EXHIBIT 2 – RATE BASE & DSP

2019 Cost of Service

Chapleau Public Utilities Corporations.
EB-2018-0087

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2.1 OVERVIEW OF RATE BASE

2.1.1 RATE BASE OVERVIEW

CPUC converted to International Financial Reporting Standards (“MIFRS”) on January 1, 2015, and had prepared this application under MIFRS. CPUC confirms that there were no other changes that would affect the utility’s net book value other than the implementation of new depreciation rates in 2013. In other words, there is no difference between the utility’s net book values in NEWCGAAP and MIFRS.

The net fixed assets used to determine the utility’s Rate Base include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. CPUC does not have non-distribution assets nor does it conduct non-distribution activities. [1]Controllable expenses include operations and maintenance, billing and collecting and administration expenses which are discussed in detail in Exhibit 4.

CPUC has calculated its 2019 test year rate base to be $1,745,588. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6. Table 1 - Test Year Rate Base below presents CPUC’s Rate Base calculations for the Test Year.

[1] MFR - Non-distribution activities - capital expenditures and reconciliation to total capital budget

Table 1 - Test Year Rate Base

	CGAAP	MIFRS	
Particulars	**Last Board Approved**	**2019**	**Var**
Net Capital Assets in Service:			
Average Gross Assets	2,554,525	3,925,018	1,370,493
Average Accumulated Depreciation	- 1,517,843	- 2,438,409	-920,566
Average Balance	1,036,682	1,486,609	449,927
Working Capital Allowance	475,601	264,158	- 211,443
Total Rate Base	**1,512,283**	**1,750,767**	**238,484**
	CGAAP	**MIFRS**	
Expenses for Working Capital	**Last Board Approved**	**2019**	**Var**
Eligible Distribution Expenses:			
3500-Distribution Expenses - Operation	205,440	242,760	37,320
3550-Distribution Expenses - Maintenance	-	1,610	1,610
3650-Billing and Collecting	84,200	133,730	49,530
3700-Community Relations	600	-	- 600
3800-Administrative and General Expenses	354,100	443,063	88,963
			-
Property Taxes	10,150	8,262	-1,888
Total Eligible Distribution Expenses	654,490	829,425	174,935
3350-Power Supply Expenses	2,516,183	2,692,686	176,503
Total Expenses for Working Capital	3,170,673	3,522,111	351,438
Working Capital factor	15.0%	7.5%	-7.5%
Total Working Capital	**475,601**	**264,158**	**- 211,443**

2.1.2 RATE BASE TREND

Table 2 - Rate Base Trend below presents CPUC's Rate Base calculations for all required years including the 2019 Test Year. Year over year variance analysis follows.

Table 2 - Rate Base Trend

	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particulars	**Last Board Appr.**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net Capital Assets in Service:									
Average Gross Assets	2,554,525	2,331,013	2,606,151	2,672,226	2,744,775	2,813,510	2,843,685	3,370,199	3,925,018
Average Accumulated Depreciation	-1,517,843	- 1,421,821	- 1,514,805	- 1,587,030	- 1,648,677	- 1,700,527	- 1,751,521	- 2,077,067	- 2,438,409
Average Balance	1,036,682	909,192	1,091,346	1,085,196	1,096,099	1,112,983	1,092,164	1,293,132	1,486,609
Working Capital Allowance	475,601	469,465	522,168	638,899	577,964	602,155	508,788	512,720	264,158
Total Rate Base	**1,512,283**	**1,378,657**	**1,613,514**	**1,724,095**	**1,674,063**	**1,715,138**	**1,600,952**	**1,805,851**	**1,750,767**
		2,331,013	2,606,151	2,672,226	2,744,775	2,813,510	2,843,685	3,370,199	3,925,018
	CGAAP	**CGAAP**	**NEWGAAP**	**NEWGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Expenses for Working Capital	**Last Board Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Eligible Distribution Expenses:									
3500- - Operation	205,440	289,711	220,412	223,211	208,239	236,332	237,909	247,400	242,760
3550- - Maintenance	-	-	-	-	-	-	-	-	1,610
3650-Billing and Collecting	84,200	95,585	115,086	135,609	129,895	121,157	121,220	135,000	133,730
3700-Community Relations	600	115	415	415	115	415	415	-	-
3800-Admin.and General Expenses	354,100	285,195	302,558	385,438	392,316	386,133	357,042	427,004	443,063
Property Taxes	10,150	9,885	7,123	7,050	6,619	6,989	7,916	8,100	8,262
Total Eligible Distribution Expenses	654,490	680,492	645,594	751,724	737,184	751,026	724,502	817,504	829,425
3350-Power Supply Expenses	2,516,183	2,449,277	2,835,527	3,507,606	3,115,911	3,263,340	2,667,417	2,600,626	2,692,686
Total Expenses for Working Capital	3,170,673	3,129,768	3,481,121	4,259,330	3,853,096	4,014,366	3,391,918	3,418,130	3,522,111
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	7.5%
Total Working Capital	**475,601**	**469,465**	**522,168**	**638,899**	**577,964**	**602,155**	**508,788**	**512,720**	**264,158**

The Rate Base for the 2019 Test Year has increased by $145,823 over the last actual (2017), and $238,484 over the last Board Approved Rate Base. The reason for the increase from the 2012 Cost of Service is mainly attributed to:

Major capital cost drivers 2012

System Access:

- Transfer of Smart Meters to Rate Base: $381,117

Major capital cost drivers 2013

General Plant:

- Substation DS's re-inhibit and clean oil (stark international) $34,700
- Burman Energy Asset Management Plan $40,000

Major capital cost drivers 2014

System Service:

- Computer software- asset management $25,000

Major capital cost drivers 2015

System Access:

- Burman energy survey & software support $54,800

Major capital cost drivers 2016

System Renewal:

- Poles, towers, fixtures, contractor work $35,193

Major capital cost drivers 2017

System Access:

- Reverification Meter Sampling : $19,668

Major capital cost drivers 2018

System Renewal:

- Poles, towers, fixtures, contractor work $25,572
- Distribution station moisture testing $32,500
- Boom Truck $389,010

Major capital cost drivers 2019

System Renewal:

- Pole replacement Contract Work : $56,985

Increased Power Supply Expenses

- CPUC has forecasted an increase in the 2019 Power Supply Expenses of over $115,708 over its 2012 Cost of Service.

Increased Distribution Expenses

- The 2019 forecast for OM&A reflects an increase of $176,823 from the 2012 Board Approved. The details of the increases in OM&A are provided in Exhibit 4, but some of the highlights include:
    - increased in operation costs
    - increased billing expenses due to increase costs from billing supplies
    - increases to regulatory expenses
    - increase in wages

The Working Capital Allowance has decreased by $211,443 over the 2012 Board Approved. The reason for the decrease from the 2012 Board Approved to the 2019 Test Year is due to the change in Working Capital Allowance rate from 15% to 7.5%.

Year over year variances are presented in the next section.

2.1.3 RATE BASE VARIANCE ANALYSIS

The following paragraphs and Table 3 – 2012 BA to 2012 Actual Rate Base Variance to Table 10- 2018-2019 Rate Base Variances provide a narrative on the changes that have driven the increase in rate base since CPUC's 2012 Board Approved Cost of Service Application.

CPUC's materiality threshold is $50,000.

CPUC has provided the following variances on the change in Rate Base:

- ✓ 2019 Test Year (MIFRS) against 2018 Bridge Year (MIFRS)
- ✓ 2018 Bridge Year (MIFRS) against 2017 Actual (MIFRS)
- ✓ 2017 Actual (MIFRS) against 2016 Actual (MIFRS)
- ✓ 2016 Actual (MIFRS) against 2015 Actual (MIFRS)
- ✓ 2015 Actual (MIFRS) against 2014 Actual (NewCGAAP)
- ✓ 2014 Actual (NewCGAAP) against 2013 Board Approved (NewCGAAP)
- ✓ 2013 Actual (NewCGAAP) against 2012 (CGAAP)
- ✓ 2012 (CGAAP) against 2012 Board Approved (CGAAP)

2012 BOARD APPROVED VS. 2012 ACTUAL:

Table 3 – 2012 BA to 2012 Actual Rate Base Variance

	CGAAP	CGAAP		
Particulars	**Last Board Approved**	**2012**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	2,554,525	2,331,013	(223,512)	8.75%
Average Accumulated Depreciation	- 1,517,843	- 1,421,821	96,022	6.33%
Average Balance	1,036,682	909,192	(127,490)	12.30%
Working Capital Allowance	475,601	469,465	6,136	1.29%
Total Rate Base	**1,512,283**	**1,378,657**	**(133,626)**	8.84%
	CGAAP	**CGAAP**		
Expenses for Working Capital	**Last Board Approved**	**2012**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	205,440	289,711	84,271	41.02%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	84,200	95,585	11,385	13.52%
3700-Community Relations	600	115	(485)	80.83%
3800-Administrative and General Expenses	354,100	285,195	(68,905)	19.46%
			-	
Property Taxes	10,150	9,885	(265)	2.61%
Total Eligible Distribution Expenses	654,490	680,492	26,002	3.97%
3350-Power Supply Expenses	2,516,183	2,449,277	(66,906)	2.66%
Total Expenses for Working Capital	3,170,673	3,129,768	(40,905)	1.29%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	475,601	469,465	(6,136)	1.29%

The total Rate Base in 2012 Actual of $1,378,667 was $133,626 or 8.84% lesser than the 2012 Board Approved. The main reason for the variance is:

- The 2012 rates did not come into effect unti January of 2013 therefore many of the capital and OM&A projects were put on hold until the decision was issued.

2012 ACTUAL VS. 2013 ACTUAL:

Table 4 - 2012-2013 Rate Base Variances

	CGAAP	NEWGAAP		
Particulars	**2012**	**2013**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	2,331,013	2,606,151	275,138	11.80%
Average Accumulated Depreciation	-1,421,821	-1,514,805	(92,984)	6.54%
Average Balance	909,192	1,091,346	182,154	20.03%
Working Capital Allowance	469,465	522,168	(52,703)	11.23%
Total Rate Base	**1,378,657**	**1,613,514**	**234,857**	**17.04%**
	CGAAP	**NEWGAAP**		
Expenses for Working Capital	**2012**	**2013**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	289,711	220,412	(69,299)	23.92%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	95,585	115,086	19,500	20.40%
3700-Community Relations	115	415	300	260.87%
3800-Administrative and General Expenses	285,195	302,558	17,363	6.09%
			-	
Property Taxes	9,885	7,123	(2,761)	27.94%
Total Eligible Distribution Expenses	**680,492**	**645,594**	**(34,897)**	**5.13%**
3350-Power Supply Expenses	2,449,277	2,835,527	386,250	15.77%
Total Expenses for Working Capital	3,129,768	3,481,121	351,353	11.23%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	**469,465**	**522,168**	**52,703**	**11.23%**

The total Rate Base in 2013 Actual of $1,613,514 was $234,857 or 17,04% greater than the 2012 Actual. The main reason for the variance is:

- The increase is mostly due to the additions of assets in the amount of $88,227. Of the capital additions, 40K went to Burman Energy for an Asset Management Plan, and 35K went to Stark International for substation testing and clean oil.
- Annual changes in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.

2013 ACTUAL VS. 2014 ACTUAL:

Table 5 - 2013-2014 Rate Base Variances

	NEWGAAP	NEWGAAP		
Particulars	**2013**	**2014**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	2,606,151	2,672,226	66,075	2.54%
Average Accumulated Depreciation	- 1,514,805	- 1,587,030	(72,226)	4.77%
Average Balance	1,091,346	1,085,196	(6,151)	0.56%
Working Capital Allowance	522,168	638,899	(116,731)	22.36%
Total Rate Base	**1,613,514**	**1,724,095**	**110,581**	6.85%
	NEWGAAP	NEWGAAP		
Expenses for Working Capital	**2013**	**2014**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	220,412	223,211	2,799	1.27%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	115,086	135,609	20,524	17.83%
3700-Community Relations	415	415	-	0.00%
3800-Administrative and General Expenses	302,558	385,438	82,880	27.39%
			-	
Property Taxes	7,123	7,050	(73)	1.02%
Total Eligible Distribution Expenses	**645,594**	**751,724**	**106,130**	**16.44%**
3350-Power Supply Expenses	2,835,527	3,507,606	672,079	23.70%
Total Expenses for Working Capital	3,481,121	4,259,330	778,209	22.36%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	**522,168**	**638,899**	**116,731**	**22.36%**

The total Rate Base in 2014 Actual of $1,724,095 is $110,581 or 6.85% greater than 2013 Actual. The main reason for the variance is:

- The $43,923 in capital additions during 2014 can be attributed to; 25K in software management by Burman Energy and approximately 13K in poles replacement including towers, fixtures and external contractors when needed. Details can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit.
- Annual changes in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.

2014 ACTUAL VS. 2015 ACTUAL:

Table 6 - 2014-2015 Rate Base Variances

	NEWGAAP	MIFRS		
Particulars	**2014**	**2015**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	2,672,226	2,744,775	72,550	2.71%
Average Accumulated Depreciation	- 1,587,030	- 1,648,677	(61,647)	3.88%
Average Balance	1,085,196	1,096,099	10,903	1.00%
Working Capital Allowance	638,899	577,964	60,935	9.54%
Total Rate Base	**1,724,095**	**1,674,063**	**(50,032)**	2.90%
	NEWGAAP	MIFRS		
Expenses for Working Capital	**2014**	**2015**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	223,211	208,239	(14,971)	6.71%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	135,609	129,895	(5,714)	4.21%
3700-Community Relations	415	115	(300)	72.29%
3800-Administrative and General Expenses	385,438	392,316	6,877	1.78%
			-	
Property Taxes	7,050	6,619	(431)	6.11%
Total Eligible Distribution Expenses	**751,724**	**737,184**	**(14,539)**	**1.93%**
3350-Power Supply Expenses	3,507,606	3,115,911	(391,695)	11.17%
Total Expenses for Working Capital	4,259,330	3,853,096	(406,234)	9.54%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	**638,899**	**577,964**	**(60,935)**	**9.54%**

The total Rate Base in 2015 Actual of $1,674,063 is $50,032 or 2.90% lesser than 2014 Actual. The main reason for the variance is:

- The increse in assets of $101,176 is mostly due to capital expenditures for 2015 include services by Burman Energy for a survey & software support.
- 40K in poles replacement including towers, fixtures and external contractors when needed. Details can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit.

2015 ACTUAL VS. 2016 ACTUAL:

Table 7 - 2015-2016 Rate Base Variances

Particulars	MIFRS 2015	MIFRS 2016	Var	%
Net Capital Assets in Service:				
Average Gross Assets	2,744,775	2,813,510	68,735	2.50%
Average Accumulated Depreciation	- 1,648,677	- 1,700,527	(51,851)	3.14%
Average Balance	1,096,099	1,112,983	16,884	1.54%
Working Capital Allowance	577,964	602,155	(24,191)	4.19%
Total Rate Base	**1,674,063**	**1,715,138**	**41,075**	2.45%

Expenses for Working Capital	MIFRS 2015	MIFRS 2016	Var	%
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	208,239	236,332	28,093	13.49%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	129,895	121,157	(8,738)	6.73%
3700-Community Relations	115	415	300	260.87%
3800-Administrative and General Expenses	392,316	386,133	(6,183)	1.58%
			-	
Property Taxes	6,619	6,989	370	5.59%
Total Eligible Distribution Expenses	**737,184**	**751,026**	**13,842**	**1.88%**
3350-Power Supply Expenses	3,115,911	3,263,340	147,429	4.73%
Total Expenses for Working Capital	3,853,096	4,014,366	161,271	4.19%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	**577,964**	**602,155**	**24,191**	**4.19%**

The total Rate Base in 2016 Actual of $1,715,138 is $41,075 or 2.45% greater than 2015 Actual. The main reason for the variance is:

- The increase in net fixed assets of $36,293 poles replacement including towers, fixtures and external contractors when needed.
- OM&A expenses were fairly stable and showed little variance from the previous year. Details of the OM&A expenditures are presented in Exhibit 4.

2016 ACTUAL VS. 2017 ACTUAL:

Table 8 - 2016-2017 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2016**	**2017**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	2,813,510	2,843,685	30,175	1.07%
Average Accumulated Depreciation	- 1,700,527	- 1,751,521	(50,994)	3.00%
Average Balance	1,112,983	1,092,164	(20,819)	1.87%
Working Capital Allowance	602,155	508,788	93,367	15.51%
Total Rate Base	**1,715,138**	**1,600,952**	**(114,186)**	6.66%
	MIFRS	**MIFRS**		
Expenses for Working Capital	**2016**	**2017**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	236,332	237,909	1,577	0.67%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	121,157	121,220	63	0.05%
3700-Community Relations	415	415	-	0.00%
3800-Administrative and General Expenses	386,133	357,042	(29,091)	7.53%
			-	
Property Taxes	6,989	7,916	927	13.26%
Total Eligible Distribution Expenses	**751,026**	**724,502**	**(26,524)**	**3.53%**
3350-Power Supply Expenses	3,263,340	2,667,417	(595,924)	18.26%
Total Expenses for Working Capital	4,014,366	3,391,918	(622,448)	15.51%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	**602,155**	**508,788**	**(93,367)**	**15.51%**

The total Rate Base in 2017 Actual of $1,600,952 is $114,186 or 6.66% lesser than 2016 Actual. The main reason for the variance is:

- The increase in net fixed assets of $24,057 poles replacement including towers, fixtures and external contractors when needed.

2017 ACTUAL VS. 2018 BRIDGE:

Table 9 - 2017-2018 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2017**	**2018**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	2,843,685	3,370,199	526,514	18.52%
Average Accumulated Depreciation	- 1,751,521	- 2,077,067	(325,546)	18.59%
Average Balance	1,092,164	1,293,132	200,968	18.40%
Working Capital Allowance	508,788	512,720	(3,932)	0.77%
Total Rate Base	**1,600,952**	**1,805,852**	**204,900**	12.80%
	MIFRS	**MIFRS**		
Expenses for Working Capital	**2017**	**2018**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	237,909	247,400	9,491	3.99%
3550-Distribution Expenses - Maintenance	-	-	-	
3650-Billing and Collecting	121,220	135,000	13,780	11.37%
3700-Community Relations	415	-	(415)	
3800-Administrative and General Expenses	357,042	427,004	69,962	19.59%
			-	
Property Taxes	7,916	8,100	184	2.33%
Total Eligible Distribution Expenses	**724,502**	**817,504**	**93,002**	**12.84%**
3350-Power Supply Expenses	2,667,417	2,600,626	(66,791)	2.50%
Total Expenses for Working Capital	3,391,918	3,418,130	26,212	0.77%
Working Capital factor	15.0%	15.0%	-	0.00%
Total Working Capital	**508,788**	**512,720**	**3,932**	**0.77%**

The total Rate Base in 2018 Bridge of $1,805,852 is projected to be $204,900 or 12.80% more than 2017 Actual. The main reason for the variance is:

- The $476,662 in capital additions during 2017 can be attributed to; purchase of a boom truck to replace an old depreciated truck ($389,010), a moisture testing on the distribution station ($32,500), purchase of two new laptops and a handheld for the linemen ($12,761) and finally $25,572 in poles replacement including towers, fixtures and external contractors when needed. Details can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit. CPUC notes that the old boom truck was sold for 50K and the proceeds posted to "other revenues."

2018 BRIDGE VS. 2019 TEST YEAR:

Table 10- 2018-2019 Rate Base Variances

	MIFRS	MIFRS		
Particulars	**2018**	**2019**	**Var**	**%**
Net Capital Assets in Service:				
Average Gross Assets	3,370,199	3,925,018	554,819	16.46%
Average Accumulated Depreciation	- 2,077,067	- 2,438,409	(361,342)	17.40%
Average Balance	1,293,132	1,486,609	193,477	14.96%
Working Capital Allowance	512,720	264,158	248,562	48.48%
Total Rate Base	**1,805,852**	**1,750,767**	**(55,085)**	3.05%
	MIFRS	**MIFRS**		
Expenses for Working Capital	**2018**	**2019**	**Var**	**%**
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	247,400	242,760	(4,640)	1.88%
3550-Distribution Expenses - Maintenance	-	1,610	1,610	#DIV/0!
3650-Billing and Collecting	135,000	133,730	(1,270)	0.94%
3700-Community Relations	-	-	-	
3800-Administrative and General Expenses	427,004	443,063	16,059	3.76%
			-	
Property Taxes	8,100	8,262	162	2.00%
Total Eligible Distribution Expenses	**817,504**	**829,425**	**11,921**	**1.46%**
3350-Power Supply Expenses	2,600,626	2,692,686	92,060	3.54%
Total Expenses for Working Capital	3,418,130	3,522,111	103,981	3.04%
Working Capital factor	15.0%	7.5%	(0)	50.00%
Total Working Capital	**512,720**	**264,158**	**(248,562)**	**48.48%**

The total Rate Base in 2019 Test Year of $1,750,767 is $55,085 or 3.05% less than the 2018 Bridge Year. The main reason for the variance is:

- The level of yearly capital spending for 2019, in the amount of $80,667 is supported by the utility 's new Distribution System Plan. The budget takes into consideration the replacement of assets at a steady pace to avoid rate shock, and unexpected failure of these assets all while ensuring the proper functioning of the CPUCs distribution system. The expenditure, for the most part, relates to poles replacement. Details regarding capital planning can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit.
- The reduction also attributed to the change in capital allowance rate from 15% to 7.5%.

2.1.4 FIXED ASSET CONTINUITY SCHEDULE

This Schedule presents a continuity schedule of its investment in capital assets, the associated accumulated amortization and the net book value for each Capital USoA account for the 2012 to 2017 Actuals and 2018 Bridge Year and 2019 Test Year.

CPUC attests that the OEB Appendices 2-BA continuity statements presented at the next page reconcile with the calculated depreciation expenses, under Exhibit 4 – Operating Costs[2], and resented by asset account. The utility also attests that the net book value balances reported on Appendix 2-BA and balances reconcile with the rate base calculation. [3] [4] [5] The Excel version of the OEB Appendices is filed in conjunction with this application. [6] The utility notes that it has not applied for an ACM or ICM in the years between its 2012 Cost of Service and this application. [7]

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

CPUC does not have any Asset Retirement Obligation related to decommissioning or asset retirement obligations,[8]

[2] MFR - Continuity statements must reconcile to calculated depreciation expenses and presented by asset account
[3] MFR - Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actuals, bridge and test year forecast)
[4] MFR - Continuity statements (year end balance, including interest during construction and overheads).
Explanation for any restatement (e.g. due to change in accounting standards)
Year over year variance analysis; explanation where variance greater than materiality threshold
Hist. OEB-Approved vs Hist. Actual
Hist. Act. vs. preceding Hist. Act.
Hist. Act. vs. Bridge
Bridge vs. Test
[5] MFR - Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g.. WIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation
[6] MFR - Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format
[7] Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications
[8] MFR - All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount

OLD CGAAP

Year		2012Old	2013Old	2014Old	2015Old	2016Old	2017Old	2018Old	
Gross Assets	**Opening**	2,099,989	2,562,037	2,650,264	2,694,187	2,795,362	2,831,655	2,855,712	
	Additions	462,048	88,227	43,923	101,175	36,293	24,057	476,662	
	TransferAssets							552,309	
	Disposals	-	-	-	-	-	-	-	
	Closing	2,562,037	2,650,264	2,694,187	2,795,362	2,831,655	2,855,712	3,884,683	

Year		2012Old	2013Old	2014Old	2015Old	2016Old	2017Old	2018Old	
Accumulated Depreciation	**Opening**	1,364,870	1,478,770	1,575,207	1,667,715	1,761,063	1,847,021	1,913,765	
	Additions	113,900	96,437	92,508	93,349	85,958	66,744	183,402	
	TransferAssets							447,699	
	Disposals	-	-	-	-	-	-	-	
	Closing	1,478,770	1,575,207	1,667,715	1,761,063	1,847,021	1,913,765	2,544,866	
Net Book Value		**1,083,267**	**1,075,057**	**1,026,472**	**1,034,299**	**984,634**	**941,947**	**1,339,817**	
RRR Gross Value Integrity Check		*2,562,037*	*2,650,263*	*2,694,186*	*2,795,361*	*2,831,645*	*2,855,712*	*3,884,684*	
Gross Value Integrity Check - diff		*0*	*1*	*1*	*1*	*10*	*0*	*- 1*	
RRR Depreciation Exp Integrity Check		*113,903*							
Depreciation Exp Integrity Check - diff		*- 3*							

New CGAAP

Year			2013 New	2014 New					
Gross Assets	**Opening**		2,562,037	2,650,264					
	Additions		88,227	43,923					
	Disposals		-	-					
	Closing		2,650,264	2,694,187					

Year			2013 New	2014 New					
Accumulated Depreciation	**Opening**		1,478,812	1,550,797					
	Additions		72,024	72,466					
	Disposals		-	-					
	Closing		1,550,836	1,623,263					
Net Book Value			**1,099,428**	**1,070,924**					
RRR Gross Value Integrity Check			*2,650,263*	*2,694,186*					
Gross Value Integrity Check - diff			*1*	*1*					
RRR Depreciation Exp Integrity Check			*72,025*	*72,466*					
Depreciation Exp Integrity Check - diff			*- 1*	*0*					

MIFRS

Year					2015 MIFRS	2016 MIFRS	2017 MIFRS	2018 MIFRS	2019 MIFRS
Gross Assets	**Opening**				2,694,187	2,795,363	2,831,656	2,855,713	3,884,684
	Additions				101,176	36,293	24,057	476,662	80,667
	TransferAssets							552,309	
	Disposals				-	-	-	-	-
Transfer of Assets	**Adj**								
	Closing				2,795,363	2,831,656	2,855,713	3,884,684	3,965,351

Year					2015 MIFRS	2016 MIFRS	2017 MIFRS	2018 MIFRS	2019 MIFRS
Accumulated Depreciation	**Opening**				1,623,263	1,674,090	1,726,964	1,776,078	2,378,056
	Additions				50,827	52,874	49,114	154,279	120,706
	TransferAssets							447,699	
	Disposals				-	-	-	-	-
Transfer of Assets	**Adjustment**								
	Closing				1,674,090	1,726,964	1,776,078	2,378,056	2,498,762
Net Book Value					**1,121,273**	**1,104,692**	**1,079,635**	**1,506,628**	**1,466,589**
RRR Gross Value Integrity Check					*2,795,361*	*2,831,645*	*2,855,712*	*3,884,684*	*3,965,351*
Gross Value Integrity Check - diff					*2*	*11*	*1*	*-*	*-*
RRR Depreciation Exp Integrity Check					*50,827*	*52,874*	*49,114*	*601,978*	*120,706*
Depreciation Exp Integrity Check - diff					*-*	*- 0*	*0*	*-*	*-*

FINAL CONTINUITY SCHEDULE

Year		2012Old	2013 New	2014 New	2015 MIFRS	2016 MIFRS	2017 MIFRS	2018 MIFRS	2019 MIFRS
Removal of Stranded Meters									
Gross Assets	**Opening**	2,099,989	2,562,037	2,650,264	2,694,187	2,795,363	2,831,656	2,855,712	3,884,684
	Additions	462,048	88,227	43,923	101,176	36,293	24,057	476,662	80,667
	TransferAssets							552,309	
	Disposals	-	-	-	-	-	-	-	-
	Closing	2,562,037	2,650,264	2,694,187	2,795,363	2,831,656	2,855,713	3,884,683	3,965,351
			0	-					

Year		2012Old	2013 New	2014 New	2015 MIFRS	2016 MIFRS	2017 MIFRS	2018Old	2019 MIFRS
Accumulated Depreciation	**Opening**	1,364,870	1,478,770	1,550,836	1,623,263	1,674,090	1,726,964	1,776,078	2,378,056
	Additions	113,900	72,024	72,466	50,827	52,874	49,114	154,279	120,706
	TransferAssets							447,699	
	Disposals	-	-	-	-	-	-	-	-
	Closing	1,478,770	1,550,836	1,623,263	1,674,090	1,726,964	1,776,078	2,378,056	2,498,762
		-	-	-	-	-	-		-
Net Book Value		**1,083,267**	**1,099,428**	**1,070,924**	**1,121,273**	**1,104,692**	**1,079,635**	**1,506,627**	**1,466,589**
RRR Net Book Value Integrity Check		*2,562,037*	*2,650,263*	*2,694,186*	*2,795,361*	*2,831,645*	*2,855,712*	*3,884,684*	*3,965,351*
Net Book Value Integrity Check - diff		*0*	*1*	*1*	*2*	*11*	*1*	*- 1*	*-*
RRR Depreciation Exp Integrity Check		*113,903*	*72,025*	*72,466*	*50,827*	*52,874*	*49,114*	*601,978*	*120,706*
Depreciation Exp Integrity Check - diff		*- 3*	*- 1*	*0*	*-*	*- 0*	*0*	*-*	*-*

Year 2012 Former CGAAP - without changes to the policies

			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)	$ 11,186		$ 57,476	$ -	$ 68,662	$ 10,447		$ 16,212	$ -	$ 26,659	$ 42,003
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
N/A	1805	Land	$ 141		$ -	$ -	$ 141	$ -		$ -	$ -	$ -	$ 141
47	1808	Buildings	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 462,817		$ 15,406	$ -	$ 478,223	$ 215,899		$ 10,185	$ -	$ 226,084	$ 252,139
47	1820	Distribution Station Equipment <50 kV	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,127,389		$ 2,502	$ -	$ 1,129,891	$ 820,020		$ 12,343	$ -	$ 832,363	$ 297,528
47	1835	Overhead Conductors & Devices	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1840	Underground Conduit	$ 77,511		$ -	$ -	$ 77,511	$ 51,524		$ 1,038	$ -	$ 52,562	$ 24,949
47	1845	Underground Conductors & Devices	$ 3,516		$ -	$ -	$ 3,516	$ 70		$ 138	$ -	$ 208	$ 3,308
47	1850	Line Transformers	$ 388,667		$ 4,439	$ -	$ 393,106	$ 253,587		$ 5,492	$ -	$ 259,079	$ 134,027
47	1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1860	Meters	$ 28,101		$ 1,108	$ -	$ 29,209	$ 12,759		$ 6,322	$ -	$ 19,081	$ 10,128
47	1860	Meters (Smart Meters)	$ -		$ 381,117	$ -	$ 381,117	$ -		$ 62,119	$ -	$ 62,119	$ 318,998
N/A	1905	Land	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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)	$ 661		$ -	$ -	$ 661	$ 564		$ 53	$ -	$ 617	$ 44
10	1930	Transportation Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
							$ -	$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 2,099,989**		**$ 462,048**	**$ -**	**$ 2,562,037**	**$ 1,364,870**		**$ 113,902**	**$ -**	**$ 1,478,772**	**$ 1,083,265**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,099,989**		**$ 462,048**	**$ -**	**$ 2,562,037**	**$ 1,364,870**		**$ 113,902**	**$ -**	**$ 1,478,772**	**$ 1,083,265**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										-$ 1,478,772	
		Total								**$ 113,902**		-$ 0	
										$ 113,903		From RRR (5705)	

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

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

Year 2013 CGAAP - with changes to policies

			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)	$ 68,662		$ 40,000	$ -	$ 108,662	$ 26,659		$ 34,102	$ -	$ 60,761	$ 47,901
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
N/A	1805	Land	$ 141		$ -	$ -	$ 141	$ -		$ -	$ -	$ -	$ 141
47	1808	Buildings	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 478,223		$ 34,700	$ -	$ 512,923	$ 226,084		$ 6,737	$ -	$ 232,821	$ 280,102
47	1820	Distribution Station Equipment <50 kV	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,129,891		$ 8,956	$ -	$ 1,138,847	$ 832,403		$ 6,040	$ -	$ 838,443	$ 300,404
47	1835	Overhead Conductors & Devices	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1840	Underground Conduit	$ 77,511		$ -	$ -	$ 77,511	$ 52,562		$ 499	$ -	$ 53,061	$ 24,450
47	1845	Underground Conductors & Devices	$ 3,516		$ -	$ -	$ 3,516	$ 208		$ 66	$ -	$ 274	$ 3,242
47	1850	Line Transformers	$ 393,106		$ 3,691	$ -	$ 396,797	$ 259,079		$ 2,717	$ -	$ 261,796	$ 135,001
47	1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1860	Meters	$ 29,209		$ 193	$ -	$ 29,402	$ 19,081		$ 511	$ -	$ 19,592	$ 9,810
47	1860	Meters (Smart Meters)	$ 381,117		$ 687	$ -	$ 381,804	$ 62,119		$ 21,289	$ -	$ 83,408	$ 298,396
N/A	1905	Land	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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)	$ 661		$ -	$ -	$ 661	$ 617		$ 24	$ -	$ 641	$ 20
10	1930	Transportation Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.				$ -	$ -				$ -	$ -		
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -			$ -	$ -	$ -	$ -
			$ -				$ -	$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 2,562,037**		**$ 88,227**	**$ -**	**$ 2,650,264**	**$ 1,478,812**		**$ 71,985**	**$ -**	**$ 1,550,797**	**$ 1,099,467**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,562,037**		**$ 88,227**	**$ -**	**$ 2,650,264**	**$ 1,478,812**		**$ 71,985**	**$ -**	**$ 1,550,797**	**$ 1,099,467**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										-$ 1,550,797	
		Total								**$ 71,985**		-$ 0	
										$ 72,025			

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

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Year 2013 Former CGAAP - without changes to the policies

			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)	$ 68,662	$ 40,000		$ -	$ 108,662	$ 26,659	$ 34,102	$ -		$ 60,761	$ 47,901
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
N/A	1805	Land	$ 141	$ -		$ -	$ 141	$ -		$ -		$ -	$ 141
47	1808	Buildings	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 478,223	$ 34,700		$ -	$ 512,923	$ 226,084	$ 10,780	$ -		$ 236,864	$ 276,059
47	1820	Distribution Station Equipment <50 kV	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,129,891	$ 8,956		$ -	$ 1,138,847	$ 832,362	$ 11,929	$ -		$ 844,291	$ 294,556
47	1835	Overhead Conductors & Devices	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -		$ -	$ 77,511	$ 52,562	$ 998	$ -		$ 53,560	$ 23,951
47	1845	Underground Conductors & Devices	$ 3,516	$ -		$ -	$ 3,516	$ 208	$ 132	$ -		$ 340	$ 3,176
47	1850	Line Transformers	$ 393,106	$ 3,691		$ -	$ 396,797	$ 259,079	$ 5,435	$ -		$ 264,514	$ 132,283
47	1855	Services (Overhead & Underground)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1860	Meters	$ 29,209	$ 193		$ -	$ 29,402	$ 19,081	$ 1,022	$ -		$ 20,103	$ 9,299
47	1860	Meters (Smart Meters)	$ 381,117	$ 687		$ -	$ 381,804	$ 62,118	$ 31,975	$ -		$ 94,093	$ 287,711
N/A	1905	Land	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
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)	$ 661	$ -		$ -	$ 661	$ 617	$ 24	$ -		$ 641	$ 20
10	1930	Transportation Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.			$ -		$ -			$ 39	$ -			
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
			$ -				$ -	$ -	$ -	$ -		$ -	$ -
		Sub-Total	**$ 2,562,037**	**$ 88,227**		**$ -**	**$ 2,650,264**	**$ 1,478,770**	**$ 96,437**	**$ -**		**$ 1,575,168**	**$ 1,075,096**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,562,037**	**$ 88,227**		**$ -**	**$ 2,650,264**	**$ 1,478,770**	**$ 96,437**	**$ -**		**$ 1,575,168**	**$ 1,075,096**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total							**$ 96,437**				

Less: *Fully Allocated Depreciation*

Year 2014 CGAAP - with changes to policies

			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)	$ 108,662	$ -	$ 25,000	$ -	$ 133,662	$ 60,761	$ -	$ 33,221	$ -	$ 93,982	$ 39,680
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 141	$ -	$ -	$ -	$ 141	$ -	$ -	$ -	$ -	$ -	$ 141
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923	$ -	$ -	$ -	$ 512,923	$ 232,821	$ -	$ 8,403	$ -	$ 241,224	$ 271,699
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,138,847	$ -	$ 13,973	$ -	$ 1,152,820	$ 838,443	$ -	$ 6,148	$ -	$ 844,591	$ 308,229
47	1835	Overhead Conductors & Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -	$ -	$ -	$ 77,511	$ 53,061	$ -	$ 489	$ -	$ 53,550	$ 23,961
47	1845	Underground Conductors & Devices	$ 3,516	$ -	$ -	$ -	$ 3,516	$ 274	$ -	$ 65	$ -	$ 339	$ 3,177
47	1850	Line Transformers	$ 396,797	$ -	$ 4,950	$ -	$ 401,747	$ 261,796	$ -	$ 2,750	$ -	$ 264,546	$ 137,201
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 29,402	$ -	$ -	$ -	$ 29,402	$ 19,592	$ -	$ 490	$ -	$ 20,082	$ 9,320
47	1860	Meters (Smart Meters)	$ 381,804	$ -	$ -	$ -	$ 381,804	$ 83,408	$ -	$ 20,889	$ -	$ 104,297	$ 277,507
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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)	$ 661	$ -	$ -	$ -	$ 661	$ 641	$ -	$ 11	$ -	$ 652	$ 9
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -			$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 2,650,264**	**$ -**	**$ 43,923**	**$ -**	**$ 2,694,187**	**$ 1,550,797**	**$ -**	**$ 72,466**	**$ -**	**$ 1,623,263**	**$ 1,070,924**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,650,264**		**$ 43,923**	$ -	**$ 2,694,187**	**$ 1,550,797**		**$ 72,466**	$ -	**$ 1,623,263**	**$ 1,070,924**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										-$ 1,623,263	
		Total								**$ 72,466**		$ 0	
										$ 72,466			

10		Transportation	**Less:** *Fully Allocated Depreciation*	
			Transportation	
8		Stores Equipment	Stores Equipment	
8		Tools, Shop	Tools, Shop	
8		Meas/Testing	Meas/Testing	
8		Communication	Communication	

Year 2014 Former CGAAP - without changes to the policies

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions		Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals		Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 108,662	$ 25,000		$ -	$ 133,662	$ 60,761	$ 33,221	$ -		$ 93,982	$ 39,680
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
N/A	1805	Land	$ 141	$ -		$ -	$ 141	$ -		$ -		$ -	$ 141
47	1808	Buildings	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923	$ -		$ -	$ 512,923	$ 236,864	$ 11,042	$ -		$ 247,906	$ 265,017
47	1820	Distribution Station Equipment <50 kV	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,138,847	$ 13,973		$ -	$ 1,152,820	$ 844,291	$ 11,981	$ -		$ 856,272	$ 296,548
47	1835	Overhead Conductors & Devices	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -		$ -	$ 77,511	$ 53,560	$ 958	$ -		$ 54,518	$ 22,993
47	1845	Underground Conductors & Devices	$ 3,516	$ -		$ -	$ 3,516	$ 340	$ 127	$ -		$ 467	$ 3,049
47	1850	Line Transformers	$ 396,797	$ 4,950		$ -	$ 401,747	$ 264,514	$ 5,390	$ -		$ 269,904	$ 131,843
47	1855	Services (Overhead & Underground)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1860	Meters	$ 29,402	$ -		$ -	$ 29,402	$ 20,103	$ 930	$ -		$ 21,033	$ 8,369
47	1860	Meters (Smart Meters)	$ 381,804	$ -		$ -	$ 381,804	$ 94,093	$ 28,848	$ -		$ 122,941	$ 258,863
N/A	1905	Land	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
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)	$ 661	$ -		$ -	$ 661	$ 641	$ 11	$ -		$ 652	$ 9
10	1930	Transportation Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
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	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
			$ -				$ -	$ -	$ -	$ -		$ -	$ -
		Sub-Total	**$ 2,650,264**	**$ 43,923**		**$ -**	**$ 2,694,187**	**$ 1,575,168**	**$ 92,508**	**$ -**		**$ 1,667,676**	**$ 1,026,511**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,650,264**	**$ 43,923**		**$ -**	**$ 2,694,187**	**$ 1,575,168**	**$ 92,508**	**$ -**		**$ 1,667,676**	**$ 1,026,511**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total							**$ 92,508**				

Less: *Fully Allocated Depreciation*

Year 2015 IFRS

			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)	$ 133,662		$ 54,800	$ -	$ 188,462	$ 93,982		$ 13,416	$ -	$ 107,398	$ 81,064
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
N/A	1805	Land	$ 141		$ -	$ -	$ 141	$ -		$ -	$ -	$ -	$ 141
47	1808	Buildings	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923		$ -	$ -	$ 512,923	$ 241,224		$ 6,792	$ -	$ 248,016	$ 264,907
47	1820	Distribution Station Equipment <50 kV	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,152,820		$ 40,267	$ -	$ 1,193,087	$ 844,591		$ 7,282	$ -	$ 851,873	$ 341,214
47	1835	Overhead Conductors & Devices	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1840	Underground Conduit	$ 77,511		$ -	$ -	$ 77,511	$ 53,550		$ 599	$ -	$ 54,149	$ 23,362
47	1845	Underground Conductors & Devices	$ 3,516		$ -	$ -	$ 3,516	$ 339		$ 79	$ -	$ 418	$ 3,098
47	1850	Line Transformers	$ 401,747		$ 5,587	$ -	$ 407,334	$ 264,546		$ 3,508	$ -	$ 268,054	$ 139,280
47	1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1860	Meters	$ 29,402		$ -	$ -	$ 29,402	$ 20,082		$ 622	$ -	$ 20,704	$ 8,698
47	1860	Meters (Smart Meters)	$ 381,804		$ 522	$ -	$ 382,326	$ 104,297		$ 18,527	$ -	$ 122,824	$ 259,502
N/A	1905	Land	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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)	$ 661		$ -	$ -	$ 661	$ 652		$ 2	$ -	$ 654	$ 7
10	1930	Transportation Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
			$ -				$ -	$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 2,694,187**		**$ 101,176**	**$ -**	**$ 2,795,363**	**$ 1,623,263**		**$ 50,827**	**$ -**	**$ 1,674,090**	**$ 1,121,273**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,694,187**		**$ 101,176**	**$ -**	**$ 2,795,363**	**$ 1,623,263**		**$ 50,827**	**$ -**	**$ 1,674,090**	**$ 1,121,273**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										-$ 1,674,089	
		Total								**$ 50,827**		$ 1	
										$ 50,827			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	

Year 2015 Former CGAAP - without changes to the policies

			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)	$ 133,662	$ 54,800		$ -	$ 188,462	$ 93,982	$ 36,894	$ -		$ 130,876	$ 57,586
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
N/A	1805	Land	$ 141	$ -		$ -	$ 141	$ -	$ -	$ -		$ -	$ 141
47	1808	Buildings	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923	$ -		$ -	$ 512,923	$ 247,906	$ 10,601	$ -		$ 258,507	$ 254,416
47	1820	Distribution Station Equipment <50 kV	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,152,820	$ 40,267		$ -	$ 1,193,087	$ 856,272	$ 12,660	$ -		$ 868,932	$ 324,155
47	1835	Overhead Conductors & Devices	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -		$ -	$ 77,511	$ 54,518	$ 920	$ -		$ 55,438	$ 22,073
47	1845	Underground Conductors & Devices	$ 3,516	$ -		$ -	$ 3,516	$ 467	$ 122	$ -		$ 589	$ 2,927
47	1850	Line Transformers	$ 401,747	$ 5,587		$ -	$ 407,334	$ 269,904	$ 5,386	$ -		$ 275,290	$ 132,044
47	1855	Services (Overhead & Underground)	$ -	$ -		$ -	$ -	$ -		$ -		$ -	$ -
47	1860	Meters	$ 29,402	$ -		$ -	$ 29,402	$ 21,033	$ 837	$ -		$ 21,870	$ 7,532
47	1860	Meters (Smart Meters)	$ 381,804	$ 521		$ -	$ 382,325	$ 122,941	$ 25,925	$ -		$ 148,866	$ 233,459
N/A	1905	Land	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
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)	$ 661	$ -		$ -	$ 661	$ 652	$ 5	$ -		$ 657	$ 4
10	1930	Transportation Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
			$ -				$ -	$ -	$ -	$ -		$ -	$ -
		Sub-Total	**$ 2,694,187**	**$ 101,175**		**$ -**	**$ 2,795,362**	**$ 1,667,676**	**$ 93,349**	**$ -**		**$ 1,761,024**	**$ 1,034,338**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,694,187**	**$ 101,175**		**$ -**	**$ 2,795,362**	**$ 1,667,676**	**$ 93,349**	**$ -**		**$ 1,761,024**	**$ 1,034,338**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total							**$ 93,349**				

Less: *Fully Allocated Depreciation*

Year 2016 IFRS

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)	$ 188,462		$ -	$ -	$ 188,462	$ 107,398		$ 16,213	$ -	$ 123,611	$ 64,851
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
N/A	1805	Land	$ 141		$ -	$ -	$ 141	$ -		$ -	$ -	$ -	$ 141
47	1808	Buildings	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923		$ -	$ -	$ 512,923	$ 248,016		$ 6,623	$ -	$ 254,639	$ 258,284
47	1820	Distribution Station Equipment <50 kV	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,193,087		$ 35,293	$ -	$ 1,228,380	$ 851,873		$ 7,966	$ -	$ 859,839	$ 368,541
47	1835	Overhead Conductors & Devices	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1840	Underground Conduit	$ 77,511		$ -	$ -	$ 77,511	$ 54,149		$ 584	$ -	$ 54,733	$ 22,778
47	1845	Underground Conductors & Devices	$ 3,516		$ -	$ -	$ 3,516	$ 418		$ 77	$ -	$ 495	$ 3,021
47	1850	Line Transformers	$ 407,334		$ -	$ -	$ 407,334	$ 268,054		$ 3,482	$ -	$ 271,536	$ 135,798
47	1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1860	Meters	$ 29,402		$ -	$ -	$ 29,402	$ 20,704		$ 613	$ -	$ 21,317	$ 8,085
47	1860	Meters (Smart Meters)	$ 382,326		$ 1,000	$ -	$ 383,326	$ 122,824		$ 17,309	$ -	$ 140,133	$ 243,193
N/A	1905	Land	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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)	$ 661		$ -	$ -	$ 661	$ 654		$ 7	$ -	$ 661	$ -
10	1930	Transportation Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
			$ -				$ -	$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 2,795,363**		**$ 36,293**	**$ -**	**$ 2,831,656**	**$ 1,674,090**		**$ 52,874**	**$ -**	**$ 1,726,964**	**$ 1,104,692**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,795,363**		**$ 36,293**	**$ -**	**$ 2,831,656**	**$ 1,674,090**		**$ 52,874**	**$ -**	**$ 1,726,964**	**$ 1,104,692**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										-$ 1,726,964	
		Total								**$ 52,874**		$ 0	
										$ 52,874		From RRR (5705)	

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

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Year 2016 Former CGAAP - without changes to the policies

			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)	$ 188,462	$ -		$ -	$ 188,462	$ 130,876	$ 31,672	$ -		$ 162,548	$ 25,914
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
N/A	1805	Land	$ 141	$ -		$ -	$ 141	$ -	$ -	$ -		$ -	$ 141
47	1808	Buildings	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923	$ -		$ -	$ 512,923	$ 258,507	$ 10,177	$ -		$ 268,684	$ 244,239
47	1820	Distribution Station Equipment <50 kV	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,193,087	$ 35,293		$ -	$ 1,228,380	$ 868,932	$ 13,665	$ -		$ 882,597	$ 345,783
47	1835	Overhead Conductors & Devices	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -		$ -	$ 77,511	$ 55,438	$ 883	$ -		$ 56,321	$ 21,190
47	1845	Underground Conductors & Devices	$ 3,516	$ -		$ -	$ 3,516	$ 589	$ 117	$ -		$ 706	$ 2,810
47	1850	Line Transformers	$ 407,334	$ -		$ -	$ 407,334	$ 275,290	$ 5,282	$ -		$ 280,572	$ 126,762
47	1855	Services (Overhead & Underground)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1860	Meters	$ 29,402	$ -		$ -	$ 29,402	$ 21,870	$ 753	$ -		$ 22,623	$ 6,779
47	1860	Meters (Smart Meters)	$ 382,325	$ 1,000		$ -	$ 383,325	$ 148,866	$ 23,407	$ -		$ 172,273	$ 211,052
N/A	1905	Land	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
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)	$ 661	$ -		$ -	$ 661	$ 657	$ 2	$ -		$ 659	$ 2
10	1930	Transportation Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
			$ -				$ -	$ -	$ -	$ -		$ -	$ -
		Sub-Total	**$ 2,795,362**	**$ 36,293**		**$ -**	**$ 2,831,655**	**$ 1,761,024**	**$ 85,958**	**$ -**		**$ 1,846,982**	**$ 984,673**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 2,795,362**	**$ 36,293**		**$ -**	**$ 2,831,655**	**$ 1,761,024**	**$ 85,958**	**$ -**		**$ 1,846,982**	**$ 984,673**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total							**$ 85,958**				

