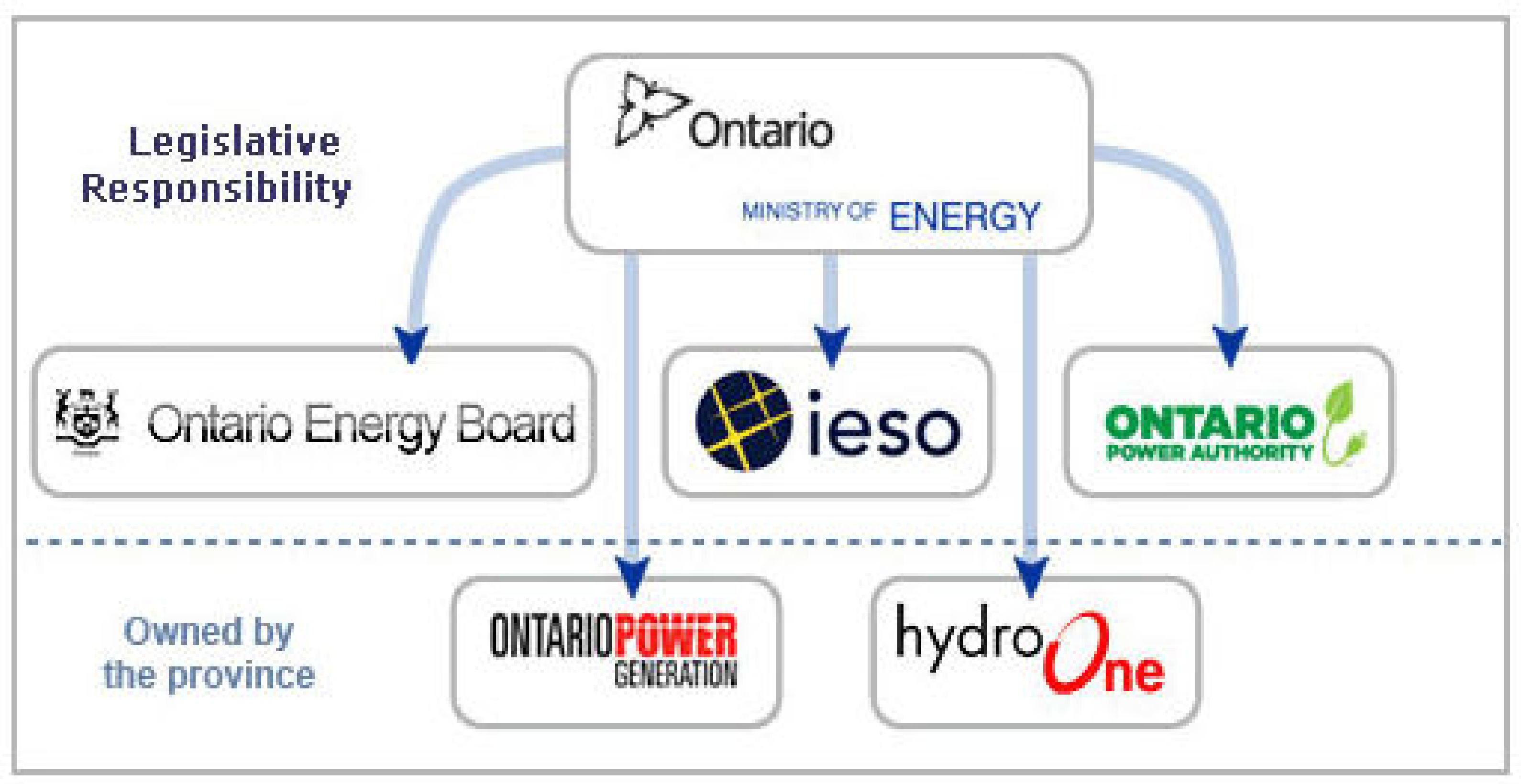
** Variance account refund ($15.76)*

** ORPC % of total is 19.25% ($20.39)*

Ontario Energy Board Scorecards

- The new industry-wide scorecard reports on the cost efficiency and performance effectiveness of all 73 of Ontario's Local Distribution Companies (LDCs).
- ORPC ranks **third lowest** in total cost among the nine LDCs in Eastern Ontario.
- Under the OEB's key "total cost per customer" metric, which levels the playfield across companies by dividing the total cost of each by the total customers of each, **we rank 3rd ($505) for low Cost/Customer in Eastern Ontario** behind Hawkesbury ($284) and Rideau St. Lawrence ($489), where the highest of the group is $731.
- We rank **14th among all LDCs in Ontario** for Cost/Customer and Hydro One was 2nd highest at $1,046.
- For our Conservation & Demand energy savings, we have achieved 77.5% of our target.
- Not included to date is the savings from the High Performance New Construction Project at Algonquin College which will increase the above percentage to 92% .

The Ontario's Electricity Markets at a glance



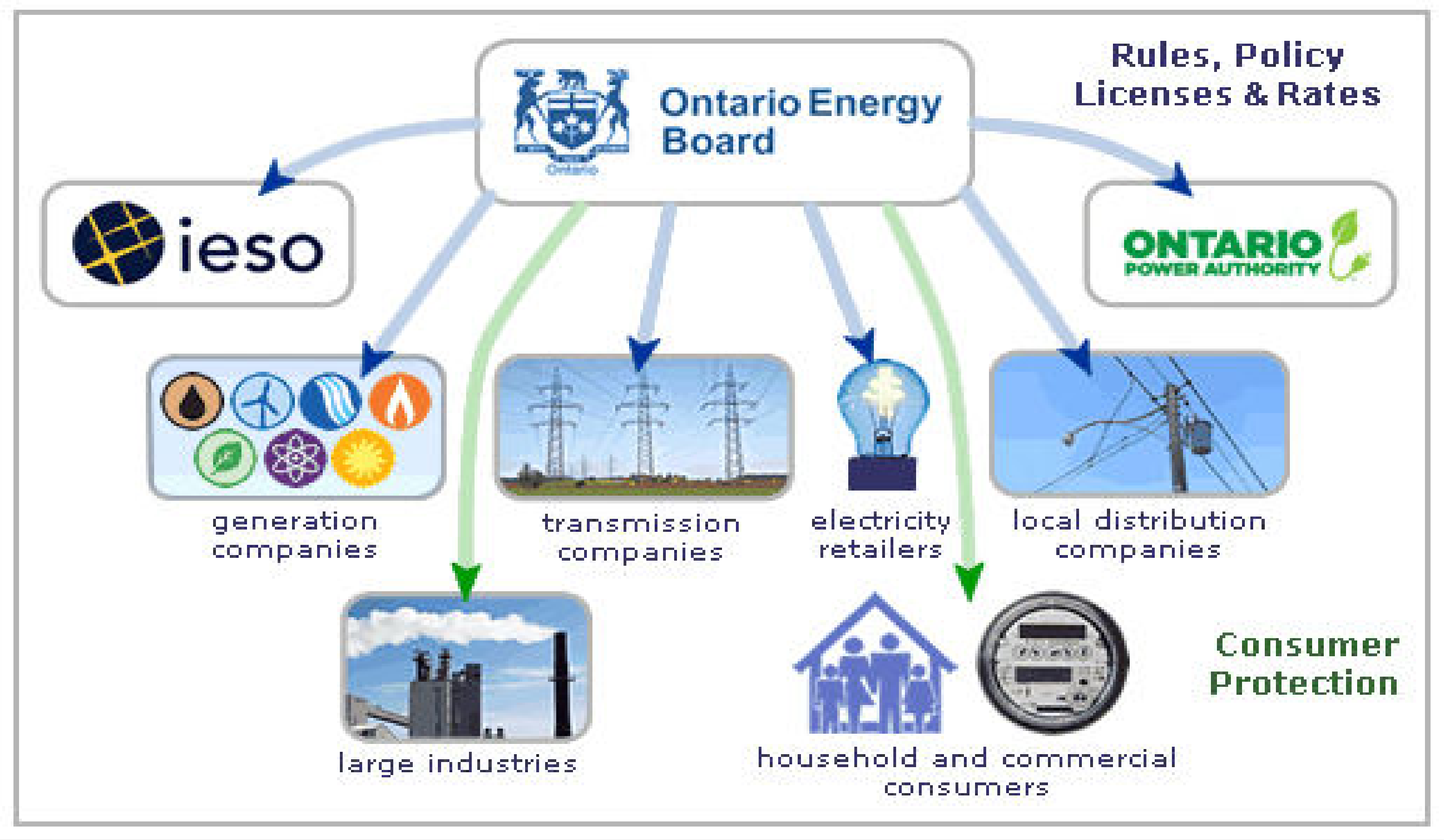
Who is the Ontario Energy Board?

Mandate of the OEB:

To regulate the province's electricity and natural gas sectors in the public interest.

- The Ontario Energy Board is the regulator of Ontario's natural gas and electricity sectors.
- The Ontario Energy Board creates and enforces rules for the electricity sector.
- The Ontario Energy Board regulates participants in the electricity sector, including distributors, transmitters, generators, retailers, wholesalers, smart sub-meterers, the Independent Electricity System Operator and the Ontario Power Authority.

Ontario Energy Board at a glance



How Rates are Set – the OEB's Role

In its role as regulator, the Ontario Energy Board sets electricity prices across the province.

Here is how the process works:

1. Each year, distributors apply to the Ontario Energy Board to change their rates.
2. The Ontario Energy Board reviews each rate application through a public process. Documents are posted on the Ontario Energy Board 's website and updated as the Ontario Energy Board reviews the application. Consumer groups and other affected groups may also take part in the process and provide comments. For larger or more complex cases, the hearing will include an open meeting which anyone can watch in person or listen to via webcast on the Ontario Energy Board's website.
3. The Ontario Energy Board decides whether or not to approve any or all of the application and then sets the rates for the distributor to charge.

Determining Distribution Rates
A Five-year Cycle

- Year <u>One</u> in the cycle is an intensive, public review of the utility's projected costs. This type of review is commonly called a **COST OF SERVICE** review. In any given year, roughly one-fifth of Ontario's 77 electricity distributors apply for a cost of service review.
- Years <u>Two to Five</u> will most commonly be formulaic rate increases - typically less than inflation. This encourages the utilities to manage their costs efficiently.

Overview of a Cost of Service Application

- An application for electricity rates is a legal process.
- A Cost of Service application take approximately 6 to 9 months to complete and contains over 250 separate schedules. An application is on average 800 to 1000 pages).
- Once the application has been submitted, the Ontario Energy Board then takes 6 months to process the application.
- The post filing process includes; 1 or 2 rounds of interrogatories, arguments, reply arguments, possible settlement conference and possible oral hearing.
- A panel appointed by the Ontario Energy Board approves the final rates through an Ontario Energy Board issued decision.

Overview of a Cost of Service Application(cont'd)

The basic format of an application for a Cost of Service filing include the following nine Exhibits:

- Exhibit 1 Administrative Documents
- Exhibit 2 Rate Base & Capital Expenditures
- Exhibit 3 Operating Revenue
- Exhibit 4 Operating, Maintenance and Administration Costs
- Exhibit 5 Cost of Capital and Capital Structure
- Exhibit 6 Calculation of Revenue Deficiency/Sufficiency
- Exhibit 7 Cost Allocation
- Exhibit 8 Rate Design
- Exhibit 9 Deferral and Variance Accounts

Administrative Documents
Exhibit 1

- This section of the application provides an overview of key elements of its application and its overall business strategy, including a narrative of how its approach supports specific outcomes established by the Ontario Energy Board.
- This section also covers customer engagement; and overview of the utility's costs, financial information and revenue sought in order to keep providing electricity to the customer.

Rate Base & Capital Expenditures Exhibit 2

Rate base is the value of property on which a utility is permitted to earn a specified rate of return. The Board expects that a distributor's investment plan will;

- optimize investment through a longer term, integrated approach
- reflect regional and smart grid considerations
- serve present and future customers
- place a greater focus on delivering value for money
- align distributor and customer interests
- support the achievement of public policy objectives

Operating, Maintenance and Administration (OM&A)Costs

- Most Cost of Service applications involve a cut to the OM&A
  - OM&A spendings are the first thing interveners will try to cut. Unlike Rate Base, every dollar cut in OM&A is a dollar cut in Revenue Requirement. Generally, interveners will try to cut Administrative cost as opposed to Operation and Maintenance.
  - In a settlement, envelope reductions to OM&A are the norm. (Generally, if a utility has more than two interveners in its application, the OEB will force a settlement conference as opposed to a written hearing.)