Less: *Fully Allocated Depreciation*

Year 2017 IFRS

			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)	$ 188,462		$ -	$ -	$ 188,462	$ 123,611		$ 12,971	$ -	$ 136,582	$ 51,880
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
N/A	1805	Land	$ 141		$ -	$ -	$ 141	$ -		$ -	$ -	$ -	$ 141
47	1808	Buildings	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923		$ -	$ -	$ 512,923	$ 254,639		$ 6,457	$ -	$ 261,096	$ 251,827
47	1820	Distribution Station Equipment <50 kV	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,228,380		$ 4,389	$ -	$ 1,232,769	$ 859,839		$ 8,230	$ -	$ 868,069	$ 364,700
47	1835	Overhead Conductors & Devices	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1840	Underground Conduit	$ 77,511		$ -	$ -	$ 77,511	$ 54,733		$ 569	$ -	$ 55,302	$ 22,209
47	1845	Underground Conductors & Devices	$ 3,516		$ -	$ -	$ 3,516	$ 495		$ 76	$ -	$ 571	$ 2,945
47	1850	Line Transformers	$ 407,334		$ -	$ -	$ 407,334	$ 271,536		$ 3,395	$ -	$ 274,931	$ 132,403
47	1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1860	Meters	$ 29,402		$ 265	$ -	$ 29,667	$ 21,317		$ 615	$ -	$ 21,932	$ 7,735
47	1860	Meters (Smart Meters)	$ 383,326		$ 19,403	$ -	$ 402,729	$ 140,133		$ 16,801	$ -	$ 156,934	$ 245,795
N/A	1905	Land	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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)	$ 661		$ -	$ -	$ 661	$ 661		$ -	$ -	$ 661	$ -
10	1930	Transportation Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
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	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 2,831,656**		**$ 24,057**	**0**	$ 2,855,713	$ 1,726,964		$ 49,114	$ -	$ 1,776,078	$ 1,079,635
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input					$ -					**$ -**	**$ -**
		Less Other Non Rate-Regulated Utility Assets *(input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)*					$ -					$ -	$ -
		Total PP&E	2831656.27		24057	0	$ 2,855,713	1726964		49114	0	$ 1,776,078	$ 1,079,635
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										**-$ 1,776,077**	
		Total								49114		$ 1	
										$ 49,114			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$ 49,114

Year 2017 Former CGAAP - without changes to the policies

			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)	$ 188,462	$ -		$ -	$ 188,462	$ 162,548	$ 14,253	$ -		$ 176,801	$ 11,661
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
N/A	1805	Land	$ 141	$ -		$ -	$ 141	$ -	$ -	$ -		$ -	$ 141
47	1808	Buildings	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923	$ -		$ -	$ 512,923	$ 268,684	$ 9,770	$ -		$ 278,454	$ 234,469
47	1820	Distribution Station Equipment <50 kV	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,228,380	$ 4,389		$ -	$ 1,232,769	$ 882,597	$ 13,912	$ -		$ 896,509	$ 336,260
47	1835	Overhead Conductors & Devices	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -		$ -	$ 77,511	$ 56,321	$ 848	$ -		$ 57,169	$ 20,342
47	1845	Underground Conductors & Devices	$ 3,516	$ -		$ -	$ 3,516	$ 706	$ 112	$ -		$ 818	$ 2,698
47	1850	Line Transformers	$ 407,334	$ -		$ -	$ 407,334	$ 280,572	$ 5,071	$ -		$ 285,643	$ 121,691
47	1855	Services (Overhead & Underground)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1860	Meters	$ 29,402	$ 265		$ -	$ 29,667	$ 22,623	$ 691	$ -		$ 23,314	$ 6,353
47	1860	Meters (Smart Meters)	$ 383,325	$ 19,403		$ -	$ 402,728	$ 172,273	$ 22,087	$ -		$ 194,360	$ 208,368
N/A	1905	Land	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
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)	$ 661	$ -		$ -	$ 661	$ 659	$ -	$ -		$ 659	$ 2
10	1930	Transportation Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
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	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
			$ -	$ -		$ -	$ -	$ -	$ -	$ -		$ -	$ -
		Sub-Total	$ 2,831,655	24057		0	$ 2,855,712	$ 1,846,982	$ 66,744	$ -		**$ 1,913,726**	**$ 941,986**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investmen					**$ -**					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -					$ -	$ -
		Total PP&E	2831655.27	24057		0	$ 2,855,712	1846982.352	66744	**$ -**		**$ 1,913,726**	**$ 941,986**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total							66744				

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing

Less: Fully Allocated Depreciation
Transportation
Stores Equipment
Tools, Shop
Meas/Testing

Year 2018 Former CGAAP - without changes to the policies

			Cost					Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	Transfer of Assets	Additions	Disposals /Correction	Closing Balance	Opening Balance	Additions Transfer of Assets	Additions	isposals/Correctio	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 188,462	$ -	$ -	$ -	$ 188,462	$ 176,801	$ -	$ 11,661		$ 188,462	$ -
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
N/A	1805	Land	$ 141	$ 30,000	$ -	$ -	$ 30,141	$ -	$ -	$ -		$ -	$ 30,141
47	1808	Buildings	$ -	$ 55,931	$ -	$ -	$ 55,931	$ -	$ 5,403	$ -		$ 5,403	$ 50,528
13	1810	Leasehold Improvements	$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 512,923	$ -	$ -	-$ 512,923	$ -	$ 278,454	$ -	$ -	-$ 278,454	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ 32,500	$ 512,923	$ 545,423	$ -	$ -	$ 21,167	$ 278,454	$ 299,621	$ 245,802
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,232,769	$ -	$ 25,572	$ -	$ 1,258,341	$ 896,509	$ -	$ 49,822		$ 946,331	$ 312,010
47	1835	Overhead Conductors & Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1840	Underground Conduit	$ 77,511	$ -	$ -	$ -	$ 77,511	$ 57,169	$ -	$ 3,100		$ 60,269	$ 17,242
47	1845	Underground Conductors & Devices	$ 3,516	$ -	$ -	$ -	$ 3,516	$ 818	$ -	$ 141		$ 959	$ 2,557
47	1850	Line Transformers	$ 407,334	$ -	$ 8,780	$ -	$ 416,114	$ 285,643	$ -	$ 16,469		$ 302,112	$ 114,002
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1860	Meters	$ 29,667	$ -	$ -	$ -	$ 29,667	$ 23,314	$ -	$ 2,967		$ 26,281	$ 3,386
47	1860	Meters (Smart Meters)	$ 402,728	$ -	$ 8,039	$ -	$ 410,767	$ 194,360	$ -	$ 40,675		$ 235,035	$ 175,732
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -	$ 2,769	$ -	$ -	$ 2,769	$ -	$ 2,577	$ -		$ 2,577	$ 192
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ 12,761	$ -	$ 12,761	$ -	$ -	$ 3,873		$ 3,873	$ 8,888
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 661	$ -	$ -	$ -	$ 661	$ 659	$ -	$ -		$ 659	$ 2
10	1930	Transportation Equipment	$ -	$ 15,910	$ 389,010	$ -	$ 404,920	$ -	$ 11,932	$ 13,615		$ 25,547	$ 379,373
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		Sub-Total	**$ 2,855,712**	**$ 104,610**	**$ 476,662**	**$ -**	**$ 3,436,984**	$ 1,913,726	$ 19,912	$ 163,490	$ -	**$ 2,097,128**	**$ 1,339,856**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investmen					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)*					$ -					$ -	$ -
		Total PP&E	**$ 2,855,712**	**$ 104,610**		**$ -**	**$ 3,436,984**	**$ 1,913,726**	**$ 19,912**	**$ 163,490**		**$ 2,097,128**	**$ 1,339,856**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total							19912				

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation
Transportation
Stores Equipment

Year 2019 IFRS

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
1611	Computer Software (Formally known as Account 1925)	$ 188,462		$ -	$ -	$ 188,462	$ 188,462		$ -	$ -	$ 188,462	$ -
1612	Land Rights (Formally known as Account 1906 and 1806)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1805	Land	$ 30,141		$ -	$ -	$ 30,141	$ -		$ -	$ -	$ -	$ 30,141
1808	Buildings	$ 55,931		$ -	$ -	$ 55,931	$ 5,403		$ 5,403	$ -	$ 10,806	$ 45,125
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 545,423		$ -	$ -	$ 545,423	$ 271,689		$ 10,908	$ -	$ 282,597	$ 262,826
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,258,341		$ 19,223	$ -	$ 1,277,564	$ 892,980		$ 25,359	$ -	$ 918,339	$ 359,225
1835	Overhead Conductors & Devices	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1840	Underground Conduit	$ 77,511		$ -	$ -	$ 77,511	$ 56,852		$ 1,550	$ -	$ 58,402	$ 19,109
1845	Underground Conductors & Devices	$ 3,516		$ -	$ -	$ 3,516	$ 641		$ 70	$ -	$ 711	$ 2,805
1850	Line Transformers	$ 416,114		$ 28,921	$ -	$ 445,035	$ 283,165		$ 8,611	$ -	$ 291,776	$ 153,259
1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1860	Meters	$ 29,667		$ -	$ -	$ 29,667	$ 24,009		$ 2,077	$ -	$ 26,086	$ 3,581
1860	Meters (Smart Meters)	$ 410,768		$ -	$ -	$ 410,768	$ 185,406		$ 28,754	$ -	$ 214,160	$ 196,608
1905	Land	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ 2,769		$ -	$ -	$ 2,769	$ 2,577		$ 252	$ -	$ 2,829	-$ 60
1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 12,761		$ -	$ -	$ 12,761	$ 3,873		$ 7,382	$ -	$ 11,255	$ 1,506
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 661		$ -	$ -	$ 661	$ 661		$ -	$ -	$ 661	$ -
1930	Transportation Equipment	$ 404,920		$ -	$ -	$ 404,920	$ 14,649		$ 30,015	$ -	$ 44,664	$ 360,256
1935	Stores Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1995	Contributions & Grants	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
etc.		$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
	Sub-Total	$ 3,436,985		$ 48,144	$ -	$ 3,485,129	$ 1,930,367		$ 120,381	$ -	$ 2,050,748	$ 1,434,381
	Less Socialized Renewable Energy Generation Investments **(input as negative)Less Socialized Renewable Energy Generation Investments (input a**					$ -					$ -	$ -
	Less Other Non Rate-Regulated Utility Assets *(input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)*					**$ -**					**$ -**	**$ -**
	Total PP&E	3436985.37		48144	0	$ 3,485,129	1930367		120381	0	$ 2,050,748	$ 1,434,381
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
	Total								**$ 120,381**			

Transportation	Transportation
Stores Equipment	Stores Equipment
Tools, Shop	Tools, Shop
Meas/Testing	Meas/Testing
Communication	Communication
	Net Depreciation $ 120,381

2.2 GROSS ASSETS

2.2.1 GROSS ASSET VARIANCE ANALYSIS

Table 11 - OEB Appendix 2-AB Capital Expenditures is presented below as well as in the DSP. The section which follows Table 2-AB presents a breakdown of capital investments by RRFE functions; System Access (Table 8), System Renewal (Table 9), System Services (Table 10) and General Plant (11). That said, in order to comply with the filing requirements, the utility is also presenting a Breakdown of the utility's Gross Assets by function (distribution plant, general plant, etc.) at Table 2.13[9]

Table 11 - OEB Appendix 2-AB Capital Expenditures[10]

	2012	2012	2013	2013	2014	2014	2015	2015
CATEGORY	BA	Actual	Planned	Actual	Planned	Actual	Planned	Actual
	$		$		$		$	
System Access		439,701		39,701		880		-
System Renewal		6,941		6,941		12,647		18,23
System Service		15,406		5,406				25,000
General Plant		-		-		4,700		
Total	58,290	462,048	8,290	62,048	8,290	8,227	8,290	3,923
Contributed Capital		-		-		-		-
Net Capital		462,048		62,048		8,227		3,923
System O&M	205,440	289,711	205,440	220,412				

(Cont'd)

	2016	2016	2017	2017	2018	2018
CATEGORY	Planned	Actual	Planned	Actual	Planned	Actual
	$		$		$	
System Access		1,000		19,668		8,039
System Renewal		45,855		4,389		34,532
System Service				100		32,500
General Plant		54,800				401,771
Total	58,290	101,655	58,290	24,157	58,290	476,842
Contributed Capital		-		-		-
Net Capital		101,655		24,157		476,842
System O&M	$205,440	$236,332	$205,440	$237,909	$205,440	$247,400

[9] MFR - Complete Appendix 2-AA along with: explanation for variances, including that of actuals v. OEB-approved amounts for last OEB-approved CoS application; for capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress

[10] MFR - Complete Appendix 2-AB - historical years must be actuals, forecasts for the bridge and test years

(Cont'd)

	Forecast (planned)					
		Test	Test+1	Test+2	Test+3	Test+4
		2019	2020	2021	2022	2023
CATEGORY		Forecast	Forecast	Forecast	Forecast	Forecast
		$	$	$	$	$
System Access						
System Renewal		80,677	80,677	80,677	80,677	80,677
System Service						
General Plant						
Total		80,677	80,677	80,677	80,677	80,677
Contributed Capital						
Net Capital		80,677	80,677	80,677	80,677	80,677
System O&M		$244,370				

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

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

Table 12 – OEB Appendix 2-AA System Access Project Table to Table 15 - OEB Appendix 2-AA General Plant Variances at the next pages shows year over year capital projects in System Access, System Service, System Renewal and General Plan. CPUC notes that in its 2012 Cost of Service capital projects were not required to be tracked by the RRFE categories.

Table 12 – OEB Appendix 2-AA System Access Project Table

Reporting basis			CGAAP	CGAAP	NewGAAP	NewGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Projects	2012 test year	**Usoa**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
System access										
To transfer computer software capital for 2008,2009,2010,2011&		**1611**								
2012 to computer software from smart meter variance acct.			$57,476							
Meters & smart meters	1,500									
Watt hour meters		**1860**	$1,108							
Transfer smart meter acct			$381,117							
Meter purchase		**1860**		$687						
"a" to "s" adapter				$193						
Meter rings		**1860**				$521				
Meter service provider		**1860**					$1,000			
Meter sampling		**1860**						$19,668		
Meter reverification		**1860**							$8,039	
Sub-total system access			**$439,701**	**$880**	**$0**	**$521**	**$1,000**	**$19,668**	**$8,039**	**$0**
Contributed capital				$0	$0	$0	$0	$0	$0	$0
Total system access			$439,701	$880	$0	$521	$1,000	$19,668	$8,039	$0

2012 – 2019 System Access investments are modifications or relocation a distributor is obligated to perform to provide customer access to electricity services. CPUC expects that its system will continue to accommodate the requests for new load connections and for service upgrades during the forecast period. CPUC does not project any significant load growth in the next five years nor any project that is above the materiality threshold.

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

Table 13 - OEB Appendix 2-AA System Renewal Variances

System renewal		Usoa	2012	2013	2014	2015	2016	2017	2018	2019
Poles ,towers & fixtures with some contract work		**1830**	$2,502			$40,267		$4,389		$0
Contractor truck& labour										$56,985
Poles towers fixtures only	23,162									
Line transformers	$8,863	**1860**	$4,439						$8,780	$0
Poles (Guelph utility poles)highline power supply equipment &		**1830**								
Labour, material from local store				$8,956						
Poles, towers, fixtures, engineering work, contractor material &										
Labour		**1830**			$13,973					
Line Transformer		**1850**		$3,691	$4,950	$5,588				
Poles, towers, fixtures, contractor work		**1830**					$35,193		$25,572	
Poles towers fixtures CPUC work & materials										$23,682
Sub-total system renewal			**$6,941**	**$12,647**	**$18,923**	**$45,855**	**$35,193**	**$4,389**	**$34,352**	**$80,667**
Contributed capital		**1995**	$0	$0	$0	$0	$0	$0	$0	$0
Total system renewal			**$6,941**	**$12,647**	**$18,923**	**$45,855**	**$35,193**	**$4,389**	**$34,352**	**$80,667**

2012 – 2019 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. Based on the similarities in asset age profile, the analysis of current information has concluded that asset renewal for other asset categories will follow essentially the same schedule as pole replacement. Specifically, assets such as customer transformers, system switches, conductors, etc. were assumed to be subject to the same vintage replacement criteria as the poles to which they were attached. Improvements to the asset management process made over the DSP forecast period will be used to justify System Renewal category projects proposed in the next DSP.

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

Table 14 - OEB Appendix 2-AA System Service Variances

System service		Usoa	2012	2013	2014	2015	2016	2017	2018	2019
Tx station equipment, re-furbished regulators x3. Replace oil in										
Same, dispose of old oil, new reg, control for one of the refurbished										
Reg.		**1815**	$15,406							
Station tx work	19,765									
Computer software	$5,000.00									
Computer software- asset management		**1925**			$25,000					
Usf standards		**1990**					$100			
Distrubution station moisture testing		**1815**							$32,500	
Sub-total system service			**$15,406**	**$0**	**$25,000**	**$0**	**$100**	**$0**	**$32,500**	**$0**
Contributed capital			$0	$0	$0	$0	$0	$0	$0	$0
Total system service			**$15,406**	**$0**	**$25,000**	**$0**	**$100**	**$0**	**$32,500**	**$0**

2012 – 2019 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. Within the current DSP period, there are no major investments planned above the materiality threshold. It is important to state that there will be a significant investment planned within the next 20-years to convert remaining 4.16kV feeders to 25kV to address the significant line loss experienced at CPUC.

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

Table 15 - OEB Appendix 2-AA General Plant Variances

General plant	General plant		Usoa	2012	2013	2014	2015	2016	2017	2018	2019
	Burman energy-asset management plan		**1925**		$40,000						
	Substation tx's re-inhibit and clean oil (stark international)		**1815**		$34,700						
	Burman energy survey & software support		**1925**				$54,800				
	Boom truck									$389,010	
	Computer upgrade and purchase									$12,761	
	Sub-total general plant			**$0**	**$74,700**	**$0**	**$54,800**	**$0**	**$0**	**$401,771**	**$0**
	Contributed capital		**1995**	$0	$0	$0	$0	$0	$0	$0	$0
Total system service	**Total system service**			**$0**	**$74,700**	**$0**	**$54,800**	**$0**	**$0**	**$401,771**	**$0**

Reporting basis	**Reporting basis**			CGAAP	CGAAP	NewGAAP	NewGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	2012 test year	**Usoa**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Transfer of assets from an affiliate										**104,610**	
Total capital expenditures				**462,048**	**88,227**	**43,923**	**101,176**	**36,293**	**24,057**	**476,662**	**80,667**
Reconciliation to yearly additions				**462,048**	**88,227**	**43,923**	**101,176**	**36,293**	**24,057**	**476,662**	**80,667**
Variance to yearly additions				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

2012 – 2019 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. The short-term plans are to address the customer-identified priorities, such as improved communications, are met by enhancing ad hoc customer communications though the web site and bill insert. This will not require capital investments, and therefore, there are no projects planned in this category over the forecast period.

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

In compliance with the filing requirements, the capital additions are presented by traditional functions in Table 16 – Yearly investments by Traditional Functions below.

Table 16 – Yearly investments by Traditional Functions[11]

Description	2012	2013	2014	20015	2016	2017	2018	2019
Computer Software (Formally known as Account 1925)	$0	$40,000	$25,000	$54,800	$0	$0	$0	$0
Transformer Station Equipment >50 kV	$0	$34,700	$0	$0	$0	$0	$0	$0
Distribution Station Equipment <50 kV	$0	$0	$0	$0	$0	$0	$32,500	$0
Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0
Poles, Towers & Fixtures	$0	$8,956	$13,973	$40,267	$35,293	$4,389	$25,572	$72,962
Line Transformers	$0	$3,691	$4,950	$5,587	$0	$0	$8,780	$7,705
Meters	$0	$193	$0	$0	$0	$265	$0	$0
Meters (Smart Meters)	$0	$687	$0	$522	$1,000	$19,403	$8,039	$0
Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$12,761	$0
Transportation Equipment	$0	$0	$0	$0	$0	$0	$389,010	$0
Sub-Total	**$0**	**$88,227**	**$43,923**	**$101,176**	**$36,293**	**$24,057**	**$476,662**	**$80,667**

[11] MFR - Breakdown by function and by major plant account; description of major plant items for test year

2.2.2 ACCUMULATED DEPRECIATION

CPUC has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at this link. [https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf]. The rates used are presented below, and the Continuity Schedules of the Accumulated Depreciation are presented in the table below. CPUC's capitalization policy and methodology are provided on the next page. The depreciation expenses continuity schedules are presented in Exhibit 4.

Table 17 - Comparison of Depreciation Rates below provides CPUC's depreciable lives by asset class.

Table 17 - Depreciation Rates

Service Life Comparison

Table F-1 from Kinetrics Report1

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	CGAAP		MIFRS		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
				Steel	30	70	95	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Line Transformers	25	4%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	1840		25	4%	50	2%	Yes	No
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80	1840		25	4%	50	2%	Yes	No
	31	Secondary Cables Direct Buried			25	35	40								
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50	1815		25	4%	50	2%	No	No
			Protector		20	35	40								

Table F-2 from Kinetrics Report1

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Offce Furniture & Equipment	15	7%	15	7%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	15	7%	15	7%	No	No
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75								
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1808	Buildings	25	4%	25	4%	Yes	No
		Parking	25	30	1808	Buildings	25	4%	25	4%	No	No
		Fence	25	60	1808	Buildings	25	4%	25	4%	No	No
		Roof	20	30	1808	Buildings	25	4%	25	4%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment	2	50%	2	50%	Yes	No
		Software	2	5	1611	Computer Software	2	50%	2	50%	No	No
13	Smart Meters		5	15	1860	Meters (Smart Meters)	20	5%	20	5%	No	Yes

2.2.3 CAPITALIZATION POLICY

CPUC's capitalization policy has not changed since its last Cost of Service in 2012[12] other than it now records capital assets at cost in accordance with MIFRS 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. CPUC does not currently capitalize interest on funds used for construction.

CPUC's adherence to the capitalization policy can be described as follows;

- ✓ Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- ✓ General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- ✓ Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity, or the useful life of the capital asset is extended) will be capitalized.
- ✓ All vehicles are capitalized.
- ✓ Maintenance services can be done using internal staff or are contracted out depending on the work to be done.

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.

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[12] MFR - Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.

2.3 ALLOWANCE FOR WORKING CAPITAL

2.3.1 DERVIATION OF WORKING CAPTIAL

CPUC has used the 7.5% Allowance Approach for the purpose of calculating its Allowance for Working Capital. This was done in accordance with the letter issued by the Board on June 03, 2015 for a rate of 7.5% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). CPUC attests that the Cost of Power is determined by the split between RPP and non-RPP customers based on actual data, using most current RPP price, using current UTR. Table 18 - Allowance for Working Capital presented below show CPUC's calculations in determining its Allowance for Working Capital.

Table 18 - Allowance for Working Capital

	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**Last Board Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Eligible Distribution Expenses:									
3500-Distribution Expenses - Operation	205,440	289,711	220,412	223,211	208,239	236,332	237,909	247,400	242,760
3550-Distribution Expenses - Maintenance	-	-	-	-	-	-	-	-	1,610
3650-Billing and Collecting	84,200	95,585	115,086	135,609	129,895	121,157	121,220	135,000	133,730
3700-Community Relations	600	115	415	415	115	415	415	-	-
3800-Administrative and General Expenses	354,100	285,195	302,558	385,438	392,316	386,133	357,042	427,004	443,063
Property Taxes	10,150	9,885	7,123	7,050	6,619	6,989	7,916	8,100	8,262
Total Eligible Distribution Expenses	654,490	680,492	645,594	751,724	737,184	751,026	724,502	817,504	829,425
3350-Power Supply Expenses	2,516,183	2,449,277	2,835,527	3,507,606	3,115,911	3,263,340	2,667,417	2,600,626	2,692,686
Total Expenses for Working Capital	3,170,673	3,129,768	3,481,121	4,259,330	3,853,096	4,014,366	3,391,918	3,418,130	3,522,111
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	7.5%
Total Working Capital	**475,601**	**469,465**	**522,168**	**638,899**	**577,964**	**602,155**	**508,788**	**512,720**	**264,158**
% change		3.97%	11.23%	22.36%	-9.54%	4.19%	-15.51%	0.77%	3.04%

2.3.2 LEAD LAG STUDY[13]

CPUC is not proposing to use a lead lag study in order to determine its Working Capital Allowance and has chosen to follow the Board's June 03, 2015 letter which provided two options for the calculation of the allowance for working capital:[14]

(1) The 7.5% allowance approach; or
(2) The filing of a lead/lag study.

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

2.3.3 CALCULATION OF COST OF POWER[15]

CPUC calculated the cost of power for the 2018 Bridge Year and the 2019 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 to April 30, 2019 Ontario Energy Board April 19, 2018. Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, CPUC will update the electricity prices in the forecast.

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

The components of CPUC's cost of power are summarized in Table 19 – Summary of Cost of Powerbelow and detailed in Table 20 - Calculation of Commodity to Table 27 - Low Voltage Charges;

[13] MFR - Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction
[14] MFR - Lead/Lag Study - leads and lags measured in days, dollar-weighted
[15] MFR - Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP (TOU) price, use current UTR. Should include SME charge.

Table 19 – Summary of Cost of Power

CoP Components	**Total $**
Commodity	$2,308,570
Transmission Network	$178,820
Transmission Connection	$50,106
Wholesale Market Service	$72,554
Rural Rate Protection	$6,046
Smart Meter Entity Charge	$8,186
Low Voltage	$68,404
TOTAL	$2,692,686

Table 20 - Calculation of Commodity[16][17][18][19]

Determination of Commodity

	Last Actual kWh's	**non GA mod**	**GA mod**	**Total**	**RPP**	**non-RPP**	**RPP**
Customer Class Name	**Last Actual kWh's**	**non-RPP**				**%**	**%**
Residential	12,775,802			-	12,775,802	*0.00%*	*100.00%*
General Service < 50 kW	4,702,580			-	4,702,580	*0.00%*	*100.00%*
General Service > 50 to 4999 kW	6,797,046		6,797,046	6,797,046	0	*100.00%*	*0.00%*
Unmetered Scattered Load	2,892			-	2,892	*0.00%*	*100.00%*
Sentinel Lighting	20,629			-	20,629	*0.00%*	*100.00%*
Street Lighting	274,259			-	274,259	*0.00%*	*100.00%*
TOTAL	**24,573,208**	**0**	**6,797,046**	**6,797,046**	**17,776,162**		
%	*100.00%*	*0.00%*	*27.66%*		*72.34%*		

Forecast Price

GA Modifiler 44.38

			non GA mod	GA mod	RPP
HOEP ($/MWh)			$21.57	$21.57	
Global Adjustment ($/MWh)			$103.80	$59.42	
Adjustments			$1.00	$1.00	
TOTAL ($/MWh)			**$126.37**	**$81.99**	**$82.00**
$/kWh			***$0.12637***	***$0.08199***	***$0.08200***
%			0.00%	27.66%	72.34%

[16] MFR - Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price, use current UTR. Calculation must fully consider all other impacts resulting from the Ontario Fair Hydro Plan Act, 2017. Distributors must complete Appendix 2-Z - Commodity Expense.
[17] MFR - In consideration of the impact of the Fair Hydro Plan, actual data must be split between Class A and Class B customers (RPP and non-RPP).
[18] MFR – N/A For customer classes that include Class A customers, distributor must incorporate Class A GA cost by completing the relevant section in Appendix 2-Z
[19] MFR – N/A If a distributor expects test year consumption data to vary significantly, a distributor may provide a forecast of the expected split between Class A and Class B and the expected split between RPP, non-RPP eligible for modifier and non-RPP non eligible for modifier consumption data and provide brief explanation of the forecast

WEIGHTED AVERAGE PRICE	**$0.0820**		**$0.0000**	**$0.0227**		**$0.0593**

The GA modifier of 44.38 originates from the Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 to April 30, 2019

Table 21 - Electricity Projections

		2018			2019		
Customer							
Class Name		Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	14,859,993	0.08200	$1,218,478	14,878,532	$0.08200	$1,219,998
General Service < 50 kW	kWh	5,151,370	0.08200	$422,398	5,249,883	$0.08200	$430,476
General Service > 50 to 4999 kW	kWh	7,543,842	0.08200	$618,574	7,688,108	$0.08200	$630,404
Unmetered Scattered Load	kWh	5,522	0.08200	$453	5,628	$0.08200	$461
Sentinel Lighting	kWh	26,134	0.08200	$2,143	26,634	$0.08200	$2,184
Street Lighting	kWh	299,727	0.08200	$24,577	305,459	$0.08200	$25,047
TOTAL		**27,886,589**		**$2,262,046**	**28,154,245**		**2,308,570**

The Commodity share of the Cost of Power is calculated in the same manner as has been previously approved by the OEB in CPUC's previous Cost of Service application as well as other applications. The utility used Table ES-1: Average RPP Supply Cost Summary from the Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 to April 30, 2019 Ontario Energy Board April 19, 2018.

Table 22 - RPP Supply Cost Summary

	Last Actual kWh's	**non GA mod**	**GA mod**	**Total**	**RPP**	**non-RPP**	**RPP**
Customer Class Name	**Last Actual kWh's**	**non-RPP**				**%**	**%**
Residential	12,775,802			-	12,775,802	*0.00%*	*100.00%*
General Service < 50 kW	4,702,580			-	4,702,580	*0.00%*	*100.00%*
General Service > 50 to 4999 kW	6,797,046		6,797,046	6,797,046	0	*100.00%*	*0.00%*
Unmetered Scattered Load	2,892			-	2,892	*0.00%*	*100.00%*
Sentinel Lighting	20,629			-	20,629	*0.00%*	*100.00%*
Street Lighting	274,259			-	274,259	*0.00%*	*100.00%*
TOTAL	**24,573,208**	**0**	**6,797,046**	**6,797,046**	**17,776,162**		
%	*100.00%*	*0.00%*	*27.66%*		*72.34%*		

The utility uses the split between the RPP and Non-RPP to determine the weighted average price. The weighted average price is applied to the projected 2019 Load Forecast to determine the commodity to be included in the Cost of Power. The commodity for 2019 is projected at $2,253,346.

Table 23 - Transmission Network and Connection

Rate Class	**Rate Description**	**Current Rates**	**Proposed RTSR-Network**
Residential	RTSR - Network	0.0068	0.0067
General Service Less Than 50 kW	RTSR - Network	0.0060	0.0059
General Service 50 to 4,999 kW	RTSR - Network	2.5062	2.4676
Unmetered Scattered Load	RTSR - Network	0.0060	0.0059
Sentinel Lighting	RTSR - Network	1.8998	1.8705
Street Lighting	RTSR - Network	1.8902	1.8611
Rate Class	Rate Description	Proposed RTSR-Connection	Proposed RTSR-Connection
Residential	RTSR - Connection	0.0016	0.0018
General Service Less Than 50 kW	RTSR - Connection	0.0016	0.0018
General Service 50 to 4,999 kW	RTSR - Connection	0.5763	0.6643
Unmetered Scattered Load	RTSR - Connection	0.0016	0.0018
Sentinel Lighting	RTSR - Connection	0.4549	0.5244
Street Lighting	RTSR - Connection	0.4456	0.5136

<u>Transmission - Network</u>							
		2018			2019		
Customer							
Class Name		Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	14,859,993	0.0068	$101,048	14,878,532	0.0067	$99,615
General Service < 50 kW	kWh	5,151,370	0.0060	$30,908	5,249,883	0.0059	$31,014
General Service > 50 to 4999 kW	kW	19,002	2.5062	$47,623	18,883	2.4676	$46,596
Unmetered Scattered Load	kWh	5,522	0.0060	$33	5,628	0.0059	$33
Sentinel Lighting	kW	65	1.8998	$123	65	1.8705	$122
Street Lighting	kW	774	1.8902	$1,463	774	1.8611	$1,440
TOTAL		**20,036,729**		**181,199**	**20,153,768**		**178,820**
<u>Transmission - Connection</u>							
		2018			2019		
Customer							
Class Name		Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	14,859,993	0.0016	$23,776	14,878,532	0.0018	$27,439
General Service < 50 kW	kWh	5,151,370	0.0016	$8,242	5,249,883	0.0018	$9,682
General Service > 50 to 4999 kW	kW	19,002	0.5763	$10,951	18,883	0.6643	$12,543
Unmetered Scattered Load	kWh	5,522	0.0016	$9	5,628	0.0018	$10
Sentinel Lighting	kW	65	0.4549	$30	65	0.5244	$34

Street Lighting	kW	774	0.4456	$345	774	0.5136	$397
TOTAL		**20,036,729**		**43,352**	**20,153,768**		**50,106**

The Transmission Network charges are calculated in the OEB's RTSR model. The Rates are applied to the 2019 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application. The transmission network charges included in the Cost of Power for 2019 is projected at $178,820. The Transmission Connection charges are also calculated in the OEB's RTSR model and are projected to be $50,106. The Rates are applied to the 2019 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application.

Table 24 - Wholesale Market

		2018			2019		
Customer			rate ($/kWh):	0.0052		rate ($/kWh):	0.0052
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	14,859,993	0.00360	$53,496	14,878,532	0.00360	$53,563
General Service < 50 kW	kWh	5,151,370	0.00360	$18,545	5,249,883	0.00360	$18,900
General Service > 50 to 4999 kW	kWh	19,002	0.00360	$68	18,883	0.00360	$68
Unmetered Scattered Load	kWh	5,522	0.00360	$20	5,628	0.00360	$20
Sentinel Lighting	kWh	65	0.00360	$0	65	0.00360	$0
Street Lighting	kWh	774	0.00360	$3	774	0.00360	$3
TOTAL		**20,036,729**		**72,132**	**20,153,768**		**72,554**

On December 15, 2016, the OEB released Decision and Order for the Wholesale Market Service (WMS) effective January 1, 2017. The Board's decision is summarized as follows:

- The WMS rate used by rate-regulated distributors to bill their customers shall be $0.0032 per kilowatt-hour, effective January 1, 2017. For Class B customers, a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0036 per kilowatt-hour. For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to peak.

In compliance with this order, CPUC has applied the Board Approved $0.0036/kWh to its 2018 Load Forecast to include $72,554 in its Cost of Power.

Table 25 - Remote Electricity Rate Protection

		2018			2019		
Customer			rate ($/kWh):			rate ($/kWh):	
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	14,859,993	0.00130	$19,318	14,878,532	0.00030	$4,464
General Service < 50 kW	kWh	5,151,370	0.00130	$6,697	5,249,883	0.00030	$1,575
General Service > 50 to 4999 kW	kWh	19,002	0.00130	$25	18,883	0.00030	$6
Unmetered Scattered Load	kWh	5,522	0.00130	$7	5,628	0.00030	$2
Sentinel Lighting	kWh	65	0.00130	$0	65	0.00030	$0
Street Lighting	kWh	774	0.00130	$1	774	0.00030	$0
TOTAL		**20,036,729**		**26,048**	**20,153,768**		**6,046**

In compliance with this order, CPUC has applied the Board Approved $0.0003/kWh to its 2019 Load Forecast to include $6,046 in its Cost of Power.

Table 26 - Smart Meter Entity

		2018			2019		
Customer			**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	1,043	0.00000	$0	1,033	0.57000	$7,066
General Service < 50 kW	kWh	150	0.00000	$0	148	0.57000	$1,015
General Service > 50 to 4999 kW	kW	15	0.00000	$0	15	0.57000	$104
TOTAL		**1,209**		**$0**	**1,197**		**$8,186**

In compliance with this order, CPUC has applied the Board Approved $0.57/kWh to its 2018 Customer Forecast to include $8,186 in its Cost of Power.

Low Voltage Charges:

The Table 27 - Low Voltage Charges below presents the derivation of proposed retail rates for Low Voltage (“LV”) service. The 2019 estimates of total LV charges were calculated based on an average of the last 4 years. The projections were allocated to customer classes, according to each class’ share of projected Transmission-Connection revenue, in accordance with Board policy. The resulting allocated LV charges for each class were divided by the applicable 2019 volumes from the load forecast, as presented in Exhibit 3. Current LV revenues are recovered through a separate rate adder and therefore are not embedded within the approved Distribution Volumetric rate. 2019 LV rates appear on a distinct line item on the proposed schedule of rates.

Table 27 - Low Voltage Charges

	2012	2013	2014	2015	2016	2017	AVG
4075-Billed - LV	($30,388)	($17,154)	($19,857)	($17,265)	($14,688)	($14,622)	($16,608)
4750-Charges - LV	$15,491	$39,969	$71,247	$74,595	$70,967	$59,187	$68,999

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Uplifted Volumes**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0018**	14,878,532	$27,439	54.76%
General Service < 50 kW	kWh	**$0.0018**	5,249,883	$9,682	19.32%
General Service > 50 to 4999 kW	kW	**$0.6643**	18,883	$12,543	25.03%
Unmetered Scattered Load	kWh	**$0.0018**	5,628	$10	0.02%
Sentinel Lighting	kW	**$0.5244**	65	$34	0.07%
Street Lighting	kW	**$0.5136**	774	$397	0.79%
TOTAL			**20,153,768**	**$50,106**	**100.00%**

Low Voltage Charges Rate Rider Calculations

(volumes are not loss adjusted)

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	54.76%	37,785	13,831,681	$0.0027	kWh
General Service < 50 kW	19.32%	13,333	4,880,502	$0.0027	kWh
General Service > 50 to 4999 kW	25.03%	17,273	18,883	$0.9147	kW
Unmetered Scattered Load	0.02%	14	5,232	$0.0027	kWh
Sentinel Lighting	0.07%	47	65	$0.7221	kW
Street Lighting	0.79%	547	774	$0.7073	kW
TOTAL	**100.00%**	**68,999**	**18,737,140**		

Low Voltage Charges to be added to power supply expense for bridge and test year.

(volumes are not loss adjusted)

Customer		**Revenue**	**Expense**	**2018**			**2019**		
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	14,078,629	$0.0006	$8,447	13,831,681	$0.0027	$37,346
General Service < 50 kW	kWh	4075	4750	4,880,502	$0.0006	$2,928	4,880,502	$0.0027	$13,177
General Service > 50 to 4999 kW	kW	4075	4750	19,002	$0.2256	$4,287	18,883	$0.9147	$17,273
Unmetered Scattered Load	kWh	4075	4750	5,232	$0.0006	$3	5,232	$0.0027	$14
Sentinel Lighting	kW	4075	4750	65	$0.2261	$15	65	$0.7221	$47
Street Lighting	kW	4075	4750	774	$0.2173	$168	774	$0.7073	$547
TOTAL		**0**	**0**	**18,984,207**		**$15,848**	**18,737,140**		**$68,404**

2.4 SMART METER DEPLOYMENT & STRANDED

2.4.1 DISPOSITION OF SMART METERS AND TREATMENT OF STRANDED METERS

CPUC's disposition and treatment of smart meter related costs were address and approved as part of its 2012 Cost of Service Application. Therefore, the utility is not seeking any futher resolution on this matter.[20]

On the topic of Smart Meters, the utility notes that it has not witnessed any cost efficiencies since its last Cost of Service in 2012 related to the utility's use of Smart Meter. [21]

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[20] MFR - Stranded Meters - if the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved, a proposal for a Stranded Meter Rate Rider must be made
Explanation for approaches that are not the OEB approach

[21] MFR - Discussion outlining capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies (e.g., AMI communications networks, ODS) in its networks. Qualitative and quantitative description and support should be provided as applicable

2.5 CAPITAL EXPENDITURES

2.5.1 PLANNING

CPUC's distribution system strategy is the set of policies, rules, guidelines, etc. that CPUC utilizes to transition its current system into its desired future system. The strategy, as described in this Distribution System Plan provides the rationale for the capital expenditures and supporting activities planned for the 2017-2021 period.

In advance of the Cost of Service application, CPUC hired the services of Metsco to conduct a Utility Load Flow and Substation Evaluation Study.

Within the RFP process, METSCO was requested to produce a report determining the acceptability of the system with current and future load growth, including loading that has been recently defined for the next 10-year period from 2018 to 2028. The report included findings with respect to optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.

The report also included finding whether the system would operate acceptably during emergency situations. and a review of Loading, System Losses, System Upgrades to minimize losses and Substation Evaluation, Redundancy and Capacity.

The report in question can be found in Appendix A of this Exhibit.

CPUC has relied Metsco who in turn relied on the OEB's filing requirements Chapter 5 to guide its presentation of its policies, practices, and decision making processes. OEB appendices related to capital investments are shown on the next page. The Distribution System Plan follows in Section 2.5.2

2.5.2 DISTRIBUTION SYSTEM PLAN

CPUC is pleased to present its Distribution System Plan on the next page.[22]

[22] MFR - DSP filed as a stand-alone document; a discrete element within Exhibit 2

Chapleau Public Utilities Corporation

Distribution System Plan

2019 Cost of Service Application

Historical Period: 2014-2018

Forecast Period: 2019-2023

31 August 2018

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1 INTRODUCTION

Chapleau Public Utility Corporation ("**CPUC**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 12 July 2018 (the "**Filing Requirements**") in support of its 2019 forward test-year cost of service rate application (the "**Application**"). CPUC retained METSCO Energy Solutions Inc. ("**METSCO**") to advise on and assist with the preparation of this DSP.

1.1 OBJECTIVES & SCOPE OF WORK

The CPUC DSP is a stand-alone document and will be filed in support of CPUC's Application. The intent of CPUC's DSP is to provide the information required by the OEB to implement the policy objectives of the Renewed Regulatory Framework ("**RRF**") as set out in the *Handbook for Utility Rate Applications*:

1. ***Customer Focus**: services are provided in a manner that responds to identified customer preferences;*
2. ***Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;*
3. ***Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and*
4. ***Financial Performance**: financial viability in maintained; and savings from operational effectiveness are sustainable.*

1.2 OUTLINE OF REPORT

This DSP describes how CPUC will develop, manage and maintain its distribution system equipment to provide a safe, secure, reliable, efficient and cost-effective service to its customers. The DSP identifies the major initiatives and projects to be undertaken over the filed planning period. Preparation of the DSP in this format is intended to supplement CPUC's Application. This is a ten-year plan, with a historical period spanning from 2014 to 2018 (2018 being the Bridge Year) and a forecast period of 2019 to 2023 (2019 being the Test Year).

The report contains four sections including this introductory section as Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of CPUC's asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of CPUC's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation ("**REG**"), and justification of material projects (above the materiality threshold of $50,000).

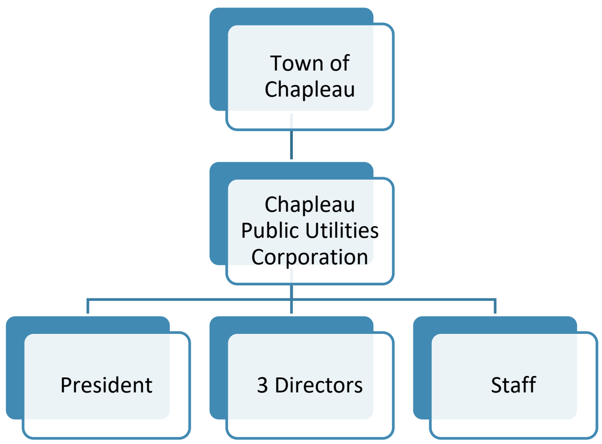
CPUC's DSP is focused on providing the most viable, value added, long term operating environment possible for its customers with a short-term focus on a continued reliable, safe service. CPUC intends to do a full execution of its capital expenditure plan within the timeframe presented, which has been prioritized within the context of an overall investment strategy for CPUC.

Where relevant, the DSP is organized using the same section headings indicated in the OEB's Filing Requirements and addresses the information outlined in each section. Other relevant information is included in separately identified sections and is intended to complement the prescribed data.

1.3 Description of the Utility Company

Formed in 2002, CPUC is a licensed, rate-regulated local distribution company ("**LDC**"), operating in the Town of Chapleau, Ontario. The Township of Chapleau is the sole shareholder of CPUC. Shown below is the corporate structure of CPUC:

Figure 1 Corporate structure of CPUC



1.3.1 Mission Statement & Business Values

<u>Mission Statement</u>

CPUC builds and operates a distribution network that supports Ontario's energy future by delivering on obligations mandated by the Ontario Government and other regulatory agencies. CPUC will continue to operate as a stand-alone LDC servicing community needs at a good value for the money. CPUC works collaboratively with customers and business partners to deliver cost-effective and reliable service with minimal interruptions to supply. CPUC employees act with integrity, maintain a safe environment and take responsibility for the community.

<u>Vision Statement</u>

CPUC strives to be a provincial leader in providing safe, secure and reliable power services.

<u>Business Values</u>

CPUC takes pride in servicing its customers and embraces its business values.

Figure 2 CPUC Business Values

Reliable - CPUC's System Reliability is a primary goal, designed to ensure appropriate management of its assets to provide a sustainable and reliable service to its customers.

Safe - CPUC ensures that the safety of its staff and the public remains its number one priority over the planning period.

Trustworthy - CPUC's employees are taking responsibility for their conduct and obligations to service their community.

Asset Stewardship - CPUC's asset stewardship ensures continual enhancement of its asset management processes as the basis for any increased investment.

Customer Focused - CPUC effectively meets the service expectations to its customers and delivers a good value for the money.

Collaborative - Decisions are made jointly, in cooperation with all stakeholders, as required, to optimize the planning process.

Accountable – CPUC operates under a board of directors who establish, maintain, and uphold high standards of accountability for the utility.

1.3.2 Customers Served

The table below illustrates CPUC's historical and forecast customer base, which includes residential, general service < 50 kW, general service >50 kW and large users. No customer growth is currently forecast. Distribution system investments to date have focused on sustaining the existing distribution system infrastructure.

Table 1 CPUC's historical total number of customers, consumption (kWh) and large commercial demand (kW)

Annual Year	*Customers & Connections (excluding Streetlighting)*	*Consumption [kWh] (Residential, GS<50, GS>50, Streetlight, USL)*	*Consumption [kW] from applicable classes (GS>50 and Streetlight)*
2012 Actual	1,308	26,150,008	19,573
2013 Actual	1,253	27,879,646	19,264
2014 Actual	1,251	27,940,070	20,992
2015 Actual	1,249	25,803,364	18,893
2016 Actual	1,254	24,574,839	19,568
2017 Actual	1,248	24,573,208	18,352
2018 Projected	*1,236*	*26,420,264*	*19,841*
2019 Projected	*1,224*	*26,332,189*	*19,841*

1.3.3 Energy Conservation and Demand Management

The graphic below shows the annual peak kW demand for the CPUC's distribution system. The forecast is calculated using the moving average of historical record data years 2005-2017.