Capital Structure

The Ontario Energy Board determines the values for the Return on Equity ("ROE") and the deemed Long-Term and Short-Term debt rates for use in the 2015 cost of service applications.

The parameters above are collectively referred to as the Cost of Capital parameters. The Board has determined that the updated Cost of Capital parameters are as follows:

Cost of Capital Parameter	Value for 2014 Cost of Service Applications for rate changes in 2014
ROE	9.36%
Deemed LT Debt rate	4.88%
Deemed ST Debt rate	2.11%

Approval of Just and Reasonable Rates

- The OEB seeks and approves just and reasonable rates.
- The rates should generate sufficient revenue for the utility to cover the cost of providing safe, adequate and reliable services to its customers plus the opportunity to earn a fair rate of return on its investment.
- Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry.
- Earn a fair rate of return while recovering prudently incurred cost.

2015 Operating Expenses

- In its 2015 Cost of Service Application, Ottawa River Power Corporation is seeking to recover operating expenses 2015 costs in the amount of $3.1M. This represents a 2.6% increase from 2014 costs.

- This increase allows the utility to perform a wide range of activities in support of providing safe service at an appropriate level of reliability and quality that benefits its customers and stakeholders.

2015 Capital Expenses

Ottawa River Power Corporation is also seeking to recover capital expenses in the amount of 1.65M. This represents a 16% increase from 2014 costs.

These investments are necessary in order to:

1. Remain in compliance with Regulatory Operational Requirements
2. Support capital investment priorities in the Distribution System such as:
    - New load growth and development projects
    - Municipally driven projects
    - System Reliability
    - Infrastructure renewal projects
    - Elimination of environmental/health or safety risks

ORPC Capital Plan/Projects

5.2 Asset Management Process

Over the last year, ORPC has worked extensively on formalizing its asset management process and on preparing its first formal asset management plan. ORPC and its predecessors had been managing distribution assets in the City of Pembroke and the Towns of Almonte Beachburg and Killaloe since the early 1900's, long before the electrification of the Province as a whole occurred. Although ORPC has extensive experience managing assets, historically a formal process or plan was never documented. As such, this is ORPC's first attempt at formally documenting its Asset Management Process in alignment with the criteria set out in the OEB Chapter 5 document "Consolidated Distribution System Plan Filing Requirements". ORPC is very pleased with the OEB's impetus for distributors to develop Distribution System Plans. ORPC believes that its newly developed asset management and capital planning processes, which are at the heart of the DS Plan, will bring tremendous future value to its customers. The initiative will allow ORPC to transition from reactive short term planning (if it ain't broke don't fix it) and historic budgeting practices, to proactive long range planning and asset condition based budgeting.

5.2.1 Asset Management Process Overview

5.2.1.1 Asset Management Process Objectives

The overall objectives of ORPC's asset management process are to:

1. Enable wise decision making with respect to balancing cost, reliability and risk
2. Align spending decisions with corporate objectives
3. Enable multiyear planning based on rigorous data driven processes

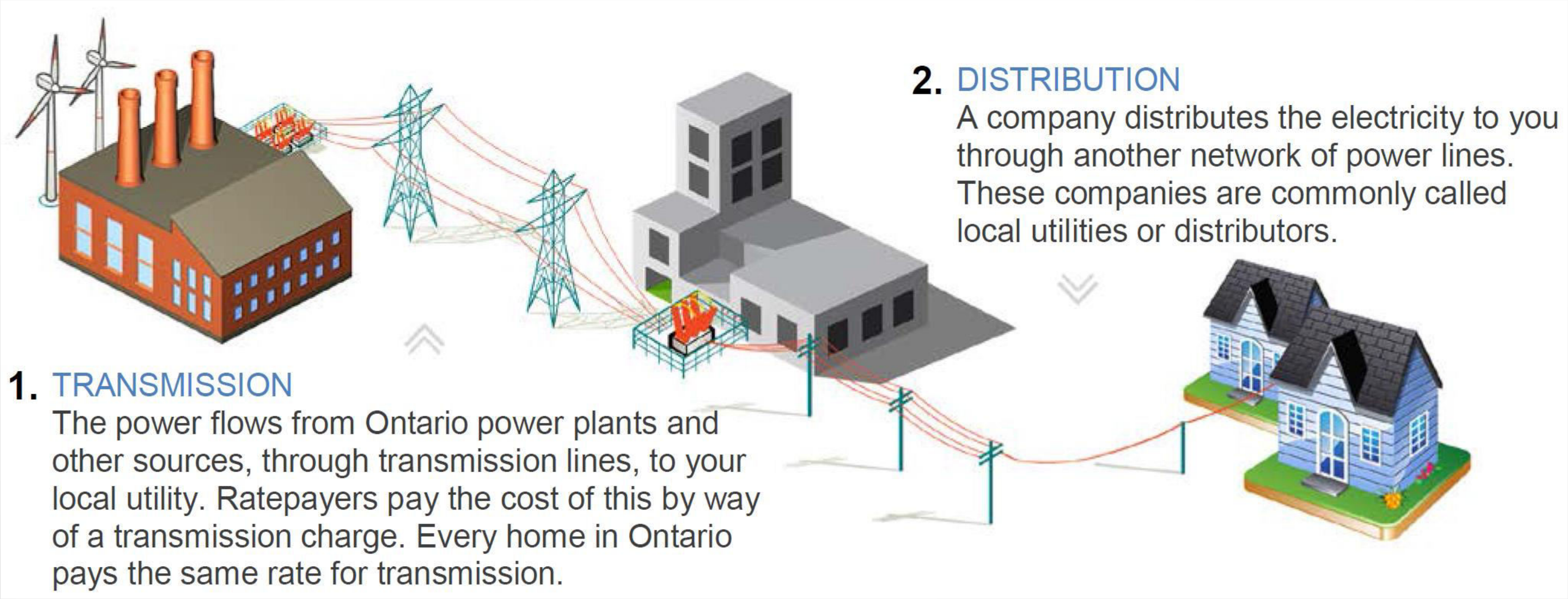
Asset Depreciation Study for the H – APPENDIX - DERIVATION OF USEFUL LIVES
Ontario Energy Board 12. Power Transformers
KINECTRICS INC - 61 - K-418033-RA-001-R000

- 12.3 Useful Life Based on the Industry Values and Utility Interviews the Useful Life Values, Minimum (MIN UL), Typical (TUL) and Maximum (MAX UL) for Power Transformers are displayed in Table 12-1.
- Table 12-1 Useful Life Values for Power Transformers

	MIN UL	TUL	MAX UL
Overall	3 0	45	6 0
Bushings	1 0	20	3 0

ORPC Capital Assets

So what are the assets that need to be maintained and upgraded?



ORPC Capital Assets Hydro Poles

TUL 45 yrs, MUL 75 yrs

IRFS - Ottawa River Power - Plant Statistics

Acct	Description		Pembroke	Almonte	Killaloe	Beachburg	Total
1830	Poles						
		Wood	3102	1037	316	465	**4,920**
		Less Bell	380	142	99		**621**
		Total Wood	2722	895	217	465	**4,299**
		Concrete	45				**45**
1860							

Age and Height Estimates

Wood Poles

Height	1960	1970	1980	1990	2000	2010	Total
30	20	40	17	0	0	0	77
35	150	225	225	200	80	23	903
40	500	500	450	156	100	20	1,720
45	0	50	160	500	500	80	1,290
50		10	20	30	20	3	89
55	15	20	60	40	10	2	147
60		2	18	15	7	1	43
65		2	6	9			17
70		1	4	4	3	1	13
	685	850	960	954	720	130	4,299
	16%	20%	22%	22%	17%	3%	100%
							4,299

Concrete Poles

Height	1960	1970	1980	1990	2000	2010	Total
45			20				20
55	25						25
	25	0	20	0	0	0	**45**

ORPC Capital Assets

	1940	1950	1960	1970	1980	1990	2000	2010	
Overhead Primary Lines and Bus (meters)									
	0.2%	11.3%	17.4%	27.3%	23.5%	14.2%	5.3%	0.7%	100.0%
1 Ph OH	128	5880	9075	14231	12228	7414	2769	341	52,065
2 PH OH	1	60	93	146	125	76	28	3	533
3 PH OH	232	10665	16461	25813	22180	13447	5023	618	94,441
44KV	45	2080	3211	5035	4326	2623	980	121	18,421
Spun Bus	28	1289	1990	3121	2682	1626	607	75	11,418
Open Bus	229	10523	16242	25468	21885	13268	4956	610	93,181

ORPC Capital Assets

	1940	1950	1960	1970	1980	1990	2000	2010	
Underground Primary Lines									
	0.0%	1.0%	0.0%	27.2%	22.3%	18.1%	23.6%	7.8%	100.0%
1 Ph UG	-	192	-	5,381	4,420	3,587	4,676	1,537	19,795
2 Ph UG	-	18	-	511	420	341	444	146	1,880
3 PH UG	-	33	-	911	748	607	791	260	3,350
Total									**25,026**

ORPC Capital Assets

	1940	1950	1960	1970	1980	1990	2000	2010	
OH Services (meters)									
1 Ph OH	233	10,740	16,577	25,995	22,337	13,542	5,059	623	95,106
3Ph OH	2	84	129	202	174	105	39	5	740
Total									**95,846**
UG Services (meters)									
1 PH UG	0	676	-	18,936	15,554	12,624	16,456	5,410	69656
3PH UG	0	13	-	358	294	238	311	102	1316
Total									**70,972**

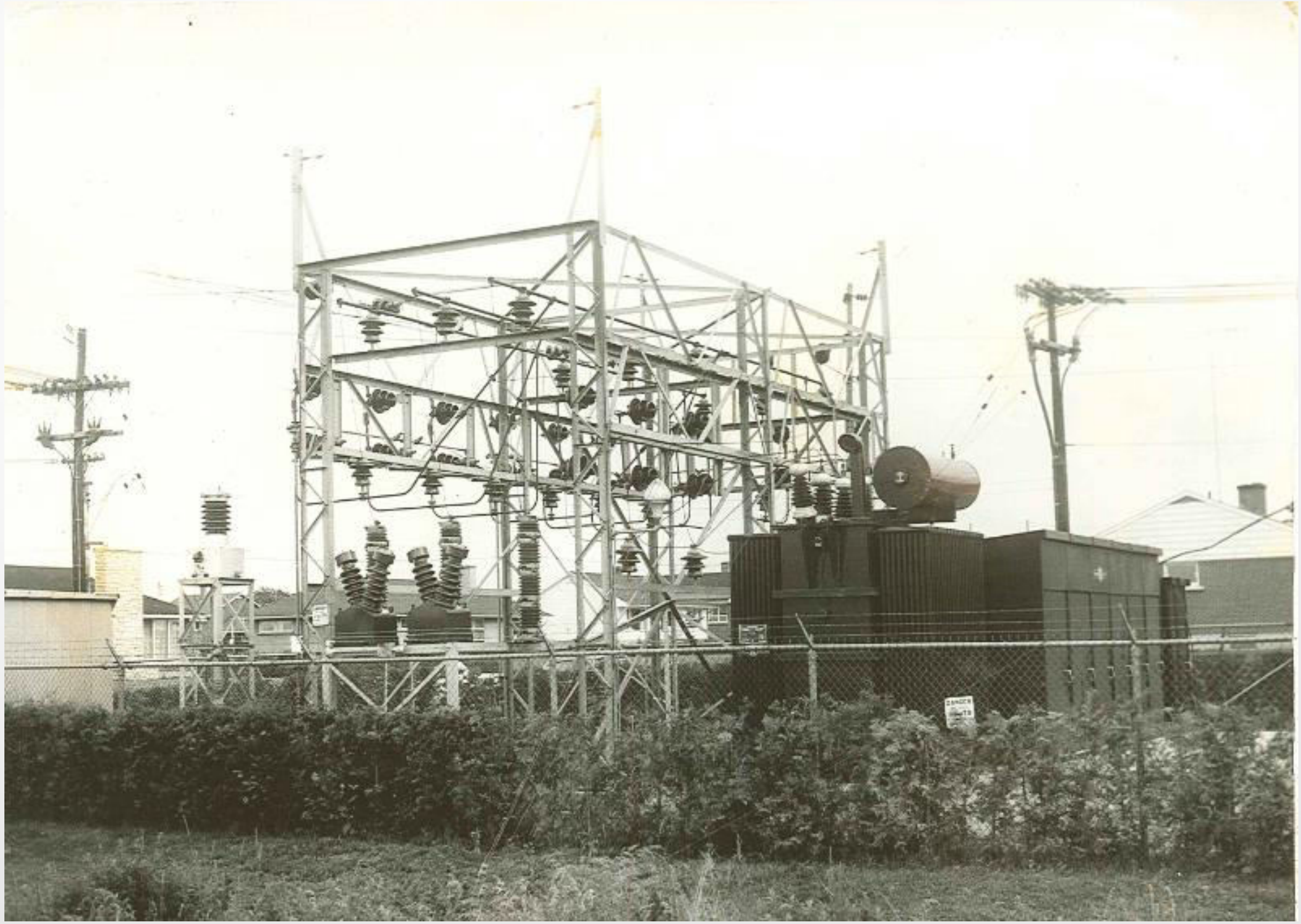
ORPC Capital Assets Substations MUL 55 years