Figure 3 Peak system demand statistics

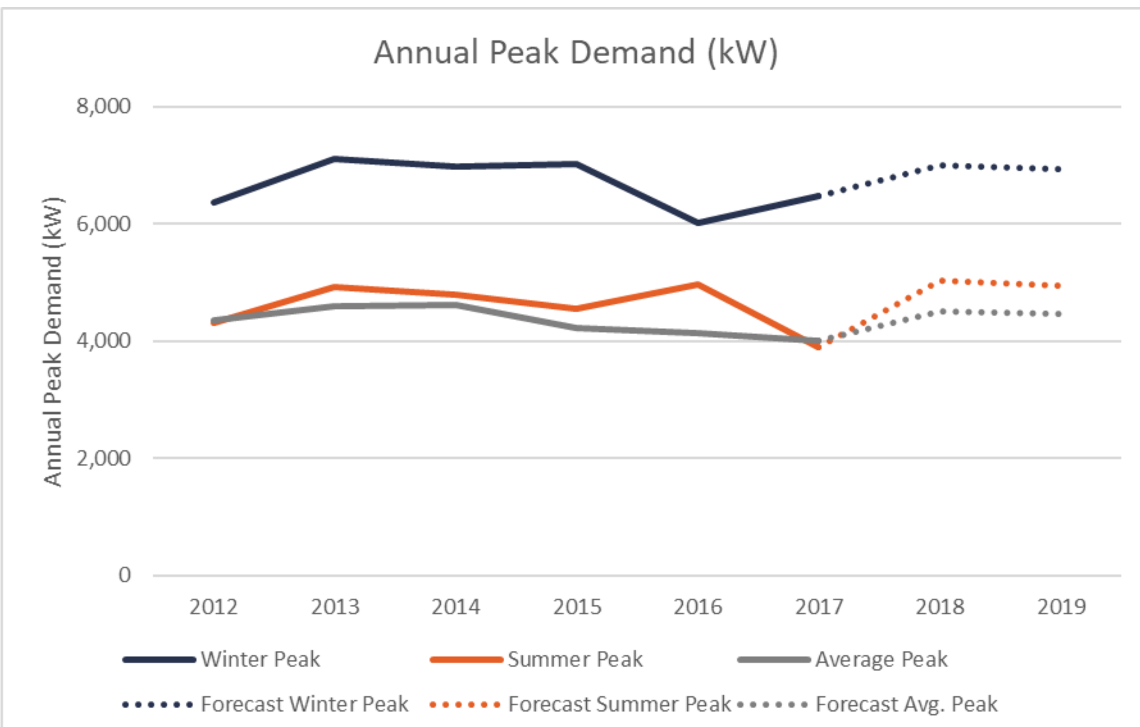


Table 2 Peak system demand statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2012 Actual	6,359	4,316	4,362
2013 Actual	7,119	4,923	4,603
2014 Actual	6,991	4,805	4,620
2015 Actual	7,029	4,548	4,230
2016 Actual	6,023	4,979	4,133
2017 Actual	6,489	3,889	4,017
2018 Projected	*6,993*	*5,032*	*4,504*
2019 Projected	*6,940*	*4,951*	*4,473*

Peak demand has gradually plateaued over the historical timeframe at CPUC. Consistent with northern climate supply areas, CPUC experiences its overall system peak during winter. Variances in seasonal peaks are attributable to varying winter conditions and loading impacts associated with the number of degree days and connection upgrades.

The table below indicates the efficiency of the kWh purchased by CPUC. Recently reported line loss reductions are a result of billing system adjustments to realign with IESO billing cycles and CPUC's continuing effort in mitigating its line loss. Projected values are based on a moving average of last four years.

Table 3 Efficiency of kWh purchased by CPUC

Annual kWh Purchased	Total kWh Delivered (excluding losses)	Total Distribution Losses (kWh)	Total kWh Purchased	Losses as % of Purchased
2012 Actual	26,150,008	1,979,556	28,011,153	7.07
2013 Actual	27,879,646	2,575,215	29,749,924	8.66
2014 Actual	27,940,070	2,000,106	29,940,176	6.68
2015 Actual	25,803,364	1,822,142	27,625,506	6.60
2016 Actual	24,574,839	1,562,885	26,137,724	5.98
2017 Actual	24,573,208	1,643,301	26,216,509	6.27
2018 Projected	*26,420,264*	*1,757,109*	*27,479,979*	*6.38*
2019 Projected	*26,332,189*	*1,696,359*	*26,864,929*	*6.31*

1.4 Background & Drivers

The Filing Requirements outline four categories of investment into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories are included in the category corresponding to the trigger driver. However, all drivers of a given project or activity were considered in the analysis of capital investment options and are further described in Section 4 of the DSP. All major investments and programs planned by CPUC fall into the system renewal category. There are no planned investments related to system access, system service or general plant.

Table 4 provides a summary of the applicable drivers considered for CPUC's projects for each investment category.

Table 4 Summary of CPUC's Major Drivers for Projects

Category	Primary Driver	Projects/Programs/Activities
System Access	Customer service requests Mandated service obligation	No major investments or programs are forecast within this DSP period that would reach the materiality threshold.
System Renewal	Failure risk	Overhead Renewal Program
System Service	No major investments or programs are forecast within this DSP period.	
General Plant	No major investments or programs are forecast within this DSP period.	

2 DISTRIBUTION SYSTEM PLAN (5.2)

Section 2.1 provides an overview of the DSP, Section 2.2 summarizes coordinated planning activities with third parties, Section 2.3 covers performance measurements to continuously improve asset management and capital expenditure planning processes, and Section 2.4 covers realized efficiencies due to smart meters.

2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to CPUC's asset management processes, aspects of the DSP that are contingent on the outcome of ongoing activities or future events and how the planned projects address the goals of the provincial government's Long-Term Energy Plan ("**LTEP**").

2.1.1 Key Elements of the DSP (5.2.1a)

Table 5 presents the capital expenditures by investment category and the system operations and maintenance ("**O&M**") costs for both the historical and forecast period. Expenditures within the 2014-2017 historical period are actual expenditures, whereas expenditures for 2018 is the expected historical (i.e. Bridge Year) expenditures, as the 2018 year has not yet concluded as of this writing.

Table 5 Historical and forecast capital expenditures and system O&M

Category	Historical ($ '000)					Forecast ($ '000)				
	2014	2015	2016	2017	2018*	2019	2020	2021	2022	2023
System Access (Gross)	-	0.5	1.0	19.7	8.0	-	-	-	-	-
System Renewal (Gross)	18.9	45.9	35.3	4.4	34.4	80.7	80.7	80.7	80.7	80.7
System Service (Gross)	25.0	-	0.1	-	32.5	-	-	-	-	-
General Plant (Gross)	-	54.8	-	-	506.4	-	-	-	-	-
Gross Capital Expenses	43.9	101.2	36.4	24.1	581.3	80.7	80.7	80.7	80.7	80.7
Contributed Capital	-	-	-	-	-	-	-	-	-	-
Net Capital Expenses after Contributions	43.9	101.2	36.4	24.1	581.3	80.7	80.7	80.7	80.7	80.7
System O&M	744.7	730.6	744.0	716.6	797.8	813.8	805.8	809.8	807.8	808.8

**8 months of actual expenditures included in 2018*

Within the current DSP timeline, CPUC will continue with like-for-like system renewal at an accelerated pace to address the continuing aging system distribution. Based on the similarities in asset age profile, the analysis of current information has concluded that asset renewal for other asset categories will follow essentially the same schedule as pole replacement. Specifically, assets such as customer transformers, system switches, conductors, etc. were assumed to be subject to the same vintage replacement criteria as the poles to which they were attached. The forecast plan is the required system renewal to plan appropriately asset replacements while maintaining CPUC's reliable, safe and secure service.

CPUC is following a recommended option after a completed line loss assessment. The option is to expend $20-100k on transformer testing and rehabilitation, with the objective of delaying the station replacement 5-10 years. In the meantime, increasing the pole replacement renewal as much as practical for 5-7 years, to establish one or two feeders ready for voltage conversion (allowing for voltage converters), then replacing transformers as needed, and converting the rest of the poles might allow for the $2Million conversion costs to be spread over 10-15 years. The primary risks would be the potential for a transformer to fail early, or for poles to start to fail quickly, both of which can be managed with increased monitoring and risk assessment. This plan will allow for a staging of capital costs, and a parallel improvement in cost of losses which would commence once the voltage conversion begins.

Within a 20-year timeline, CPUC will convert its 4.16-kV distribution infrastructure system to 25 kV by building a new substation and changing the conductors, poles and associated equipment over the next 20 years. The voltage conversion will result in several benefits, including:

- Reduced line losses;
- Providing an opportunity to introduce contingency points to increase system reliability and making the system more resilient to high-impacting outages;
- Providing an opportunity to offset intrinsic investments required for replacement of end of life assets;
- Increased shareholder value; and
- Distributed rate impacts over a 20-year period versus an immediate rate impact.

The long-term plan will consolidate CPUC's distribution assets at the 25-kV level, removing the interconnection points with Hydro One's 25-kV system. This project will become the singular focus of CPUC for long-term planning (the 20-year timeline). The significance of the project is such that it addresses numerous operational and business issues surrounding line loss mitigation, reliability improvements, asset renewal and standardization of system assets.

Investments into the categories of System Access, System Service and General Plant in this DSP period will be minimal and under the materiality threshold set out in the Filing Requirements.

The investments have been aligned through the asset management process (Section 3) and review of customer preferences (Section 4.1.8). Throughout the planning process, CPUC has also considered field assessments, engineering judgement and system configuration to determine the needs of infrastructure investments.

The system O&M costs budgeted over the forecast period are, on average, 7.7% higher than the historical period costs. The main drivers for the increase in system O&M costs over the forecast period are:

- Increased O&M costs associated with IT systems; and
- Distribution system inspection cost increases to acquire condition data on assets.

2.1.2 Overview Customer Preferences and Expectations (5.2.1b)

CPUC admits that until this Cost of Service, it had taken a passive more reactive approach to customer service but that in preparing the application, CPUC was reminded of the value of the Renewed Regulatory Framework for Electricity which contemplates enhanced engagement between distributors and their customers to better align a distributor's operational plans with its customers' needs and expectations.

In response, CPUC is increasing its efforts in engaging customers to understand their needs better. CPUC always has and will continue to focus on its customers by striving to provide superior service to its customer base. The utility is investing time and effort in new capabilities, programs, and technologies that allow it to communicate more effectively and efficiently with our customers.

With CPUC's most recent engagement, the utility sent out a 2-page summary of its 2017 and 2018 proposed capital budget as bill inserts to all customers and posted on its website and social media outlets. The two-page summary highlighted the bill impact that will be seen by the customers for the next five years. The few responses that were received is a general understanding as to why there is a bill increase and the required need for CPUC to invest into its distribution system. CPUC's letter and responses received can be found in *Exhibit 1 – Administrative Documents*.

Based on past customer interactions and surveys, CPUC has concluded that customer preferences fall into four categories, in order of priority (highest to lowest), as follows:

- Reliability – continuity of electrical supply.
- Cost – lowest possible cost, accepting modest rate increases as required to refresh assets.
- Quality – the absence of momentary interruptions and non-standard voltage levels.
- Process – answering the phone, as accuracy of customer bills, timely construction of new service connections and upgrades to electrical services and outage notices that are given far enough ahead of the outage to allow action or reaction by the customer.

2.1.3 Anticipated Sources of Cost Savings (5.2.1c)

Within the current DSP period, CPUC is targeting a like-for-like replacement of assets of those that have failed and are in poor condition but with a focused approach in preparation for the voltage conversion project in the next DSP timeline. Planned replacements allow for assets to be replaced with a minimal cost impact to its business as well as its customers. CPUC targets assets that either reach their typical useful life, are identified to be in poor condition through its visual inspections or need to be relocated. Replacing these assets in a proactive approach versus a reactive approach will result in lower costs. In addition to the proactive approach, CPUC prioritizes to relocate transformers over purchasing and installing newer transformers to reduce the cost impact on its customers. Only transformers deemed to be a risk to the public safety, environment or the system's reliability will be replaced.

Additionally, with each replacement, CPUC is standardizing its designs that meet the requirements of the *Distribution System Code* ("**DSC**") and the *Electrical Safety Authority Reg 22/04* ("**ESA**") for a 25-kV circuit. The use of standardized designs reduces the resource requirements of project design. Standardized component lists reduce the spare inventory that CPUC must hold.

Presently, CPUC is undertaking the following initiatives that will result in further additional cost savings for this DSP period:

- CPUC is sampling its meters to determine if they are operating and reading at acceptable level. Should the meters be tested positive, CPUC can extend the seal life of its meters by eight years, further reducing the costs and allowing CPUC to invest in its assets
- CPUC is completing a station power transformer dehydration in order to extend the life of the station transformers. This action resulted in mitigating the impact on the customer bill; and it allowed for investments to be directed into the asset renewal program.

Moving forward, the asset replacement resulting from the voltage conversion from 4.16 kV to 25 kV in future DSP timeline periods is expected to have a number of positive impacts on future O&M costs:

- Replacing the poles in the 4.16-kV system during the voltage conversion will reduce the frequency of pole failure and the costs associated with outage response and reactive replacement.
- Legacy units, such as transformers and switches, that can no longer be economically maintained will be replaced and will result in a much less labour-intensive program of inspection and corrective maintenance as required, as opposed to the periodic preventive maintenance required for legacy assets.
- The voltage conversion will reduce line losses.
- The inherent replacement of older assets will have a positive impact on overall system reliability, resulting in lower costs associated with outage response.
- This investment also mitigates increased staff resource costs that would be required to deal with an otherwise more frequent rate of system failure.

2.1.4 Period Covered by DSP (5.2.1d)

The planning horizon for this DSP covers ten years with a five-year historical period of 2014 to 2018, where 2018 is the Bridge Year, and a five-year forecast period of 2019 to 2023, where 2019 is the Test Year.

2.1.5 Vintage of the Information (5.2.1e)

The information contained in this DSP is current as of August 2018. There are no ongoing activities or future events anticipated that will materially change this DSP.

2.1.6 Important Changes to Asset Management Processes (5.2.1f)

This DSP is a significant advancement in the application of asset management principles by CPUC. The intent is to use the developing asset management process to draw a roadmap for future developments and improvements. The asset management process will be continually improved and implemented over the forecast period by adding additional asset data and analytics to CPUC's future asset and program planning.

2.1.7 DSP Contingencies (5.2.1g)

System Access investments over the forecast period are expected to be limited due to no load or customer growth but are unknown at the time of filing – the project specifics and costs are not known until a request is made. These investments are contingent upon municipal work as well as customer work; however, CPUC can manage any requests due to the small number of projects planned.

Stakeholder interests can be categorized into the four RRF objectives: customer focus, operational effectiveness, public policy responsiveness and financial performance. Stakeholder interests are not expected to change within the DSP period, however they would be a contingency to CPUC's planned investment should they change drastically. CPUC accommodates stakeholder interests as summarized in Table 6.

Table 6 Stakeholder interest accommodation

RRF Objective	*How CPUC accommodates stakeholder interests*
Customer Focus (Service Quality and Customer Satisfaction)	CPUC conducted a customer survey to determine customer preferences and customers indicated that they expect their utility to provide consistent and reliable service. Customers also want improvement in communications. To address customer preferences, CPUC will continue to effectively maintain its infrastructure and invest in reducing line losses and sustaining system reliability.
Financial Performance	CPUC's strategy must be cost-effective and, at the same time, be sufficient to continue to balance distribution system reliability, efficiency and return on investment.
Operational Effectiveness	CPUC intends to maintain a reliable system and will implement this DSP in an effective manner to benefit the interests of all key stakeholders. CPUC intends to keep the public and its staff safe by ensuring all assets are structurally sound and by continuously improving its safety management program.
Public Policy Responsiveness	CPUC will continue to deliver on obligations mandated by the government. CPUC continues to investigate possible smart grid development.

Additionally, CPUC is sampling its meters to determine if they are operating and reading at acceptable level. Should the meters be tested positive, CPUC can extend the seal life of its meters by eight years, further reducing the costs and allowing CPUC to invest in its assets. If the meter sample returns a negative test, a meter replacement program will have to be planned and initiated. CPUC recognizes this as a small risk and expects the sampling test to return as positive.

2.1.8 Grid Modernization, Energy Resources & Climate Change Adaptation (5.2.1h)

CPUC is committed to following the provincial government's Long-Term Energy Plan ("**LTEP**"), where possible for an LDC of CPUC's size. Within the historical period, the majority of planned projects involved either mandated service requests or minimal infrastructure renewal to mitigate any major asset failures. In return, CPUC provided affordable service to its customers. Moving forward, CPUC's planned projects continue to address the minimum infrastructure renewal at an increased rate to maintain the system health, as well targeting replacements to prepare feeders for a voltage conversion over a 20-year timeline. With completion of the voltage conversion, the line loss experienced on the system will be drastically reduced which will reduce the cost to the customers.

The planned renewals will provide many benefits and addresses the key initiatives found in the LTEP that pertain to CPUC, including:

- Maintaining asset health through the planned replacement program ensures affordable prices and accessible energy for customers;
- Converting the legacy 4.16-kV system to a modern 25-kV system facilitates grid modernization and improves the flexibility of the electricity system;
- Improving customer value and performance in key customer measures such as reliability;
- Modernizing the grid by reducing CPUC's dependency on Hydro One's station and allowing for renewable energy and energy storage solutions to be implemented if there is an identified need from the customers;
- Informing the customers of available energy efficiency options through customer engagement initiatives;
- Minimizing climate change impacts by reducing energy losses and trying to reuse/relocate transformers as much as possible versus buying new transformers; and

- Improving the system's efficiency by reducing line losses over the 20-year timeline.

2.2 Coordinated Planning with Third Parties (5.2.2)

The forecast loads at the points of interconnection are not expected to grow in the planning period. Although REG projects have been identified and preliminary work has been completed on connection impact assessments, the absence of a regional plan results in uncertainty with regards to CPUC's plans to accommodate REG and smart grid investments. Until plans are developed to address the capacity limitations of Hydro One's transmission facilities, definitive plans surrounding required investments are not feasible.

2.2.1.1 *Consultation with Regionally Interconnected Distributors*

CPUC has consulted with regionally interconnected distributors and transmitter(s) to which the distributor is connected through the regional planning process. Further consultations will be initiated as the need arises.

Within the historical period, CPUC has attended meetings with Hydro One to maintain perspective on the issue of supply and will continue to work towards a collaborative approach with Hydro One to seek common understanding of issues with respect to supply conditions and available capacity. These meetings are initiated by either CPUC or Hydro One. The resulting outcome is the decision for CPUC to off-load their feeders from the Hydro One station by upgrading CPUC's station and converting CPUC's feeders to 25 kV.

2.2.1.2 *Regional Planning Process*

Regional planning at CPUC is conducted through the Integrated Regional Resource Planning ("**IRRP**") process, whereby local stakeholders collaborate in the development of integrated solutions for maintaining a reliable supply of electricity to Ontario communities. The regional planning process begins with a needs assessment performed by the transmitter which determines whether a regional plan is required. If a regional plan is required, the IESO then conducts a scoping assessment to determine whether a more comprehensive IRRP is required (led by the IESO) or a more transmission (and distribution)-focused Regional Infrastructure Plan is required (led by the transmitter).

The objective of the IRRP process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options, such as conservation and demand management, distributed generation, and large-scale generation, transmission and distribution.

Planning the distribution system infrastructure in a regional context will help promote the cost-effective development of electricity infrastructure in Ontario. Regional planning is conducted through the IRRP process where local stakeholders collaborate in the development of integrated solutions for maintaining a reliable supply of electricity to Ontario communities. The map below shows Ontario's 21 electricity regions.

Figure 4 Map electricity regions

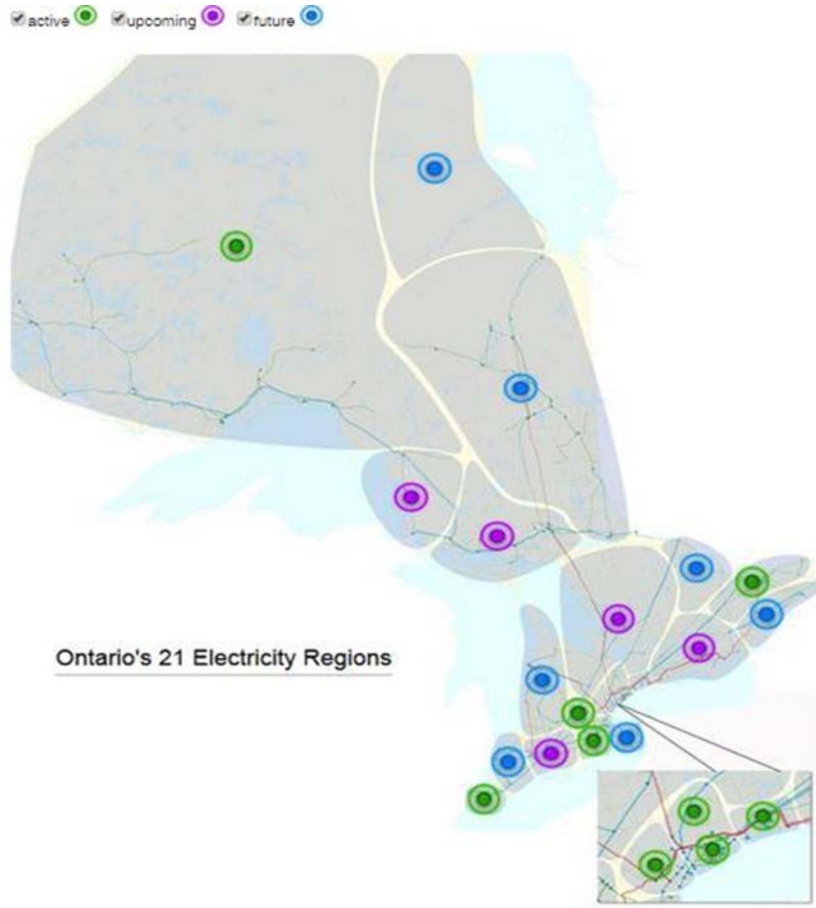


Figure 5 Electricity regions by group

Regions

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA North	Peterborough to Kingston	Niagara
GTA East	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener-Waterloo-Cambridge-Guelph		Renfrew
Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

The objective of the IRRP process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options, such as conservation and demand management, distributed generation, large-scale generation, transmission and distribution.

As per regional planning initiative, the province is divided into three planning groups:

- Group 1 & Group 2 – Active Plans
- Group 3 – Upcoming Plans

CPUC is part of regional planning Group 2 of East Lake Superior Region. The Great Lakes Power Transmission ("**GLPT**") has been assigned the lead role in the East Lake Superior ("**ELS**") Region, which is prioritized in Group 2.

The ELS Region includes all of GLPT's 560 km of transmission lines as well as ties to the provincial grid at Hydro One's Wawa TS in the North West and Mississagi TS in the North East plus the Hydro One's 115 kV line supplied from Wawa TS. East Lake Superior Distribution Companies include Algoma Power Inc., PUC Distribution Inc., Hydro One Distribution and Chapleau Public Utility Corporation.

GLPT along with all stakeholders in the region will evaluate the electrical infrastructure needs such as growth, reliability and end of life of major system components. If deemed necessary, a Regional Infrastructure plan will be developed to identify alternatives and recommend solutions.

The stages of the process are described in the Working Group Report to the OEB (Appendix A). For the process to be sustainable it is expected that the process will have a minimum cycle review of 5 years; this may occur sooner if an unexpected planning concern triggers the regional planning process. Information from the municipal development department is also used to project the amount of customer-driven activity (such as community upgrades or new commercial construction). Most of these customer-driven projects are accommodated with minimal changes to the distribution system. These projects fit into the annual capital budget directly and are used to allocate the customer driven portion of the five-year capital budget.

As the lead Transmitter, GLPT completed the ELS Region planning process on December 12, 2014 with the issuing of a final ELS Region - *Needs Assessment Report* to team members as well as posting the report on this GLPT web-site[1]. The ELS team was composed of participants representing GLPT, IESO, Hydro One, Algoma Power Inc., PUC Distribution Inc. and Chapleau Public Utilities Corporation.

The report did not recommend the need for any further regional planning so there will not be any need for an IESO Scoping Process for the ELS Region. The report did contain three recommendations on issues that do not require further regional coordination; the three issues are "localized" wire-only solutions and are to be developed by GLPT and the impacted distributor or customer.

With the issuing of the *Needs Assessment Report* on December 12, 2014, the regional planning process was completed. GLPT plans to undertake the next regional planning process in five years (2019) as outlined by the *Transmission System Code*, unless there is sufficient load growth or a trigger event that requires the initiating of the regional planning process.

CPUC's DSP is not affected by the historical IRRP consultations and does not expect to have an impact within the forecast years of the DSP period.

[1] http://www.glp.ca/eng_content/_regional_planning_new/planning_status-40891.html

2.2.2 IESO Comment Letter (5.2.2d)

CPUC has received a comment letter from the IESO with regards to long-term system limitations and/or plans for future development and it is included in Appendix B.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

CPUC relies on the OEB`s Electricity Distributor Scorecard to provide the metrics, feedback and trends needed to assess performance gaps. Where applicable, the performance measures included on the scorecard have an established minimum level of performance expected to be achieved (referred as the "**OEB Target**"). The scorecard is also used to continuously improve CPUC's asset management and capital planning process.

Each year CPUC reports on scorecard performance results to the OEB. CPUC's current performance state is represented by CPUC's official scorecard results for 2017 as published by OEB. The scorecard helps CPUC operate effectively, while continually seeking ways to improve productivity and focus on improvements. The scorecard is designed to track and show CPUC's performance results over time and helps to clearly benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer.

Each metric provided influences CPUC's DSP to achieve the best performance providing a reliable, secure and safe service for its customers. The following sections addresses performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements. The OEB scorecard is shown in Appendix C. The table below summarizes the performance metrics for CPUC. Each performance measure that has an established OEB target is highlighted within the table. Each performance measure has CPUC's intended action on delivering the target within this DSP.

Table 7 DSP Performance Metrics for CPUC

Performance Outcome	Measure	Motivation	Metric	CPUC Action	Scorecard Target
Customer-oriented performance	Service Quality	Regulatory/ Customer	New Residential/Small Business Services Connected on Time	Maintain	90%
			Scheduled Appointments Met on Time	Maintain	90%
			Telephone Calls Answered on Time	Maintain	65%
	Customer Satisfaction	Customer	First Contact Resolution	Maintain	
			Billing Accuracy	Maintain	98%
			Customer Satisfaction Survey Results	Maintain	
	System Reliability	Regulatory/ Customer	SAIDI	Monitor	1.36
			SAIFI	Monitor	0.92
Cost Efficiency & Effectiveness	Cost Control	Regulatory/ Customer/ Corporate	Efficiency Assessment	Improve	
			Total Cost per Customer	Monitor	
			Total Cost per km of Line	Monitor	
			O&M Cost per Customer	Monitor	
			O&M Cost per km of Line	Monitor	
			O&M Cost per MW of Average Peak Capacity	Monitor	
	Asset Management	Corporate/ Regulatory	Distribution System Plan Implementation Progress	Monitor	
Asset/system operations performance	Safety	Regulatory/ Corporate	Level of Public Awareness	Improve	
			Level of Compliance with Ontario Regulation 22/04	Maintain	C
			Serious Electrical Incident Index	Maintain	0
	Distribution Losses	Corporate	Line Losses	Improve	3.82%

2.3.1 Customer-Oriented Performance

2.3.1.1 *Customer Focus*

2.3.1.1.1 Methods and Measures

Customer focus performance measures can be broken down into two major groups: Service Quality and Customer Satisfaction.

Service Quality measures include includes: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. All these measures are self-explanatory in nature and all relate to CPUC's high quality in providing their connection services as well as their customer services. CPUC is committed to meeting and exceeding all targets found in the Service Quality performance measure group. Historically, CPUC has not experienced many service upgrades or connections for new residential homes or small business services; however, when CPUC does receive a request it is targeted for completion within five days. CPUC uses the established OEB Targets for these measures and relies on their friendly staff to meet these targets.

Customer Satisfaction measures include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. CPUC uses the OEB Targets for these measures and relies on their friendly staff to meet these targets.

CPUC's unique "small town" environment affords CPUC staff the ability to readily communicate informally at various local social venues within the Town of Chapleau. This facilitates clear dissemination of information and is significantly more effective and aligned with CPUC customers' preferred mode of communication. CPUC now has a Facebook page and Twitter account to encourage customer engagement. The social media sites are used to provide information on power outages, energy savings ideas, electrical safety, and billing information to customers. Additionally, CPUC logs all complaints, which are addressed personally and in a timely fashion.

In 2014, CPUC has recognized the importance that stakeholder engagement plays in determining customer preferences and chose, as a more appropriate method, to conduct customer consultation via targeted surveys and direct phone interviews. The survey was conducted through telephone interviews, based on a customer list provided by CPUC. It was offered in both official languages (English and French - 20% of the respondents were French-speaking).

Customer responses to targeted questions were also used to determine customer preferences for investment decisions and asset management planning.

2.3.1.1.2 Historical Performance

Service Quality

Table 8 Service Quality Historical Performance

Measure	2013	2014	2015	2016	2017
New Residential / Small Business Services Connected on time	100%	100%	100%	100%	100%
Scheduled Appointments Met on Time	100%	100%	100%	100%	100%
Telephone Calls Answered on Time	100%	100%	100%	100%	99.68%

CPUC has maintained an excellent performance exceeding the industry average. The combined average of the three Service Quality measures is 100%. This includes New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. CPUC maintains their commitment to complete corrections within the five-day timeline. Additionally, CPUC is enabled to answer all calls in a 30-second time period. This enablement is due to the utilities' location in a small town which brings CPUC few connection requests, and manageable appointments and calls received.

Customer Satisfaction

Table 9 Customer Satisfaction Historical Performance

Measure	2013	2014	2015	2016	2017
First Contact Resolution	-	100%	100%	100%	100%
Billing Accuracy	-	100%	100%	100%	99.99%
Customer Satisfaction Survey Results	-	95%	95%	95%	95%

First Contact Resolution and Billing Accuracy were measured to be 100%. CPUC exceeded the industry average in billing accuracy by 1.99%. All complaints and inquiries are resolved within ten days. CPUC continues to strive for high billing accuracy results and addressing complaints in a timely fashion while continuing its ongoing effort to recognize any issues that may arise.

The customer feedback produced a Customer Satisfaction (CSAT) Score of 95%, which includes responses on rating the "overall customer satisfaction." The survey was developed in-house through a collaborative effort of, Hearst Power Distribution Company Limited Inc. Chapleau PUC., Hydro Hawkesbury, Cooperative Hydro Embrun and Hydro 2000 Inc. ("The Group"). (Note that Chapleau was not involved in the drafting of the survey but is now using it as their bi-annual survey) 2017's survey was created by Hearst using the Survey Monkey site.

The main purpose of the collaborative effort was to minimize the cost of the survey by the sharing of intellect and resources. CPUC felt that using a in-house survey gives the utility more control and flexibility surrounding the delivery of the survey.

The utility used Survey Monkey to publish its survey and posted it on its website. A bill insert communicating the survey and prize was included in all bills. The ideal recommended sample size is determined to be 286. The margin of error is a measure of the precision of a sample estimate of the population value. It uses probability to substantite the precision of a sample estimate by providing a range of values in which a sample value would be expected to fall. The utility received 179 responses. The utility understand that the results may not be entirely representative of the customer's opinion and the utility commits to trying to improve its response rate in future surveys, however the utility submits that the 179 responses are the best results the utility could get. Going forward, the utility expects to focus its efforts on improving its communication with its customers.

2.3.1.1.3 Performance Trends into the DSP

CPUC has exceeded the industry targets for each service quality and customer satisfaction measure. CPUC's outstanding performance on these measures indicate no substantial additional material projects are required for investments and will continue its performance. CPUC continues to strive to better serve the customer with the highest excellence. CPUC's intended action for these measures is to maintain the performance.

The utility intends on continuing surveying its customers on a bi-annual basis in an effort monitor and assess residential and commercial customer knowledge, perceptions and satisfaction regarding utility services.

2.3.1.2 *System Reliability*

2.3.1.2.1 Methods and Measures

The reliable service supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's *Electricity Reporting & Record Keeping Requirements* dated May 3, 2016. SAIDI, or the System Average Interruption Duration Index, is the length of outage customers experience in the year on average, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

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

Loss of supply, LOS, outages occur due to problems associated with assets owned by another party then CPUC or the bulk electricity supply system. CPUC tracks SAIDI and SAIFI including and excluding LOS. Major Event Days, MEDs, are calculated using the IEEE Std 1366-2012 methodology. MEDs are then confirmed by assessing whether interruption was beyond the control of CPUC (i.e. force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

2.3.1.2.2 Historical Performance

CPUC's reliability indices for 2013-2017 are shown in the figures below.

Figure 6 Performance Measure - SAIDI

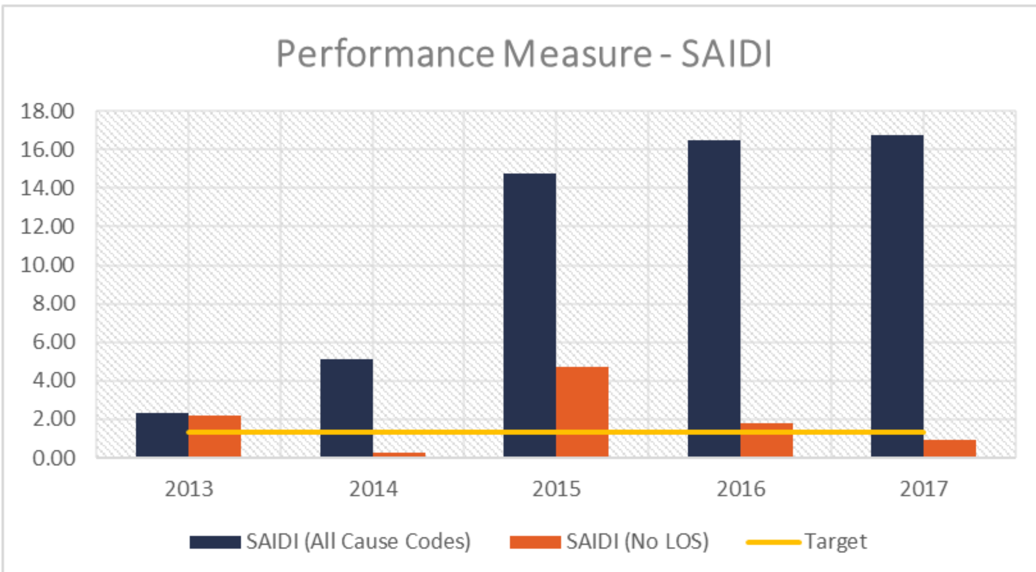
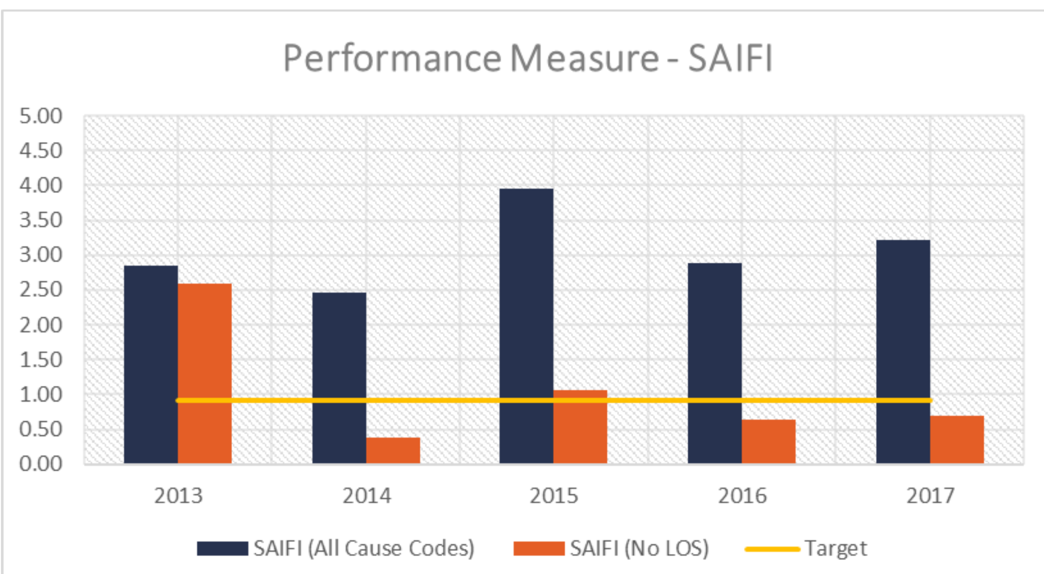


Figure 7 Performance Measure - SAIFI



The variance in 2013 SAIDI and SAIFI occurred when CPUC performed oil reclamation and re-inhibit treatment to its transformer station. This required three half-hour scheduled power outages to 1,001 customers. The future planned construction of distribution circuits to convert the existing aging 4.16kV circuits to the new standard of 25 kV level will improve the future reliability of supply be reducing the frequency of outages. Additionally, the variance in 2015 is due a higher amount of Foreign Interference experienced on the system as well as Scheduled Outages. Details on cause codes per year are provided below.

<u>Outage Details for Years 2013-2017</u>

The following sections and figures provide the breakdown of historical outages for years 2013-2017 regarding to number of outages, number of customers interrupted, and number of customer hours experienced by the outages. CPUC has not reported any MEDs between the years 2013 to 2017 and therefore are not included in the analysis.

<u>Outages Experienced</u>

Figure 8 presents the summation of outages experienced at CPUC with and without Loss of Supply (“LOS”). There is a relatively constant trend in the number of outages experienced without considering LOS. Table 10 presents the count of outages broken down by cause code. Additionally, Figure 9 and Table 11 present the main contributors to outages for years 2013 to 2017. Scheduled Outages and Defective Equipment contribute to half of the outages experienced at CPUC.

Figure 10 presents the number of outages related to defective equipment. An increasing historical trend is observed due to the aging distribution system. This supports CPUC’s DSP justification requiring investments into System Renewal.

Figure 8 Total Number of Outages (2013-2017)

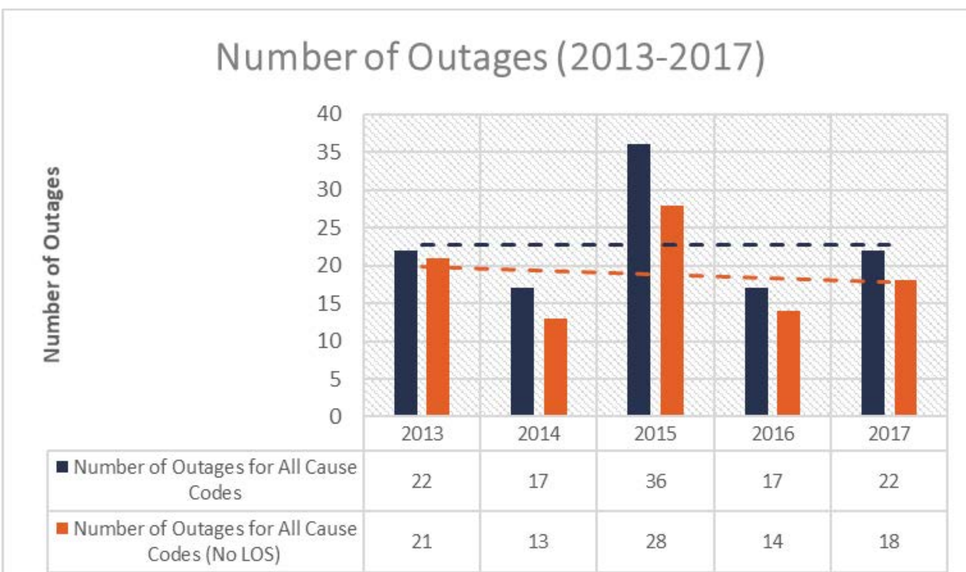


Table 10 Outage details broken down into cause codes (2013-2017)

Cause	2013	2014	2015	2016	2017
Scheduled	8	6	8	3	7
Loss Of Supply	1	4	8	3	4
Tree Contact	0	0	1	0	0
Defective Equipment	9	2	6	5	6
Adverse Weather	0	1	4	2	3
Human Element	1	0	0	0	1
Foreign Interference	3	4	8	4	1
Lightning	0	0	1	0	0

Figure 9 Outage Count contribution by Cause Code

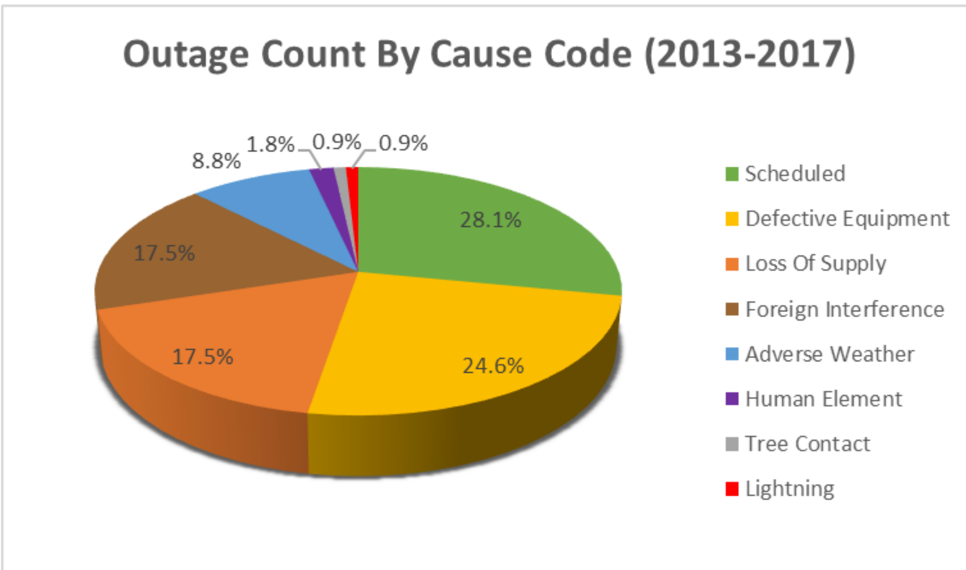
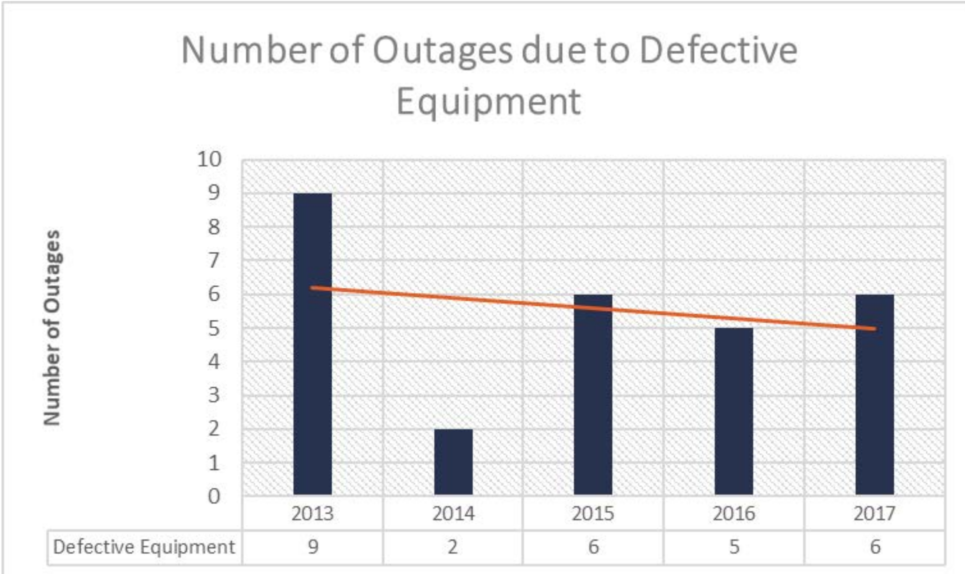


Table 11 Sum outage count and contribution by cause code

Cause Code	Total Outages (2013-2017)	Percent of Total Outages (2013-2017)
Scheduled	32	28.07%
Defective Equipment	28	24.56%
Loss Of Supply	20	17.54%
Foreign Interference	20	17.54%
Adverse Weather	10	8.77%
Human Element	2	1.75%
Tree Contact	1	0.88%
Lightning	1	0.88%

Figure 10 Number of Outages due to Defective Equipment



Customers Interrupted

Figure 11 presents the summation of customers interrupted at CPUC with and without LOS. A gradual decreasing trend can be seen on customers interrupted without LOS. This is a result of CPUC's continuing effort of mitigating outages where possible. However, a significant increase of customer interrupted can be seen with the inclusion of LOS figures. Table 12 presents the count of customers interrupted by cause code. Additionally, Figure 12 and Table 13 present the main contributors to customers interrupted for years 2013 to 2017. It can be seen LOS and Scheduled Outages are primary contributors for customers interrupted.

Figure 13 presents the number of customers interrupted related to defective equipment. An increasing historical trend is observed due to the aging distribution system. This supports CPUC's DSP justification requiring investments into System Renewal.

Figure 11 Total Number of Customers Interrupted (2013-2017)

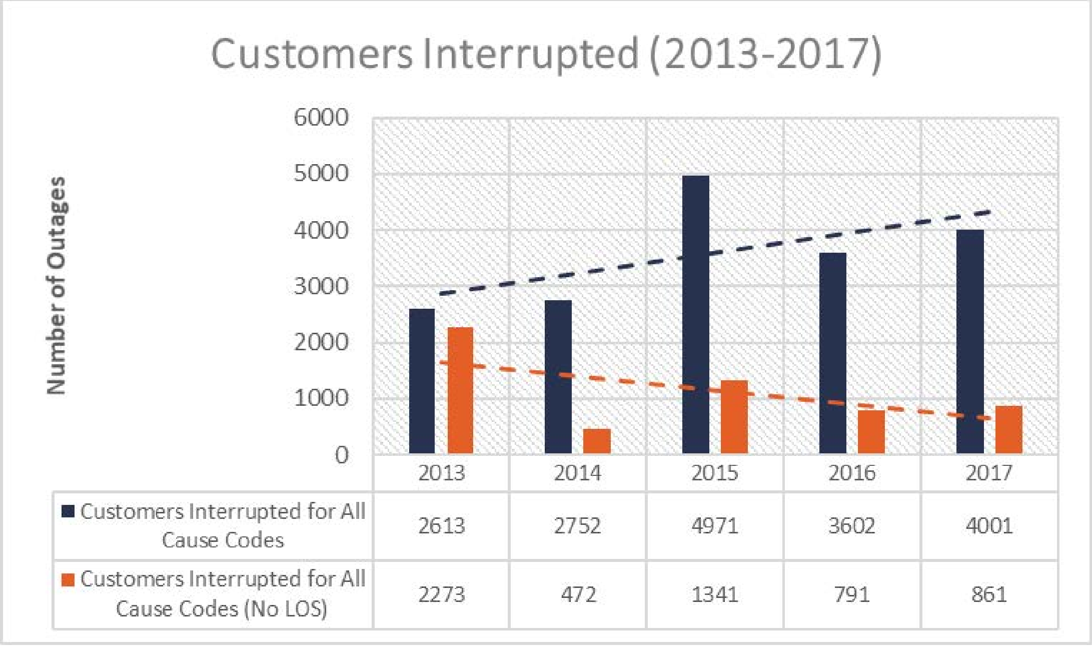


Table 12 Customers interrupted details broken down into cause codes (2013-2017)

Cause	2013	2014	2015	2016	2017
Scheduled	2206	50	954	339	50
Loss Of Supply	340	2280	3630	2811	3140
Tree Contact	0	0	1	0	0
Defective Equipment	39	26	24	191	99
Adverse Weather	0	208	43	240	694
Human Element	7	0	0	0	11
Foreign Interference	21	188	274	21	7
Lightning	0	0	45	0	0

Figure 12 Customers Interrupted contribution by Cause Code

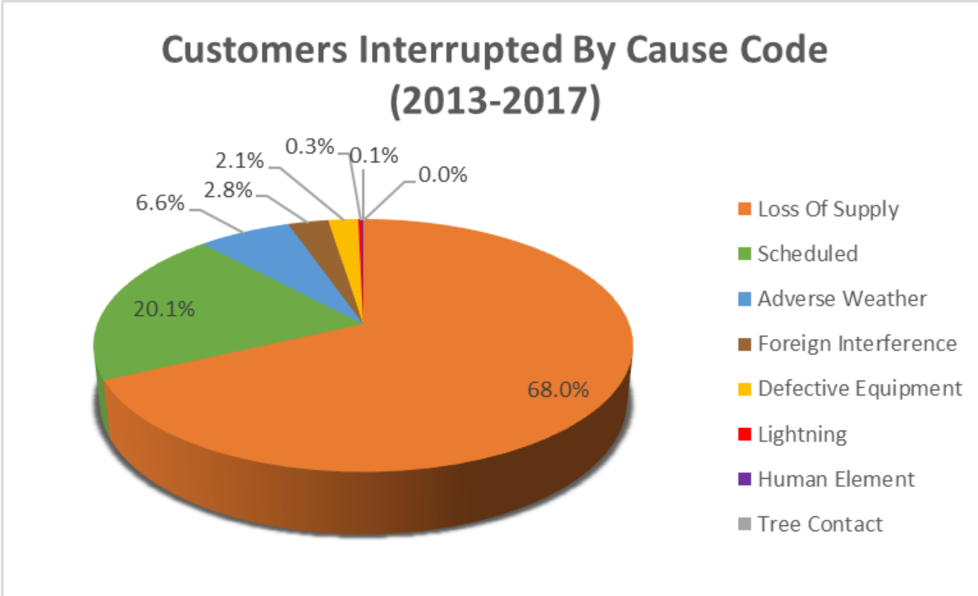
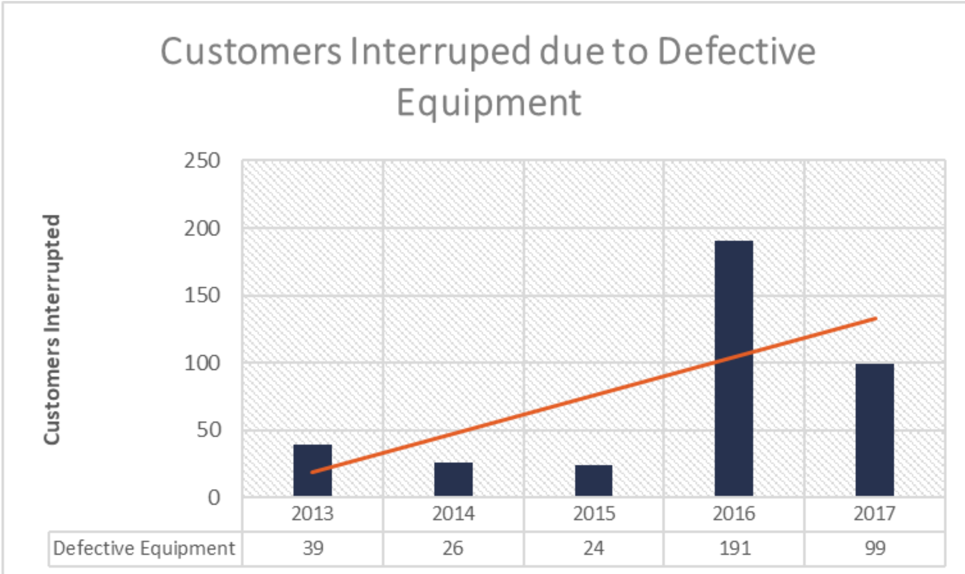


Table 13 Sum Customers Interrupted and contribution by cause code

Cause Code	Sum Customers Interrupted (2013-2017)	Percent of Customers Interrupted (2013-2017)
Loss Of Supply	12201	68.01%
Scheduled	3599	20.06%
Adverse Weather	1185	6.61%
Foreign Interference	511	2.85%
Defective Equipment	379	2.11%
Lightning	45	0.25%
Human Element	18	0.10%
Tree Contact	1	0.01%

Figure 13 Number of Customers Interrupted due to Defective Equipment



Customer Hours Interrupted

Figure 14 presents the summation of customer hours experienced at CPUC with and without LOS. A very slight increasing trend on the number of customer hours experienced without LOS is observed. CPUC's continuing effort in mitigating outages and addressing issues within a timely manner prevents the trend from increasing drastically. However, an increasing trend of customer hours experienced including LOS is witnessed. Table 14 presents the count of customer hours by cause code. Additionally, Figure 15 and Table 15 present the main contributors to outages for years 2013 to 2017. LOS and Scheduled Outages contribute to a significant portion of the customer hours experienced at CPUC.