Distribution Station Analysis **Allocation of Substation Cost**				
Substation	Year put in Service	Years in service	Cost	**Replacement cost 2014**
MS1	1962	52	$ 129,781.31	$ 1,286,259.80
MS2	1952	62	$ 1,244.28	$ 1,286,259.80
MS3	1957	57	$ 9,931.12	$ 1,286,259.80
MS4	1964	50	$ 98,003.83	$ 1,286,259.80
MS5	1969	45	$ 14,031.66	
MS6	1974	40	$ 222,509.68	$ 1,286,259.80
MS7	1974	40	$ 42,826.75	$ 1,286,259.80
MS8	1991	23	$ 440,739.71	$ 1,286,259.80
MS1 - Almonte	2010	4	$ 609,472.69	$ 1,100,025.34
MS2 - Almonte	1975	39		$ 1,100,025.34
MS3 - Almonte	1965	49		$ 1,100,025.34
			$ 1,568,541.03	$ 12,303,894.60

Note: It is assumed that the cost of equipment has increased by 20% per decade.

ORPC Capital Plan/Projects

- ORPC Substation 2



Substation 2 replacement
Constructed 1964
TUL of 40 years
MUL of 55 years

Ottawa River Power Corp
Distribution Station Analysis
MS4

Distribution Station	Sub Asset Description	Replacement cost	Replacement cost 2014
MS4	***Building and Infrastructure:***		
	Structure	$ -	$ 50,000.00
	Civil Work, Site:	$ -	$ 50,000.00
	Fencing		$ 30,000.00
		$ -	$ 130,000.00
	Distribution Station Equipment:		
	HV Switchgear, OCB	$ 142,560.00	$ 153,964.80
	Secondary Switchgear	$ 142,560.00	$ 200,000.00
	Substation Electrics	$ 131,576.40	$ 142,102.51
	Metering, Protection & Controls	$ 40,500.00	$ 43,740.00
	Fuses	$ 43,858.80	$ 47,367.50
	Grounding Grid	$ 43,858.80	$ 47,367.50
	Lightning Protection	$ 43,858.80	$ 47,367.50
	Battery Rack	$ 32,400.00	$ 34,992.00
	T&D Lines	$ 48,600.00	$ 52,488.00
	Prof. Fees	$ 80,435.16	$ 86,869.97
	Environment protection		100000
		$ 750,207.96	$ 856,259.80
	Transformer(s):		
	1964 Transformer - 44KV - 6MVA	$ 216,000.00	$ 300,000.00
	Total:	$ 966,207.96	$ 1,286,259.80

MS4	Land	900 sq m	1964
	Building	Steel building for MC	
	HV Gear	AB and HV Fuses	
	Transformers	6000 KVA, 6000 KVA, 44000/4160	
	Secondary Gear	Five cell metalclad breakers	
	Feeder Cables		

2014 addition

VEHICLE ID#		Division	YEAR	DESCRIPTION	VIN	PLATE #	Gross Vehicle Weight	ORIGINAL PRICE	Additions	New Cost
1	HT	Almonte	1994	FREIGHTLINER -RBD LINE TRUCK	1FV6JFAB2RL772820	YH2083	15875			$ 300,000.00
3	HT	Almonte	2005	INTERNATIONAL 4400	1HTMKAAR45HA04727	3490NM	24500	$ 193,037.11		$ 193,037.11
8	HT	Pembroke	2008	INT'L MODEL 4400 4X2 LINE	1HTMKAAR68J69052	4114WE	17000	$ 277,601.92		$ 277,601.92
9	HT	Pembroke	2010	International 4400 SBA	1HTMKAAR9AH264533	8535ZA	16783			$ 300,000.00
11	HT	Pembroke	1997	INTERNATIONAL	1HTGLATT1VH436563	2303CN	60000	$ 314,035.45	21074.65	$ 335,110.10
31	HT	Pembroke	2014	INT'L MODEL 70S	1HTWNAZT9EH799349	AF72434	25275	$ 396,307.00		$ 396,307.00
4	LT	Pembroke	2003	CHEV ASTRO VAN	1GCDM19XX3B100899	6910LJ	3000	$ 25,266.32	2493.3	$ 27,759.62
5	LT	Pembroke	2013	FORD F150 1/2 TON	1FTFX1EF7DK62254	8795KP	3000	$ 27,000.00		$ 27,000.00
6	LT	Pembroke	2014	Dodge Ram 1500	1C6 - RR7FT7ES - 111820	AE73663	2345	$ 25,170.00		$ 25,170.00
10	LT	Pembroke	2008	Dodge Caravan	2D8HN44H88R775533	BDHC481	3000	$ 22,318.58		$ 22,318.58
14	LT	Almonte	2011	CHEVROLET PICK UP TRUCK	1GCRKPE37BZ444486	1919JV		$ 28,000.00		$ 28,000.00
15	O	Pembroke	2007	JOHN DEERE BACKHOE	TO310SJ147918	No Plate		$ 65,000.00		$ 65,000.00
21	O	Pembroke	1960	FORK LIFT				$ 25,000.00		$ 25,000.00
22	O	Pembroke	2014	FORK LIFT	Toshiba			$ 25,000.00		$ 25,000.00
23	O	Almonte		FORKLIFT				$ 25,000.00		$ 25,000.00
25	O	Pembroke		LAWNTRACTOR				$ 5,000.00		$ 5,000.00
7	PV	Pembroke	2012	DODGE GRAND CARAVAN	2C4RDGBG5CR234742	BNJS670		$ 27,000.01		$ 27,000.01
28	PV	Pembroke	2007	DODGE CARAVAN C/V	1D4GP23R77B106902	3486TP	1762	$ 22,099.66		$ 22,099.66
2	T	Pembroke	2012	VERMEER BRUSH CHIPPER BC1200X	1VR7141Y0C1000473	No Plate	2812	$ 46,830.00		$ 46,830.00
12	T	Pembroke	1981	CASE DH4 TRENCHER	ser #1192872	No Plate		$ 29,185.23		$ 29,185.23
13	T	Pembroke	1979	KING POLE TRAILER H3CPT	18565-KB	79097E		$ 9,020.79		$ 9,020.79
16	T	Pembroke	1981	HAVELOCK DUMP TRAILER	CDT05	79099E		$ 7,372.26		$ 7,372.26
17	T	Pembroke	1986	CUSTOM REEL TRAILER	VIN #1786	A26526		$ 3,116.94		$ 3,116.94
18	T	Pembroke	1986	CUSTOM REEL TRAILER	VIN #1886	A26527		$ 3,116.94		$ 3,116.94
19	T	Pembroke	1990	TIMBERLINE TENSIONER/PULLER	2T9C2136LA022021	H69715	4275	$ 41,678.59	3240	$ 44,918.59
20	T	Pembroke	1990	TIMBERLINE TENSIONER/PULLER	2T9C21G34LA022020	H69716	4275	$ 41,678.59	6821.1	$ 48,499.69
24	T	Almonte		POLE/UTILITY TRAILER				$ 9,020.79		$ 9,020.79
26	T	Pembroke		MULTI REEL TRACTOR				$ 9,020.79		$ 9,020.79
27	T	Pembroke	2005	UTILITY (BOX) TRAILER				$ 9,020.79		$ 3,023.10
29	T	Pembroke	2007	Splicing Trailer				$ 9,020.79		$ 4,505.76
30	T	Almonte	2010	Trailer				$ 9,020.79		$ 4,505.76

TOTAL Replacement Cost **$2.38 Million**

Questions and Comments

County of Renfrew Public Utilities Coordinating Committee

Tuesday, April 8, 2014

A meeting of the County of Renfrew and Public Utility Companies was held on Tuesday, April 8, 2014 at 9:00 a.m., at the County of Renfrew Administration Office, 9 International Drive, Pembroke, Ontario.

Present were: Steve Boland, County of Renfrew Director, Public Works & Engineering
Mike Pinet, Manager of Capital Works Division
Nathan Kuiack, Infrastructure Technician
Alan Johnson, County of Renfrew
Connie Roesner, County of Renfrew Operations Secretary
Mark Behm, Public Works Manager, Laurentian Valley
Richard Miceli, Bell Aliant
Jeff Hitchcock, ON1Call
Andre Gaudette, Enbridge Gas
Steve Howarth, UDI – Cogeco
Jim Mulligan, Bell Aliant
John Hung, Enbridge Gas
Bob Miron, Ottawa River Power
Dennis Montgomery, Ottawa River Power
John Weir, ProMark Telecon
Chris Overton, NRTC
Tom Reaud, Road Superintendent, Town of Petawawa
Peter Lapointe, Town of Petawawa
Luke Barker, Bell
Murray Hauley, Hydro One
Paul Howarth, Cogeco
Randy Thur, County of Renfrew
Rick Bechamp, Cogeco

Welcome & Orientation

On behalf of the County of Renfrew Public Works & Engineering Department, Mike Pinet welcomed all who attended and presented opening comments stating that he was pleased with the attendance. Connie Roesner went through the procedure in case of a fire. Mike Pinet gave a brief overview of some of the topics on the agenda that Public Works agencies and Utility Companies may have in common. Mike Pinet will chair this meeting of the group.

ISSUES **Action**

1. Introductions

All in attendance introduced themselves and advised the group of the organization they represented.

6. Capital Works Program Updates

Introductions

All in attendance introduced themselves and advised the group of the organization they represented.

Review of Previous meeting Minutes

We held a brief discussion on the previous minutes. There were no questions or concerns. Minutes are to be circulated prior to meeting.

Update on Ontario One Call Legislation

Jeff H. to give an update to Public Works Supervisors to meet and encourage them to join in the ON1CALL system for all Municipalities. Everyone should be registered by June 1, 2014. Jeff will forward information to be passed along to other committees.

a) 2013 program

Mike gave a overview of what projects the County has scheduled for the future. It was then passed around the table for all to give a brief overview of what projects were taken place in the months to come.

b) Possible future upgrades (Mid to Long term) **Connie Roesner**

The County's 10 Year Capital Work's Forecast was handed out for review and a brief discussion was held as to what projects are proposed for the 2013 year. An electronic version will be attached to the minutes of the meeting.

c) Future Directions

It was agreed that meetings should be held twice a year with dates in late January or early February and in late September.
Individual project specific meetings and discussions will continue to occur as required.

5. Other Business

Municipalities will be asked to send copies of their Capital Works forecast which in turn will be forwarded to PUCC members. **Municipalities & Connie**

John Wier indicated that when locates are requested the nature and depth of the proposed work can be helpful in determining the level of detail needed for the locate and the length of time required.

Jeff Hitchcock provided an overview of legislation change which will affect municipalities in 2014. He suggested that municipalities join ON1CAL before then while there is no cost.

Attendees were advised to forward agenda items for the next meeting to Mike Pinet.

Meeting adjourned at 11:30 a. m.

Next Meeting to be September 27, 2013 at 9:00 a. m. – County of Renfrew Administration Building

Author: Connie Roesner
Secretary, Operations Division
croesner@countyofrenfrew.on.ca

Please advise author of any errors or omissions.