Figure 16 presents the number of outages related to defective equipment. An increasing historical trend is observed due to the aging distribution system. This supports CPUC's DSP justification requiring investments into System Renewal.

Figure 14 Total Number of Customer Hours Interrupted (2013-2017)

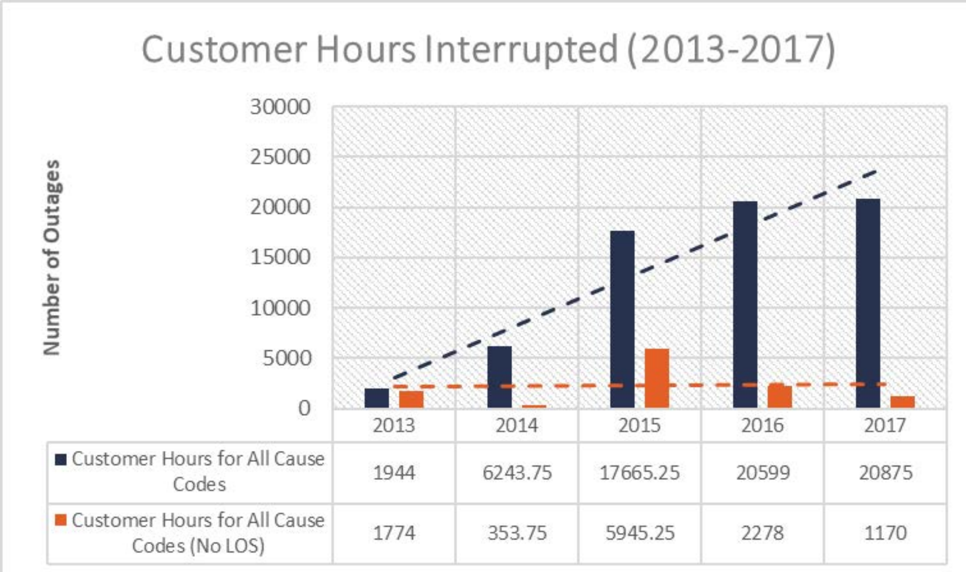


Table 14 Customer Hours interrupted details broken down into cause codes (2013-2017)

Cause	2013	2014	2015	2016	2017
Scheduled	1702.75	57	5605	1848.75	144.5
Loss Of Supply	170	5890	11720	18321	19705
Tree Contact	0	0	0.25	0	0
Defective Equipment	41.25	8.75	34.5	208	129
Adverse Weather	0	104	49	135.25	878.5
Human Element	7	0	0	0	11
Foreign Interference	23	184	211.5	86	7
Lightning	0	0	45	0	0

Figure 15 Customer Hours Interrupted contribution by Cause Code

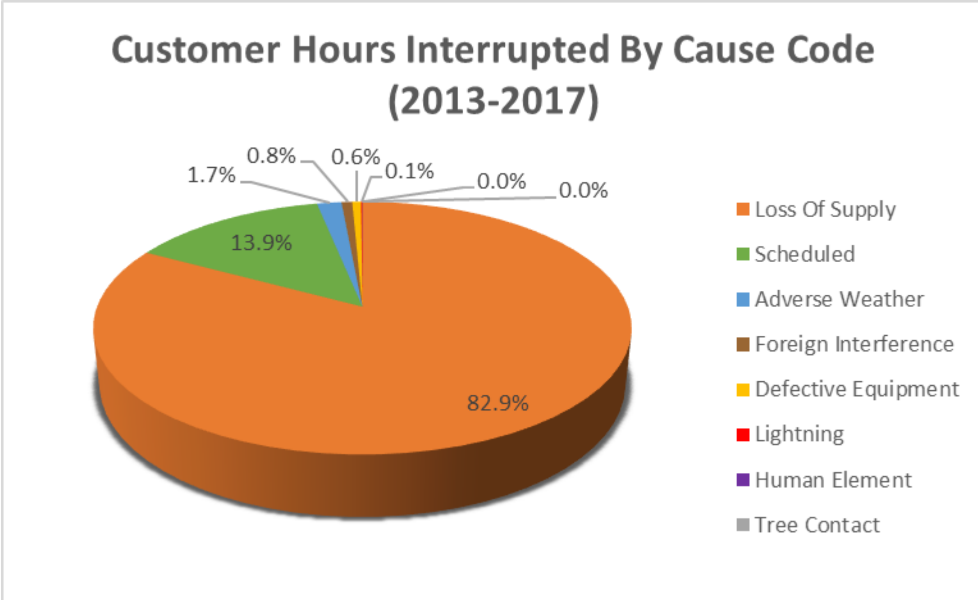
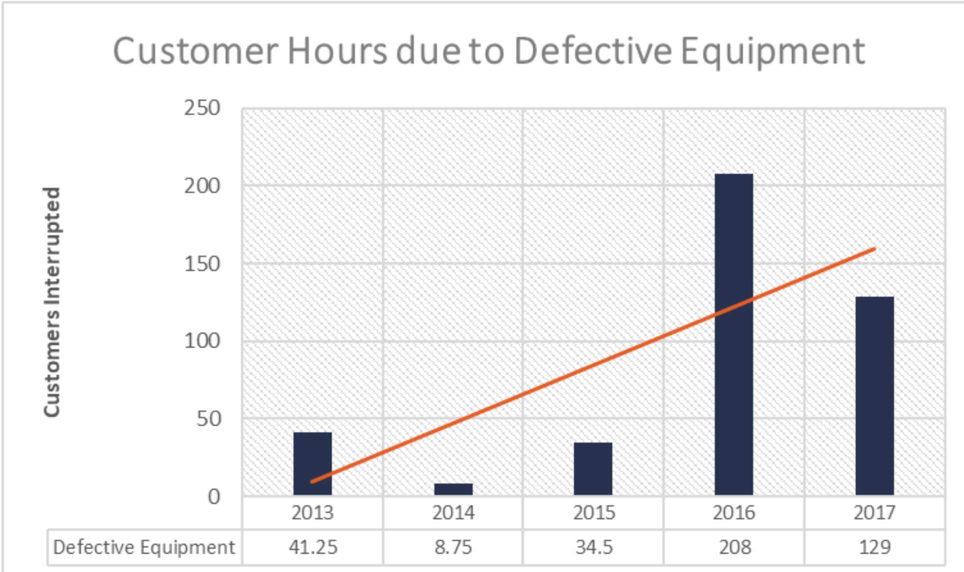


Table 15 Sum Customer Hours Interrupted and contribution by cause code

Cause Code	Sum Customer Hours Interrupted (2013-2017)	Percent of Customer Hours Interrupted (2013-2017)
Loss Of Supply	55806	82.89%
Scheduled	9358	13.90%
Adverse Weather	1166.75	1.73%
Foreign Interference	511.5	0.76%
Defective Equipment	421.5	0.63%
Lightning	45	0.07%
Human Element	18	0.03%
Tree Contact	0.25	0.00%

Figure 16 Number of Customer Hours due to Defective Equipment



2.3.1.2.3 Performance Trends into the DSP

In the most recent year, 2017, CPUC has achieved its SAIDI and SAIFI targets. Through good asset management, CPUC has been able to achieve these targets and plans to continue the trend through the required investments proposed within this DSP. The proposed investments will replace assets at or past their typical useful life which will help to reduce or maintain the amount of failures experienced from defective equipment. CPUC's intended action for these measures is to monitor the performance.

Additionally, CPUC plans on utilizing specialized contractors in assisting with its Overhead Renewal program. These contractors will be able to perform a portion of the work without requiring a scheduled outage. CPUC expects this will reduce the impact of scheduled outages moving forward.

2.3.2 Cost Efficiency and Effectiveness

2.3.2.1 *Cost Control*

2.3.2.1.1 Methods and Measures

Efficiency Assessment

Electricity distributors are divided into five groups based on the difference between their actual and predicted costs. CPUC is in Group IV. This group consists of utilities that have costs in excess of 10% to 25% of that predicted and receives a stretch factor of 0.45%. The 2016 Benchmarking update report has thirteen utilities in Group IV up from eleven in 2015.

Additional Cost Metrics

Managing costs is a responsibility taken seriously at CPUC. The levels of spending are measured and prudently controlled so that customer rates are minimally affected. Total cost per customer is calculated as the sum of CPUC's capital and operating costs and dividing this cost figure by the total number of customers the utility serves.

$$Cost/customer = \frac{\sum CPUC's\ capital\ costs}{Number\ of\ customer\ served}$$

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

$$\frac{Cost}{km\ of\ line} = \frac{\sum CPUC's\ capital\ costs}{Kilometers\ of\ line}$$

Additionally, CPUC can calculate the additional new metric introduced by OEB's newest update to Chapter 5; the O&M Cost per customer, O&M Cost per kilometer of line and O&M Cost per MW of Peak Capacity. The metrics are calculated with the total recoverable O&M costs divided by the respective number for each metric, defined as follows:

$$O\&M\ Cost/customer = \frac{\sum CPUC\ O\&M\ Cost}{Number\ of\ customer\ served}$$

$$O\&M\ Cost/km\ of\ line = \frac{\sum CPUC\ O\&M\ Cost}{Kilometers\ of\ line}$$

$$O\&M\ Cost/MW\ of\ Peak\ Capacity = \frac{\sum CPUC\ O\&M\ Cost}{Average\ Peak\ Capacity\ (MW)}$$

2.3.2.1.2 Historical Performance

Efficiency Assessment

The actual cost performance of 68 LDC's benchmarked was better than predicted by the model. August 2014-2016 cost performance for the industry improved by 0.88%. CPUC has experienced an increase in its total cost required to deliver quality and reliable services to its customers. Growth in employee compensation costs along with increase in renewal spending have all contributed to increased operating and capital costs. CPUC will continue working pro-actively with replacing assets and towards improving its ranking to a more efficient group.

Additional Cost Metrics

CPUC's cost metrics have historically fallen within a narrow range for the previous five years between with the latest year being an exception. CPUC's total cost per customer in 2017 was $718. This is approximately a 10% increase over the last five years, year 2017 inclusive. There is an increasing trend in cost with the increase of asset replacements needed to maintain the system health. The total costs per kilometre of line matched the trend of costs per customer for CPUC. The Town of Chapleau is experiencing a slight decrease in residents therefore the capital cost will be higher for a customer in a shrinking town population. The kilometres of line has not changed significantly but the reported capital cost had increased. Additionally, the O&M cost metrics as defined in the updated Chapter 5 Filing Requirements are presented in the figures below.

Figure 17 Performance Measure - Total Cost per Customer

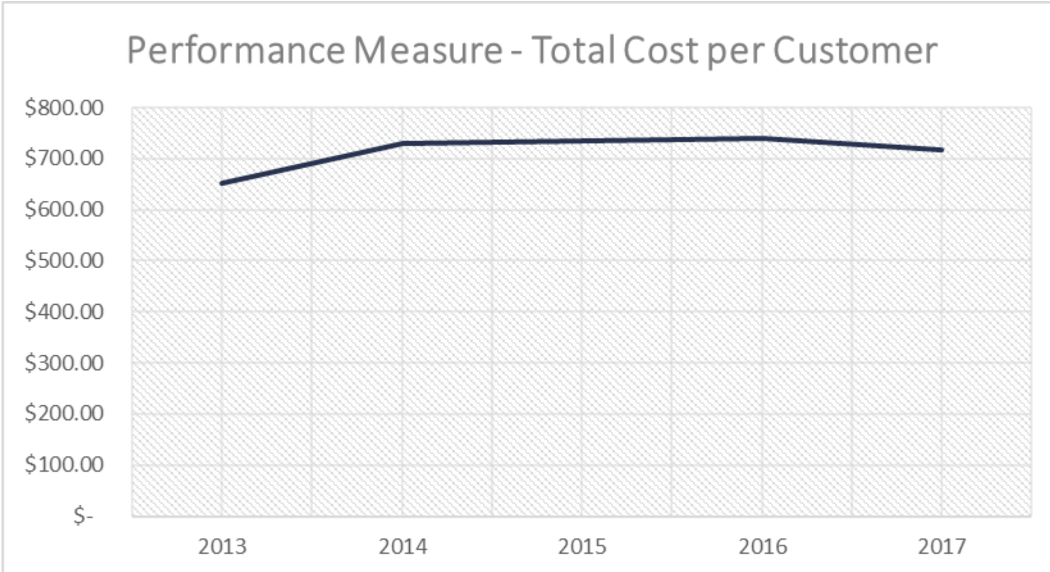


Figure 18 Performance Measure - Total Cost per Kilometer of Line

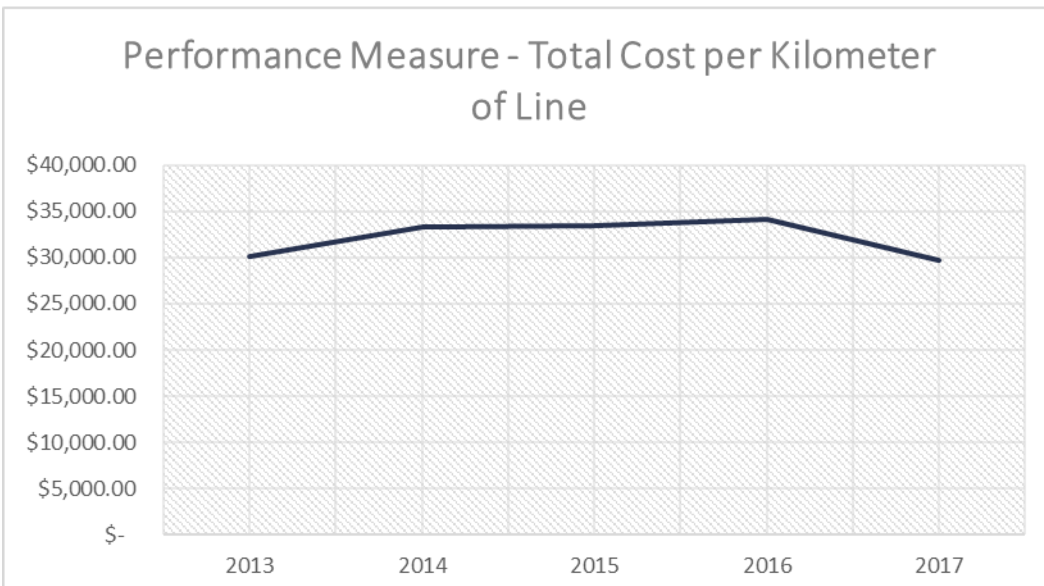


Figure 19 Performance Measure – O&M Cost per Customer

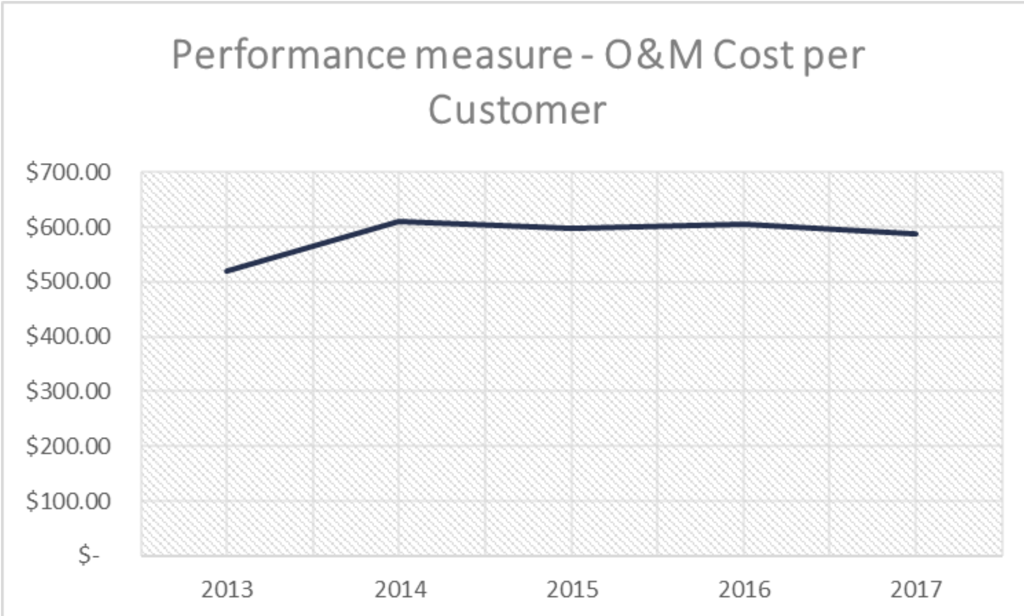


Figure 20 Performance Measure – O&M Cost per Kilometer of Line

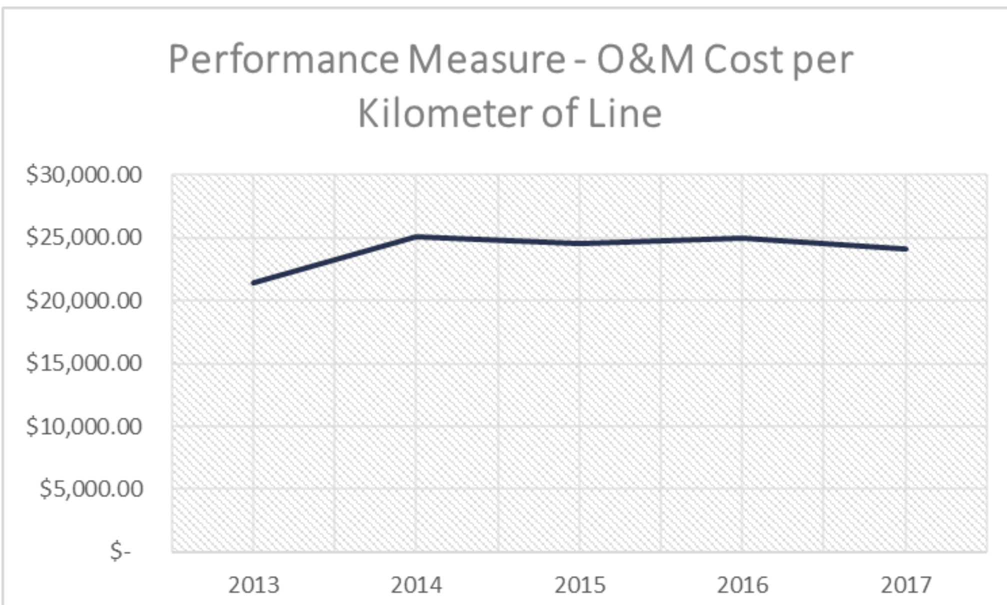
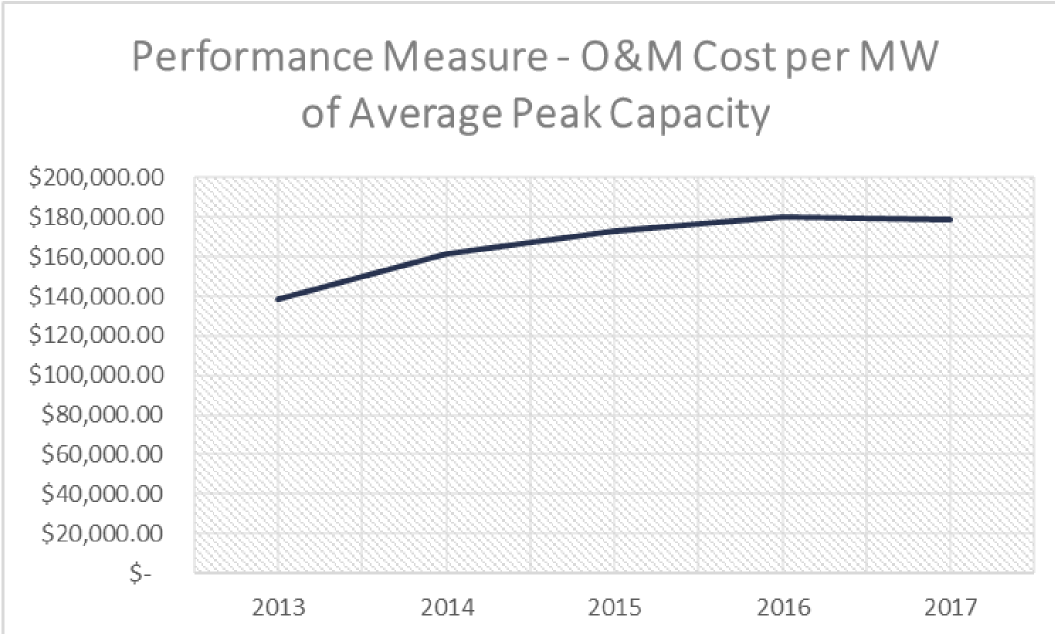


Figure 21 Performance Measure – O&M Cost per MW of Average Peak Capacity



2.3.2.1.3 Performance Trends into the DSP

With an increasing aging distribution system and the requirements to obtain asset condition assessments, the O&M cost metrics will remain steady whereas the increased renewal investment would increase the capital cost metrics. CPUC considers the projects that would have a minimal cost impact on customers but return a benefit to the quality of the service. These trade-offs are considered and communicated with customers to understand their preference. The renewal program considered within this DSP is a proactive approach so that CPUC would able to maintain its distribution system while mitigating the cost per customer as much as possible. CPUC's intended action for these measures is to monitor the performance, with the exception of the Efficiency Assessment performance measure where CPUC's intended action is to improve its performance.

2.3.2.2 *Asset Management*

2.3.2.2.1 Methods and Measures

The 'Distribution System Plan Implementation Progress' measure is a new metric under the RRF. CPUC began work preparing its DSP in 2018 to comply with the Filing Requirements for its Application. Significant efforts were made to date to collect and organize asset baseline data required in support of asset management and DSP preparation. This document is CPUC's first DSP. At the time this document was being prepared, a final version of the DSP had not been approved, and therefore no portion of the DSP has been deployed, and the DSP Implementation Progress Measure has not yet been assessed.

CPUC's DSP outlines how it will develop, manage and maintain its distribution system equipment to provide a safe, reliable, efficient and cost-effective service. Although this is CPUC's first DSP, CPUC previously engaged in planning capital projects that serve to develop and maintain its distribution system. Upon approval of CPUC's DSP, the following metrics are being explored for measuring the implementation of the DSP over the forecast period:

- Financial DSP progress: measuring the variance of planned annual expenditures to actual annual expenditures; and

- Projects completed: measuring the project/program completion of the DSP annually in terms of cost, asset counts and deliverance on time.

Targets for each measure are to be decided once CPUC receives approval on their DSP.

2.3.2.2.2 Historical Performance

Since there has been no historical DSP filed by CPUC, there is no historical performance to report for these performance metrics.

2.3.2.2.3 Performance Trends into the DSP

The DSP progress metrics have no direct impact to the material investments proposed within this DSP. CPUC's intended action for these measures is to monitor the performance.

2.3.3 Asset/ System Operations Performance

2.3.3.1 *Safety*

2.3.3.1.1 Methods and Measures

Safety is a standard performance measure reported by utilities in the Province under the RRF for each utilities'' scorecard. In 2014, the OEB asked the ESA to recommend an electrical safety measure for LDC scorecards. The first survey was completed in 2015 with 35 LDCs participating. CPUC participated in another survey in spring of 2016 along with Hearst Power, Northern Ontario Wires, Hawkesbury Hydro and Embrun Hydro. The safety measure is generated by the ESA and includes three components:

- Component A – Public Awareness of Electrical Safety
- Component B – Compliance with Ontario Regulation 22/04
- Component C – Serious Electrical Incident Index

2.3.3.1.2 Historical Performance

CPUC is fully engaged in a public safety awareness campaign delivered through its web site. CPUC is audited annually as part of *Regulation 22/04 – Electrical Distribution Safety* and its audit results indicate a full level of compliance. For each component CPUC performs very well with no reported electrical incidences no issues reported with compliance of Ontario Regulation 22/04. CPUC continues to strive for a higher public awareness in electrical safety while continuing its ongoing effort to keep the public safe from any incidents as well being compliant with Ontario Regulation 22/04. The table below highlights CPUC's historical performance for each of the three components.

Measure	2013	2014	2015	2016	2017
Public Awareness of Electrical Safety			76%	76%	79%
Compliance with Ontario Regulation 22/04 (1)	C	NI	C	C	C
Serious Electrical Incident Index	0	0	0	0	0

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

2.3.3.1.3 Performance Trends into the DSP

In the most recent year, 2017, CPUC has achieved its OEB Targets with regards to the utilities' safety performance. CPUC's outstanding performance on these measures indicate no substantial material projects are required for investments and will continue providing service at current levels of performance. CPUC continues to strive to serve its customers and employees with the highest degree of safety. CPUC's intended action for these measures is to maintain the performance apart from the Level of Public Awareness measure, where CPUC would like to improve the performance.

2.3.3.2 *Distribution Losses*

2.3.3.2.1 Methods and Measures

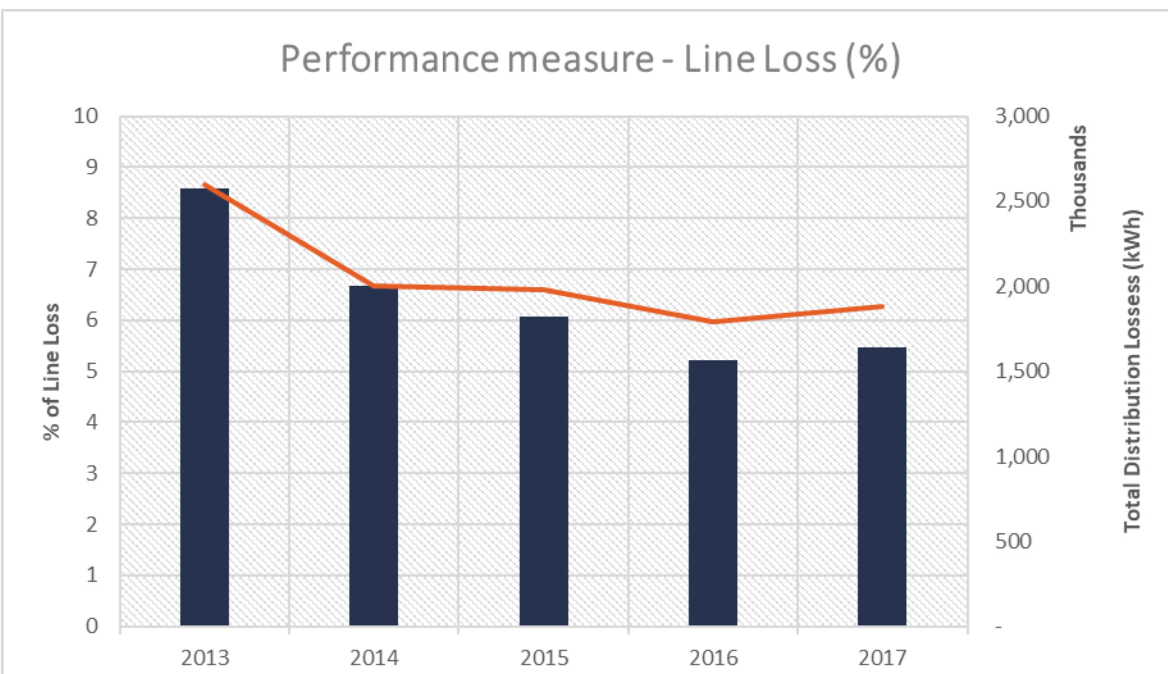
Distribution line losses refer to the difference between the amount of energy delivered to the distribution system and the amount of energy customers are billed. Distribution line losses are comprised of two types: technical and non-technical. Technical losses are primarily due to heat dissipation resulting from the impedance of current carrying elements of the Distribution System. Technical losses can be estimated analytically. Non-technical losses occur because of theft, billing errors, metering inaccuracies and unmetered energy. Such losses cannot be quantified analytically, other than by subtracting technical losses from total losses. Distribution system line loss is defined as the annual percentage line loss.

CPUC measures its losses by calculating the difference between the energy supplied and the energy purchased. CPUC's target for an acceptable line loss is the benchmarked average value of line loss for all LDCs in Ontario. In 2017, the average is 3.82%.

2.3.3.2.2 Historical Performance

CPUC purchased a total of 26,216,509 kWh in 2017 (of which 1,643,301 kWh account for distribution losses). Figure 22 presents the percentage line losses for the historical period of the DSP. CPUC has seen a decrease in line losses attributed to CPUC's continuing efforts to minimize line loss. CPUC recognizes that additional infrastructure renewal and voltage conversion efforts are required to reduce line losses to an acceptable target that is more closely aligned to the provincial average.

Figure 22 Line loss as percentage of purchased kWh



2.3.3.2.3 Performance Trends into the DSP

The distribution losses experienced on CPUC's distribution system is an identified priority that will be addressed over a long-term plan to minimize the cost impact on its customers and to complete what is achievable in each given year with the resources on hand. It is likely the line losses moving forward will be at the present similar levels until a voltage conversion of the first transformer station and first feeder is completed. CPUC has recently completed a line loss study that is assisting CPUC in determining an optimal approach in addressing this target. The line loss study can be found in Appendix D. CPUC's intended action for these measures is to improve the performance.

2.4 Realized Efficiencies due to Smart Meters (5.2.4)

CPUC notes that it has not witnessed any cost efficiencies since its last Cost of Service in 2012 related to the utility's use of Smart Meter.

3 ASSET MANAGEMENT PROCESS (5.3)

This section provides an overview of CPUC's asset management process, an overview of the assets managed by CPUC, and a presentation of CPUC's asset lifecycle optimization policies and practices.

CPUC's intent is to comply fully with OEB's Filing Requirements, however, CPUC has only recently begun embarking upon the application of asset management principles. From a practical perspective, the first place to start was to complete an inventory of assets and capture spatial, attribute and other relevant distribution system information. These data form the foundational elements for preparing an initial, broad-based assessment of alternatives to enable optimal long-term asset management. It also provides the opportunity to identify gaps where essential data are currently unavailable or incomplete. It is within CPUC's scope to incorporate and develop plans to identify and capture data required to bridge these gaps.

An example of absent data which was rectified is the unique customer transformer identifiers within CPUC's distribution system. The absence of this data represented a substantial gap in CPUC's asset information inventory. Without this data, effective economic groupings of tasks and work packages can only be made with the use of broad-based assumptions. To address this, the process of numbering and recording all field equipment installed and inventorying customer transformers was initiated. Concurrent with this, customer accounts connected to each transformer were identified, rendering a more comprehensive relational dataset for future analyses. Overall, it is estimated that the ensuing task of continually improving CPUC's asset management process will incur similar efforts annually and will essentially form the basis for ongoing annual investment to support the analytical framework, data collection and data systems refresh.

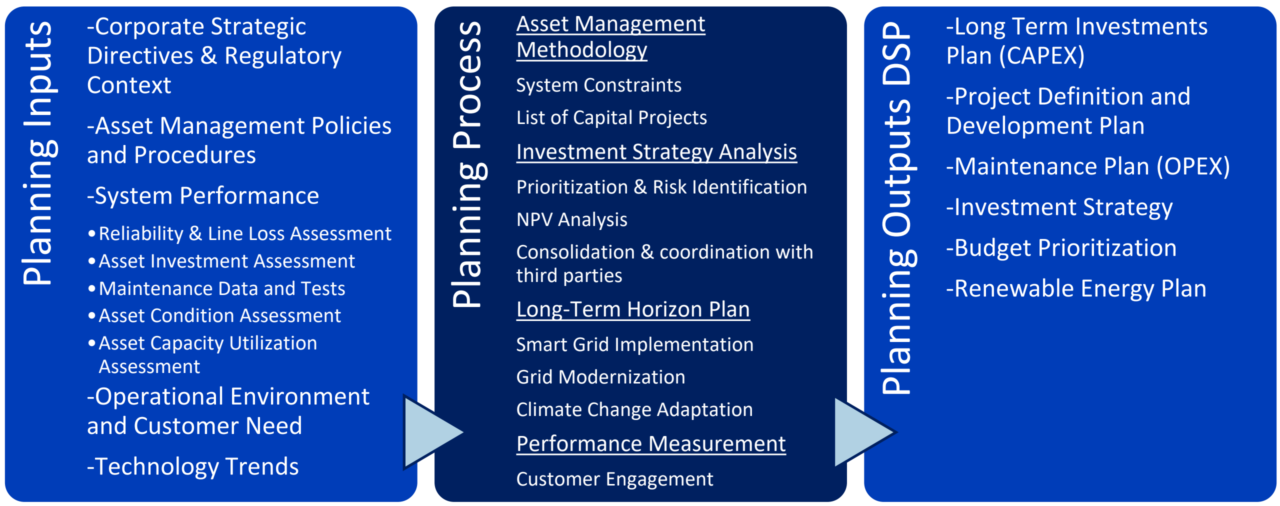
3.1 ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

3.1.1 Asset Management Objectives (5.3.1a)

CPUC approaches distribution system planning within a continuous improvement framework that considers investment objectives for system renewal and expansion, REG connections, smart grid development and regional planning forecasts using an integrated and iterative process. CPUC's overall asset management objective is to provide a reliable, safe and secure service to its customers. Simultaneously with CPUC's objective, CPUC intends on being compliant with regulatory requirements, having a positive financial performance and addressing additional system needs with proven technological advancements in the electrical distribution practice.

CPUC's capital expenditure plan consolidates all categories of system investments. The DSP presents a current, best information approach to address the distribution system requirements. In addition, as developments in the electricity delivery market continue at a rapidly increasing pace, the DSP is intended to be a living document and will be amended to reflect changing priorities. The DSP was developed through an asset management approach that reflects CPUC's strategic commitment to customer service excellence, net investment in distribution infrastructure and investment optimization consistent with its expected future financial performance. The figure below illustrates CPUC's distribution system planning process inputs, outputs and planning elements as CPUC seeks to align asset-management-driven business operations.

Figure 23 CPUC Distribution System Planning Process Inputs and Outputs



Planning Inputs

- **Corporate Strategic Directives** – Align with CPUC mission and vision statement and to stay true to the core business values
- **Regulatory Context** - Obligations imposed by government agencies and CPUC's stakeholders expect CPUC to act ethically and with integrity. These considerations influence the commercial and administrative arrangements CPUC makes as a business entity and its overall approach to asset management.
- **System Performance**
    - **Asset Condition Assessment** - The current age and condition profile of the assets has a major influence on CPUC's future asset management plans. Where possible, asset investment decisions will take into account the current condition and performance of assets and the expected condition and performance profile under different investment scenarios. Such an idealized approach, based on modelling remaining life and associated asset performance, is not always possible due to a lack of available data. Where this is the case, CPUC seeks to apply sound engineering judgment, coupled with analyses of observed asset performance and the age of the asset, as a proxy for asset condition. A core component of CPUC's asset management improvement initiative is the improvement of data capture and information provision.
    - **Capacity Utilization Assessment** - General load growth brings about a need to invest in additional network capacity
    - **Reliability & Line Loss Assessment** – Providing a reliable service while minimizing distribution losses will help reduce costs on the customers end but not without an upfront cost to converting the asset base to the standard required
- **Customer Needs** - This includes ongoing monitoring and plan adjustments as required to address service expectations of the end-customer. Customer requirements are also reflected in the setting of internal performance targets such as response times for outages or system upgrades. Customer requirements are validated and, if necessary, updated via customer satisfaction surveys, routine customer contact and through feedback received via various CDM programs.

- **Technology Trends** - Continuous improvement is a key part of asset management. New technologies, tools or methods that have a potential benefit to the company continually become available. Given that some of CPUC's assets have an expected life in excess of 40 years, it is important that investment undertaken now takes into account potential future technology trends. CPUC intends to actively seek and evaluate new technology opportunities.

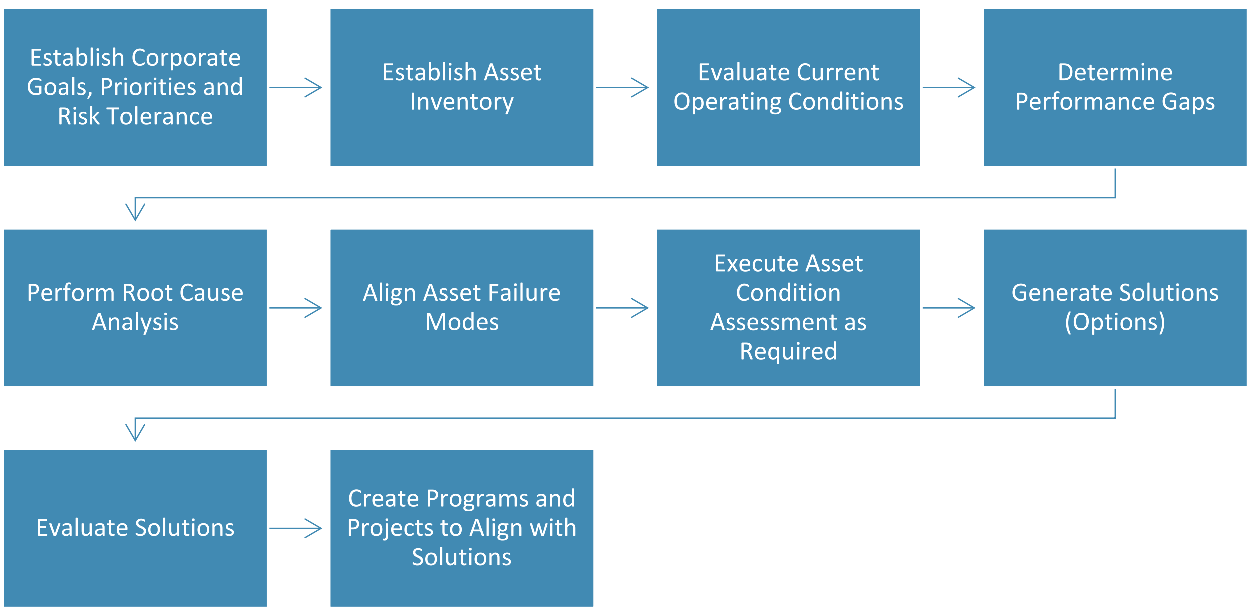
3.1.2 Components of the Asset Management Process (5.3.1b)

CPUC's Asset Management Methodology compiles of four parts: the Asset Management Process, the Investment Strategy Analysis, the Long-Term Horizon Plan and Continuous Measurement and Enhancement Cycle.

3.1.2.1 *Asset Management Process*

CPUC has implemented its Asset Management Process, as described in Figure 24, to determine the programs and projects needed to manage its distribution asset base.

Figure 24 CPUC's Asset Management Process Overview



ESTABLISH CORPORATE PRIORITIES, GOALS AND RISK TOLERANCE

The asset planning process began with a validation of CPUC's mission and values statements with CPUC's Board of Directors. These statements became guideposts and inputs for various steps in the asset management process.

CPUC developed the corporate priorities regarding the management of its assets by reviewing the available datasets providing key performance criteria and results. The datasets included corporate scorecard results, customer survey results and other historical engagement exercises. In 2014, the consistent theme of the feedback received was that reliability is the top concern for most customers. Rate impacts are also a high priority with customers, while most users responded that they were not interested in increasing control over their energy use if this ability came at the cost of increasing rates.

In CPUC most recent survey, customers that have given feedback are generally in compliance with higher rates so that CPUC can continue to invest in renewing its system

Central to CPUC's asset management process is the management of risk since it has a significant influence on the quantum and focus of future investment. CPUC's formal approach to the assessment of risk is one of the areas identified by its Board of Directors and through Burman Energy Consulting as being in need of strengthening. A formal approach to the assessment of risk was the focus of this step in the process at CPUC.

CPUC's risk assessment was performed from a holistic perspective which enveloped consideration of key factors including:

- Current operations and related scorecard metrics;
- Feedback from the most recent customer survey;
- The nature and extent of current and future asset resilience;
- Forecasts of operating conditions and overall system performance;
- CPUC's risk tolerance; and
- Potential for variability in outcomes and resulting scenarios.

ESTABLISH ASSET INVENTORY

For this initial planning process cycle, CPUC has developed an asset registry in its Geospatial Information System ("**GIS**") and started collecting asset data. This system is in its infancy and currently has limited attributes captured for each asset class. It is CPUC's intention to continue to expand the attributes measured and collected to comprehensively bridge information gaps that were identified in the initial assessment.

The following represents components of the asset registry after data gathering is completed.

I. Poles
   - Spatial representation
   - Size and class
   - Age
   - Unique numerical identifier

II. Customer Supply Transformers
   - Spatial representation
   - Electrical characteristics (e.g. Impedance)
   - Size
   - Unique numerical identifier (new)
   - Age

III. CPUC-Owned Station Transformer
   - Age
   - Year of last refurbishment
   - Size
   - Load profile

IV. Switches
   - Spatial representation

V. Protective Equipment Fuses
   - Spatial representation

VI. Other
- Capacitor Banks
  - Spatial representation
- Overall system configuration
  - System loss calculations

CPUC recognizes the need to enhance the current asset registry and supporting data population to provide a more comprehensive picture of the assets' capabilities and conditions.

Evaluate Current Operating Conditions

In this step, CPUC reviewed the current operating environment to determine the effectiveness of previous asset management decisions. Scorecard analyses were performed comparing past performance, industry benchmarks and year-over-year trends (see Section 2.3). CPUC also undertakes an assessment of the general state of the distribution network and its ability to efficiently deliver a reliable supply to its customers. Through this evaluation and by forecasting future trends, CPUC determines the performance gaps that need to be addressed through projects and programs. In the current operating system, CPUC identified the significant energy losses occurring on the distribution system as a prime gap that needs to be addressed over the next 20 years.

Perform Root Cause Analysis

CPUC analyzes the events and conditions on the distribution system that lead to the identified gaps.

Align Asset Deficiency Modes

Information about CPUC's asset attributes and condition data are held within the GIS database, various paper records and files. This information is reviewed to determine alignment of asset deficiencies with the root causes of the performance gaps. CPUC recognizes that the data attributes and collection methods for each asset will require revision to better reflect evolving condition assessment information priorities.

Execute Asset Condition Assessment

CPUC uses the best available information to assess the condition of its assets. The current information used to prepare this DSP is limited to asset age. CPUC's long-term plans include adding asset information attributes such as inspection and maintenance activities. This detailed information will be continually improved, and with time, the confidence level of this information will be enhanced. Eventually, CPUC intends to move to using an asset health index as the basis for project/program prioritization.

Generate Solutions (Options)

The ultimate goal of the asset management process is to determine the best solutions for addressing the performance gaps. This requires the generation of various options that can be analyzed against business and technical drivers using the asset management methods available to CPUC.

Evaluate Solutions

CPUC utilizes several methods to evaluate the various solutions available to address the performance gaps. This includes modelling the financial impacts of investment decisions and assessing the solutions using investment drivers.

CREATE PROGRAMS AND PROJECTS TO ALIGN WITH SOLUTIONS

In this step, CPUC generates programs and projects that support its operating objectives. One of the main guiding objectives in this step of the process is establishing the level of service that CPUC will deliver for the planning period. The targeted level of service is used to prioritize projects and programs.

CPUC has defined four levels of service used for developing investment scenarios:

I. **LEVEL 1 (Minimum)** – represents the elimination of only high severity defects that pose safety, environmental or imminent failure risk. This forms the minimum level of investment for each type of asset and may result in minor performance deterioration over time.
II. **LEVEL 2 (Sustain)** – addresses Level 1 needs and looks forward five years to sustain the assets that will exceed their typical useful life. The result is an annual level of investment to replace end-of-life units maintaining the condition of the portfolio and sustaining performance near current levels.
III. **LEVEL 3 (Improve)** – is a higher level of investment that provides a "catch-up" opportunity to replace assets that already exceed end of life in addition to addressing Level 2 requirements. It provides for a catch-up over a five-year period, and expects to improve the performance of the portfolio, albeit at an increased cost, relative to other levels.
IV. **LEVEL 4 (Optimize)** – is a longer-term smoothing approach comparable to Level 2 but looks forward 10 to 20 years to provide a further opportunity for smoothing. This allows for an investment to "catch-up" in replacing assets tat exceed their end of life in an optimal and cost reduced way. The overall performance of the portfolio would be maintained over the longer term; however, there may be year-over-year variations that may necessitate reprioritization during the plan. Ultimately, this should be accommodated within the overall system renewal capital levels. Level 4 is the selected level of service used for CPUC's renewal program.

In the end, the selected level of service is implemented through programs covered under the O&M budget and capital programs/ projects that fall within one of the OEB's assigned investment categories.