Distribution: Attendees

Maintenance Index

1. Purpose

Ottawa River Power Corporation Maintenance program has been prepared to outline the details with respect to the inspection and maintenance of ORPC distribution lines and substations as required by the Ontario Energy Board as a condition of an LDC license in the Province of Ontario.

Primarily it is aimed at addressing the timelines for inspection and the recording of hazards and inefficiencies in our Distribution network system.

The plan implements the requirements of the OEB Distribution Code Appendix “C” and the Ontario Regulation 22/04 of the Electricity Act 1998 (Electrical Distribution Safety)

2. Scope

ORPC will ensure that only persons qualified under the Occupation of Health and Safety Act are involved in inspection activities. Some inspections can expose personnel to energized equipment and shall be carried out by qualified personnel.

The inspection patrol will be a simple visual inspection that can consist of walking or driving by equipment to identify obvious structural problems and hazards such as leaning poles, damaged enclosures, and vandalism.

The specifics of the inspection will be recorded using the appropriate inspection form (Appendix A, B, or C) and any corrective action shall be identified to the appropriate supervisor.

3. Demarcation Point

The demarcation point shall include all line and equipment from the point of supply from Hydro One Networks (HONI) and Brascan at ORPC substations to the point of ORPC / customer demarcation.

The demarcation point for residential and commercial customers shall be consistent with ORPC Conditions of Service section 3.1.1 and 3.2.1. Customer shall be notified of any hazards or defective materials that may be identified during the inspection that are customer owned.

4. Inspection Rotation

ORPC shall inspect all distribution transformer stations on a monthly basis utilizing inspection forms as illustrated in Appendix A.

ORPC shall inspect all distribution overhead and underground plant on a three year rotation utilizing inspection forms as illustrated in Appendix B and C.

The inspection of distribution overhead and underground plant shall follow the rotation of zone inspections as follows:

1. Year 1 to be the Village of Beachburg and the City of Pembroke from the most easterly boundary of the City of Pembroke to the Muskrat River
2. Year 2 to be the 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.
3. Year 3 to be the 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.

Inspections of underground and overhead plant shall be recorded on the GIS system on an inspection layer as they are completed. This will allow ORPC to track the inspection progress throughout the year as inspections are complete on specific areas within the zone.

5. Inspection Detail Descriptions

The following is a detailed list of inspections to be performed:

Underground Plant:

a) Cabinet damage – loose or broken hinges, corrosion and rust, dents, graffiti, vandalism
b) Cabinet Access – locks and penta bolts in place, vegetation blocking access, landscape issues, drainage from ground water
c) Cable terminations – evidence of flash over, cable distortion, missing test points, discoloration of neutrals, tracking
d) Nomenclature – proper labeling installed and legible, missing or damaged I.D. tags

Substation Inspection:

a) Substation signage – ensure proper signs are installed and legible, replace damaged or missing signs,
b) Substation Fencing – check for damage, vandalism, proper grounding is in place, public access under or over fence,
c) General Building Condition – broken windows, eaves, ice build up, vandalism, paint, leaking roof,

Overhead Plant:

a) Transformers – Check for leaks, company numbers, damaged bushings, lighting arrestor connection, proper grounding
b) Poles – over all shape of pole, woodpecker holes, access to pole, posters installed
c) Overhead Conductors – insulation condition, sag, overall appearance
d) Guys – missing or damaged guards, loose guys, broken insulators, pulling anchors
e) Vegetation – close proximity of trees, back lot access

6. ORPC Distribution Inspection Cycles

Distribution Transformers	Patrol Interval in Years
Overhead	3
Vaults	3
Pad Mounts	3

Distribution Stations	Patrol Interval in Months
Transformer and Structure	1 month
Building and Grounds	1 month
Lines and associated Equipment	**Patrol Interval in Years**
Conductors	3
Poles	3
Vegetation	3
Switching and Protective Devices	3

Ottawa River Power Corporation

Overhead Inspection Form

Circulation	
Lyle	
Mapping	
File	

Area ____ Date ___________Time ______________

Overhead Plant Inspection

Checks to be performed

Transformers		Poles (leaning, damaged)	
Switching and Protective Devices		Guys and Guards (missing, slack)	
Proximity of Vegetation		Nomenclature (missing, legible)	
Overhead Conductors (sag, condition)		Visual Inspection of Insulators (cracked or flashed)	

Deficiency & Follow Up

Description	Equipment Affected	Repair/Hazard	Priority Grade 1	Priority Grade 2

Grade 1	High Priority	Grade 2	Low Priority

Inspected By __________________________

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Ottawa River Power Corporation

Substation Monthly Inspection

Circulation	
Dennis	
File (Greg)	

Station ____ Date ____________Time _______________

Transformer Checks

		T1	T2
Temp Gauges (Record and Reset)	Tank	Act- °C Max- °C	Act- °C Max- °C
	Core	Act- °C Max- °C	Act- °C Max- °C
Check Terminations			
Check for Oil Leakage			
Check Oil Levels on Gauge			

Structure Checks

Visual and audible Inspection of Terminations		Visual Inspection of Switches	
Visual Inspection of Disconnects		Visual Inspection of Insulators	

Internal Checks

Visual inspection of all battery terminals		Test battery cell voltage Low	#	V
Voltage on DC Supply	V	High	#	V

General Building/Grounds Checks

Check for signs of leaking roof, etc..		Check Substation signage	
Check Substation lighting		Check for presence of rodents	
General building condition		Check for signs of vandalism	
Check Substation fencing and Security		Condition of Fire Extinguisher	

Station Readings

Feeders	Flags Timed	Flags Inst	Reset	R -Amps	W-Amps	B-Amps	Counter
1				/	/	/	
2				/	/	/	
3				/	/	/	
4				/	/	/	
5				/	/	/	
Total	--	--	--	/	/	/	
Stn Service Reading	kWhr			Station Energy Reading		kW	kW-hr