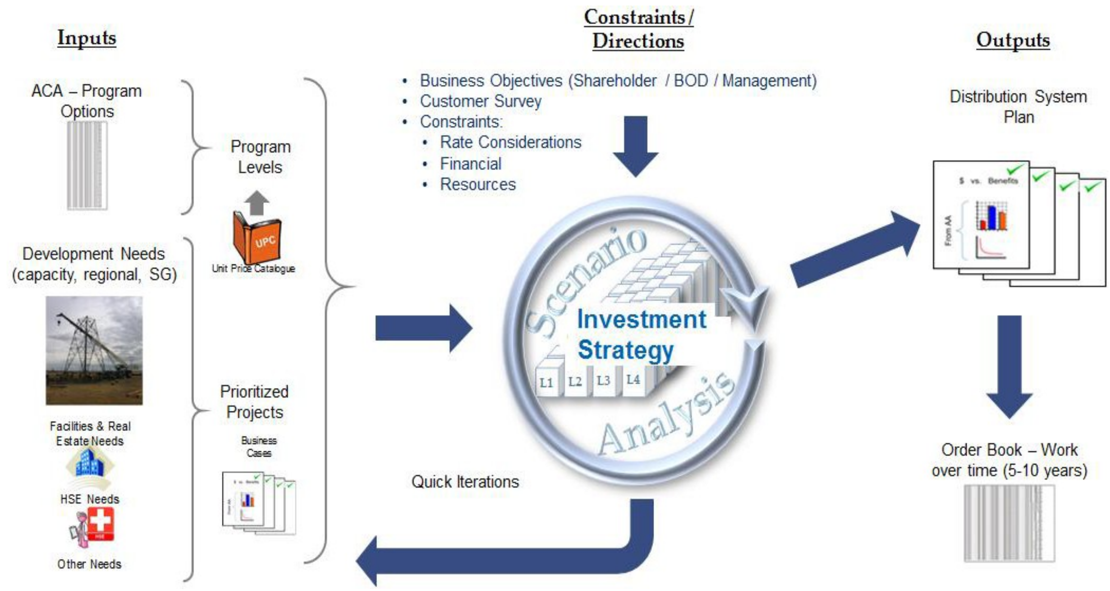
3.1.2.2 *Investment Strategy Analysis*

CPUC applies an investment strategy analysis to help evaluate the investment options. This approach provides the necessary information to effectively balance the various competing needs. The investment strategy methodology integrates the "bottom-up" asset needs with "top- down" strategic criteria and review.

The "bottom-up" approach ties investment strategy to assets and projects through consolidation of an initial work program portfolio. The "top-down" analysis is performed by developing a long-term planning framework to model multiple planning scenarios that include variations to "bottom-up" projects, impacts on capital investments and resultant impacts on the RRF objectives: customer focus, operational effectiveness, public policy responsiveness and financial performance.

This approach provides CPUC with context to make decisions by understanding projected outcomes. It also provides information for customers, shareholders and stakeholders to provide more effective input into the CPUC planning process. The graphic below shows the various considerations included in the CPUC investment planning process.

Figure 25 Investment strategy overview



3.1.2.3 *Long-Term Planning Horizon*

In order to support integrated planning and better align the distributor planning cycles with rate-setting cycles, the approach to long-term planning has incorporated the following elements into the plan:

Table 16 Long-Term Planning Horizon

LONG-TERM PLANNING ELEMENT	APPROACH
Enhance the predictability necessary to facilitate planning – including regional planning – and decision-making by customers and other LDCs.	• Heighten the emphasis on regionally planned infrastructure by identifying the supply challenges. • Complete system renewal and expansion – refresh assets as per assets' lifecycle. • Encourage efforts to enable the connection of REG. • Ensure the long-term viability and economic benefit of investment alternatives using a capital investment model.
Facilitate the cost-effective and efficient implementation of the DSP, thereby achieving customer service and cost performance outcomes.	• CPUC's first efforts in moving towards a structured planning approach was to develop a system model and study to report on loss mitigation.
Manage consumer rate impacts.	• Coordination in development of detailed five-year implementation plans for CDM.

<u>Five-Year Plan</u>

CPUC uses results from its long-term planning efforts and other studies, such as maintenance reports and line loss study reports, to perform 'tactical' planning for a five-year outlook.

Annual updates to the long-term plan incorporate new information that may arise, such as new regulations, individual customer needs or updated information arising from the activities described in the long-term planning process. Typical inputs to the five-year planning outlook include:

- Customer-driven needs;
- Municipal-driven needs;
- Health, safety and environmental issues;
- Regulatory requirements;
- Reliability and system analysis;
- Asset Condition Assessment;
- Asset replacement requirements (based on the outcome of long-term planning);
- Expansion requirements (if any are identified through long-term planning); and
- Innovative initiatives, such as smart grid and smart meter investments (if any are identified).

The results of the medium-term planning process provide the basis by which to select and prioritize projects for inclusion in the five-year CPUC Capital plan. Results of medium-term planning are also considered to review the effectiveness of maintenance programs and to adjust as required.

<u>One-Year Capital Plan</u>

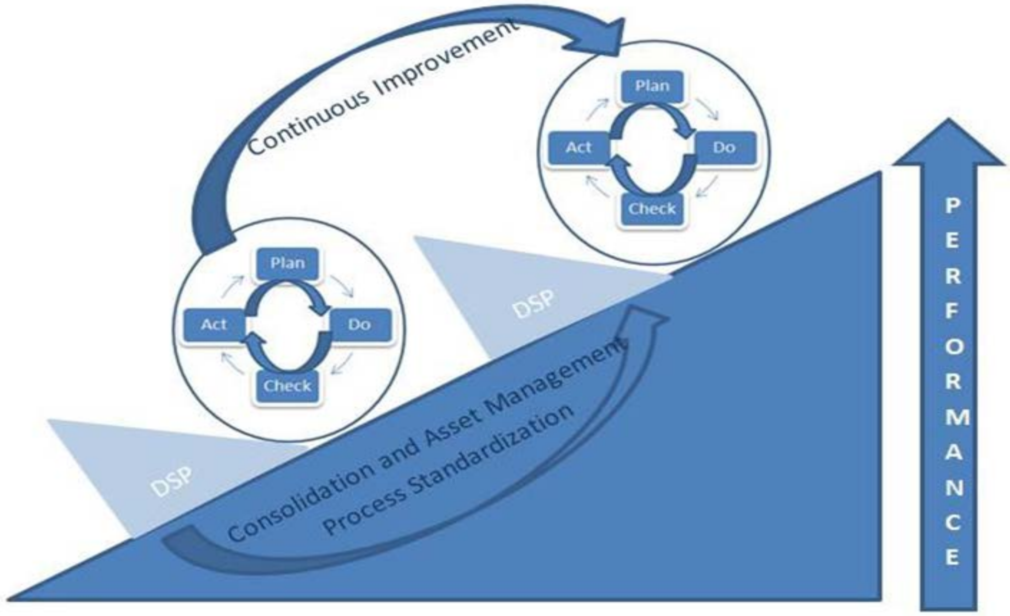
Short-term planning involves developing specific plans to implement the projects defined in the budget for the current year, as well as to operate and maintain the distribution system(s) in a safe and reliable manner. It also addresses short-term needs such as connection of new customers or reaction to external events including severe weather conditions and storms. The one-year capital plan covers:

- Current budget year project design;
- Customer-driven asset development (if and when they develop);
- Municipal and developer-driven asset development (if and when they develop); and
- Other short-term projects.

3.1.2.4 *Measurement and Enhancement Cycle*

The Plan Do Check Act ("**PDCA**") continuous improvement cycle is core to the CPUC asset management methodology. The following diagram shows the elements being adopted through the planning process.

Figure 26 PDCA Diagram for Continuous Improvement



Plan - Establish the objectives and processes necessary to deliver results in accordance with the expected outcomes. Start, on a small scale, to test possible effects and financial feasibility. Develop a DSP, prioritizing budgets, resources and timelines.

Do - Implement the Plan and collect data for analysis in the following "Check" and "Act" steps. Develop project designs and plan for execution, prepare status reports and implement planned activities.

Check - Study the actual results (measured and collected in "Do" above) and compare against the expected results (targets or goals from the "Plan") to ascertain any differences. Evaluate any deviations in implementation from the Plan and evaluate the appropriateness and completeness of the Plan to enable the execution, i.e., "Do". This Plan elaborates on CPUC's Performance Outcomes in the later sections of the document. CPUC's Performance Scorecard (Appendix C) represents an approach to managing utility performance through specific measurable key performance indicators.

Act - Recommend improvements and adjustments to the initial Plan; determine the course of corrections and modifications to the Pan.

3.2 Overview of Assets Managed (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

The Town of Chapleau is located in Northern Ontario, as shown in Figure 27, and has a population of 1,964 residents.

Located in Sudbury District, Ontario, the Town size is approximately 14.3 square kilometers, compared to CPUC's total service area of 13.5 square kilometers. Set against the backdrop of pristine lakes, rivers and abundant forests of northern Ontario, the Town is the gateway to the world's largest crown game preserve and is a paradise for everyone who loves the outdoors.

For over 100 years, Chapleau has served the railroad and the forestry industry, a heritage that continues to this day. Chapleau is home to a vibrant Francophone community with First Nations as close neighbours. The Francophone presence dates to the Town's beginnings and contributes to Chapleau's strong bilingual foundation.

CPUC serves approximately 1,300-metered rural, small commercial, forestry and Canadian Pacific Railway loads within the Township boundaries. Refer to Figure 28 for a map of CPUC's service area. Chapleau experiences an average yearly high at 8 ^{0}C with summer month temperatures reaching an average high near 24 ^{0}C and an average yearly low at -4 ^{0}C with winter month temperatures reaching an average low near -22 ^{0}C. Chapleau experiences snowfall as early as late-September and can continue to fall as late as mid-May, averaging 282 cm of snowfall yearly. Additionally, between October and April inclusively, Chapleau's historical average of snowfall days (greater than 0.2 cm) ranges from 5 days to 18 days. From November to March, it is difficult for CPUC to execute planned projects when the average of snowfall days in a month is on the higher end and there is a large amount falling.

CPUC's distribution system consists of almost 30 circuit kilometers of line, of which of approximately 28 kilometres is overhead primary conductor and the remaining is underground primary cable. Approximately 36% of the utility's electrical load is connected to Hydro One's 25-kV supply and the remainder of the load is currently serviced at 4.16 kV through CPUC-owned transformation facilities (115 kV to 4.16 kV). Several plant closures prior to 2006 in the forestry industry resulted in reductions to town population and corresponding reductions in electricity consumption. There have been no significant local economic developments since that time. There are no new significant economic developments in the Township of Chapleau forecast for the 2019-2023 planning period in this plan.

Figure 27 Chapleau location

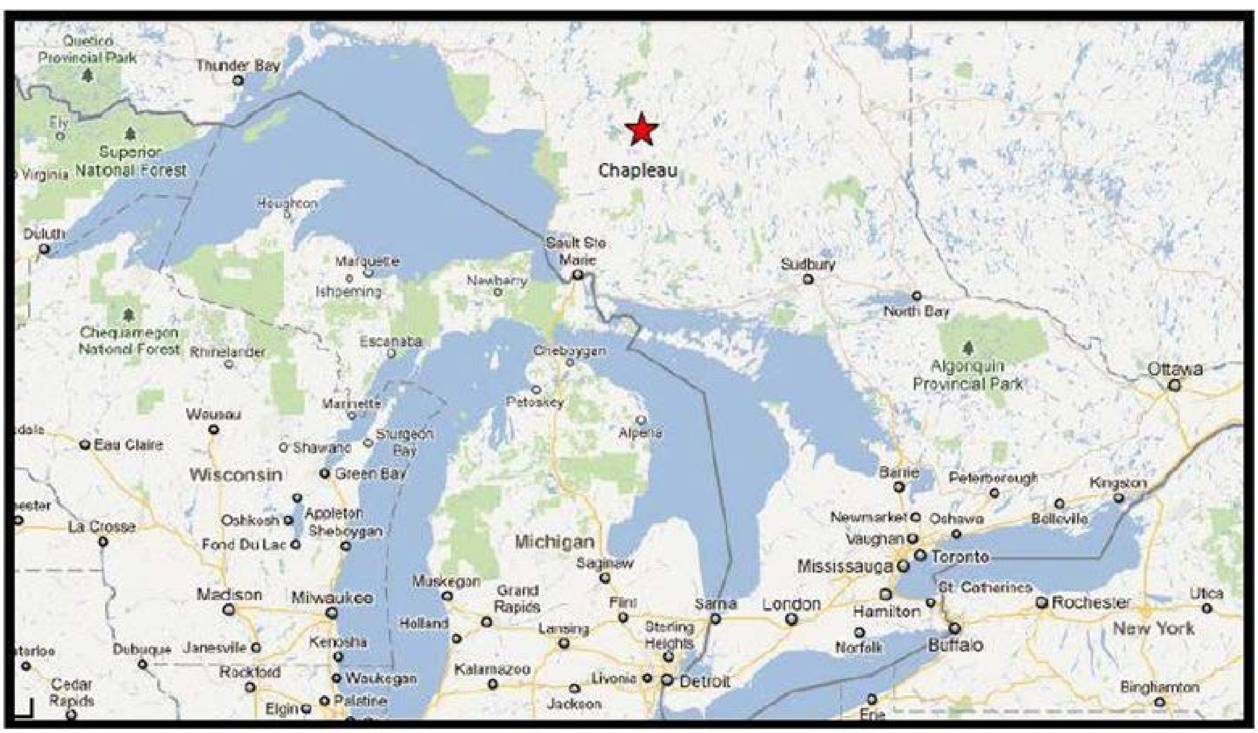


Figure 28 Chapleau service area

CPUC receives power in bulk from Hydro One's 115-kV transmission system and pays a transformation uplift charge for the 25-kV supply it receives directly from the adjacent Hydro One distribution system. Distribution voltages are 4.16 kV through CPUC's 115 kV to 4.16 kV distributing station and 25 kV delivered through Hydro One's adjacent service territory.

3.2.2 Summary of System Configuration (5.3.2b)

CPUC's assets under management include poles, conductors, transformers, switches, meters, office building, transportation equipment and storage areas. Electricity delivery is achieved via overhead conductors and both underground and submarine cables. CPUC's distribution system consists of a single transformer station with three transformers:

- Two 4.16-kV transformers (3750 kVA and 2500 kVA) owned and operated by CPUC; and
- One 25-kV transformer owned by Hydro One (listed at 7500 kVA).

CPUC's 25-kV load is supplied by an overhead distribution network which is approximately 9.7 kilometers in length. CPUC's 4.16-kV overhead distribution network is approximately 18.0 kilometers in length and its underground distribution network is approximately 2.05 kilometers in length.

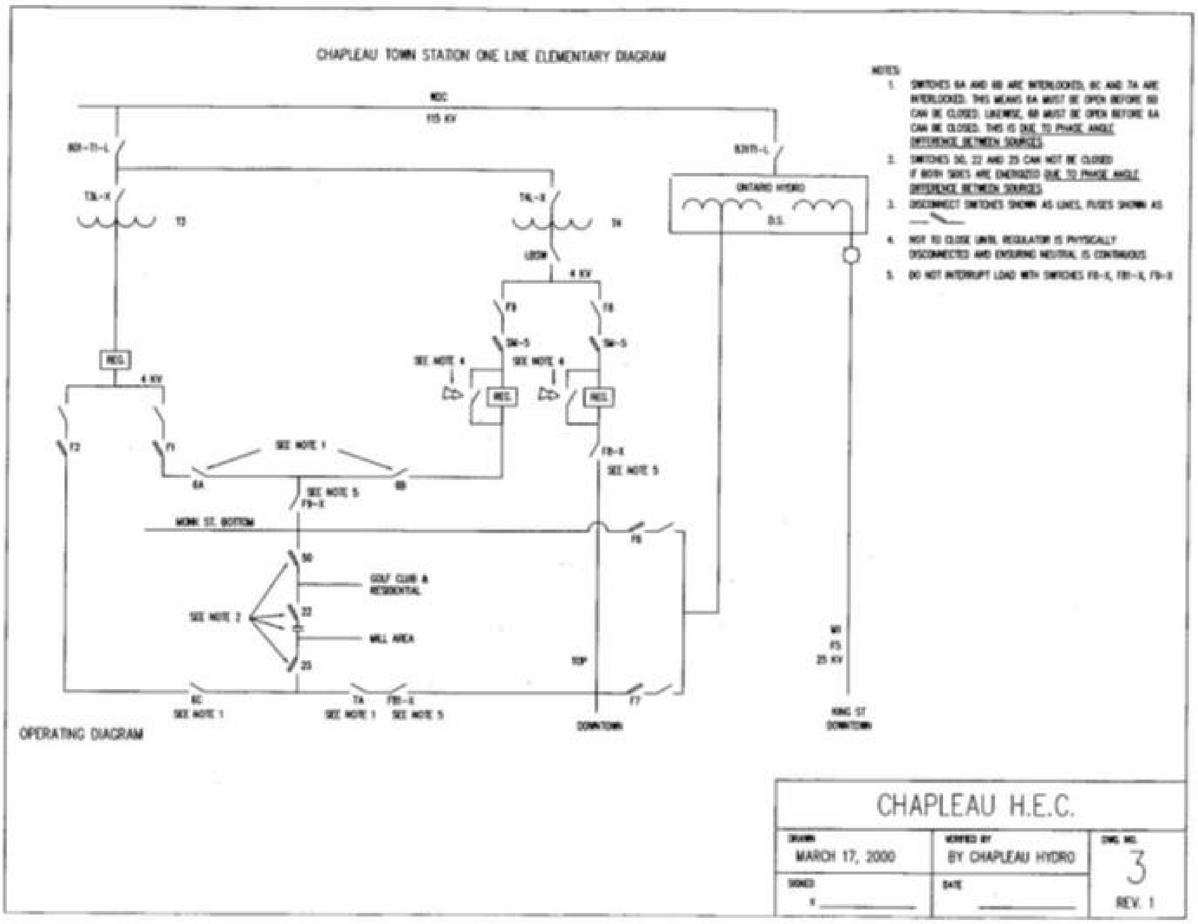
NETWORK CONFIGURATION

CPUC's distribution system is connected to the 115-kV transmission system through Chapleau DS. The distribution system is comprised of two voltage systems: one at 4.16 kV and the other at 25 kV. CPUC owns two 115 kV to 4.16 kV transformers at Chapleau DS totalling 6.25 MVA which supply three feeders. In addition, CPUC has one 25-kV feeder supplied by Hydro One which is limited to supplying approximately 3.5 MVA of capacity. Approximately 65% of the distribution assets are rated at 4.16 kV and 35% are rated at 25 kV.

- The 4.16-kV F2 circuit feeds to switch #22 across the river; approximately 210 customers.
- The 4.16-kV F8 circuit supplies the downtown area and most of the south side of Birch St.; approximately 330 customers.
- The 4.16-kV F9 circuit feeds west of the railroad tracks, all other customers across the river and south heading out of town past switch # 15; approximately 465 customers.
- The 25-kV F5 circuit feeds King St., Broomhead Rd. and east along Pine St.; approximately 340 customers.

The configuration of Chapleau DS is shown Figure 29 and the detailed design of CPUC's distribution system, which includes station locations, is provided in Appendix E.

Figure 29 Configuration of Chapleau DS



3.2.3 Asset Assessment (5.3.2c)

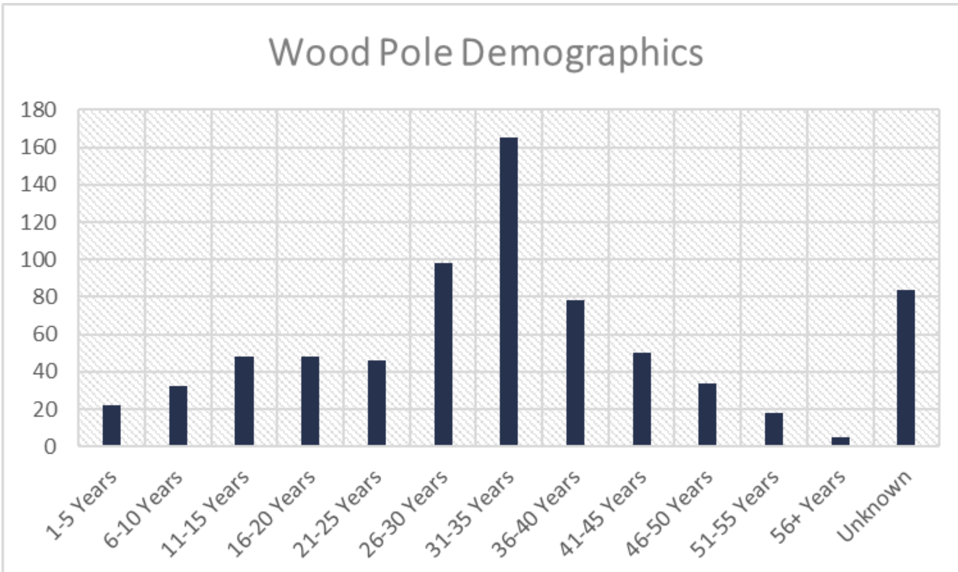
The following table provides information regarding CPUC's assets:

Table 17 CPUC asset information

Asset Type	# of Assets
Wood Poles	730
Three Phase Transformers	33
Single Phase Transformers	234
Switches	52
Meters	1276
Station Transformers	2
Overhead Conductor	27.7 km
Underground Cables	2.05 km

Additionally, the wood pole age demographic is identified in Figure 30. Two major points observed are: 1) the large amount of wood poles with an unknown age; and 2) the large number of poles between 31 and 35 years of age. In the current analysis, poles with an unknown age are assumed to have an age over 45 years old. Poles with an unknown age have usually a rusted nameplate or missing nameplate which identifies the installation year. If these poles were new, rust on the nameplate would not be an issue. Additionally, poles found in the 31-35 year age range are mostly found on Chapleau's 25-kV circuit which was the last feeder that was rebuilt. Most poles currently in service are part of the 4.16-kV feeders and will need to be upgraded to the standard poles used for 25-kV construction within the next twenty years. The typical useful life considered by CPUC is 45 years old.

Figure 30 Wood Pole Demographic



The future intent is to enhance attributes beyond age demographics to reflect asset location, asset condition, asset failure modes and risk tolerances.

The following identified points were considered to determine CPUC's distribution system plans and allocation of investments:

- CPUC currently does not officially record condition data but does evaluate the pole's overall condition through its visual inspection. There is an opportunity to better capture the data into a consistent format and source system (single system of record), as well as define condition standards that can be consistently translated to probability and outcome. This will continue to be a subject of the PDCA continuous improvement process as inspections are conducted and source systems are integrated over time (e.g. GIS with DESS, etc.).
- Reliability statistics and line losses need to be addressed; as a result CPUC has identified voltage conversion as a high priority for capital investments within the 20-year timeline. This project will also lead to partial renewal of the asset base.
- Plant inspections over the last few years have identified very few assets with high severity defects; those identified are typically addressed in a timely manner.

CPUC has initiated efforts to develop a credible asset management process. Foundational data organization work, such as spatially identifying assets and their attributes, has been used to populate a GIS shared with the municipality. Additional work was required to assign unique identification numbers to specific assets in the field. Work is currently underway to migrate field-collected data into the GIS asset registry.

Asset attribute data gathered thus far have centred on asset age as the primary precursor to preventative maintenance or replacement programming.

Station Transformers

CPUC manages the operation of two 4.16-kV station transformers on which weekly patrol inspections and annual oil tests are performed.

CPUC's sustainment strategy is predicated on the following factors:

- TUL for power transformers is 45 years
- Continual inspections are designed to identify any emergent issues.
- Stations are maintained over the short-term. A station refurbishment is preferred for life extension compared to a direct replacement through a voltage conversion to reduce cost impacts on customers.
- Inspection and testing of station transformers oil is performed and is a good predictor of when a transformer is reaching the end of its service life. Regular inspection and testing allow time to make decisions about capital investment based on a proactive approach.

Within a 20-year timeline, CPUC is planning station transformer replacements as a part of the voltage conversion project, which will be proposed within the next DSP period.

3.2.4 System Utilization (5.3.2d)

Peak transformer loading was derived from metering information provided in kW and an assumed Power Factor of 0.9. The transformer loading is shown in the table below.

Table 18 Transformer loading

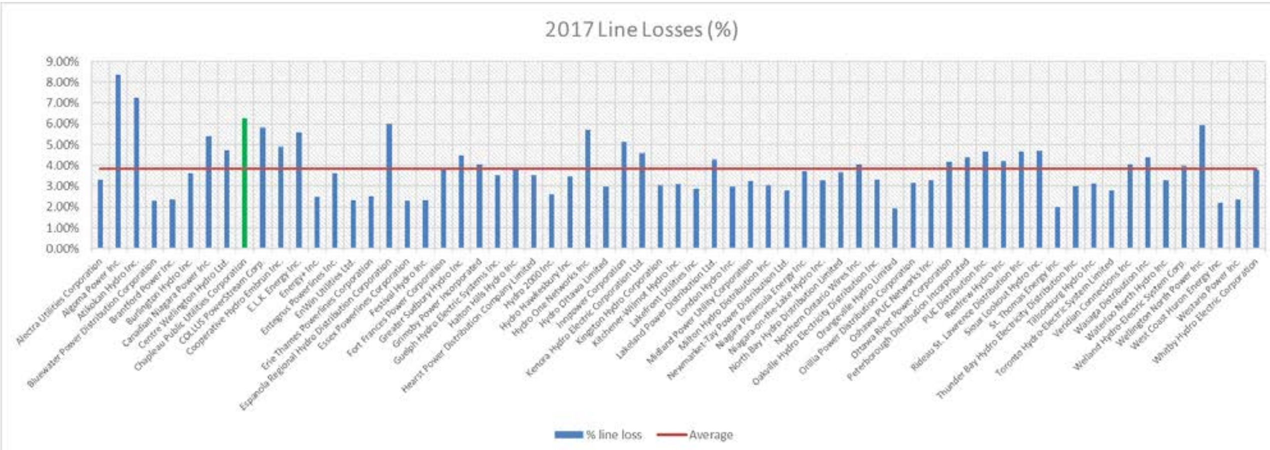
Transformer Loading #	Voltage (kV)	Size (kVA)	Peak kW	Calculated kVA (PF .9)
T3	4.16	2500	484.5	539
T4	4.16	3750	3497.2	3920
25 kV Feeder	25	--	2207.4	2453
Total				6911

The load has been falling slightly in the area over the last ten years due to the loss of a small number of customers and persistent CDM achievements. The overall transformation capacity levels are reasonable for the loads; however, with the current configuration, the load on T4 exceeds its nameplate capacity during peak load conditions. There are no immediate concerns with the supply capability at the station or feeder level.

According to data from 2017 OEB Yearbook of Ontario Electricity Distributors[2], the average annual loss factor in Ontario was 3.82% in that year. CPUC's loss factor in 2017 was 6.27%. CPUC recognizes the importance of reducing the losses in its distribution system given its position relative to other Ontario LDCs. The figure below highlights CPUC's line loss percentage in relation to other utilities and the provincial average. The visible green bar is CPUC's line loss percentage. It is evident it is one of the few utilities that experiences a high distribution loss.

[2] http://www.ontarioenergyboard.ca/

Figure 31 2017 OEB Yearbook of Ontario Electricity Distributors Average Annual Line Loss



CPUC has attempted to reduce its losses in the past with some success (see Section 2.3.3.2.2); however, additional efforts are required. A recent line loss study was commissioned to determine a recommended strategy to address simultaneously the line loss and the over-loaded T4 transformer.

The line loss report provides an alternate option is to expend $20-100k on transformer testing and rehabilitation, with the objective of delaying the station replacement 5-10 years. In the meantime, increasing the pole replacement renewal as much as practical for 5-7 years, to establish one or two feeders ready for voltage conversion (allowing for voltage converters), then replacing transformers as needed, and converting the rest of the poles might allow for the $2Million conversion costs to be spread over 10-15 years. The primary risks would be the potential for a transformer to fail early, or for poles to start to fail quickly, both of which can be managed with increased monitoring and risk assessment. This plan will allow for a staging of capital costs, and a parallel improvement in cost of losses which would commence once the voltage conversion begins.

The full report can be found in Appendix D.

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

Electricity distribution assets, like any other type of physical asset, have a defined lifecycle. This section describes how CPUC's assets are managed over their entire lifecycle, from conception to retirement. CPUC continues to work towards a lifecycle asset management program as the basis for longer-term planning and predictable investment levels that optimize operational and financial risks.

CPUC's approach in Asset Lifecycle Management and Planning is holistic in nature and takes into consideration the combined implications of managing all types of assets, including physical assets, financial and human capital. CPUC focuses on a system and process approach of asset management and planning, considering assets in their operating context and optimizing the value of the overall assets system rather than the individual asset.

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

The following table defines the key lifecycle activities at CPUC.

Table 19 Key Lifecycle Activities at CPUC

Activity	Detailed Definition
Operations	Involves changing the design parameters of an asset, such as changes in circuit configuration or setting taps on a transformer. Does not involve a physical change to the asset.
Maintenance	Involves replacing consumable components on asset assemblies, but not the whole assembly. Generally, these sub-components wear out before the whole assembly fails. For example, an insulator on a pole assembly or an arc snuffer/muffler on a gang operated load break switch.
Sustainment	Involves replacing assets within asset categories. For example, replacing a pole or poles (pole asset category).
Retirement	Removes an asset from the distribution system. For example, removing a redundant circuit from service.

3.3.1.1 *Operation Lifecycle and Policies*

CPUC bases its operational activities on delivering satisfactory service levels to its customers. CPUC's services cover a broad range, including capacity, quality of electrical supply, continuity, restoration, grounding of equipment (public safety) and the absence of (radiant) interference. The measure of CPUC service levels is related to the performance of its distribution assets.

Operational activities generally arise in dealing with distribution system issues when assets are not operating steady state and as designed. As an example, a number of triggers would initiate activities to restore normal operations, as follows:

- Voltage levels too high or too low – outside of Canadian Standards Association Voltage Variation Limits;
- Fault current exceeds thresholds on protective devices such as breakers and fuses;
- Demand exceeds thresholds on protective devices and or the assets current carrying capacity; or
- Customer concerns about the quality or reliability of electricity being supplied to them.

CPUC would investigate the reported triggers and address the issue within a timely manner to maintain its objective of providing a reliable, secure and safe service to its customers.

3.3.1.2 *Lifecycle Optimization through Maintenance Planning – Criteria & Assumptions*

Basic maintenance deals primarily with replacing consumable components of assets. Components wear out in a number of ways, including oxidation, pitting or erosion of contact surfaces, material rot, gasket degradation, pitting of insulators, etc. Continued operations of devices which clearly exhibit component degradation, will eventually lead to a failure in the distribution system. Failure of assets is influenced by a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycles, stress due to fault events, ambient temperature, contaminants and the maintenance performed during the life of the asset.

For some assets, run to fail is the only feasible option due to limitations of maintenance that can be performed. For example, distribution transformers are manufactured and deployed with no corresponding regular maintenance for the duration of their lifecycle.

Conversely, a small percentage of the distribution assets, such as station transformers, require regular maintenance. These transformers generally supply a large number of customers and a failure would likely result in a lengthy outage requiring a significant amount of resources to replace a failed unit. This maintenance involves regular condition testing (e.g. gas-in-oil analysis) which highlights or identifies possible problems.

Asset maintenance and inspection are based on manufacturer recommendations, industry regulatory requirements, industry best practices and CPUC's own experience with performing the maintenance or inspection. Currently, CPUC intends to build a knowledge base to provide enough information to make informed decisions on future maintenance activities. Initial intervals for maintenance may be changed, based on actual experience with field data collected. The data collected from the maintenance will provide valuable information upon which to base repair work, refurbishment activities and asset replacement schedules.

CPUC maintains a record of maintenance activity on all major assets as follows:

I. Distribution System Assets
   a. Wood Poles
   b. Overhead Transformers
   c. Switches
II. Station Transformers and Substation assets

3.3.1.3 *Description of Maintenance and Inspection Practices*

CPUC inspects assets in accordance with the DSC and performs other maintenance activities to effectively manage its assets, as summarized in the table below.

Table 20 Summary of maintenance and inspection practices

Assets	Category	Activity	Frequency
System distribution plant	Inspections	Visual system patrol	Six times per year
		Infrared	Annually
	Predictive maintenance	Pole testing	Bi-Annually
Station	Inspections	Visual	Once per week; readings taken two to three times per month
	Preventative maintenance	Field repairs	As required
	Condition-based maintenance	Transformer oil testing	Yearly

The following O&M programs are completed to extend the life of distribution assets, obtain a condition assessment, and improve the safety and reliability of the distribution system. Prioritization of capital programs and projects is based, in part, on the impacts of the above.

Visual Patrol Inspection – Overhead distribution assets are inspected visually six times a year. This frequency satisfies the requirements of the DSC. Identified deficiencies or problems are noted and acted upon immediately to prevent extensive failure damage that would have been experienced. Corrective action plans are carried out as required.

Infrared Scanning - The purpose of infrared scanning is to identify any hot spot issues on distribution system, indicative of potential for system failure. Detected hot spots are verified and further assessed through visual inspections and verification by line crews. Critical items identified are corrected immediately and non-critical items are scheduled for repair in conjunction with other planned work.

Wood Pole Inspections – CPUC has recently begun completing a wood pole inspection to gather condition-based data on its assets. The inspections are completed through a third-party vendor. Data collected over a series of years will drive investments at CPUC related to asset condition.

Transformer Station Inspections – The station at CPUC is visually inspected weekly and readings are taken two to three times per month. Transformer oil testing is completed annually. In addition, field repairs are completed as needed when minor deficiencies are found.

3.3.1.4 *Sustainment Lifecycle and Policies*

With a developing asset knowledge base CPUC intends to continually improve programs for asset repairs, replacements or enhancements based on the following criteria (as appropriate):

- Age (relative to expected life);
- Physical condition;
- Performance history and service reliability;
- Maintenance records (repair frequency and cost);
- Maintainability (availability of parts, comparison to new technology);
- Safety impacts (worker and public);
- Future use (local and regional planning);
- External demands (customer driven, road relocations); and
- Efficiency opportunities (voltage conversions, new technology, cost reduction).

The physical condition of the distribution system is assessed by both scheduled inspections, planned maintenance and unplanned inspections and repairs. When an area of the distribution system is identified for upgrade or replacement, further analysis is conducted to review available options.

To aid CPUC in planning for future maintenance work, all outages locations are recorded allowing CPUC to track distribution system problem areas. CPUC tracks the following information related to power outages:

- Time and date of occurrence;
- Customers affected;
- Duration;
- Cause; and
- Customer complaints.

Loss of supply outages from Hydro One currently have the greatest impact on CPUC customers.

A recent example of CPUC's sustainment lifecycle is the completion of a station power transformer dehydration in order to extend the life of the station transformers. This action resulted in a major benefit outcome allowing for CPUC to extend its operating capability of its system with a lower investment compared to a direct station transformer renewal which would also be a voltage conversion.

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

CPUC's Distribution System Maintenance and Inspections are aimed, in part, at protecting the public from physical, electrical and environmental hazards, by maintaining a schedule of regular asset inspections and maintenance activities and to continue providing a secure and reliable service.

CPUC complies with ESA and the DSC and material standards as key documents addressing electrical safety. CPUC also employs construction verification programs to safeguard the public from hazards. The ESA is responsible for enforcing the regulation and monitors CPUC compliance through the annual third-party safety audits and regular field inspections.

CPUC promotes excellence in health and safety management in order to prevent losses to people, assets, environment and reputation. Key elements to Health & Safety management are the evaluation of risk for all workplace hazards, regular Health & Safety meetings with staff and feedback about safety-related incidents.

CPUC follows all regulatory requirements and guidelines to ensure the distribution system has a low risk impact on the environment.

CPUC assesses its reliability performance for asset management decision-making and focuses on remedial work for specific system components that have a high risk of failure and a correspondingly high consequence. Broader strategies, which CPUC recently began evaluating, include:

- Identifying a voltage conversion strategy plan to improve system reliability, reduce line losses and partially offset costs associated with increases in age-related maintenance and/or replacement;
- Maintaining poles and basic infrastructure at end of life; and
- Sustaining inspection and maintenance programs to reduce risk of failure.

A priority will be placed on addressing concerns from maintenance reports provided from crew walk-through inspection activities in the services area. CPUC will continue to use the customer satisfaction survey and customer complaints to inform prioritization of maintenance work and ultimately determine whether the reliability and efficiency levels are optimal.

3.4 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION (5.3.4)

CPUC's distribution system operates at two voltage levels: a 25-kV system fed from a Hydro One station and a 4.16-kV system fed from a CPUC-owned station. CPUC has performed a system analysis and is aware of the capacity of its feeders to accept REG. CPUC has not identified the need for REG-enabling capital expansion expenditures.

Both the 25-kV and 4.16-kV systems currently have upstream capacity constraints on the Hydro One transmission side that are inhibiting new REG connections. For example, a solar installation project initiated by the Town of Chapleau was not completed due to inadequate upstream capacity on the Hydro One transmission network.

CPUC has asked Hydro One to consider upgrades in order to remove the upstream capacity constraint, given that the OEB direction is to have an integrated approach to distribution network planning. Hydro One's current position is that there are no plans to enable the connection of REG for CPUC customers due to the high cost of upgrades. Further details about the regional planning outcomes are provided in Appendix A.

Although its distribution system has the capacity to connect renewable generation, CPUC does not anticipate any renewable generation connections over the forecast period, as Hydro One has no plan to remove the upstream constraints.

4 CAPITAL EXPENDITURE PLAN (5.4)

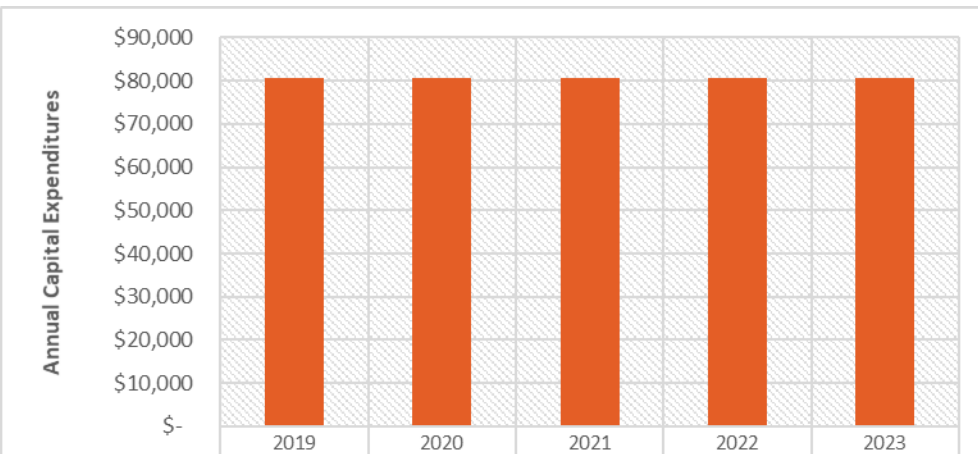
This section describes CPUC's five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of CPUC's capital expenditure planning process, an assessment of CPUC's system to connect new REG, a summary of capital expenditures, and justification of capital expenditures.

4.1 SUMMARY

4.1.1 Capital Expenditures over the Forecast Period

In summary, CPUC will make investments into System Renewal. System Renewal investments are typically based on the requirements of asset replacement programs. As previously indicated, asset replacement programs are being driven by a developing asset management process that uses the age of assets as the main indicator of asset health. The added level of precision inherent within the acquisition of additional asset attribute data sets is anticipated to further refine the analyses. Based on the similarities in asset age profile, the analysis of current information has concluded that asset renewal for other asset categories will follow essentially the same schedule as pole replacement. Specifically, assets such as customer transformers, system switches, conductors, etc. were assumed to be subject to the same vintage replacement criteria as the poles to which they were attached. Improvements to the asset management process made over the DSP forecast period will be used to justify System Renewal category projects proposed in the next DSP. The figure below presents the forecast expenditures for CPUC over the DSP period.

Figure 32 Capital Expenditures over the forecast period, with capital contributions



	2019	2020	2021	2022	2023
General Plant	$-	$-	$-	$-	$-
System Service	$-	$-	$-	$-	$-
System Renewal	$80,667	$80,667	$80,667	$80,667	$80,667
System Access	$-	$-	$-	$-	$-

CPUC plans to maintain the current infrastructure in the short term with a focused approach on preparing feeders for a voltage conversion within the next 20-years to alleviate resource constraints. This approach will maintain system efficiency and minimize customer costs over the timeline. However, as stated, a voltage conversion strategy is being explored within the 20-year timeline and will provide benefits such as reducing line losses, improve reliability by renewing assets and enable additional REG capacity when Hydro One capacity constraints are addressed. The following describes the planned investments in each of the OEB prescribed categories.

4.1.2 Customer Engagement and Preferences (5.4.a)

4.1.2.1 *Customer Engagement*

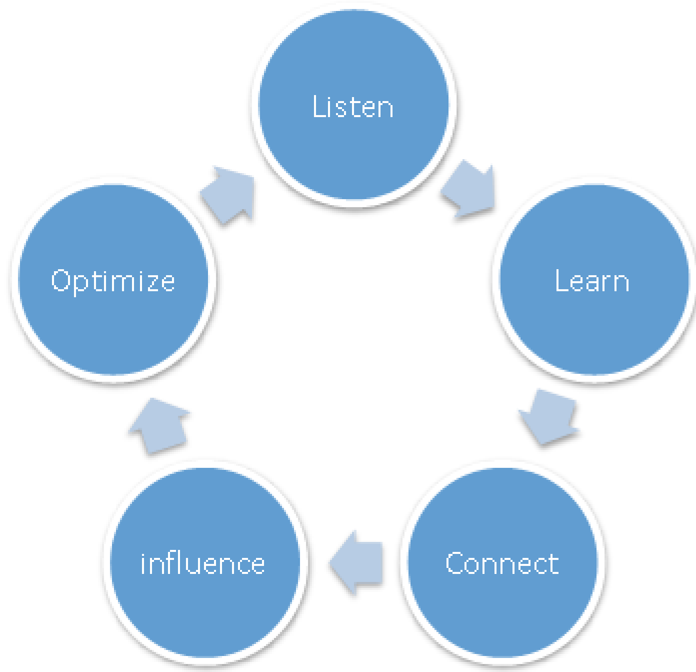
CPUC's town site is over 450 km from Greater Sudbury, 250 km from Sault Ste. Marie, and almost 200 km from Timmins, the three closest major centres. CPUC staff are members of the small community, thus they are very in touch with any major issues experienced by the customers.

CPUC communicates with its customers regarding ongoing business, accomplishments and changes in regulatory matters. In the past, the voice of the customer has shaped CPUC's business direction, with regard to its long-term strategy of improving reliability, service quality and communications.

CPUC undertakes activities to reach out to customers, stakeholders and third parties as part of its business relations. The engagement activities support the primary business goal aimed at customer focus in shaping utility features and implementing environmentally friendly solutions, while improving distribution system reliability. The activities are part of a continuous engagement improvement process which is designed to transform customer service channels into powerful relationship and branding tools. CPUC has entered a new phase of customer engagement after redefining the strategic plan, positioning customer engagement points and offering educational components to help customers to modify their behavior and allow them to take control over their energy usage choices.

In the past, the relationship with the customer has been largely transactional. However, CPUC has now taken the lead in the community to empower customers through customer education to help them to modify their consumption behaviors. The graphic below outlines the stages of customer engagement at CPUC.

Figure 33 Stages of customer engagement at CPUC



Some customer communication activities include:

Customer Survey - CPUC conducted a customer satisfaction survey and targeted research of customer preferences to support the DSP investment planning process.

Meetings with Commercial and Industrial Customers – Large general service customers are invited to meet with CPUC, to explore conservation initiatives and opportunities, as well as to learn more about changes in the industry and the company's efforts to address the changes. Customers are encouraged to ask questions and provide feedback in support of CPUC distribution activities.

Corporate Website – The website provides information about energy conservation and safety. CPUC's website also provides customers a mechanism by which they can reach out for services and provides contact information. CPUC as well plans to update the portal website on the township website to address customer feedback on ease of access and visibility to CPUC's operations.

Social Media – CPUC is making efforts in being accessible on many platforms of engagement with their customers. A recent example is CPUC having a page on Facebook allowing employees and customers to interact on the social platform.

Bill Inserts – CPUC sends bill inserts regularly to its customers with monthly invoices. These inserts include information on specific customer initiatives, energy savings coupons, safety messages, community involvement, twelve-month energy consumption data, cost of power rate information and information regarding current CDM initiatives.

Day-to-Day Operations - The day-to-day interactions between CPUC staff and customers affirm the fact that CPUC customers are concerned about the rising cost of electricity.

Conservation and Demand Management Programs– CPUC performed its formal customer survey in 2017 identifying the concerns and preferences of the members of this small community in Northern Ontario.

4.1.2.2 *Customer Preference*

CPUC admits that until this Cost of Service, it had taken a passive more reactive approach to customer service. The utility sent out a 2-page summary of its 2017 and 2018 proposed capital budget. The 2-page newsletter was sent as a bill inserts to all customers, posted on its website and social media accounts. With the few responses received, CPUC customers understand the need of the increase in bills as long as a reliable service is continuously provided. The newsletter and responses can be found in *Exhibit 1 – Administrative Documents*.

The 2014 customer survey provided insight for the CPUC Board of Directors and staff about customer preferences regarding the capital expenditure scenarios under consideration. 87% of the survey respondents delivered a message that supported a modest increase in the distribution portion of rates to revitalize the existing electricity distribution system controlled by CPUC. The survey results also revealed that 100% of respondents considered CPUC as a partner and trust that their interests are aligned with the interests of the community. Supporting results from the survey are described below.

In the 2014 customer survey, customers were given four investment options and asked to choose their preferred option:

- 0% of the respondents chose -- “Do not make any investments. Keep our distribution costs as they are.”
- 2% of the respondents chose – “Finance the investment in a new modern system under CPUC control by holding the distribution rates at their current level and not returning any money to the town.”
- 11% of the respondents chose – “Borrow the funds necessary to maintain our system.”
- 87% of the respondents chose – “Finance the investment in a new modern system under CPUC control through a slight increase in our distribution rates.”

The survey also found that:

- 97% of respondents ranked the statement “How important is it for Chapleau to take action to improve the delivery of continuous, reliable power?” as a 9 or a 10.
- 53% ranked the statement “How important is it that CPUC support efforts to “green” the community by investing in such things as facilitating renewable energy for home and business, etc.” as a 9 or a 10.
- 44% of all respondents indicated they intend to invest in renewable energy in the next 5 years.

CPUC assesses customers’ preferences by obtaining informal feedback from customers during regular daily interactions with the utility and by formal surveys. Based on past customer interactions and surveys, CPUC has concluded that customer preferences fall into four categories, in order of priority (highest to lowest), as follows:

- Reliability – continuity of electrical supply.
- Cost – lowest possible cost, accepting modest rate increases as required to refresh assets.
- Quality – the absence of momentary interruptions and non-standard voltage levels.
- Process – answering the phone, as accuracy of customer bills, timely construction of new service connections and upgrades to electrical services and outage notices that are given far enough ahead of the outage to allow action or reaction by the customer.

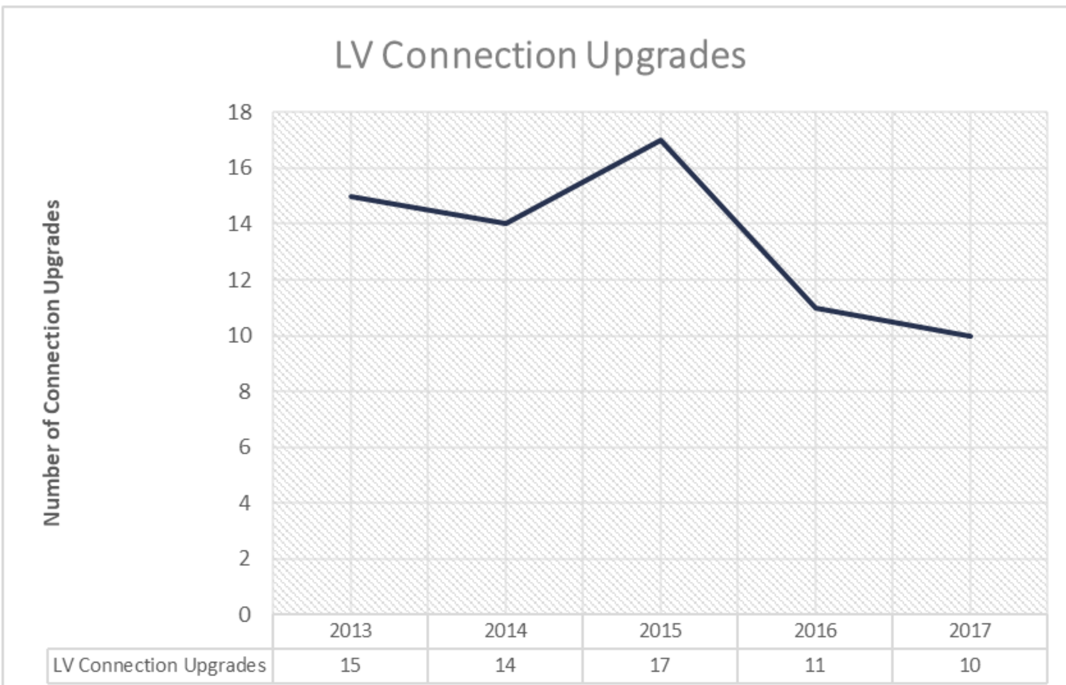
4.1.3 System Development over the Forecast Period (5.4.b)

4.1.4 Ability to Connect New Load/Generation

The current and predicted economic outlook for Chapleau suggests an assumption of 0% load growth over the forecast period is reasonable. This position is consistent with the load forecast included in the CPUC cost of service rate application. Renewable generation connections are constrained by the Hydro One transmission system, but recent customer impact assessments indicate no particular problems with potential CPUC REG connections on CPUC's distribution system at this time, should Hydro One's transmission constraints be addressed.

Recently, CPUC has had no new customer connections. During 2017, CPUC provided 10 connection upgrades. The following charts provide the specifics of historical trends for low voltage (LV) connection upgrades.

Figure 34 LV connection upgrades



CPUC is actively participating in the municipal planning activities although there is no expected load growth in the area during the next five-year period.

4.1.4.1 *Load and Customer Growth*

The Town of Chapleau is a remote, isolated, community that has experienced difficult economic times with the downturn in the softwood lumber market. Load loss and not load growth has been the norm for the historical period of the DSP. As there is no immediate relief to the economic conditions in the foreseeable future, load is expected to continue to decline in the short term.

CPUC's capital plan is primarily focused on sustaining infrastructure to serve existing customers at an acceptable level of reliability, security, safety and cost efficiency.

4.1.4.2 *Smart Grid Development*

CPUC has investigated several methods to address smart grid development. Table 21 provides further information about CPUC's plans for smart grid development and implementation.

Table 21 Smart Grid Development at CPUC

LONG TERM PLANNING ELEMENT	APPROACH
The activities CPUC 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 CPUC 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 CPUC has considered for the purpose of providing customers with the ability to make decisions affecting their electricity costs.*	• Through a past customer survey, CPUC explored smart grid options with its customer base.
	• Based on responses received, customer expectations were clearly prioritized toward reliability at the lowest possible cost.
	• Given the high priority placed by customers on reliability and low cost, smart grid investments were evaluated to not be prudent at this time.
The consideration CPUC 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 CPUC has considered regarding operational efficiencies and improved asset **management; and*** *CPUC's awareness and adoption of innovative processes, services, business models and technologies.*	• CPUC performs Connection Impact Assessments to ensure the system has adequate distribution system capacity for REG.
	• A GIS network model, initially developed by the Township for municipal purposes, has been employed to facilitate spatial referencing of assets, attributes and query-enabled connectivity for asset management analyses.
	• CPUC has investigated new technologies in the past that could be implemented within the system. Currently, CPUC does not anticipate installing new smart technology. CPUC will continue to monitor technologies within this DSP period that can be implemented in the future years.

CPUC will continue to investigate new smart grid technologies to add capabilities to its distribution system including increased visibility through remote telemetry, automatic control, self-healing and increased efficiencies. As an example of its efforts in this regard, CPUC applied to the Smart Grid Fund and executed a project that with the potential to reduce system losses and improve voltage and power quality to customers. The project used low voltage power factor compensation (ENGOs by Varentec) and remote metering to improve power factor for customers at an extended distance from the transformer station. The result of the initial testing indicates some positive impact however the long-term solution to the losses problem would still appear to be voltage conversion of the 4.16-kV network.

4.1.4.3 *REG Accommodation*

CPUC is not expecting to make any major changes to its distribution system to accommodate load growth or REG projects. There is no foreseeable load growth and the upstream transmission system is constrained limiting the connection of REG projects. CPUC will monitor developments in smart grid technologies that can provide customer control capabilities and enhance the reliability of the local network and will consider implementing those technologies if economically and technically feasible.

4.2 Capital Expenditure Planning Process Overview (5.4.1)

4.2.1 Planning Objectives, Assumptions, and Criteria (5.4.1a)

4.2.1.1 *Planning Objectives*

CPUC's capital expenditure planning objective is to put forward capital investment expenditures that align with optimal value determined from the investment strategy analysis. The funding sources for these expenditures include:

- Returns from operations (over and above working capital requirement);
- Leveraging CPUC's favourable financial position through debt acquisition; and
- Distribution rate increases.

The planning process traditionally follows a "bottom-up" project-by-project portfolio development by identifying issues and their solutions. A cost-opportunity analysis or feasibility study is used to analyze possible solutions and alternatives, as well as potential costs and consequences if the project is not a like-for-like case. Cost-opportunity options are analyzed and cost estimations are compared so that the selected solutions move to the next planning stage.

CPUC considers all viable alternatives for resolving system or operational issues. For major capital projects, a "do-nothing" alternative is considered in order to determine whether the risks associated with the issue or constraint merit any significant investment.

Table 22 describes how CPUC has aligned its strategic objectives with long-term strategic planning. The overall objective is to review the full value chain in order to provide the optimum long-term value.

Table 22 CPUC's planning objectives and tactics summarized

Objectives	Tactics
CPUC will remain a viable business entity.	• Develop a long-term strategy / business plan. • Build a business that creates value for the future while balancing the needs of customers.
CPUC will be operated efficiently to provide maximum value: • *Effective and efficient use of capital;* • *Effective and efficient operating and capital plans; and* • *Build value into the business for now and the future.*	• Use tools such as asset condition, risk optimization, lowest lifecycle cost to balance operations and capital spending. • Look at the full value chain (energy generation to end point delivery) to provide lowest cost to ratepayers. • Include business valuation into the business planning process – consider longer-term business value.
Develop a robust energy delivery system optimized to meet current and future needs: • *Community;* • *Provincial energy policy; and* • *the RRF.*	• Study delivery system operating and capital scenarios that provide future flexibility. • Ensure customers needs are understood and incorporated (reliability versus investment and rates). • Investment scenarios must include plans for smart grid, the ability to incorporate green power, and meet current and future load growth.

4.2.1.2 *Planning Assumptions*

A series of key assumptions form the basis of the development of this DSP. These key assumptions guide CPUC's forecast of future activities and help CPUC decide whether to monitor, replace or relocate assets.

The key assumptions for this DSP are as follows:

- The economic development of the Town of Chapleau depends on a secure, safe, affordable and reliable supply of electricity.
- Regulatory activities by the OEB will continue at the current pace over the next five years.
- Smart meters installed in 2009 produce significant amounts of operational and energy consumption data that can be used to help CPUC assess smart grid opportunities. CPUC will continue to evaluate feasible smart grid technologies.
    - Currently, a sample of smart meters are being tested to determine if they are reading correctly since the meters are reaching end of life. A positive test result would allow CPUC to extend the life of its smart meters for an additional eight years. CPUC expects the test results to be positive.
- CPUC's DSP is a strategic document to convey future distribution system development and maintenance plans to stakeholders.
- CPUC's asset management systems will undergo continuous improvement to ensure that CPUC can meet its supply condition obligations without measurable degradation to performance.
- Compliance with relevant regulatory requirements, as they pertain to electricity rates, Filing Requirements, Health & Safety and environmental protection, will be maintained.
- The DSP process will continually improve, balancing stakeholder requirements. Further data will be collected to refine forecast plans for capital projects and programs.

CPUC's analysis to date indicates an approaching need to increase system renewal expenditures due to the advanced age of much of CPUC's asset base.

4.2.1.3 *Planning Criteria*

The CPUC DSP was developed considering the assessment of:

- Future load projections;
- The 2018 and 2014 customer survey;
- The current state of the assets;
- The ability of the system to accept REG;
- The results of the Regional Planning Process;
- The performance outcomes mandated by the OEB; and
- The financial health of CPUC and the rate impacts of the DSP.

4.2.1.4 *Outlook and Objectives for Accommodating REG*

CPUC has experienced little REG activity in its service area. CPUC has completed a small number of REG connection impact assessments that have been constrained by limitations to Hydro One's upstream transmission capacity. A solar installation project was initiated by the Town of Chapleau, but the project was not completed due to this constraint. CPUC has discussed the option of upgrades with Hydro One in order to remove the system constraint but the cost of upgrades was deemed to be excessive by Hydro One and, as a result, there are no plans to enable the connection of REG for CPUC customers.

Accordingly, CPUC has not identified the need for REG-enabling capital expansion expenditures in this DSP. Once improvements to Hydro One's system are made, the need for REG initiatives will be reassessed.

A summary of the Filing Requirements with respect to REG and outcome of CPUC's activities in each regard is described in the table below.

Table 23 CPUC's activities to REG Filing Requirements

REG Requirements	Summary
The applications CPUC has received from renewable generators through the FIT program for connection in the distributor's service area	FIT applications have been rejected due to lack of upstream system capacity on the Hydro One system.
Whether CPUC has consulted with the IESO, or participated in planning meetings with the IESO	CPUC has participated in planning meetings with the IESO.
The potential need for coordination with other distributors and/or transmitters or others on implementing elements of the REG investments	Although Hydro One's system currently prohibits any further REG development, should plans be developed to enhance transmission capacity, the planned voltage conversion will enable more REG projects to be connected on CPUC's distribution system.

4.2.2 Processes, Tools, and Methods (5.4.1b)

Asset management at CPUC has historically involved manual collection and largely relied on anecdotal analysis of inspection, maintenance and reliability records. Going forward, CPUC will continue collecting asset attributes in the ESRI GIS platform and will leverage third-party consultants for studies with Distribution Engineering Simulation Software ("**DESS**"). CPUC is also planning to consolidate its databases into a single source of information for use by each application in the future.

CPUC's key tool used to manage asset knowledge is the ESRI GIS, licensed by the Township of Chapleau. This system, in conjunction with a number of spreadsheets and paper records contain maintenance and inspection information for some of the distribution assets. Collecting and consolidating the information in the GIS will be a focus area of continuous improvement, given the need for data integrity in this area and the new reliance on analytics to drive asset replacement programs.

4.2.2.1 *Project Identification/Selection*

According to data from 2017 OEB Yearbook of Ontario Electricity Distributors[3], the average annual loss factor in Ontario was 3.82% in that year. CPUC's loss factor in 2017 was 6.27%. CPUC recognizes the importance of reducing the losses in its distribution system, given its position relative to other Ontario LDCs. Over the historical period of this DSP, CPUC engaged Burman Energy Consultants Group ("**Burman Energy**") to perform various power system analyses on CPUC's distribution system using state-of-the-art engineering analysis software. The results of the analyses showed that a significant portion of CPUC's system losses resided on the 4.16-kV system.

As Burman Energy worked with CPUC to perform the required power system analyses, it became apparent that the required geospatial and equipment attribute characteristics were not available in a sustainable format. To solve this problem, CPUC agreed to further engage Burman Energy to create

[3] http://www.ontarioenergyboard.ca/

a geospatial referenced database of CPUC's distribution system using the ESRI GIS. The numerous benefits of having a geospatially correct distribution system model with accurate equipment attributes have become apparent as the OEB mandated asset management principles for Ontario LDCs.

Creating and maintaining a geospatially correct distribution system model was not a trivial exercise. During the historical period of this DSP, the initial effort required significant data acquisition efforts by both CPUC and supporting Burman Energy staff including:

- Capture of current system components;
- Determining and confirming feeder characteristics (voltage, phasing, conductor size); and
- Establishing basis for integrating feeder loading.

In the past, Burman Energy has constructed and is maintaining a separate model of CPUC's distribution system suitable for analysis with DESS. The development of this model precedes the ESRI GIS model and includes modeling all overhead and underground lines, distribution transformers, switches, station transformers, and primary supply lines. The distinct difference, however, is that the DESS model is used to analyze the system electrically based on existing assets, their electrical characteristics and overall system electric connectivity; capabilities the GIS does not have. Although currently the GIS and DESS models remain separate, the long-term goal is to integrate data management for both systems.

System losses or technical losses on distribution systems are primarily due to heat dissipation resulting from the impedance of current-carrying elements of the distribution system. Losses are inherent to the distribution of electricity and can be reduced by either lowering the impedance of current-carrying elements or decreasing the current. The effects of current reduction are greater than the effects of impedance reduction due to the underlying physics relating losses to the current squared.

In 2017, METSCO undertook an analysis of system losses at CPUC and recommended an alternatate option in addressing the system losses. The report in summary, states an alternate option is to expend $20-100k on transformer testing and rehabilitation, with the objective of delaying the station replacement 5-10 years. In the meantime, increasing the pole replacement renewal as much as practical for 5-7 years, to establish one or two feeders ready for voltage conversion (allowing for voltage converters), then replacing transformers as needed, and converting the rest of the poles might allow for the $2Million conversion costs to be spread over 10-15 years. The primary risks would be the potential for a transformer to fail early, or for poles to start to fail quickly, both of which can be managed with increased monitoring and risk assessment. This plan will allow for a staging of capital costs, and a parallel improvement in cost of losses which would commence once the voltage conversion begins. The full report report is attached in Appendix D.

CPUC decided that the need to meet industry benchmarks for system losses is one of the top priorities. To achieve this with a minimal impact on its customers, CPUC will invest pole renewal on the feeder experiencing the largest line loss in the current DSP period. Within the next DSP period, this feeder will be ready for conversion immediately after the conversion of the station from 4.16 kV to 25 kV.

4.2.2.2 *Project Pacing and Prioritization*

CPUC uses a long-term forecasting model to evaluate the financial effects and inherent risks of different investment approaches to help define the pace of execution of projects. The investment planning model allows CPUC to vary parameters such as:

- Debt-to-equity ratio;
- Dividends;
- Special dividends;

- Equity injection;
- Customer growth and/or energy growth;
- Depreciation;
- Productivity; and
- Regulatory options such as rebasing dates, choice of IRM model, rates, etc.

The capital costs of the Overhead Renewal program were estimated, and the alternative capital costs were calculated based on the average historic capital spend at CPUC over the historic period. These costs were then input into four scenarios in the investment planning model.

As can be expected, the value of the business is further enhanced in the DSP scenarios where additional capital is expended, resulting in an increase in rate base and the associated reduction in the cost of capital over the plan horizon by introducing debt financing. Each investment alternative is evaluated as a singular project at this point in the process. The capital project prioritization method used at CPUC to evaluate the relative benefits of proposed capital projects is based on a model that ranks the project's strategic fit, system needs, and feasibility based on the following criteria:

I. Strategic Fit
    - Alignment with Goals and Objectives – Evaluates the alignment of project or action to corporate strategic and planning goals and objectives.
    - Customer Focus - Evaluates how well the project or action meets customer preferences (customer survey).
    - Public Policy Responsiveness - Evaluates if the project or action aligns with REG, CDM

II. System Needs
    - Criticality - Evaluates if the project or action mitigates an identified business risk.
    - Asset Health (Age/Condition) - Evaluates the expected useful life (or remaining life) of the assets.
    - Health & Safety, Environmental - Evaluates if there are health, safety and/or environmental risks.

III. Feasibility
    - Cost-Benefit – Evaluates the cost benefit of project or action.
    - Operational and Technology Risk - Rates if the project or action will address operational or technology risks and issues.
    - Resources - Evaluates the potential of job creation in the local community.

JUSTIFICATION OF SELECTED APPROACH

CPUC generated two main asset expenditure scenarios that delivered various levels of service, addressed various corporate and customer priorities and delivered varying shareholder returns.

The two scenarios developed and evaluated through CPUC's methodology are:

1. Intrinsic Approach – This scenario is based on operating the distribution system status quo. Under this scenario, CPUC operates the assets along a predetermined budget that includes like-for-like replacement of equipment at end of life and operating the local grid in much the same way it has been in the past. This approach targets approximately 1% of the asset base for replacement for every year over 20 years. This scenario pushes back the voltage conversion past the 20-year target, which limits CPUC's capability to reduce line losses. This approach utilizes both the minimum and sustain service level.

2. Investment Optimization Approach – This scenario describes an investment approach that optimizes the operation of the distribution system and recapitalizes CPUC to finance the investments. This approach increases the target of 2% asset renewal in the first five years and increases in the next 15 years as CPUC prepares to do a voltage conversion on their system. This allows for CPUC to complete a voltage conversion within a 20-year timeline and address the line loss to the reasonable Ontario average of 3.82%. This approach utilizes both the improve and optimize service level.

CPUC's investment strategy analysis shows that operating the system as it has been in the past would result in the lowest rate impact to customers but would not address the line losses or refresh the asset base with TUL ranges. This strategy refreshes assets on a 100-year cycle, significantly exceeding industry-accepted and CPUC's own TUL values.

The investment scenario that delivers both a direct customer benefit and the best value for the shareholder is Scenario 2 – the "Investment Optimization Approach". This scenario includes recapitalizing and investing in converting the 4.16-kV system to 25 kV over a 20-year timeline. As can be expected, the value of the business is further enhanced in the scenario where additional capital is expended, resulting in an increase in the rate base over the plan horizon. The voltage conversion will also result in an asset refresh of the aging 4.16-kV system with improved reliability and will increase system efficiency by reducing line losses to the benefit of ratepayers. In addition, maintaining a single voltage infrastructure will provide operating efficiencies which will benefit CPUC customers.

CPUC plans to begin the voltage conversion of the first station transformer within the next DSP period.

4.2.3 REG Investment Prioritization (5.4.1c)

If applicable, the REG investments are prioritized in the same manner as other investments, as detailed in Section 4.2.2.

4.2.4 Assessing Non-Distribution System Alternatives (5.4.1d)

In the past, CPUC has implemented a distribution system loss program to reduce its losses without significant increases to system renewal spending as part of the voltage conversion. Based on cost-effectiveness criteria, CPUC manages technical losses in the following ways.

a) Traditional system loss reduction projects including phase balancing, voltage improvement, power factor correction and voltage upgrades. Recent projects completed in this regard include:
   - Installation of three 225-kvar capacitors in April 2009 on Elgin Street; and
   - Installation of three 225-kvar capacitors in May 2009 on Golf Course Road.

b) Installing larger conductors. When replacing conductors that reach their end-of-life, larger size conductors than the ones required for meeting thermal requirements are installed when feasible. This reduces losses, particularly on heavily loaded feeders. CPUC completed a re-conductoring of Demers St. in the fall of 2014.

c) Technical evaluation of projects. Presently, when CPUC evaluates projects, the incremental cost of mitigating losses is considered among the options. If two projects are close in cost, the option that will result in lower losses may be a deciding factor. Standard planning practices include developing options to reduce system losses. This includes the consideration of installing low-loss transformers, conductors and other equipment where it is economic to do so.

d) Reducing load on heavily loaded feeders. Unloading heavily loaded feeders by transferring load to alternate feeders or new feeders can be effective in reducing losses where operationally feasible and economic.
e) Voltage conversion. CPUC is developing plans for the design of a new 25-kV substation and the replacement of the existing 4.16-kV transformer supply with a 25-kV supply from the new 115/25-kV station, reducing delivery current and resulting line losses.

4.2.5 System Modernization (5.4.1e)

In the current DSP plan developed by CPUC, no investments are allocated for system modernization. CPUC's primary objective is to maintain its reliable service to its customers through the renewal of its asset base that is manageable through its own resources; but with an increased amount in order to avoid the overburden of replacing a complete feeder and the rate shock that is associated.

Once a feeder is closer to the date of a voltage conversion, CPUC will investigate options in where it can modernize its system to provide additional visibility to its customers. Currently, CPUC has not identified a need to purchase additional asset management tools or new technologies until they have gathered data for a complete asset registry, which includes age information and condition data. Once this baseline is formed, CPUC will investigate options that can help its asset management processes.

This decision allows for CPUC to keep its own costs down while investing more into its assets which is a higher priority.

4.2.6 Rate-Funded Activities to Defer Distribution Infrastructure (5.4.1.1)

4.2.7 Conservation & Demand Management

CPUC contracted CustomerFirst to manage energy conservation and demand management activity in the local service area. CustomerFirst is very active in the community and assisted residential and business customers to earn the incentives available to them. CPUC has an active customer engagement strategy for dissemination of various energy conservation activities through coupon savings events, small business lighting program and web energy conservation tips.

For the 2011 to 2014 period, the Ontario Energy Board established targets for energy conservation and peak demand reductions for each LDC in the Province. CDM targets established for CPUC were 1.21 GWh of cumulative energy savings. CPUC achieved 123% of its energy savings target by the end of 2014. Under the new Conservation First Framework for the 2015 to 2020 period, the provincial CDM focus has shifted to only energy savings and CPUC was assigned a target of 1.152 GWh of cumulative energy savings. CPUC has achieved 61% of its energy savings forecast as of the end of 2017.

Figure 35 Net Incremental 2020 Annual Energy Savings

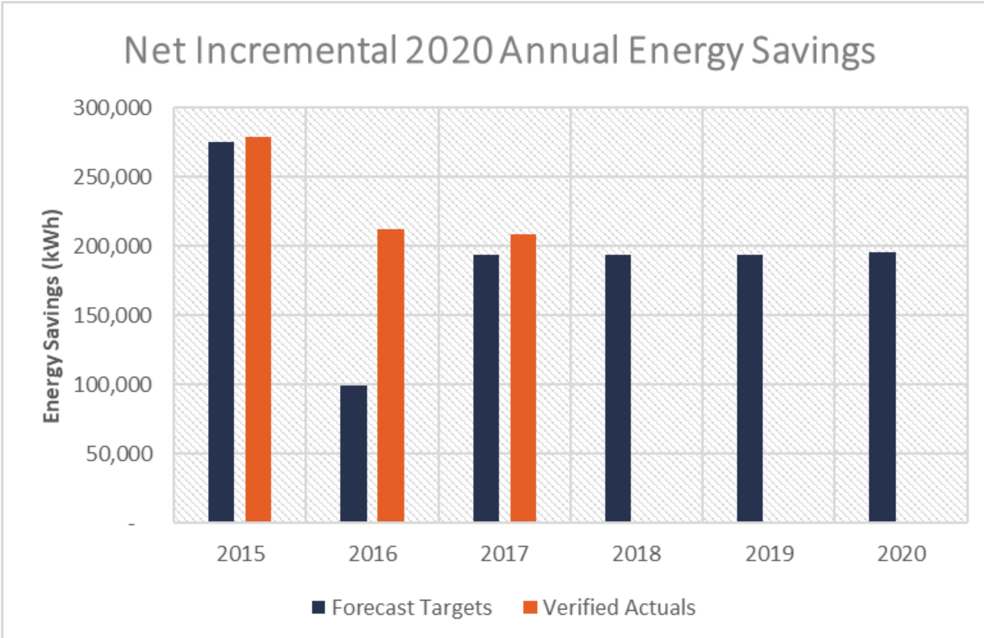
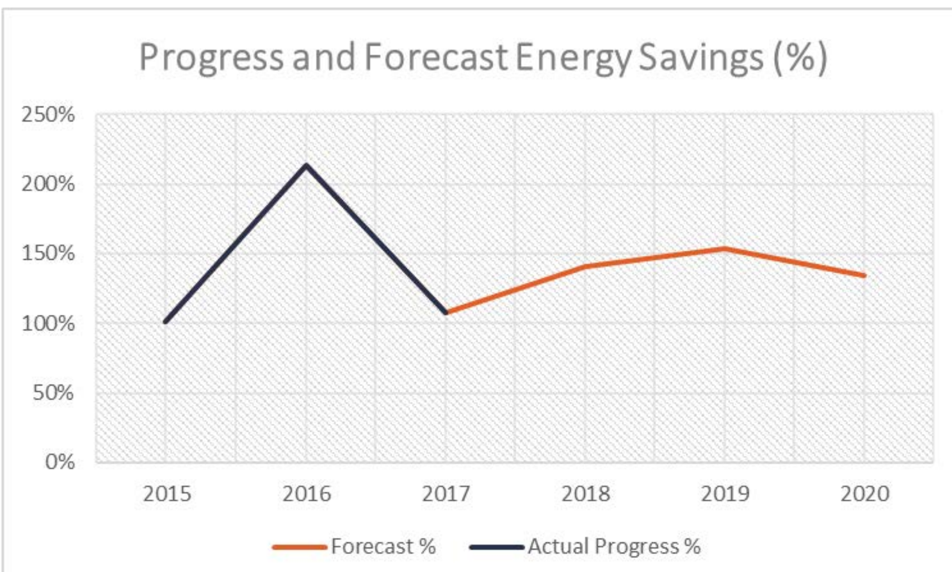


Figure 36 Percentage in Energy Savings to date and forecast to 2020



4.2.7.1 *Connection of Renewable Generation*

Ontario runs two REG programs. FIT ("Feed-in Tariff") applicants are those customers setting up solar or other renewable generation equipment to generate more than 10 kW of electricity at a time. MicroFIT applicants are those customers applying to generate electricity at a level less than or equal to 10 kW of electricity at a time.

CPUC has not connected a REG project due to upstream capacity constraints on the transmission system. An IESO comment letter is provided on CPUC's ability to connect REG.

4.2.7.2 *Additional Activities to Defer Distribution Infrastructure*

In 2018, CPUC complete a station power transformer dehydration to extend the life of the station transformers. This action resulted in three outcomes: 1) it allowed for CPUC to extend its operating capability of its system with a lower investment compared to a direct station transformer renewal which would also be a voltage conversion; 2) it mitigated the impact on the customer bill; and 3) it allowed for investments to be directed into the asset renewal program.

Additionally, CPUC is sampling its meters to determine if they are operating and reading at acceptable level. Should the meters be tested positive, CPUC can extend the seal life of its meters by eight years, further reducing the costs and allowing CPUC to invest in its assets. If the meter sample returns a negative test, a meter replacement program will have to be planned and initiated. CPUC recognizes this as a small risk and expects the sampling test to return as positive.

4.3 CAPITAL EXPENDITURE SUMMARY (5.4.2)

Table 24 provides a ten-year overview of CPUC's capital expenditures including a five-year historical summary and a five-year forecast. Most of the capital expenditures are planned to maintain system performance and fall under the System Renewal category.

System Access projects generally fall under the "obligation to serve" and "mandatory connection" requirements of the *Electricity Act*, and as such, must be completed by CPUC when the customer meets all the requirements of the DSC. CPUC is expecting a negligible load growth and has not included a forecast of System Access costs as the costs will not be material. General Plant investments are not expected to be material. The System Service category is forecast to have no material investments. Capital investments forecast within this DSP period will have little to no impact on the system O&M costs, which are expected to slightly increase to further maintain the aging asset system. Additionally, there are no expenditures for non-distribution activities in CPUC's budget.

Table 24 Historical and forecast capital expenditures and system O&M

	Historical															Forecast				
	2014			2015			2016			2017			2018			2019	2020	2021	2022	2023
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.*	Var.					
Category	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	1.5	0	-	1.5	0.5	-	1.5	1	-	1.5	19.7	-	1.5	8.0	-	0	0	0	0	0
System Renewal	51.8	18.9	-	51.8	45.8	-	51.8	35.3		51.8	4.4	-	51.8	34.4	-	80.6	80.6	80.6	80.6	80.6
System Service	-	25.0	-	-	0	-	-	0.1	-	-	0	-	-	32.5	-	0	0	0	0	0
General Plant	5.0	0	-	5.0	54.8	-	5.0	-	-	5.0	-	-	5.0	401.7	-	0	0	0	0	0
Total	58.3	43.9	*-24.7*	58.3	101.2	*73.6*	58.3	36.4	*-37.6*	58.3	24.1	*-58.7*	58.3	581.3	*897*	80.6	80.6	80.6	80.6	80.6
System O&M	-	744.7	-	-	730.6	-	328.0	744.0	*127*	321.2	716.6	*123*	327.6	797.8	*144*	813.8	805.8	809.8	807.8	808.8

** includes 8 months of actual expenditures*

4.3.1 Variances in Capital Expenditures

CPUC is filing their first DSP and has therefore no actual historical planned values. However, the historical total planned value is based on CPUC's last Board approved 2012 budget. The breakdown provided is based a best estimate at slotting the 2012 projects into the respective categories. For the discussion of variances, the variance is looked at each year and discussed at the total summation level for the most part. Additional detail is provided for larger variances.

2014

Variances in capital additions during 2014 can be attributed to an investment of $25k in software management by Burman Energy and approximately $18.9k in asset renewal which included poles, transformers, towers, fixtures and external contractors when needed.

2015

Capital expenditures includes services by Burman Energy for a survey and software support, accounting for $54.8k. Additionally, $45.8k in asset renewal which included poles, transformers, towers, fixtures and external contractors when needed.

Of the visually inspected poles, a small percentage was identified subjectively to be in a poor condition and required replacing immediately to avoid the failure risk associated with the wood poles. There has been an overall reduced spending on the system's asset renewal than originally planned in CPUC's 2012 Test Year.

2016

Capital expenditures included an investment of $35.2k in asset renewal which included poles, transformers, towers, fixtures and external contractors when needed.

Of the visually inspected poles, a small percentage was identified subjectively to be in a poor condition and required replacing immediately to avoid the failure risk associated with the wood poles. There has been an overall reduced spending on the system's asset renewal than originally planned in CPUC's 2012 Test Year.

2017

Capital expenditures included an investment of $4.4k in asset renewal which included poles, transformers, towers, fixtures and external contractors when needed.

In 2017, CPUC purchased sufficient smart meters (125 FM2S) so that a meter reverification project could be undertaken in 2018. The intent of the meter reverification process is to determine if the smart meters are still functioning well and can be left in service. If the re-verification is successful, the meters life will be extended from 10 to 18 years, significantly deferring capital costs and doubling the life of the meter. This resulting investment was $19.7k.

2018

The major increase in total capital expenditures is attributed to the following investments:

- purchase of a boom truck to replace an old depreciated truck ($389k);
- completion of moisture testing on the CPUC's station ($32.5k);
- purchase of new laptops and a handheld for the linemen ($12.7k);

- fraction of meter requiring replacements determined from the previous years meter sampling ($8k); and
- asset renewal which included poles, transformers, towers, fixtures and external contractors when needed ($34.3k).

Like most hardware and software, the technology becomes obsolete and presents more problems to the operation of the system. Discontinued software loses vendor support and no longer receives security patches. Compatibility between newer and older software becomes an issue and eventually hinders the efficient operation of the utility. The business case CPUC used for purchasing a new boom truck is found in Appendix F.

Additionally, a routine station maintenance detected a trend of moisture ingress into the station transformers. This is likely an artifact of the transformer maintenance activity conducted in 2013. A project to conduct a more thorough test and moisture removal was undertaken to avoid having to replace the station transformers. Initial estimates of transformers needing replacement within 2 to 5 years is expected to be superseded with a 5 to 8-year life extension. A capital project of $1.5M to $2.0M is expected to be deferred because of this life-extending maintenance.

O&M
Historical investments provided little reduction in O&M costs. CPUC has mostly been maintaining their asset base through O&M and addressing the worst of the worst assets, which are captured in the asset replacement program. Increases in O&M expenditures attribute to:

- Increase in operation costs
- Increasing billing expenses due to the increased costs from billing supplies
- Increase in regulatory expenses
- Increase in wages

4.4 Justifying Capital Expenditures (5.4.3)

This section provides the necessary data, information, and analyses to support the capital expenditure levels proposed in this DSP.

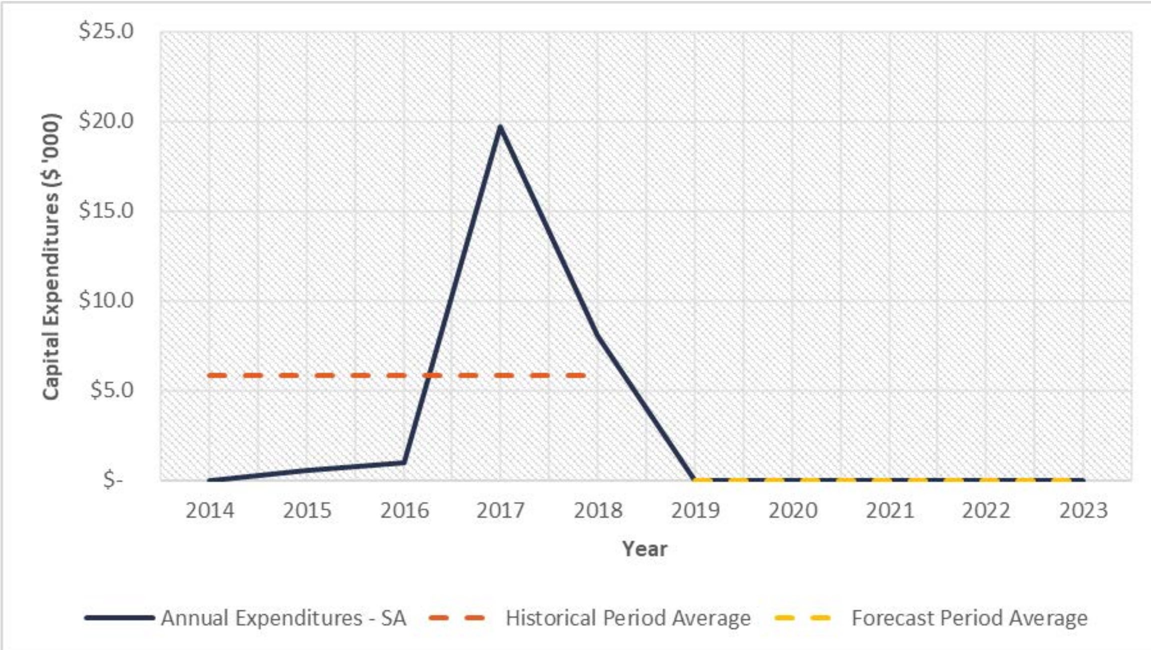
4.4.1 Overall Plan (5.4.3.1)

4.4.1.1 *System Access*

4.4.1.1.1 Comparative Expenditures over the Historical Period

System Access expenditures over the forecast period are 100% lower compared to the historical period. CPUC does not expect to be investing in any major System Access investments over the forecast period, with the exception of any mandatory project to be compliant with regulation. With no forecast cost in System Access, there is no impact on O&M costs.

Figure 37 Trends in System Access expenditures



4.4.1.1.2 Investment Drivers

System Access investments are modifications or relocation a distributor is obligated to perform to provide a customer access to electricity services. CPUC expects that its system will continue to accommodate the requests for new load connections and for service upgrades during the forecast period. CPUC does not project any significant load growth in the next five years nor any project that is above the materiality threshold.

4.4.1.2 *System Renewal*

4.4.1.2.1 Comparative Expenditures over the Historical Period

System Renewal expenditures over the forecast period are, on average, 51% higher compared to the historical period. There is a renewed focus on replacing critical, failed wood poles and attached assets on poles to the newer standard poles. The newer standard poles will support the new 25-kV converted feeders in the long-term plan. Additionally, older poles in the system are being replaced gradually over the forecast period in order to alleviate the rate shock and resource constraint to be experienced in the long-term once CPUC plans to convert remaining 4.16-kV feeders to 25 kV. System Renewal investments have little to no impact in O&M costs since the utility is obligated by the DSC to conduct the required maintenance tasks and frequency. However, there is always a possibility that the utility can save on reactive maintenance practices by reducing the amount of high risk poles in-service. Quantification of these O&M impacts is not directly translatable into O&M cost reductions.

Figure 38 Trends in System Renewal expenditures

4.4.1.2.2 Investment Drivers

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. Based on the similarities in asset age profile, the analysis of current information has concluded that asset renewal for other asset categories will follow essentially the same schedule as pole replacement. Specifically, assets such as customer transformers, system switches, conductors, etc. were assumed to be subject to the same vintage replacement criteria as the poles to which they were attached. Improvements to the asset management process made over the DSP forecast period will be used to justify System Renewal category projects proposed in the next DSP.

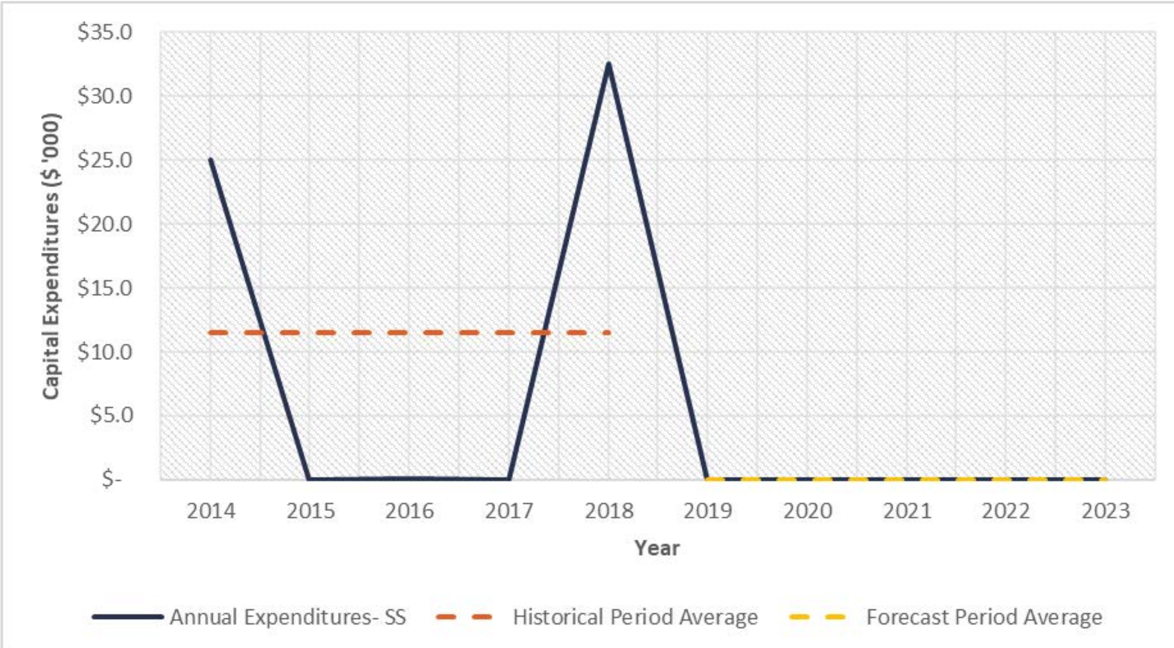
Projects in this category involve targeting replacement of assets that are in critical condition on a "like-for-like" replacement strategy. Past expenditures in this category have ranged from $15,000 to $45,000 over the past five years addressing required asset replacements identified through CPUC's maintenance inspections. It is expected that portion of the assets replaced will be on the existing 4.16-kV feeders that will eventually be converted to 25 kV. These assets will be fitted in a way that can accommodate the long-term plan of a voltage conversion of the system.

4.4.1.3 *System Service*

4.4.1.3.1 Comparative Expenditures over the Historical Period

System Service expenditures over the forecast period are 100% lower compared to the historical period. CPUC does not expect to be investing in any major System Service investments over the forecast period. With no forecast cost in System Service, there is no impact on O&M costs.

Figure 39 Trends in System Service expenditures



4.4.1.3.2 Investment Drivers

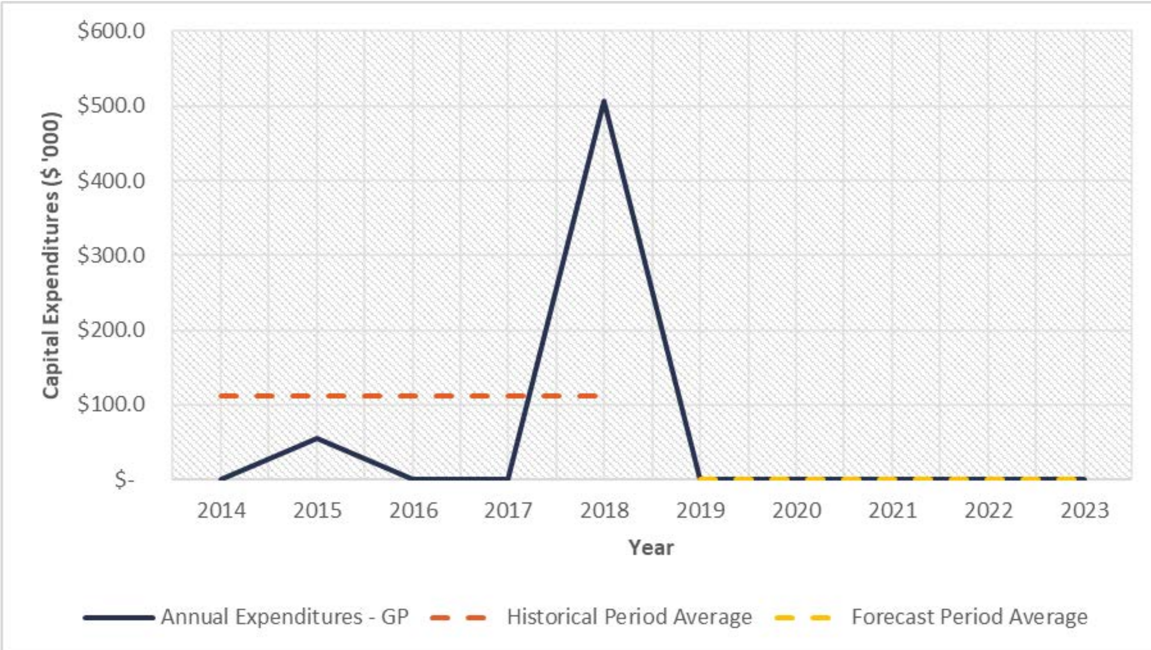
System Service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements, such as the ability for the system to connect to REG and smart grid elements. Within the current DSP period, there are no major investments planned above the materiality threshold. It is important to state that there will be a significant investment planned within the next 20-years to convert remaining 4.16kV feeders to 25kV to address the significant line loss experienced at CPUC.

4.4.1.4 *General Plant*

4.4.1.4.1 Comparative Expenditures over the Historical Period

General Plant expenditures over the forecast period are 100% lower compared to the historical period. CPUC does not expect to be investing in any major General Plant investments over the forecast period. With no forecast cost in General Plant, there is no impact on O&M costs.

Figure 40 Trends in General Plant expenditures



4.4.1.4.2 Investment Drivers

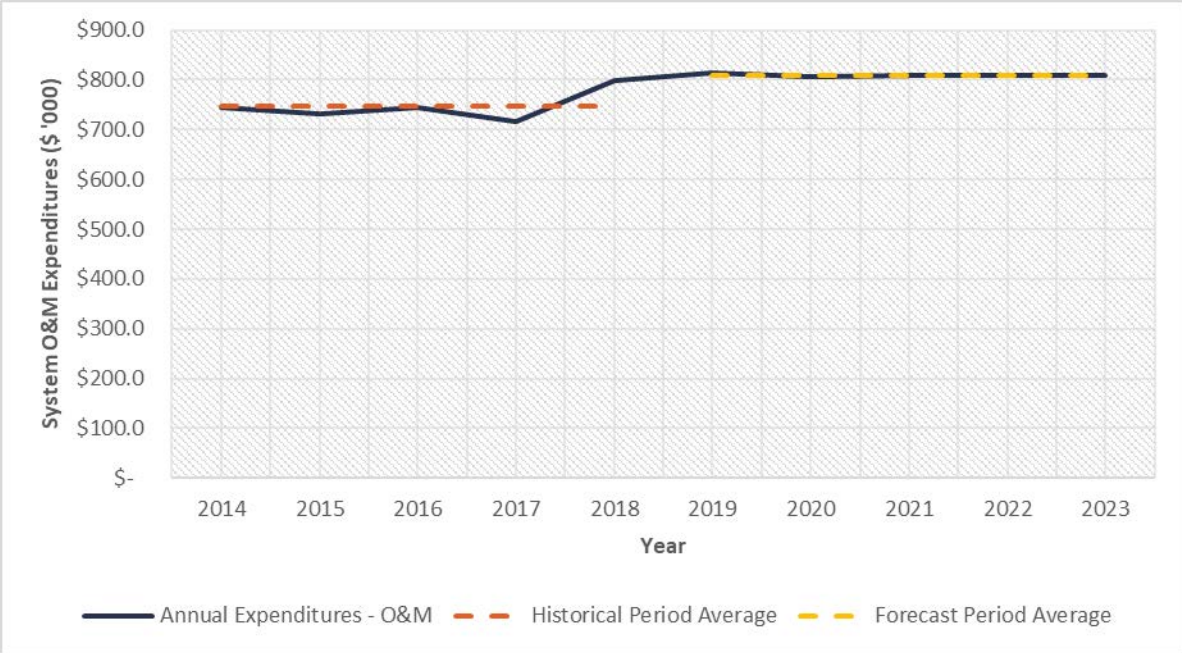
General Plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities. The short-term plans are to address the customer-identified priorities, such as improved communications, are met by enhancing ad hoc customer communications though the web site and bill inserts. This will not require capital investments and therefore, there are no projects planned in this category over the forecast period.

4.4.1.5 *Forecast Impact of System Investment on System O&M Costs*

The figure below summarizes the forecast system O&M costs compared to the historical period costs. The system O&M costs budgeted over the forecast period are, on average, 7.7% higher than the historical period costs. The main drivers for the increase in system O&M costs over the forecast period are:

- Increased O&M costs associated with IT systems; and
- Distribution system inspection cost increases to acquire condition data on assets.

Figure 41 Forecast impact of system investment on system O&M costs



4.4.2 System Capability Assessment

CPUC's capability assessment can be found in Section 3.4 with additional information on the systems utilization and projected load growth in Section 4.1.3.

4.4.2.1 *REG Requirements*

Information regarding CPUC's ability to accommodate REG can be found in Section 4.1.4.3.

4.4.3 Material Investments (5.4.3.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For this Application, the materiality threshold is $50,000. Since CPUC does not have any project in a given year that reaches the threshold in this Filing, CPUC is providing the following information on a program level and as good asset management practice to justify its approach.

Table 25 List of material capital programs in the 2019 Test Year

Category	Project/Program Name	Priority Rank	Capital Cost	Contributed Capital	Net Capital
System Renewal	Overhead Renewal	1	$ 80, 667	$ 0	$ 80, 667

4.4.3.1 *Program Narratives*

Investment Category:	**System Renewal**
Program Name:	**Overhead Renewal**

PROGRAM DESCRIPTION

This capital expenditure includes "like-for-like" replacement costs related to renewal of major overhead assets (poles, transformers) that have a risk of failure due to asset condition degradation or the asset reaching its useful life. Major drivers in this category are risk of failure with secondary drivers of reliability and safety. Replacement of assets within this program will lead into the preparation of the feeder voltage conversion as part of CPUC's long-term plan.

While the overall objective of this program is to replace assets at end-of-life in the most cost-effective way from a planned capital stand-point, a related objective is the reduction of potential O&M costs directly relating to reactive maintenance:

- Emergency call-outs due to equipment failure;
- Inventory of non-standard parts;
- Non-standard installation standards; and
- Safety non-compliance.

The O&M cost avoidances are not directly translatable to O& cost savings nor cost reductions since the O&M funds are still required for any potential failures experienced on the system.

HISTORICAL AND FUTURE CAPITAL AND RELATED O&M EXPENDITURES

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capital (Gross)	18.9	45.9	35.3	4.4	34.4	80.7	80.7	80.7	80.7	80.7
Contributions	-	-	-	-	-	-	-	-	-	-
Net Capital	18.9	45.9	35.3	4.4	34.4	80.7	80.7	80.7	80.7	80.7

The cost estimates are based on historical known replacement costs for wood poles and overhead transformers. Historically, CPUC replaced approximately six poles and two transformers per year. Over the forecast period, CPUC will replace fourteen poles and two transformers per year while relocating the remaining transformers on the poles to another section of the feeder to reduce costs as much as possible. For the forecast amount, an experienced contractor will have to be hired to assist CPUC with the installation of wood poles in high-load and high-risk areas since CPUC lacks the resources and expertise to handle such situations without having a planned outage. Thus, the hired contractor would be able to replace the poles while maintaining the service to customers and not affecting the reliability performance.