Deficiency & Follow Up

Description	Equip Affected	Repair/Hazard	Priority Grd 1	Priority Grd 2

Inspected By ______________________________

Ottawa River Power Corporation

Underground Inspection Form

Circulation	
Lyle	
Mapping	
File	

Area ____ Date ____________Time _______________

Overhead Plant Inspection

Checks to be performed

Visual Inspection of Terminations		Cable Terminations	
Placement on Pad		Grounding	
Switching and Protective Devices		Accessibility	
Cabinet Damage		Nomenclature (missing, legible)	
Phase Indicators and Unit Numbers		Visual Inspection of Insulators (cracked or flashed)	
Grading Changes		Oil Leaks	
Paint and Corrosion		Safety Decals	
Check for Lock and Penta Bolt			

Deficiency & Follow Up

Description	Equipment Affected	Repair/Hazard	Priority Grade 1	Priority Grade 2

Grade 1	High Priority	Grade 2	Low Priority

Inspected By _____________________________ Operations manual 7-6

Ex.2/Tab 5/Sch.3 - Capitalization Policy

ORPC records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles as well as guidelines set out by the Ontario Energy Board, where applicable. 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 does not currently capitalize interest on funds for construction. ORPC's adherence to the capitalization policy can be described as follows. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not capitalized.

Ottawa River Power Corporation implemented accounting changes on January 1, 2013 that were consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* ("APH").

Ottawa River Power changed its depreciation rates to reflect the typical useful life of its capital assets as set out in the Kinectrics report. The change that implementation of this policy caused was in the extension of the useful lives of certain distribution assets. This in turn caused a decrease in overall depreciation expense which was recorded in account 1576 Accounting Changes Under CGAAP, as stipulated by the Board. At the same time ORPC also reviewed its overhead costs and found that they were consistent with overhead rates under International Financial Reporting Standards and that no changes were required.

POLICY

It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital projects that enhance or improve the efficiency of the Company's assets.

Capital Assets include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or “betterment” of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

A “betterment” is a cost which enhances the service potential of a capital asset and is therefore capitalized. A “betterment” includes increasing the capacity of the asset, lowering associated operating costs, improving the quality of output or extending the asset useful life. This enhancement can result in an increase in physical output or service capacity, a decrease to operating costs, extension of the useful life of the asset, or improvement in the quality of the asset’s output. Service potential may be enhanced when there is an increase in physical output or service capacity, associated operating costs are lowered, the useful life is extended, or the quality of output is improved. For example a refurbished transformer in which the service potential has been enhanced should be capitalized. Further, if during an underground fault repair, the work results in a reconfiguration of the asset that will clearly benefit future periods, there may be an argument to capitalize the work.

REPAIR

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

MATERIALITY

The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary cost incurred to place a capital asset into its intended state of operation.

Assets that are expected to provide future economic benefit greater than one year will be capitalized.

Individual items such as the following

- New plant providing services over the value of $1,000.

- Rebuilding of facilities or vehicles when the value is over $2,000 and when the life of this equipment or facility will be extended.
- Equipment over the value of $500.

CAPITAL SPARES

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

AMORTIZATION

As stated above, capital assets are amortized based on a method and life set by the OEB, currently following the Kinetrics Report, which is considered a suitable indicator of estimated useful life for the electrical distribution industry. The half year rule is utilized for amortization purposes, with a half year of amortization being recorded in the year of acquisition and a half year being recorded in the year of disposal.

DISPOSALS AND WRITE-OFFS

For assets taken out of service, the asset cost and the related accumulated amortization is removed from the records. Any difference between the proceeds and the unamortized asset cost including removal costs are recorded as a gain or loss in the year of disposal.

Ex.2/Tab 5/Sch.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.

In compliance with the Board's letter issued July 17, 2012 which state that utilities must changes change their capitalization policies, ORPC has adopted these mandatory changes effective on January 1, 2013.

ORPC did not require any change to its accounting policy for the accounting of overhead costs associated with capital work as clarified by the Board in its letter dated February 24, 2010. On February 24, 2010 the OEB issued additional guidance on the accounting for overhead costs associated with capital work. In this letter the OEB specifically noted that the Board was requiring full compliance with IFRS requirements on capitalization of overheads which would result in a reduction in capitalized overhead for some electricity distributors that had previously capitalized administration and overhead costs.

ORPC concluded that it was in compliance with not including the capitalization of general overhead costs, including indirect labour, general administration and material handling, for regulatory and external reporting.

Ottawa River Power does include a direct labour burden of 54% to self-constructed assets. This burden rate is calculated annually and covers employee benefits such as vacation, sick leave, pension, health care and dental benefits. It also includes life insurance benefits, WSIB expenses and the Employer Health Tax expense.

Ex.2/Tab 5/Sch.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.

Ex.2/Tab 5/Sch.6 - New Policy Options for the Funding of Capital

ORPC is not proposing any special or different approach of funding its capital expenditures.

Ex.2/Tab 5/Sch.7 - Addition of ICM and/or ACM Assets to Rate Base

Ottawa River Power Corporation confirms that it has no addition of Incremental or Advanced Capital Additions to its rate base.

ORPC also confirms it has no balances in account 1508 Other Regulatory Assets- Sub-Account – Incremental Capital Charges.

Ex.2/Tab 5/Sch.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
- CAIDI = Total Customer-Hours of Interruptions/Total Customer Interruptions

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 reports its service quality indicators ("SQIs") annually to the Ontario Energy Board. The SQIs are defined in Chapter 7 of the Distribution System Code. ORPC has not only met but exceeded the minimum standards for all SQIs each year, as indicated in the following tables:

Indicator	OEB Minimum Standard	2008	2009	2010	2011	2012	2013	2014
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Appointment Scheduling	65.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	80.0%		99.4%	99.8%	99.8%	99.9%	99.9%	99.9%
Rescheduling a Missed Appointment	80.0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	80.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Written Response to Enquires	10.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	100.0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	n/a	n/a	n/a	100.0%	100.0%	100.0%	100.0%

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Includes outages caused by loss of supply							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**6 Yr Avg**
SAIDI	3.200	1.210	10.690	3.310	3.970	1.740	4.476
SAIFI	2.870	1.400	6.010	2.250	3.040	3.990	3.114

Excludes outages caused by loss of supply							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**6 Yr Avg**
SAIDI	2.660	0.710	2.390	1.690	0.910	1.240	1.388
SAIFI	2.100	0.790	1.430	1.080	0.810	0.790	0.980

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