PRIORITIZATION

This is the only program proposed for the Test Year; therefore, there is no need to prioritize this program against other programs. The only time the scheduled tasks of this program will be pushed back is when a mandated service obligation project comes up and requires resources to be diverted. CPUC does not anticipate for this risk to materialize; however, the risk will be handled through a risk mitigation plan.

RISKS AND MITIGATION EFFORTS

Risk Identified	Activities to Mitigate Risk
Scheduling Risks	Mitigation plans to address the identified risk include practicing good project management skills and having progress meetings with members of CPUC to review project status.

INVESTMENT DRIVERS

Primary Driver	Reasoning
Failure Risk	The main purpose of the program is to reduce the risk of the reactive costs of failure for overhead assets by proactively replacing the existing poles that are in critical condition. Many have reached end-of-life and their failure probabilities will continue to increase. The replacement of associated equipment such as transformers will also help to maintain existing reliable service.
Secondary Drivers	**Reasoning**
Reliability	A planned process minimizes the risk of overhead line failures (poles). It also assists in reducing the likelihood of future unplanned customer outages.
Safety	The new asset renewals will be engineered and constructed to CPUC standards, *Ontario Regulation 22/04* and *CSA C22.3 No.1 (Overhead Systems)*. This will make the lines safer to work on for CPUC crews and more capable of withstanding storm conditions.

EVALUATION CRITERIA

Evaluation Criteria	Reasoning
Net Customer Benefits	Customers in affected areas will benefit from the renewal of poles and transformers since it will reduce the risk of failure and resulting unplanned customer outages and costs.
Reliability Impact	This program is chosen to maintain the level of reliability for customer on the system. Reliability would decline if CPUC did not complete the work.
Safety	The use of current construction standards will enhance worker safety as well reduce the number of critical poles in service, thereby enhancing the public's safety.
Efficiency	Proactive asset replacement saves O&M and Reactive Capital costs. Since the assets are past their useful life, they will eventually fail causing costs relating to patrol, restoration, temporary and permanent replacements.
Cyber Security/Privacy	This project does not impact cyber security nor privacy.
Coordination Efforts	The investment incorporates CPUC standards which in turn incorporate standards from groups such as the Canadian Standards Association (CSA) and Institute of Electrical and Electronics Engineers (IEEE). The investment applies the requirements of *Ontario Regulation 22/04* as overseen by the ESA. This investment partially enables future

Evaluation Criteria	Reasoning
	technological functionality, i.e the voltage conversion of feeders found in the system in the long-term plan.
Environmental Benefit	As part of the renewal program, CPUC removes older poles which were predominately treated with chemicals that do not meet current environmental standards. As a result, CPUC can replace older poles with poles that adhere to current environmental standards.
Economic Development	There is no direct impact on economic development within Chapleau through this program. Rather it maintains the economic continuity for each of the customer's daily lives.

PROGRAM NEED

In this DSP, CPUC is applying sound planning methodology and asset management principles. At this point in the asset management process development, CPUC has only asset age data upon which to base the asset health. As the asset management process improves over the forecast period, CPUC will collect further asset condition data including information about the severity of identified defects for the various asset types. It is anticipated that with these improvements, CPUC will be able to refine its plans and develop assessments based on adjusted ages that can be objectively compared to typical useful lives (CPUC utilizes the typical useful life of assets noted in the Kinectrics study[4]).

Proactive asset replacement saves O&M and Reactive Capital costs. Since the assets are near end-of-life, they will eventually fail causing costs relating to patrol, restoration, temporary and permanent replacements. Proactive projects within the program can be planned for efficiencies of costs and outages. Furthermore, the associated transformers and other equipment also often need replacement and/or repair. By completing renewals of wood poles, CPUC can address several elements within the project. If this program is not undertaken, there would be a greater risk of overhead failures (poles and transformer equipment) and resulting unplanned customer outages. O&M costs would increase as crews would have to perform spot replacements and repair line sections as they fail, which is less efficient and costlier compared to planned renewal. Running to failure would increase O&M costs as failures could also occur outside normal business hours and require unplanned overtime. Lastly, in the long-term plan once CPUC is ready to do a voltage a conversion, the new assets installed will be suited for the voltage conversion.

The Overhead Renewal program is a transitional program into the forecast system voltage conversion. The voltage conversion project, expected to be within the next DSP period, will address customer issues by lowering system losses and the price of electricity to customers, increasing the reliability of the distribution system and decreasing costs by eliminating the need for the replacing the end-of-life 4.16-kV assets. Captured benefits as part of the voltage conversion in the future include:

- The project will improve the delivery of safe, reliable power. The project will replace the old 4.16 kV substation and wood pole lines with a state-of-the-art, smart grid ready 25 kV system;
- The project will enable the connection of renewable energy generation;
- The project will reduce system losses; and

[4] Kinectrics report is published as a part of OEB Revised Chapter 2 Appendices - version 2.1 from Aug 1-14 at Appendix 2-BB Service Life

- The project will enhance shareholder value.

A system analysis was completed on the line losses and recommended actions for CPUC can be found in Appendix D.

CATEGORY-SPECIFIC REQUIREMENTS

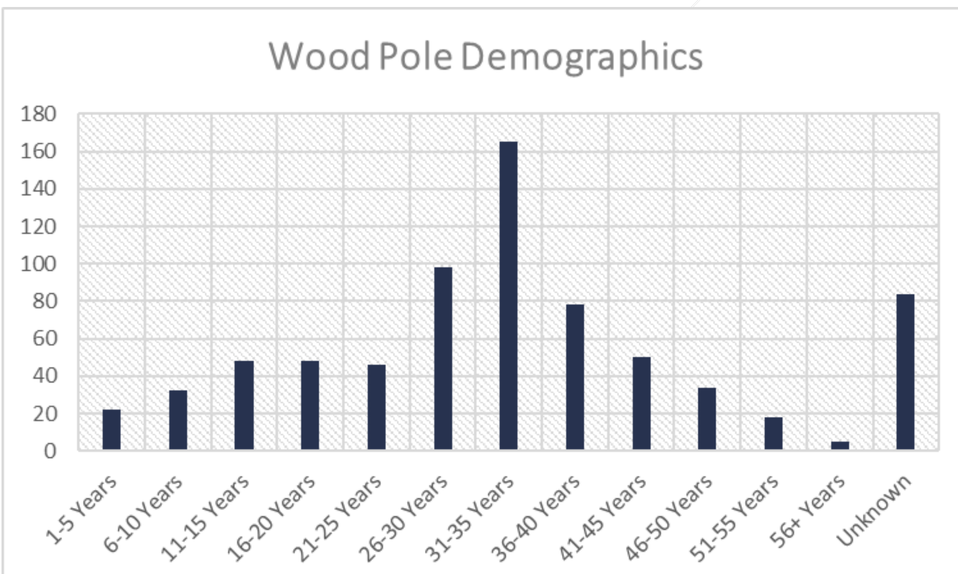
ASSET DETAILS

Wood Poles

Wood Poles, by far, are the largest quantum of assets within the distribution system. CPUC has 730 poles in its system with 76% of them being 4.16-kV poles and the rest 25-kV poles. The age and condition of the poles cover the full range of possibilities, from newly installed to over 40 years of age. A large number of the population of older wood poles will be replaced when CPUC proceeds with voltage conversion. CPUC has used a typical useful life (TUL) of 45 years for poles.

The graphic below provides information about the total wood pole count of 730 and their age distribution.

Figure 42 Wood Pole Demographic



The vintage distribution of wood poles indicates that a significant number of the poles need to be replaced in the next fifteen years.

Pole-Mounted Transformers

CPUC has approximately 267 pole-mounted transformers constituting large dollar value portion of the asset base. CPUC has used a TUL of 40 years for pole-mounted transformers historically. In most cases, transformers are either relocated or are replaced if the pole they are mounted on is being replaced as well for operational effectiveness and efficiency. In the current budget, it is estimated a single transformer is replaced or installed for every sixth wood pole replaced.

CPUC is currently installing unique transformer location numbers and collecting more information about its transformers. CPUC is planning for pole-mounted transformer replacements based on transformer age criteria in the future.

PROJECT IMPACTS

The extent of planned outages to customers as part of the construction project directly depends on CPUC's resources in replacing the assets. This means that should CPUC plan to use its own resources, the number of planned outages can be high and have a high impact on customers. Strictly using only CPUC resources will allow for more assets to be replaced in the defined budget. Should CPUC hire external contractors who have specialized equipment to complete the work, the number of planned outages can be minimal to none with very little impact on customers. However, strictly using contractors will limit the amount of work that can be done with the budget due to the high cost of contractors. Nevertheless, outages during a planned project are shorter and can be more convenient than unplanned or emergency outages since they can be planned during off-peak hours. With the renewed assets, customers will experience fewer outages relating to defective equipment in the future compared to if the work was not done.

Overall project costs are minimized by executed proactive replacements. Customer satisfaction is affected by CPUC's ability to deliver safe, secure and reliable electricity. As this program assists in maintaining the delivery of safe, secure and reliable electricity, the Overhead Renewal program will have a positive impact. As assets continue to be replaced and standardized to 25-kV construction, there will be greater efficiency gains and lower distribution system losses that will benefit all customers in the long term.

The financial cost of the loss of power to a business customer can be high. The financial cost of the loss of power for residential customers is typically much lower, but the personal impact can be high. Impact of a pubic safety event is high, but low probability. CPUC will communicate and maintain all positive relations with its customers while carrying out the program.

TIMING AND PACING

The factors that affect the timing of this project are scheduling and weather. Scheduling is a significant factor as it must be planned in coordination with outside sources such as the other municipality utilities and businesses. Coordination may be required with telecom providers for any joint-use pole attachments. Weather impacts affect timing as unfavorable weather delays construction progress. Chapleau experiences an extended winter season which limits the time permitted for CPUC to complete pole renewals due to the snow accumulation as well as the frozen ground.

CONSEQUENCES FOR SYSTEM O&M COST

Assets targeted through the Overhead Renewal program are well past their service life. There are consequences relating to the failure of the assets found within this program that affect the public safety, the environment and the utilities' service to the customers. Such consequences can include poles falling or transformers leaking oil into the environment. Should these assets not be replaced in a proactive manner but in a reactive manner will increase the overall cost.

In addition, since the Overhead Renewal program is on a like-for-like basis, there is no reduction in maintenance costs since the utility is mandated by the DSC with the required maintenance practice and frequencies.

PROGRAM EVALUATION

Four alternatives are evaluated against the chosen recommended option:

1. Replace the minimum amount of assets as needed for the system;
2. Replace assets like-for-like to the 4.16-kV specifications to sustain the system (historical approach);
3. Replace assets like-for-like to the 4.16-kV at an increased rate to address the aging system; and
4. Do nothing.

The recommended option follows:

5. Replace the assets through an optimized approach that improves the asset's age base and is ready for a future voltage conversion

The first alternative will likely degrade the reliability performance as the system continues to age and defective equipment will fail, as presented in CPUC's DSP. In addition, this replacement strategy will not be ahead of the curve of aging assets, will not address the high line loss and it would not be optimal to replace these recently installed assets with assets that conform to the future voltage conversion specifications.

The second alternative would likely to maintain the reliability performance of the system in compliance to all safety and construction standards. This alternative is not optimal, however, since it does not address the aging system as well as the line loss reported at CPUC. In addition, within a 20-year timeline the assets that were standardized for the 4.16-kV system will need to be replaced again to meet construction standards for a 25-kV line. Within this 20-year timeline, the assets would have not reached their useful life nor would have degraded to a point where replacing would be required. The primary reason the assets would need to be replaced to meet the 25-kV standards is to permit the voltage conversion of the feeders to ultimately reduce the line loss on the distribution system.

The third alternative would directly address the aging system and would target the oldest and worst condition poles found in the system. Though This may be a viable option, it would not address the poor line loss reported at CPUC anytime soon. Therefore, this alternative had to be modified by targeting the aging assets but as well address the line loss. From this, the recommended option was created.

The "Do nothing" alternative allows the assets run to failure completely and replace assets at a reactive rate. This option is unfavourable as it would hinder CPUC's reliability metrics, put its customers and the public at a safety risk and put an operational strain on utility resources – both human and material resources. This option is evident it would put the utility at an unfavourable position in front of the regulators and the utilities' shareholders.

In conclusion, the recommended option would provide the following benefits:

- Strategic Fit
    - Alignment to corporate strategic and planning goals
    - Meets the customer preferences of having a reliable, safe and secure service at minimal costs

- System Needs
    - Compliance with ESA and ensuring the historical safety levels moving forward
    - Maintaining the reliability performance while addressing the higher failure risk assets
        - There is a small possibility this can improve the reliability performance in the Defective Equipment cause code
    - Addresses the aging system through a prioritized and optimized approach that will prepare the system for a voltage conversion in the next 20-years
        - Over this period, the reported high line loss is expected to be reduced to the provincial average
- Feasibility
    - Increase the utilities' financial position and shareholder value

5 APPENDIX

5.1 APPENDIX A

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Revision: FINAL R0
Date: December 12, 2014

Prepared by: East Lake Superior Region Study Team

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the East Lake Superior Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Great Lakes Power Transmission LP (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT SUMMARY REPORT

NEEDS ASSESSMENT SUMMARY REPORT			
NAME	East Lake Superior Region Study		
LEAD	Great Lakes Transmission LP (GLPT)		
REGION	East Lake Superior		
START DATE	October 12, 2014	**END DATE**	December 12, 2014

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the East Lake Superior Region (ELS-Region), determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary such needs will be addressed among the relevant Local Distribution Companies (LDCs), GLPT and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

2. REGIONAL ISSUES/TRIGGER

The Needs Assessment for the East Lake Superior Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. East Lake Superior Region belongs to Group 2 and the Needs Assessment for this Region was triggered on October 12, 2014 and was completed on December 12, 2014.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans.

4. INPUTS/DATA (INFORMATION REQUIRED TO COMPLETE ASSESSMENT)

Study team participants, including representatives from Local Distribution Companies (LDC), the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO) and Hydro One Networks Inc. (Hydro One) provided information and input to GLPT for the East Lake Superior Region. The information provided includes the following:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

5. ASSESSMENT

The assessment's primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

A. 230kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at the one 230kV connected load station throughout the study period. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

- Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

- East-West Tie lines are to be upgraded within the time period of this Needs Assessment. Hydro One's Customer Impact Assessment (CIA) entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customer in the area.

B. 230/115kV Autotransformers

- No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

C. 115kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

- Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the increased demand forecast from one large industrial customer in Sault Ste. Marie projecting an increase in peak. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

D. System Reliability, Operation and Restoration Review

- Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

- There is a concern about transformer failure in the region where there are some load stations with just one transformer supplying customer load. The Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

E. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)

- Tarentorus TS (equipment & relaying)

7. RECOMMENDATION

The Team Recommends:

The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution continue to be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

The potential needs identified regarding the capacity of the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS do not require further regional coordination. The study team recommends that a "localized wire only solution be developed in the near-term to address the above need through planning between GLPT and the impacted customer.

The potential need identified for the restoration of load (ORTAC 8 hours violated) after a single supply transformer failure does not require further regional coordination. The study team recommends that a "localized" wire only solution be developed by GLPT and the impacted distributor.

PREPARED BY: East Lake Superior Region Study Team

PARTICIPANTS: LISTED BELOW

COMPANY	NAME
Great Lakes Power Transmission LP (Lead)	**Jim Tait**
Ontario Power Authority	**Bob Chow**
Independent Electricity System Operator	**Phillip Woo**
Hydro One Networks Inc. (Transmitter)	**Ajay Garg**
PUC Distribution Inc.	**Rob Harten**
Algoma Power Inc.	**Greg Beharriell**
Chapleau Public Utility Corporation	**Alan Morin**

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1. INTRODUCTION

This Needs Assessment report identifies needs in the East Lake Superior Region ("ELS-Region"). For needs that require coordinated regional planning, the OPA will initiate the Scoping process to determine the appropriate regional planning approach. The approach can either be the OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements.

This report was prepared by the ELS-Region Needs Assessment study team (Table 1) and led by the transmitter, Great Lakes Power Transmission LP (GLPT). The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA), Hydro One Network Inc. and the Independent Electricity System Operator (IESO) to determine possible needs in the ELS-Region.

Table 1: Study Team Participants for ELS-Region

Company
Great Lakes Power Transmission LP (GLPT) (Lead Transmitter)
Ontario Power Authority (OPA)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Hydro One) (Transmitter)
PUC Distribution Inc. (PUC)
Algoma Power Inc. (API)
Chapleau Public Utility Corporation (CPUC)

Figure 1: East Lake Superior Region

2. REGIONAL ISSUE / TRIGGER

The Needs Assessment for the ELS-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. The ELS-Region belongs to Group 2. The Needs Assessment for this ELS-Region was triggered on October 12, 2014 and was completed on December 12, 2014.

Additional information about Regional Planning can be found on the GLPT website: http://www.glp.ca/content/regional_planning_new/history-40236.html

3. SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the ELS-Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment includes a review of system capability which covers transformer station loading and transmission thermal and voltage analysis based on recent detailed studies. Asset sustainment issues and other considerations were taken into account as deemed necessary.

3.1. EAST LAKE SUPERIOR REGION DESCRIPTION AND CONNECTION CONFIGURATION

Figure 2a – Wawa TS/Anjigami TS Northern Area – Hydro One 230/115 kV autotransformers at Wawa TS, Hydro One 115 kV circuit supplying CPUC load and GLPT 115 kV lines and stations connected via Anjigami TS.

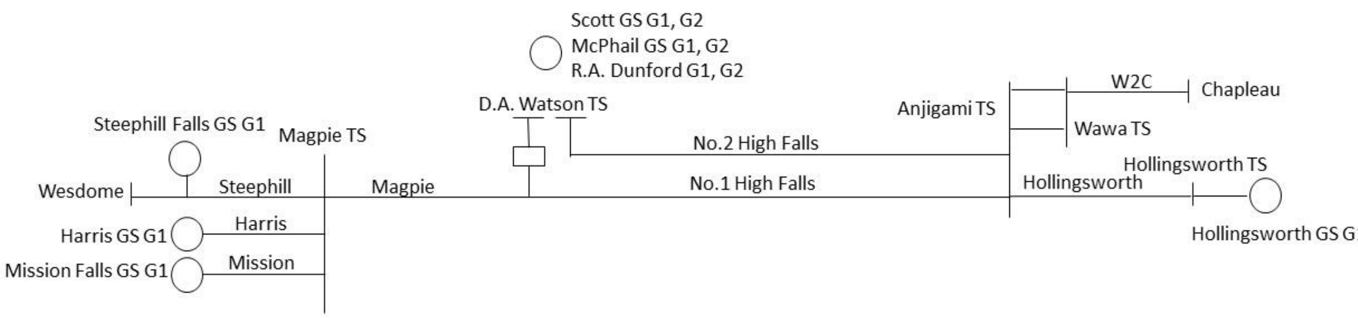


Figure 2b – MacKay TS South Central Area – GLPT 230/115 kV autotransformer at Mackay TS and 115 kV lines/stations connected via Mackay TS and two transformer stations connected to No.3 Sault.

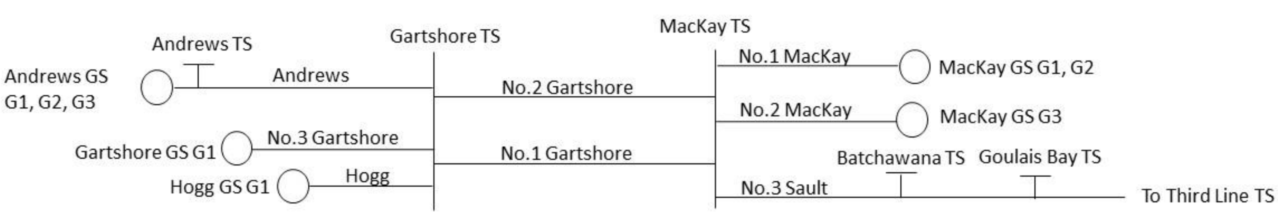


Figure 2c – Sault Ste. Marie Southern Area – GLPT 230/115 kV autotransformers at Third Line TS and 115 kV lines/stations in Sault Ste. Marie.

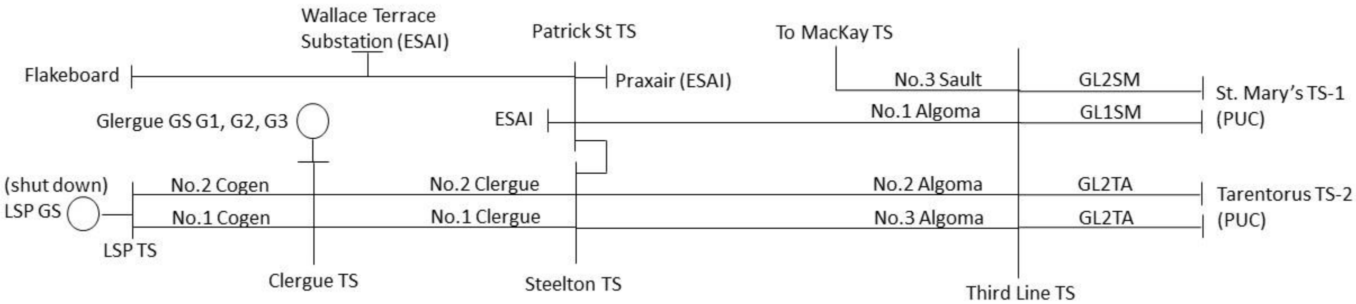
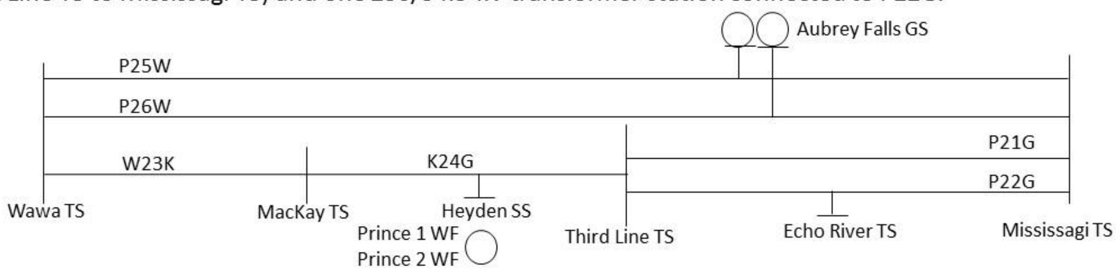


Figure 2d – GLPT and Hydro One 230 kV Eastern Area – Hydro One 230 kV lines P25W and P26W from Wawa TS to Mississagi TS, GLPT 230 kV lines W23K (Wawa TS to MacKay TS), K24G (MacKay TS to Third Line TS), P21G and P22G (Third Line TS to Mississagi TS) and one 230/34.5 kV transformer station connected to P22G.



4. INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to GLPT:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- GLPT provided transformer, station and line ratings
- Hydro One provided Wawa TS autotransformer ratings
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1. LOAD FORECAST

As per the data provided by the LDCs, the load in the ELS-Region is expected to grow at a rate varying from -0.1% to 2.5% plus some larger customer load increases.

Table 2: Annual Load Growth for ELS-Region

LDC	Approximate % Growth Rate 2013 to 2018	Approximate % Growth Rate 2019 to 2023
PUC	Slightly Negative	Slightly Negative
API	0.0 to 2.5%	0.0 to 2.5%
CPUC	0%	0%

Large Industrial Customer Load Increases	Approximate MW Increase 2013 to 2018	Approximate MW Increase 2019 to 2023
Sault Ste. Marie Southern Area	19.4	3.2
Wawa TS/Anjigami TS Northern Area	20.85	0

The Needs Assessment considered gross loads at individual stations based on the 2013 summer or winter peak non-coincident load and the peak summer or winter load forecast for stations within the Region. The station load forecast was developed by using data provided by the LDC's load forecasts and other customer load forecasts.

5. ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Assessment:

1. The Region is winter peaking, but this assessment includes both summer and winter peak loads where one is more critical than the other due to equipment ratings.

2. Forecast loads are provided by the LDCs and other customers.

3. Stations having negative load growth over the study period are assumed to have steady load.

4. In developing a worst-case scenario, DG and CDM contributions were not considered.

5. Review and assess impact of any on-going or planned development project in the ELS-Region during the study period.

6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables and stations.

7. Station capacity adequacy is assessed assuming a 90% lagging power factor on the HV and non-coincident station loads.

8. Transmission line adequacy to be assessed using non-coincident peak station loads in the region.

9. The needs were first identified by looking at the total normal supply capacity (TNSC) of the elements that supply a specific LDC or other customer compared to the three month average peak over the last 5 years and the peak load over the last five years. This was used to identify any planning issues based on the existing peak loads. The 2023 peak load was then compared to the TNSC and if peak loads were greater than 75% of the TNSC for specific station/line(s), these station/line(s) were identified for further study. The TNSC takes into consideration one element out of service where load is not supplied via a single line/station.

10. Transmission adequacy assessment is primarily based on:

    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their continuous ratings and transformers within their summer 10-Day limited time ratings (LTR) if there are two transformers and 10 day LTR's exist.
    - All voltages and voltage declines must be within pre- and post-contingency ranges as per ORTAC criteria.

11. The ELS-Region has a considerable amount of hydro generation connected to the 115 kV system and wind generation connected to the 230 k system. Two new wind farms are in the process of connecting to the Gartshore 115 kV lines (58.3 MW) and K24G 230 kV lines (25.3 MW). Both have had recent detailed IESO System Impact Assessments (SIA) and GLPT Customer Impact Assessments (CIA) completed which did not identify concern in the area regarding overload of facilities. Generation in the area is generally more critical to line overload than LDC and other customer load. These studies were reviewed as part of this Needs Assessment process.

12. For the Sault Ste. Marie Southern section of the ELS-Region, the 98% dependability of generation from Clergue GS was used in this assessment. Glergue GS dependable generation was assumed to be 10 MW. This is based on an IESO Feasibility Study (Confidential) undertaken to assess the Algoma lines for adequate capacity.

This Needs Assessment was conducted to identify emerging needs and determine whether or not further coordinated regional planning should be undertaken for the Region or electrical areas. It is expected that further studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements.

6. RESULTS

6.1. Transmission Capacity Needs

6.1.1. 230kV Connection Facilities

Based on the demand forecast, there is sufficient capacity throughout the study period at Echo River TS which is a 230kV connected load station. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

East-West Tie lines are to be upgraded in 2019. Hydro One's CIA entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customers in the area. The Hydro One CIA assessed the Short-Circuit Impact, Voltage Impact and Supply Reliability Impact.

6.1.2. 230/115kV Autotransformers

No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

6.1.3. 115kV Connection Facilities

Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the demand forecast from one of the other customer in Sault Ste. Marie projecting an increase in peak load. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

6.2. System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

There is a concern about transformer failure in the region where there are many load stations with just one transformer supplying customer load. The ORTAC restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

6.3. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)
- Tarentorus TS (equipment & relaying)

6.4. Other Considerations

Restoration of most of the GLPT transmission system can be accomplished from a black start procedure which energizes the Sault Ste. Marie Southern Area load/generation and eventually up to MacKay TS South Central Area to load/generation and run as an island. It is expected that for the loss of Wawa TS T1 and T2 transformers and by configuration the Wawa TS/Anjigami TS Northern Area, the delay in restoration of GLPT connected load/generation can be greater than the ORTAC standard of 8 hours. There is a need to study if this area could be operated as an island until the supply from Hydro One Wawa TS can be restored.

7. RECOMMENDATIONS

The study Team Recommends:

7.1. The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

7.2. The potential needs identified for the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS does not require further regional coordination. The study team recommends that a "localized" wire only solution be developed by GLPT and the impacted customer.

7.3. The potential need identified for the restoration of load after a single supply transformer failure which could violate the ORTAC criteria of restoring load within 8 hours does not require further regional coordination. The study team recommends that GLPT and the impacted distributor continue to work on this need.

8. NEXT STEPS

Following the Needs Assessment process, the next regional planning step, based on the results of this report, are:

8.1. GLPT and the relevant LDC's are to further assess and/or develop local wires solution as identified in the needs outlined in Section 7.1 and 7.3.

8.2. GLPT and the relevant customers will further assess and/or develop local wires solution as identified in the needs outlined in Section 7.2.

9. REFERENCES

Planning Process Working Group (PPWG) Report to the Board

IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

IESO Feasibility Study (Confidential) for Algoma Lines Redevelopment

IESO System Impact Assessment (SIA) Report and Addendum Report for Bow Lake Wind Farm (CAA ID#: 2010-392)

IESO System Impact Assessment Report and Addendum Report for Goulais Wind Farm (CAA ID#: 2010-397)

GLPT Customer Impact Assessment (CIA) Report for RTK Canada, ULC (Rentech) increased 44 kV load dated April 23, 2014.

Customer Impact Assessment (CIA) Report for Hydro One New East-West Tie Project dated October 29, 2014.

10. KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity (NSC): The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.
Coincident Peak Load: The electricity demand at individual facilities at the same specific point in time when the total demand of the region or system is at its maximum.

Contingency: The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM): Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers' use of electricity.

Distributed Generation (DG): Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load: Amount of electricity that must be generated to meet all customers' needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR): A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast: Prediction of the load or demand customers will make on the electricity system

Net Load: Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load: The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load: The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Total Normal Supply Capacity (TNSC): The maximum loading that electrical equipment may be subjected to post contingency (n-1) under nominal ambient conditions such that an acceptable accelerated loss of equipment life would be expected. For a single element supply system the TNSC equals the NSC.

11. ACRONYMS

CDM Conservation and Demand Management

CIA Customer Impact Assessment

DG Distributed Generation

DSC Distribution System Code

IESO Independent Electricity System Operator

IRRP Integrated Regional Resource Planning

kV Kilovolt

LDC Local Distribution Company

LTR Limited Time Rating

LV Low-voltage

MVA Mega Volt-Ampere

MW Megawatt

NA Needs Assessment

NSC Normal Supply Capacity

OEB Ontario Energy Board

OPA Ontario Power Authority

ORTAC Ontario Resource and Transmission Assessment Criteria

PF Power Factor

PPWG Planning Process Working Group

RIP Regional Infrastructure Planning

SIA System Impact Assessment

SS Switching Station

TNSC Total Normal Supply Capacity

TS Transformer Station

TSC Transmission System Code

5.2 APPENDIX B

IESO Letter of Comment

Chapleau Public Utilities Corporation

Renewable Energy Generation Investments Plan

July 4, 2018

Independent Electricity

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[1] ("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 Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Chapleau Public Utilities Corporation - Distribution System Plan

On June 29, 2018, the IESO received a Renewable Energy Generation Investments Plan ("Plan") from Chapleau Public Utilities Corporation ("CPUC") as part of their 2019-2023 Distribution System Plan. The IESO has reviewed the REG investments information and provides the following comments:

FIT/microFIT Applications

CPUC's Plan indicates that it has no Renewable Energy Generation, including any microFIT or FIT projects connected to its distribution system due to upstream system constraints with Hydro One transmission. This, along with very little renewable generation activity in its service territory, CPUC's Plan contains no forecast for any additional REG connections over the 2019-2023 Plan period.

The IESO's information confirms that there are no microFIT or FIT projects in CPUC's distribution area.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that combined the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with any Regional Infrastructure Plan

For regional planning purposes CPUC is one of the LDCs within the East Lake Superior Region (Group 2). The initial Needs Assessment for the region completed in 2014, was led by Great Lakes Power Transmission LP (now Hydro One Sault Ste. Marie LP) in consultation with the study team consisting of the former OPA and IESO[2], Hydro One Networks Inc., Algoma Power Inc., PUC Distribution Inc. and CPUC. The Needs Assessment concluded that no further regional coordinated planning was required[3]. As such, subsequent planning processes were not initiated (Scoping Assessment, Integrated Regional Resource Plan and Regional Infrastructure Plan).

The second cycle of regional planning for the East Lake Superior Region is not scheduled to begin until 2019, unless there is sufficient load growth or a trigger event that requires the regional planning process to commence before then.

The IESO looks forward to continuing to work with CPUC through the next regional planning cycle and appreciates the opportunity to comment on the REG information provided as part of its Distribution System Plan.

[2] Ibid

[3] Needs Assessment Report – East Lake Superior Region December 12, 2014, page 15 https://www.glp.ca/_Global/27/img/content/file/Regulatory/GLPT%20Needs%20Assessment%20Report%20East%20Lake%20Superior%20Region%20FINAL%20R0%2012_Dec_14.pdf

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5.3 APPENDIX C

Scorecard - Chapleau Public Utilities Corporation

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	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%	100.00%	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		100.00%	100.00%	100.00%	100.00%	99.68%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution			100%	100	100	100			
		Billing Accuracy			100.00%	99.99%	99.99%	99.99%	→	98.00%	
		Customer Satisfaction Survey Results			95%	95	95	95			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				76.00%	76.00%	79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	NI	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.18	0.28	4.75	1.82	0.94	↑		1.36
		Average Number of Times that Power to a Customer is Interrupted [2]		2.58	0.38	1.07	0.63	0.69	↑		0.92
	Asset Management	Distribution System Plan Implementation Progress			0%	50	100	75			
	Cost Control	Efficiency Assessment		4	4	4	4	4			
		Total Cost per Customer [3]		$653	$729	$735	$740	$718			
		Total Cost per Km of Line [3]		$30,175	$33,329	$33,436	$34,163	$29,706			
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 Cumulative Energy Savings [4]				26.22%	44.81%	66.56%			1.05 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.75	2.04	2.05	2.03	1.95			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.00	0.00	0.00	0.00	0.00			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	19.84%	16.88%	0.40%	-3.82%	-1.99%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: ↑ up ↓ down → flat
Current year: target met; target not met

5.4 APPENDIX D

Chapleau PUC

Utility Load Flow and Substation Evaluation, Capacity and Redundancy Study

METSCO Project P-17-206

June 7, 2018

Prepared By: Daryn Thompson P.Eng.

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Contents

1 Introduction

This report was commissioned by Chapleau PUC as part of the documentation process relating to the upcoming rate filing submission.

Within the RFP process, METSCO was requested to produce a report determining the acceptability of the system with current and future load growth, including loading that has been recently defined for the next 10-year period from 2018 to 2028

This report includes findings with respect to optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.

The report also includes finding whether the system would operate acceptably during emergency situations. and a review of Loading, System Losses, System Upgrades to minimize losses and Substation Evaluation, Redundancy and Capacity.

2 Acceptability of System

An assessment was conducted of the acceptability of the system to meet current and future load growth, including loading that has been recently defined for the next 10-year period from 2018 to 2028. Subsequent to this initiation of this study it was confirmed that previously projected new loads will not materialize.

Peak transformer loading was derived from metering information provided in kW and an assumed Power Factor of 0.9. The transformer loading is shown in Table 1 below

Table 1- Transformer Loading

Transformer Loading #	Voltage	Size (kVA)	Peak kW	Calculated kVA (PF .9)
T3	4160	2500	484.5	539
T4	4160	3750	3497.2	3920
25kV Feeder	25kV	--	2207.4	2453
Total				6911

Note: Peak Loads provided by Meter Technician, on Dec 5/17 in kW and converted to kVA using assumed 0.9PF

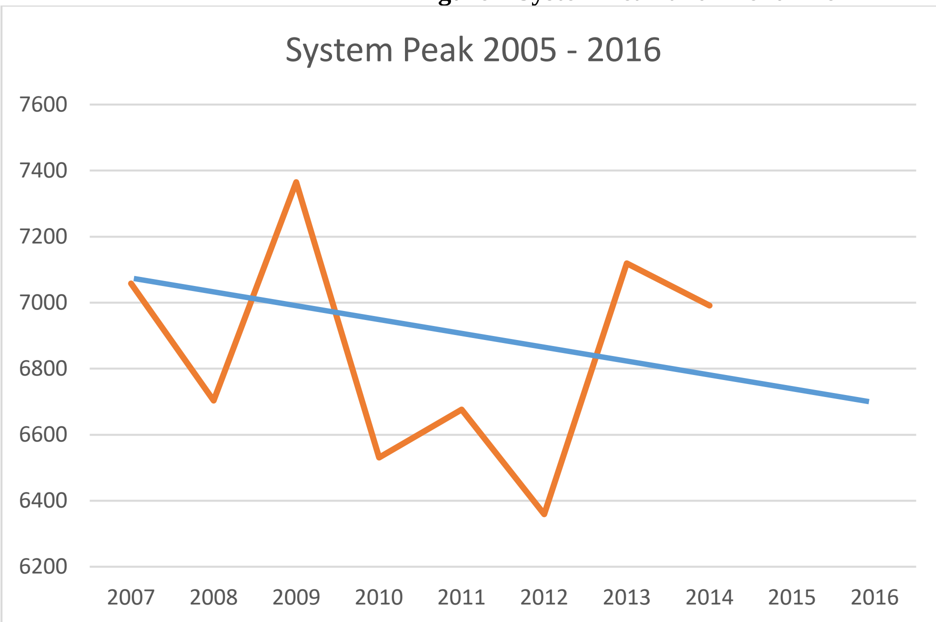
Load forecast

Historical

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
System Peak	7058	6703	7365	6531	6676	6359	7119	6991		
Customer Count	1338	1335	1326	1306	1293	1304	1276	1263	1229	1247
CDM Impact					36	653	39	88	28	19

The load has been falling slightly in the area over the last 10 years as a result of small loss of customers and persistent results of CDM. For the purposes of the forecast, the anomalous results of 2012 are ignored, resulting in an average system peak reduction of 42kW/year due to CDM.

Figure 1 System Peak and Trend line



Actual system peak was not reported for years 2015 and 2016 and are assumed at 6750 and 6700 based on the trend line extrapolated from the previous 10 years data.

Chapleau PCU also reports that load growth scenarios anticipated at the time of issuance of the RFP are no longer likely to occur, except that the new opportunities will provide enough economic activity to maintain the Town in its current situation. As a result, for the purpose of this report, the Load Forecast is presented with a stable customer base and shown with and without the impact of continued CDM.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Forecast Peak w/o CDM	6700	6700	6700	6700	6700	6700	6700	6700	6700	6700	6700
CDM	-42	-42	-42	-42	-42	-42	-42	-42	-42	-42	-42
Forecast Peak w CDM	6658	6616	6574	6532	6490	6448	6406	6364	6322	6280	6238

The IESO Ontario Planning Outlook, forecasts electrical loads in Ontario could vary from -10% to +60% depending on the penetration of Electric Vehicles and Distributed Energy Resources as well as electrification of transportation systems. The most likely scenario for Chapleau is a continuation of a relatively flat profile due to limited adoption of such technologies.

Configuration

The Chapleau Distribution System comprises 1 25kV feeder, 2 4160kV feeders generally supplying loads on either side of the river (F9 on the WEST, and F8 on the EAST and downtown) supplied from T4 and on a single 4160kV (F2) feeder from T3 supplying loads to the north. See appendices for images of the System Map and Single Line Drawing.

The loads in the north include approximately 1500kVA of transformers that have previously been moved from the F2 to the F9 in order to off load a submersible feeder section of the F2 which is considered to be high risk of failure. This 1500kVA of connected load, more likely represents between 400 and 600kVA of actual load (approx. 50-75A)

There have been 2 capacitor banks (each 225 kVAR) installed on the F9, both located relatively close to the station, and a regulator installed 2/3 of the distance out the feeder to provide voltage support in the rural area.

Condition

The condition of the 4160 transformers T3 and T4 would be heavily indicated by the latest test results from SDMyers. (May 2018 report attached)

Both transformers are showing signs of moisture ingress (T3 1.3-2.3%, T4 1.9-3.4%). While the oil sampling tests performed can have a range of results these results are a strong indicator that close attention should be paid to the condition of these unit. Anything over 2% would be recommended for further testing using a more precise Dielectric Frequency Response (DFR) test. Any results from the DFR showing more than 3% would indicate a need for moisture removal. Of additional concern is to determine how moisture is getting into the unit.

Analysis – Voltage Drop & System Loss

The system as it exists was modelling using a mathematical technique that is based on mapping the 3 phase feeder lengths and wire types and assume single phase loads are "point loads" on the feeder. The loads are estimated based on the ratio of total transformation on each feeder vs the peak load on that feeder. Since the F9 and F8 feeders are measure together, they have the same ratios. The load vs connected capacity ratio for the F9 and F8 feeders is 0.32 and the ratio for the F2 feeders is 0.46.

Table 2- Voltage Drop (%) and Losses (%) on 4kV system

System Voltage	4 kV		Calculated Line Loss at Peak Load	
Feeder	Min Voltage at End of Line (kV)	Voltage Drop (%)	Line Loss (kVA)	Line Loss (%)
F2	2.28	4.9%	35.31	3.74%
F8	2.22	7.6%	118.56	7.7%
F9	1.97	17.7%	217.86	13.2%

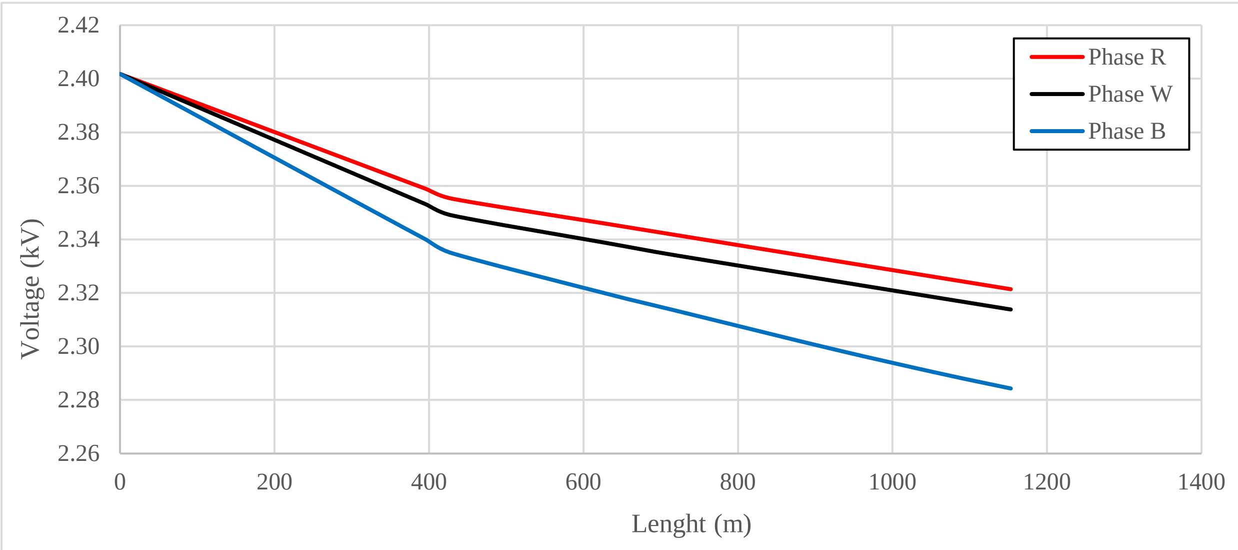


Figure 1- Feeder F2 Voltage Drop [4 kV]

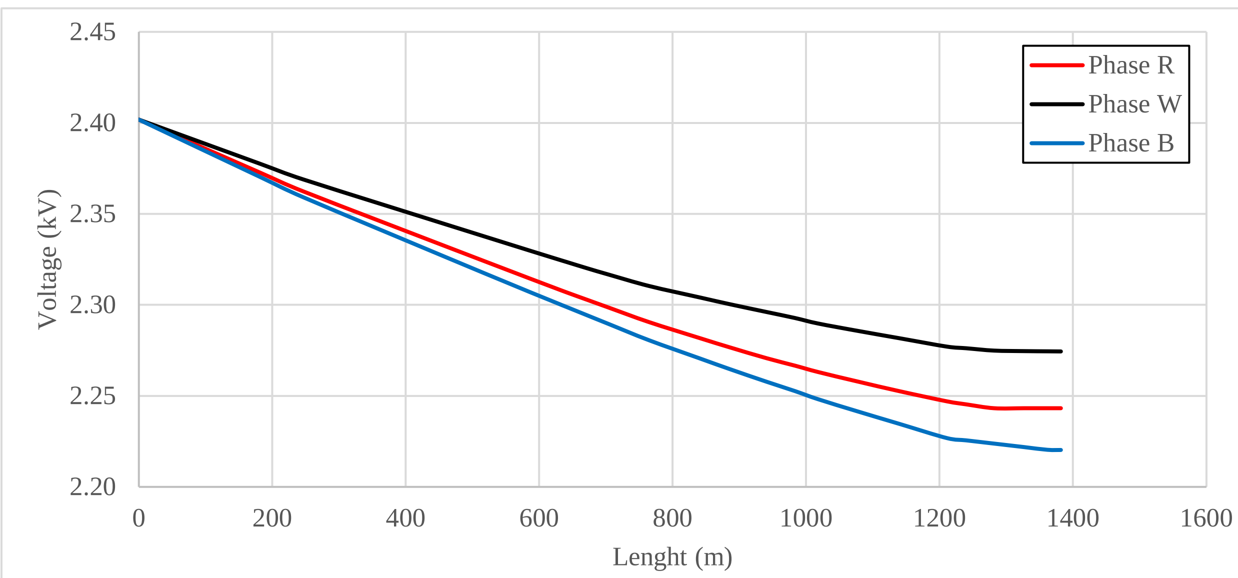


Figure 2- Feeder F8 Voltage Drop [4 kV]

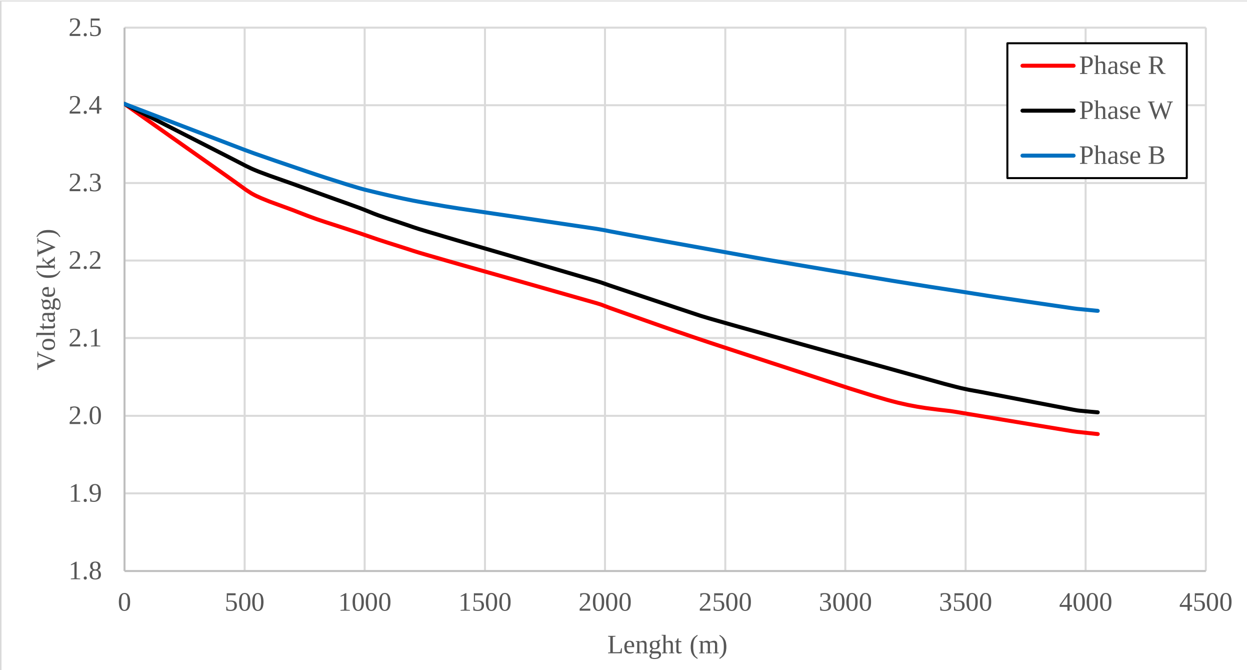


Figure 3- Feeder F9 Voltage Drop [4 kV]

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Conclusion of Assessment of Acceptability of Existing System

Load and Load Growth:	The system load growth is not a driver for investment. The overall transformation capacity levels are reasonable for the loads., however as configured T4 is carrying greater than its nameplate capacity on peak.
Feeder Configuration:	The feeder configuration in generally acceptable for operation, based on the assumption that faulted overhead feeders can be repaired within a reasonable time. However, if system reliability result (typical feeder driven SAIDI) were to deteriorate, the network would not be a candidate for automation as there are no strategic feeder ties at feeder ends or mid-points.
Pole Condition/Health:	As a preliminary recommendation of this report, a pole strength testing program was initiated for the utilities 730 wood poles. Approximately 50 poles (7%) were identified as needing short term replacement out of the 730 poles tested. This represents a significant increase in System Renewal costs above the current plan of about 5 poles/year (<1%).
Cable Condition/Health:	The area known as the "Golf Club" is serviced by an overhead line on the F9 and a submersible cable on the F2. The cable is of suspect condition and currently most of the load has been transferred to the F9. The preferred supply option is the F2 feeder for load balancing reasons and therefore this cable should be tested for usefulness and if necessary considered for replacement.
Transformer Health:	Transformer T4 is showing signs of degradation and is in a condition much worse than expected for a transformed that is <20 years old. This transformer should be tested regularly, and a plan put in place for replacement most likely in the next 5-10 years. Transformer T3, is showing some indication of moisture ingress and should also be monitored closely. As a minimum, comprehensive condition testing is recommended for T4 and T3 which may lead to a rehabilitation plan.

3 System Arrangement

In this section, an assessment is conducted of opportunities to optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.

Load Balancing (Feeders)

Table 3 below shows the relative loading and phase loading of the 3 feeders in the 4160 system.

Table 3- Feeder and Phase Loads (4160 system)

Feeder #	Ph-R Load (kVA)	Ph-W Load (kVA)	Ph-B Load (kVA)	Total Loads (kVA)
F2	264	300	381	945
F9	733	527	394	1654
F8	530	442	574	1546

Due to network limitations, there are no opportunities to move open points and transfer loads except in the “Golf Club” are north of the lake. In this area, there is an opportunity to move 1500 kVA of transformers or about 500 kVA load from F9 to F2 which would result in a well-balanced system. However, due to limitations of the submersible cables supplying the area, it is undesirable to add load to the F2 feeder.

Due to system voltage mis-matches none of the above loads can be moved to the 25kV feeder supplied from Hydro One. Coordination with Hydro One over this feeder is an operational constraint.

Phase Balancing (Within Feeders)

There is an opportunity to improve the phase balancing within the feeder network by moving some single-phase taps from one phase to another. Table 4 below shows the estimated relative percentage imbalance of the 4160 feeders before and after single phase transfers are conducted.

Table 4- Percentage Phase Unbalanced

Feeder	Existing System	Updated System
F2	33%	14%
F8	22.7%	2.2%
F9	53.7%	1.3%

As a result of phase balancing a modest improvement in losses could be achieved as shown in Table 5.

Table 5- Losses and Voltage Drop on Existing vs Phase Balanced System

	Existing System		Updated System	
Feeder	Voltage Drop (%)	Line Loss (%)	Voltage Drop (%)	Line Loss (%)
F2	4.9%	3.74%	4.2%	3.66%
F8	7.6%	7.7%	6.9%	7.5%
F9	17.7%	13.2%	17.5%	12.9%

This is a theoretical exercise as the model assumes an even ratio of load/capacity at every distribution transformer and therefore the actual system changes should be made incrementally and monitored at the station. Also, since each transfer would result in a short outage to the affected customers and the improvement is relatively nominal, consideration should be given as to value of this exercise.

Conclusion of Assessment of System Arrangement

Feeder Balancing: There are no significant opportunities to enhance system performance through load transfers and open point optimization. The best improvement is limited by the condition of the submersible cables.

Phase Balancing: There are opportunities to make small improvements to losses and voltage drop through phase balancing within the feeder, however given the low rate of return, it is suggested that phase balancing be considered a secondary objective of other projects. For instance, if a car strikes a pole requiring an outage to single (red) phase loads fed from the F9, it might be prudent to reconnect those loads on the blue phase during restoration.

HONI 25kV Feeder: There is a general expectation within Chapleau PUC that operational constraints would be improved if all Chapleau PUC loads were located on the Chapleau PUC transformers. However, this will remain a minor driver.

4 System would operate acceptably during emergency situations.

The system has a number of limitation in the event of an emergency situation.

Feeders

None of the feeders are in a position to pick up significant loads in the event of a prolonged feeder emergency. Generally, it is assumed that overhead feeders can be repaired almost as fast as they can be switched, and therefore the practise of using radial overhead feeders is common. In some areas however, there are higher risks. Examples of risks that could result in prolonged outages due to the radial nature of the feeders include:

- a major event in the down town core, such as a fire or significant traffic accident that blocks access for Chapleau PUC crews to repair overhead feeders.
- a significant structural problem at the Lisgar Street Bridge that might block access for Chapleau PUC crews.
- a significant event or road closure on Hwy 129 preventing crews from restoring power to customers at the end of the feeder.
- an equipment fault such as a breaker failure at the Ontario Hydro DS 25kV supply.

Transformers

The loss of any station transformer would result in the overload of the other transformers if the loss occurred at peak times.

Conclusion of Assessment of Emergency Operations

Feeder:	Feeder emergencies would result outages consistent with overhead radial feeder design. Given the costs of alternatives, and the severity of the emergencies required to make a major impact, it is recommended to maintain the status quo.
Transformers:	The risks of a prolonged outage due to a transformer emergency are high. There should be a satisfactory way to take one transformer out of service and maintain supply of loads.

5 Recommended System Upgrades

A review of alternatives for system upgrades was conducted and the most likely options are discussed from a technical standpoint in the following section.

The major drivers for system investment are:

- Transformer Condition
- Pole Condition
- Transformer Loading in Emergency Conditions.
- System Losses.

Accompanying these drivers are secondary drivers that should be considered are

- Feeder Balancing
- Feeder Configuration (backup)
- Phase Balancing

Options:

A number of options are considered for System upgrades that will address the main drivers. Where practical, secondary drivers are also considered with suggested action plans.

	Description	Benefits/Omissions
Option 1	Replace T4 with 4160 unit, at 5MVA.	Addresses growing risk of failure of T4, would provide backup in event of loss of T3 No other improvements to system
Option 2	Replace T4 with 4.16kV unit in short term and follow up with replacement of T3 at 4.16kV, Conduct pole renewal programs as needed and cable replacement/rehabilitation (Most likely around 15 poles/year for 3 years and 10/year after that)	Basic System renewal and risk improvements of existing assets. No other system improvement.
Option 3	Replace both T4 and T3 with new transformers at 25kV.	Accomplishes same renewal and risk improvement benefits of Option 2, and nominal incremental costs.

	Convert voltage of pole lines and submersible cable during renewal projects.	Additionally, allows for improvements in system losses and voltage drop, also provides backup to customers fed from 25kV System
Option 4	Do nothing	Leaves system exposed to high risk of T4 failure

Technical Analysis of Option 3

Option 3 is the only option listed above that measurably changes system performance. A technical assessment of the system operating at 25kV with no other change (such as phase balancing etc.) indicates a dramatic improvement in system performed. Voltage Drops and Losses are significantly improved with the higher voltage and lower currents.

With the 25kV configuration, the technically complex and unreliable capacitors and regulators currently being used to maintain system stability can be removed. Table 6 and Table 7 below compare the technical performance of the 25kV system to the previously assessed 4.16kV version.

Table 6- Voltage Drop (%) at 25kV

System Voltage	25 kV			
Feeder	Min Voltage at End of Line (kV)	25kV Voltage Drop (%)	4kV Voltage Drop (%) (table 4)	Δ at User
F2	14.41	0.1%	4.9%	+ 4.8%
F8	14.4	0.2%	7.6%	+ 7.4%
F9	14.35	0.5%	17.7%	+ 17.2%

Table 7- Line Loss

System Voltage	25 KV	
Feeder	Line Loss (kVA)	Line Loss (%)
F2	0.98	0.1%
F8	3.28	0.2%

F9	6.03	0.4%

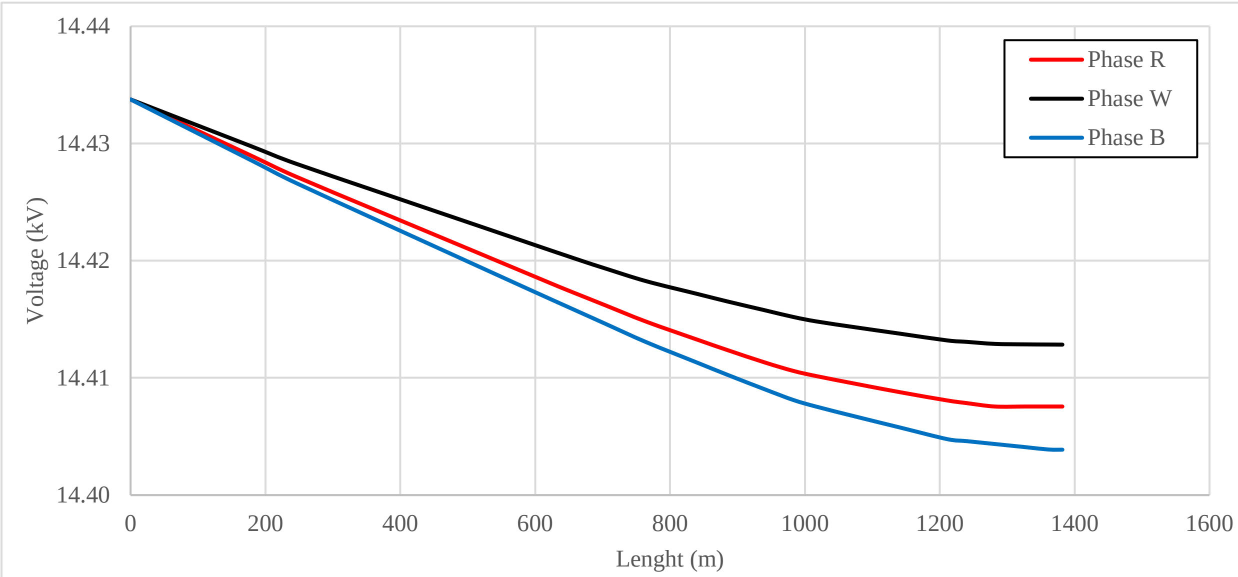

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Figure 4- Feeder F2 Voltage Drop [25kV]

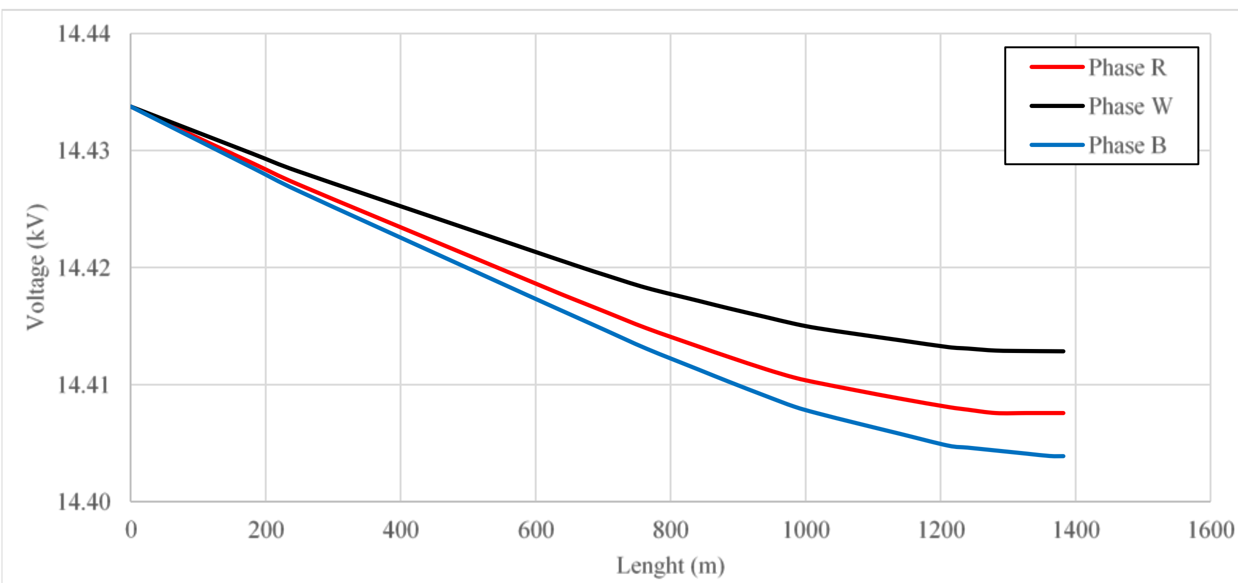


Figure 5- Feeder F8 Voltage Drop [25kV]

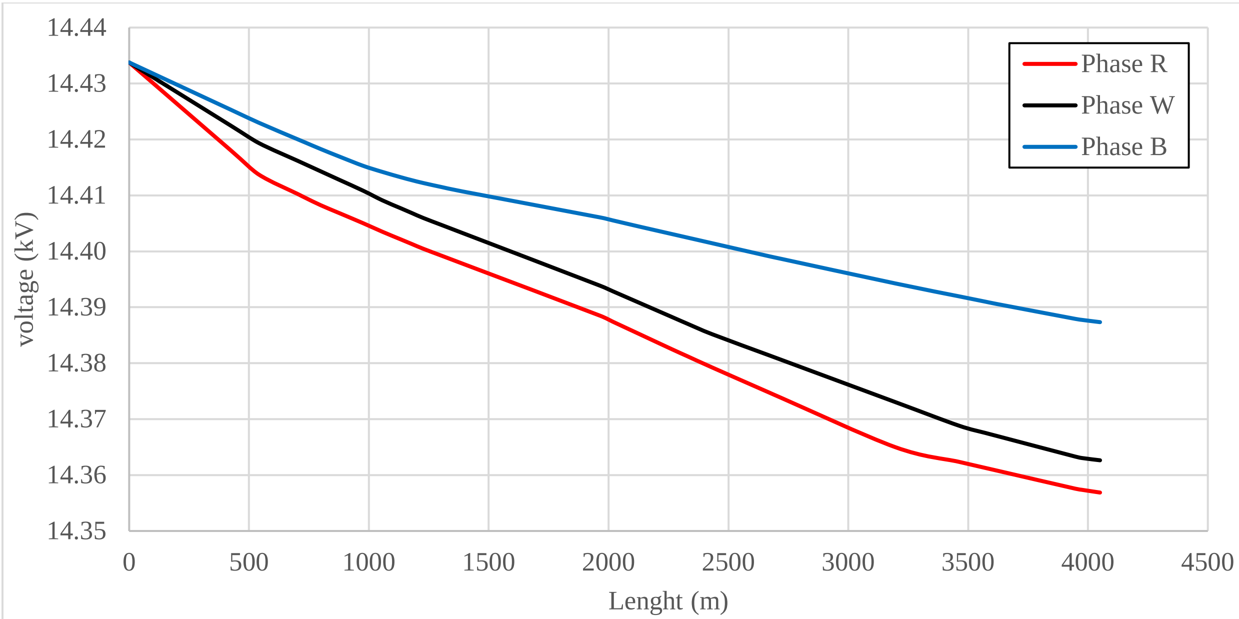


Figure 6- Feeder F9 Voltage Drop [25kV]

Cost of Losses Calculation (Savings of Conversion)

The cost of the system losses and thus conversion savings can be estimated for a distribution system with the following formulae. (Where LF represents the "Loss Factor" which is multiplied by the cost of energy x the peak load over the year.)

$$LF = 0.2(LdF) + 0.8(LdF^2); \qquad LdF = \frac{Average\ kVA\ consumed}{Maximum\ kVA\ demand}$$

$$A = k(8760 \times C_{KWH} \times L \times Peak \times LF + C_{KW} \times L \times Peak); \quad k = \frac{Average\ Monthly\ System\ Peak[kW]}{Maximum\ Monthly\ Peak[kW]}$$

Feeder Loss Assessment

Description	F2	F8	F9
Avg Monthly System Peak [KW]	**2690**	**2690**	**2690**
Max Monthly Peak [KW]	**4186**	**4186**	**4186**
Cost per KWh	$ 0.1300	$0.1300	$0.1300
Peak [KVA]	539	2026.15	1893.85
Cost per KW per Annum	$142.92	$142.92	$ 142.92
Loss Factor	**0.385388**	**0.264269**	**0.264269**
Line Loss %	3.74%	7.70%	13.20%
Hours in a year	**8760**	**8760**	**8760**
Feeder Operating Cost	*$7,538.90*	*$44,513.46*	*$71,326.12*
Annual Operating Cost			$123,378.48
Line Loss % (After Conversion)	0.10%	0.20%	0.40%
Feeder Operating Cost	*$ 201.57*	*$1,156.19*	*$2,161.40*
Annual Operating Cost			$3,519.17
Conversion Savings due to Improvement in Losses (Annually)			**$119,859.32**

Note: The average cost of energy was given by Chapleau PUC as $0.13. and the average cost of "power" was assumed from previous studies and is relatively non-impactive.

Conclusion of System Upgrade Options Analysis and Staging

Option 4: The "Do Nothing" option is not viable long term as transformer T4 needs some level of service and the population of poles is continuing to age.

Option 1: Replacing T4 is presumed to be the minimum acceptable option, however it does not address system renewal of poles or of T3. Both Transformers should undergo comprehensive testing to confirm condition.

Option 2: Renewing the system with similar assets and a possibly larger pair of transformers is the minimum option to maintain the status quo. It is preferred over Option 1, as it permits the management of investment, and the orderly planning of renewal projects, however it does not consider the $120k/year in system losses.

Option 3: Converting the system voltage to 25kV is the recommended option, as significant improvements to system technical and reliability performance can be expected and the costs are incremental relative to the basic renewal option.

Staging of Upgrade Projects

In previous costing studies, the replacement of the transformer station was estimated at $1.5Million, and if voltage conversion is executed a rapid feeder replacement program in the range of $200k/year for 3 years would be anticipated. A savings of $120k per year could be expected once conversion is complete and would be prorated over the years of the project.

> This plan is likely to be too great a rate shock and possibly an over-investment based on renewal needs.

An alternate option is to expend $20-100k on transformer testing and rehabilitation, with the objective of delaying the station replacement 5-10 years. In the meantime, increasing the pole replacement renewal as much as practical for 5-7 years, to establish one or two feeders ready for voltage conversion (allowing for voltage converters), then replacing transformers as needed, and converting the rest of the poles might allow for the $2Million conversion costs to be spread over 10-15 years. The primary risks would be the potential for a transformer to fail early, or for poles to start to fail quickly, both of which can be managed with increased monitoring and risk assessment.

> This plan will allow for a staging of capital costs, and a parallel improvement in cost of losses which would commence once the voltage conversion begins.

6 EPC Tender

If requested, METSCO will develop a performance specification, and manage the tendering process for a design-build station replacement or upgrade.

Appendix -- Analysis

The following data is recorded as it was used in the mathematical model and has no specific bearing on the conclusions of the study.

Assumptions:

- Transformer nameplate kVA of feeders F2, F8 and F9 are proportionally reduced to match the feeder peak load at the location of the transformers
- The analysis is performed on the feeder's backbone.
- The two 225 kVAR capacitor banks on Feeder F9 are ignored.
- Unbalance analysis is performed based on zero sequence current over average of phase currents.
- Power factor is considered to be 0.9.
- System voltage value is considered at the secondary side of the transformers.
- Constant Voltage (xxx) method is used to calculate load current.
- Overhead wire on F9 south of Maple St. is considered to be 1/0 ACSR.
- Overhead wire on F8 is considered to be 4/0 ACSR from Station to West of Lorne St and from there to be 1/0 CU.
- a 3 phase 750kVA transformer on Martel Road shown on the SLD on the F9, is believed to actually be on the F2.

Input Data

Table 8- Overhead Wires info used in Chapleau System

OH Wire #	GMR (mm)	RAC (Ω/km)
2 ACSR	**1.33**	**0.87**
1/0 CU	**3.49**	**0.35**
1/0 ACSR	**1.36**	**0.55**
3/0 ACSR	**1.83**	**0.35**
4/0 ACSR	**2.48**	**0.284**

Table 9- Existing System Voltage

Vp-p (kV)	Vp-n (kV)	Power Factor
4.16	**2.40**	**0.9**

Table 10- Feeder Loads

Feeder #	Ph-R Load (kVA)	Ph-W Load (kVA)	Ph-B Load (kVA)	Total Loads (kVA)
F2	**264**	**300**	**381**	**945**
F9	**733**	**527**	**394**	**1654**
F8	**530**	**442**	**574**	**1546**

Appendix Transformer Inspection

Condition Assessment Form

STATION INSPECTION

Station/Substation CHAPLEAU DS

Built in Year T3 in service 1974/T4 in service 2000

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☐ Worker Safety
- ☐ Environmental Hazard
- ☐ Maintenance Issues
- X Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- X Bottom of the fence
- ☐ Between the supports
- ☐ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☐ Gravel outside the fence

Comments:

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [ ] Shrubs and grass maintenance
- [ ] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [ ] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [ ] Lighting
- [ ] Signage
- [ ] **Animals**
- [ ] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**

X Rivers/ pond

- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. Control Building Equipment Concerns

- [ ] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

D. Cable Concerns

- ☐ Guarding and grounding
- ☐ Leaking potheads
- ☐ Cable supports
- ☐ Termination
- ☐ Oil-filled cables
- ☐ Cable condition
- ☐ Lead sheath cables
- ☐ Unsealed Cable ducts/ conduits
- ☐ Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- ☐ Enclosure Rust (Cabinet)
- ☐ Grounding
- ☐ PCB
- ☐ Porcelain Insulators
- ☐ Fuses
- ☐ Switches
- ☐ Interlocks
- ☐ Foundations
- ☐ Inoperability
- ☐ Bus
- ☐ Damaged Insulator
- ☐ Station service TX
- ☐ Multiple sizes of voltage

Structures

- ☐ Grounding
- ☐ Porcelain arrestors
- ☐ Porcelain switches
- ☐ Height clearance
- ☐ Working clearance
- ☐ Safe limit approach
- ☐ Guarding
- ☐ Substandard design
- ☐ Switching Area difficult
- ☐ Reclosers
- ☐ Connections
- ☐ Foundations
- ☐ Alignment
- ☐ Locks
- ☐ Designation
- ☐ Rust
- ☐ Insulators
- ☐ Station device TX
- ☐ Cut-out

Comments:

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	T3	T4				
Grounding/ connections						
Age	43	17				
Clearances						
Condensation						
Oil Containment	no	no				
Rust	some					
Oil leakage/ sweating						
Cracked bushings						
Arrestors						
Bushings						
Cooling fans	Yes	no				
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading	7	ND				
Birds/ Animals						

Comments:

Last PCB reading from 2016 SD Myers

Inspected by: A. Morin **Date: Dec.-11-17**

Appendix Transformer Test Results

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT®

Date Printed 5/15/2018 **TC# 9000**

Customer	7237768 CHAPLEAU PUBLIC UTILITIES CORP	**City**	CHAPLEAU, ON	**Location**	OUTDOOR/GROUND
Sub-Name	CHAPLEAU D.S.	**Unit No.**	T3	**Other**	

NAMEPLATE DATA

Manufacturer	PENNSYLVANIA TRANS		**Equipment Type**	TRANSFORMER
Manufacture Date			**Transformer Class**	OA
Serial No.	C-01297-5-1		**Impedance %**	6.40
KVA Rating	2,500		**Phase/Cycle**	3/60
High Voltage	115,000	D	**Liquid Type**	OIL
Low Voltage	4,160	Y	**Gallons**	2,600
Weight	45,300		**Other Access**	BOLTED TOP

ADDITIONAL EQUIPMENT

Radiators	Yes	**Conservator Tank**	No
Fans	No	**LTC Compartment**	No
Water Cooled	No	**Bushing Location**	Top
Oil Pumps	No	**Breather**	Free
Top FPV (inch)		**Hose Length (feet)**	
Bottom FPV (inch)	2.50 Valve	**Service Online**	
InsulationType	55/65C	**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
10/20/15	NORMAL	11	36	0.50	FAIR	NONE
10/25/16	NORMAL	8	31	-1.00	FAIR	NONE
10/23/17	NORMAL	18	40	0.30	FAIR	NONE
05/08/18	NORMAL	18	39	0.50		

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR		SP. GRAV.	VISUAL	SEDIMENT	
10/22/08		0.020 AC	32.7 AC	50 AC			2.00	AC	0.886 AC	CLEAR AC	NONE AC	*
10/28/09		0.030 AC	31.2 QU	50 AC			2.00	AC	0.884 AC	CLEAR AC	NONE AC	
07/20/11		0.060 QU	32.7 AC	50 AC			2.00	AC	0.881 AC	CLEAR AC	NONE AC	
08/20/12		0.080 QU	28.5 QU	43 AC			2.00	AC	0.877 AC	CLEAR AC	NONE AC	
09/30/14		0.010 AC	43.8 AC	49 AC			1.00	AC	0.878 AC	CLEAR AC	NONE AC	
10/20/15		0.020 AC	43.0 AC	48 AC			1.00	AC	0.880 AC	CLEAR AC	NONE AC	
10/25/16		0.020 AC	45.0 AC	48 AC			0.50	AC	0.880 AC	CLEAR AC	NONE AC	
10/23/17		0.030 AC	42.0 AC	45 AC			0.50	AC	0.831 AC	CLEAR AC	NONE AC	

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT
08/20/12	ND UN
09/30/14	0.254% AC
10/20/15	0.257% AC
10/25/16	0.267% AC
10/23/17	0.250% AC

NOTE - STUDIES SHOW THAT A LEVEL OF 0.3% INHIBITOR IS OPTIMUM FOR PRESERVATION OF IN-SERVICE TRANSFORMER OILS. OILS WITH A LEVEL BELOW 0.08% ARE CONSIDERED TO BE UNINHIBITED.

LIQUID POWER FACTOR

DATE	25 C	100 C
08/20/12	0.180 QU	5.330 UN
09/30/14	0.002 AC	0.499 AC
10/20/15	0.013 AC	0.535 AC
10/25/16	0.012 AC	0.478 AC
10/23/17	0.007 AC	0.592 AC

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

Customer	7237768 CHAPLEAU PUBLIC UTILITIES CORP	**S/N**	C-01297-5-1				
Sub-Name	CHAPLEAU D.S.	**Mfg.**	PENNSYLVANIA TRANS	**Gallons**	2,600	**High Volt.**	115,000
Location	OUTDOOR/GROUND	**Unit No.**	T3	**KVA**	2,500	**Low Volt.**	4,160

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION		MOISTURE BY DRY WEIGHT PCT.
09/30/14	19	10	18.9	UN	2.28
10/20/15	16	7	15.1	QU	1.82
10/25/16	13	7	17.2	QU	2.09
10/23/17	23	8	12.8	QU	1.50
05/08/18	23	7	11.2	QU	1.32

RECOMMENDATION RETEST 6 MONTHS

The moisture content is questionable based on the equipment class and liquid type. This may be due to an incursion of moisture or disruption in equilibrium due to changing load/temperature. A shorter test interval is recommended to monitor this unit.

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL
07/20/11	ND	ND	88	ND	ND	88
08/20/12	ND	ND	ND	ND	ND	ND
09/30/14	ND	ND	1	ND	ND	1
10/20/15	ND	ND	30	ND	ND	30
10/25/16	ND	ND	30	ND	ND	30
10/23/17	ND	ND	29	ND	ND	29

RECOMMENDATION RETEST 1 YEAR

NO DIAGNOSTIC CHANGES ARE NOTED IN FURAN LEVELS SINCE THE PREVIOUS ANALYSIS. THE CELLULOSIC INSULATION APPEARS TO BE IN GOOD CONDITION.

CALCULATED DP 800 **EST. LIFE REMAINING** 100%

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS
10/28/09	28	2,418	76,696	110	293	6,869	181	30	ND	642	86,625
05/19/10	28	843	77,296	106	290	5,789	180	31	ND	635	84,563
07/20/11	30	344	77,287	110	259	6,112	163	28	ND	590	84,333
08/20/12	44	1,161	87,475	127	363	4,830	162	27	ND	723	94,189
09/30/14	6	9,642	81,235	16	216	2,391	15	5	ND	258	93,526
10/20/15	ND	6,349	72,086	13	330	3,081	17	8	ND	368	81,884
10/25/16	7	5,760	82,800	17	354	3,640	18	12	ND	408	92,608
10/23/17	ND	24,300	65,500	10	113	3,030	15	12	ND	150	92,980

RECOMMENDATION RETEST 1 YEAR

B-THE ANALYSIS OF THIS SAMPLE SHOWS NO SIGNIFICANT INCREASE IN THE COMBUSTIBLE GAS VOLUME. THIS INDICATES NORMAL OPERATION.

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER
10/22/08	ND	ND	0.171 *
10/28/09	ND	ND	0.132
07/20/11	ND	ND	0.122
08/20/12	ND	ND	0.600
09/30/14	ND	ND	0.021
10/20/15	ND	ND	ND
10/25/16	ND	ND	0.030
10/23/17	ND	ND	ND

RECOMMENDATION RETEST 1 YEAR

THERE HAS BEEN NO DIAGNOSTIC CHANGE SINCE THE PREVIOUS ANALYSIS. THESE DATA INDICATE NORMAL OPERATION.

PCB CONTENT EXPRESSED IN PPM

DATE	1242	1254	1260	OTHER	TOTAL	
10/22/08			8		8	*
07/20/11			11		11	
08/20/12			11		11	
09/30/14			9		9	
10/20/15		8			8	
10/25/16		7			7	

COLOR LABEL: Green **CLASS:** NON-PCB

Results in mg/kg
ND means None Detected
(<2 mg/kg per ASTM D4059)

NOTE: * After a result indicates that the test or service was performed by an outside source.

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT®

Date Printed 5/15/2018 **TC# 9001**

Customer	7237768 CHAPLEAU PUBLIC UTILITIES CORP	**City**	CHAPLEAU, ON	**Location**	OUTDOOR/GROUND
Sub-Name	CHAPLEAU D.S.	**Unit No.**	T4	**Other**	

NAMEPLATE DATA

Manufacturer	GENERAL ELECTRIC		**Equipment Type**	TRANSFORMER
Manufacture Date			**Transformer Class**	OA
Serial No.	E-690953		**Impedance %**	9.70
KVA Rating	3,750		**Phase/Cycle**	3/60
High Voltage	115,000	D	**Liquid Type**	OIL
Low Voltage	4,160	Y	**Gallons**	2,150
Weight	41,800		**Other Access**	BOLTED TOP

ADDITIONAL EQUIPMENT

Radiators	Yes	**Conservator Tank**	No
Fans	No	**LTC Compartment**	No
Water Cooled	No	**Bushing Location**	Top
Oil Pumps	No	**Breather**	Free
Top FPV (inch)		**Hose Length (feet)**	
Bottom FPV (inch)	2.50 Valve	**Service Online**	
InsulationType	55C	**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
10/20/15	NORMAL		52	0.80	GOOD	NONE
10/25/16	NORMAL	10	50	0.80	FAIR	NONE
10/23/17		19	55	0.80	GOOD	NONE
05/08/18	NORMAL	18	55	0.80		

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR		SP. GRAV.	VISUAL	SEDIMENT	
10/22/08		0.010 AC	40.0 AC	50 AC			1.50	AC	0.864 AC	CLEAR AC	NONE AC	*
10/28/09		0.010 AC	39.0 AC	50 AC			1.00	AC	0.861 AC	CLEAR AC	NONE AC	
07/20/11		0.020 AC	45.2 AC	44 AC			1.00	AC	0.859 AC	CLEAR AC	NONE AC	
08/20/12		0.060 QU	33.6 AC	40 AC			1.00	AC	0.855 AC	CLEAR AC	NONE AC	
09/30/14		0.020 AC	44.7 AC	41 AC			0.50	AC	0.859 AC	CLEAR AC	NONE AC	
10/20/15		0.020 AC	43.0 AC	49 AC			0.50	AC	0.868 AC	CLEAR AC	NONE AC	
10/25/16		0.010 AC	45.0 AC	49 AC			0.50	AC	0.850 AC	CLEAR AC	NONE AC	
10/23/17		0.030 AC	40.0 AC	46 AC			0.50	AC	0.825 QU	CLEAR AC	NONE AC	

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT
08/20/12	0.060% UN
09/30/14	0.302% AC
10/20/15	0.305% AC
10/25/16	0.308% AC
10/23/17	0.300% AC

NOTE - STUDIES SHOW THAT A LEVEL OF 0.3% INHIBITOR IS OPTIMUM FOR PRESERVATION OF IN-SERVICE TRANSFORMER OILS. OILS WITH A LEVEL BELOW 0.08% ARE CONSIDERED TO BE UNINHIBITED.

LIQUID POWER FACTOR

DATE	25 C	100 C
08/20/12	0.028 AC	1.540 AC
09/30/14	0.001 AC	0.159 AC
10/20/15	0.003 AC	0.241 AC
10/25/16	0.004 AC	0.294 AC
10/23/17	0.005 AC	0.327 AC

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

Customer	7237768 CHAPLEAU PUBLIC UTILITIES CORP	**S/N**	E-690953				
Sub-Name	CHAPLEAU D.S.	**Mfg.**	GENERAL ELECTRIC	**Gallons**	2,150	**High Volt.**	115,000
Location	OUTDOOR/GROUND	**Unit No.**	T4	**KVA**	3,750	**Low Volt.**	4,160

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION		MOISTURE BY DRY WEIGHT PCT.
09/30/14	25	13	19.2	UN	2.21
10/20/15	42	12	9.2	QU	0.78
10/25/16	15	13	28.1	UN	3.41
10/23/17	24	12	18.4	UN	2.16
05/08/18	23	11	16.8	UN	1.97

RECOMMENDATION MOISTURE REDUCTION
The moisture content is confirmed as being unacceptable, based on the equipment class and liquid type. Moisture reduction should be considered.

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL
07/20/11	ND	ND	83	ND	ND	83
08/20/12	ND	ND	ND	ND	ND	ND
09/30/14	ND	ND	120	ND	ND	120
10/20/15	ND	ND	188	ND	ND	188
10/25/16	ND	ND	222	ND	ND	222
10/23/17	ND	ND	140	ND	ND	140

RECOMMENDATION RETEST 1 YEAR
NO DIAGNOSTIC CHANGES ARE NOTED IN FURAN LEVELS SINCE THE PREVIOUS ANALYSIS. THE CELLULOSIC INSULATION APPEARS TO BE IN GOOD CONDITION.

CALCULATED DP 695 **EST. LIFE REMAINING** 90%

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS
10/22/08	ND	29,255	58,830	1	16	445	2	ND	ND	19	88,549 *
10/28/09	ND	31,134	63,345	ND	14	380	ND	ND	ND	14	94,873
07/20/11	ND	23,762	64,905	3	28	454	5	1	ND	37	89,158
08/20/12	ND	31,546	68,448	ND	12	369	ND	ND	ND	12	100,375
09/30/14	ND	34,968	71,879	ND	39	600	ND	ND	ND	39	107,486
10/20/15	ND	33,653	68,105	ND	36	601	ND	ND	ND	36	102,395
10/25/16	ND	34,000	68,500	ND	31	622	ND	ND	ND	31	103,153
10/23/17	ND	32,500	65,800	ND	30	606	ND	ND	ND	30	98,936

RECOMMENDATION RETEST 1 YEAR
B-THE ANALYSIS OF THIS SAMPLE SHOWS NO SIGNIFICANT INCREASE IN THE COMBUSTIBLE GAS VOLUME. THIS INDICATES NORMAL OPERATION.

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER
10/22/08	ND	ND	ND *
10/28/09	ND	ND	ND
07/20/11	ND	ND	ND
08/20/12	ND	ND	ND
09/30/14	ND	ND	ND
10/20/15	ND	ND	ND
10/25/16	ND	ND	ND
10/23/17	ND	ND	ND

RECOMMENDATION RETEST 1 YEAR
THERE HAS BEEN NO DIAGNOSTIC CHANGE SINCE THE PREVIOUS ANALYSIS. THESE DATA INDICATE NORMAL OPERATION.

PCB CONTENT EXPRESSED IN PPM

DATE	1242	1254	1260	OTHER	TOTAL	
10/22/08					ND	*
07/20/11					ND	
08/20/12					ND	
09/30/14			2		2	
10/20/15			2		2	
10/25/16					ND	

COLOR LABEL: Green **CLASS:** NON-PCB

Results in mg/kg
ND means None Detected
(<2 mg/kg per ASTM D4059)

NOTE: * After a result indicates that the test or service was performed by an outside source.

INTELLIGENT TRANSFORMER MANAGEMENT®

Date Printed 5/15/2018

TC# 9035

Customer	7237768 CHAPLEAU PUBLIC UTILITIES CORP	**City**	CHAPLEAU, ON	**Location**	
Sub-Name		**Unit No.**	#14	**Other**	

NAMEPLATE DATA

Manufacturer		**Equipment Type**	TRANSFORMER
Manufacture Date		**Transformer Class**	
Serial No.		**Impedance %**	
KVA Rating		**Phase/Cycle**	
High Voltage		**Liquid Type**	OIL
Low Voltage		**Gallons**	
Weight		**Other Access**	

ADDITIONAL EQUIPMENT

Radiators		**Conservator Tank**	
Fans		**LTC Compartment**	
Water Cooled		**Bushing Location**	
Oil Pumps		**Breather**	
Top FPV (inch)		**Hose Length (feet)**	
Bottom FPV (inch)		**Service Online**	
InsulationType		**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
05/08/18						

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR	SP. GRAV.	VISUAL	SEDIMENT

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT

NOTE - TESTING FOR INHIBITOR CONTENT IS USEFUL, SINCE INHIBITOR SLOWS THE AGING RATE OF THE INSULATION SYSTEM.

LIQUID POWER FACTOR

DATE	25 C	100 C

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

Customer	7237768 CHAPLEAU PUBLIC UTILITIES CORP	**S/N**			
Sub-Name		**Mfg.**		**Gallons**	**High Volt.**
Location		**Unit No.** #14		**KVA**	**Low Volt.**

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION	MOISTURE BY DRY WEIGHT PCT.

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER

PCB CONTENT EXPRESSED IN PPM

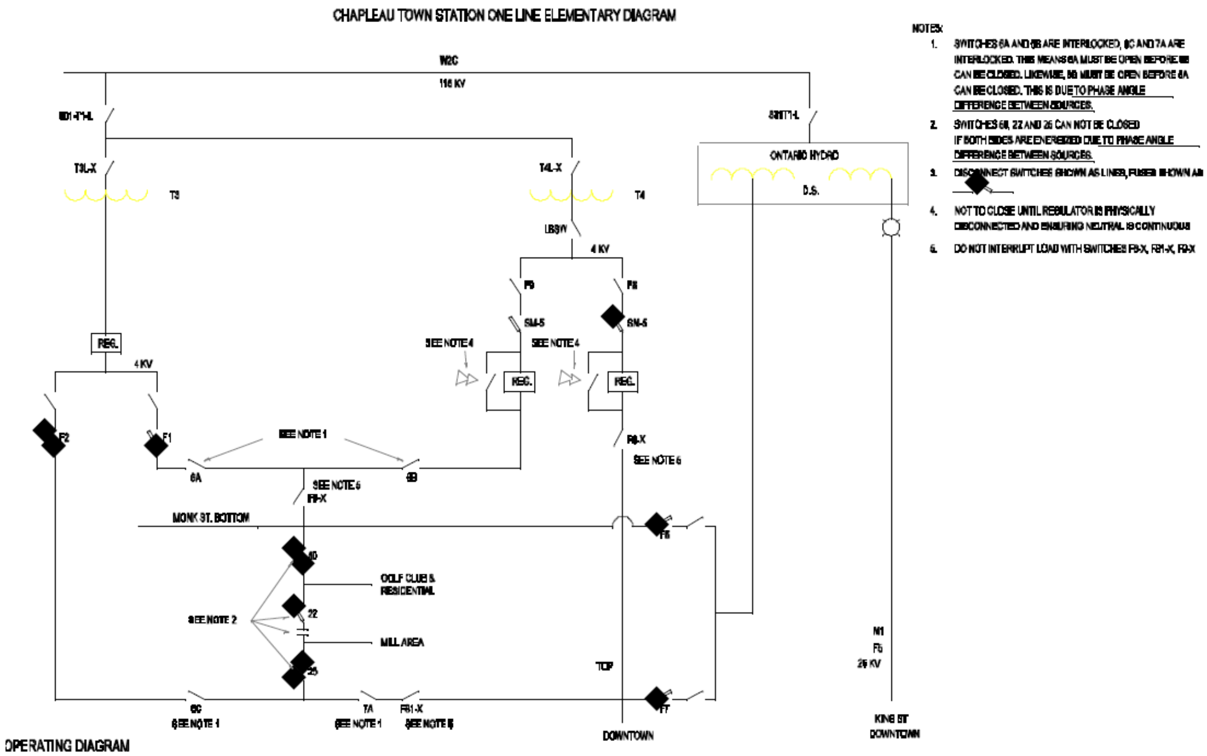
DATE	1242	1254	1260	OTHER	TOTAL
05/08/18					ND

COLOR LABEL: Green **CLASS:** NON-PCB

Results in mg/kg
ND means None Detected
(<2 mg/kg per ASTM D4059)

NOTE: * After a result indicates that the test or service was performed by an outside source.

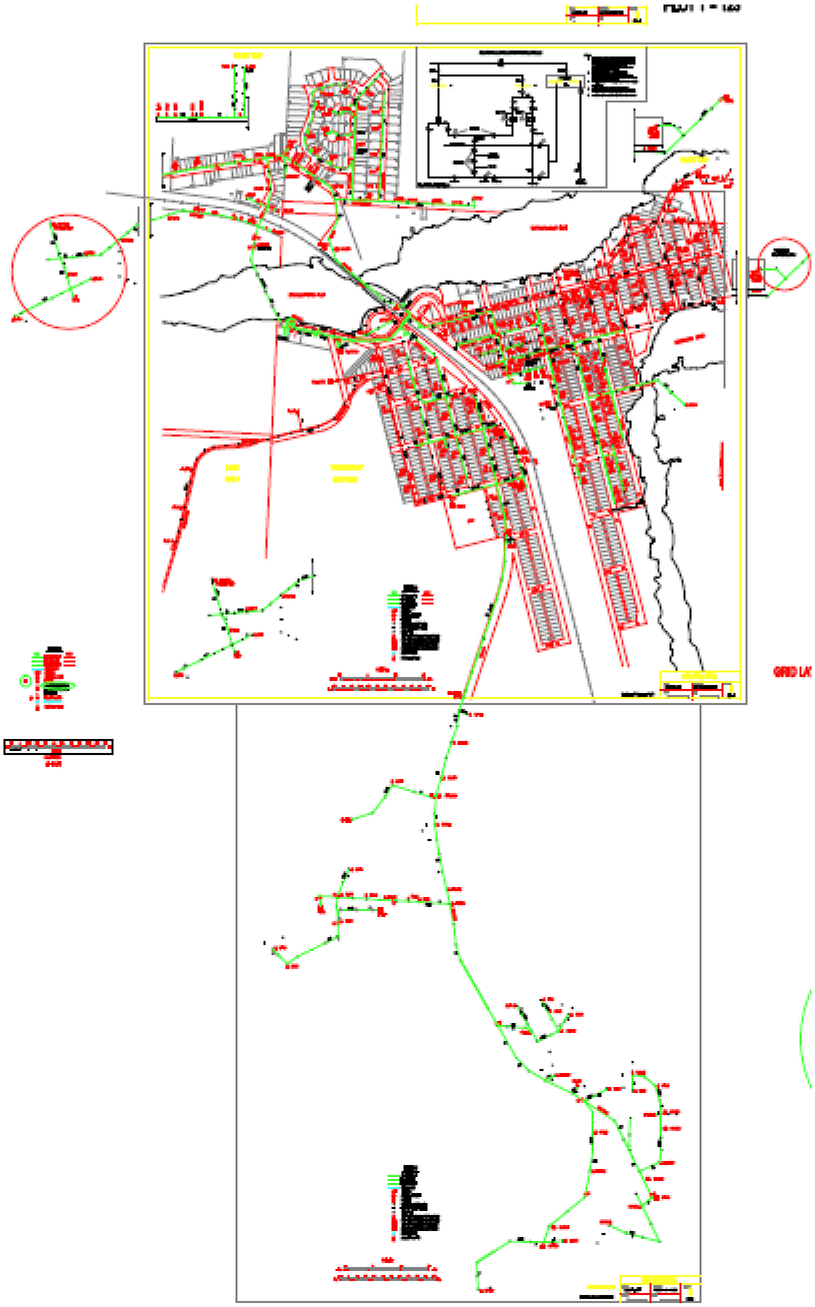
Appendix Operating Map



OPERATING DIAGRAM

5.5 APPENDIX E

Appendix System Map



5.6 APPENDIX F

BUSINESS CASE NEW BOOM TRUCK

NEW BOOM TRUCK (TEREX C-4047-PG)

The decision to replace the current asset was based on the following analysis.

OPTIONS:

1) Do nothing and delay the acquisition of a new line truck. We felt that this is
    a. The need for a safe, reliable unit is very important to the business of an LDC, our closest mutual help is 2 hrs away minimum.
    b. Current asset is at an age where the unit's reliability is in question. With only one unit reliability is critical to servicing our customer reliably and safely.
    c. The current asset was expected to require extensive amount of work, which required it leaving the area, to remain in a safe operating condition. This poses larger operating costs, along with long downtimes, for repairs, affecting our ability to respond to our customers needs, as well as the shareholder.
    d. The chassis that the device is installed on ceased being manufactured in 2009, therefore the accessibility of parts to repair this chassis will be scarce. This would mean higher maintenance cost and longer asset downtime.

USED REPLACEMENT:

2) We felt this was not a viable option for the following reasons.
    a. Used assets would mean maintenance cost sooner than later.
    b. Could not find an asset that met our requirements.
    c. The secondary market for line equipment is very limited based on our utilities requirements. Specifically, for a radial boom Derick, complete with upper hydraulic controls and fiberglass operator's platform.

d. Through research we found out that units that were applicable to our needs are very expensive and at an age where we would be concerned about reliability. Approximately 10 years old.
e. Most of these units were trade in assets from USA utilities that life cycled them out or were from a rental house and required a lot of work.

PURCHASE NEW RADIAL BOOM DERECK

3) WE CHOSE THIS OPTION:
   a. Advantage of purchasing new allows Chapleau PUC to have a piece of equipment that is highly reliable, proven, exploits latest technologies and with a safe operation for the employee's and around the public.
   b. The new unit would allow us to do the required work in our area with out the worry of downtime for repairs.
   c. Through our tendering process we decided ultimately to buy a unit that met all our criteria. We added features that allowed us to perform tasks that required outages with the older unit.
   d. Due to the remote nature of our location we required a unit that would do and provide multiple job functions as we only have the one line truck. Reliability and parts availability is paramount.
   e. The vendor we chose has a facility a little over 2 hrs drive that can supply replacements parts and repairs.
   f. The next vendors parts would only be accessed via USA distribution centre.
   g. The purchase of the new unit required us to increase our garage door height to accommodate the truck. This meant a new door and weather stripping which has provided a more efficient, energy saving system than the older door. The cost of the new door was covered by the new truck dealer by lowering the cost of the door from the purchase price of the unit.
   h. The expense of the new RBD was payed for by the investments of the affiliate company Chapleau ESC.
   i. Order time to build a new unit is 1 year minimum, therefore we needed to place the order before the older unit really started to cause expense and downtime.

j. In the end we selected a Terex C-4047-PG with a fiberglass platform for the lineman and upper controls from the bucket. The same as our previous truck. We found that this configuration was perfect for the work we perform as it allows the truck to be used as a radial boom Derick, or an insulated aerial device.
k. The unit had several key features that other vendors could not provide for example: full pressure open centre hydraulic system with full pressure controls, increased stability package, dual lift cylinders and more.
l. Access to parts and mobile service very important to our remoteness.

2.5.4 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. (as such Appendix 2-D is not applicable in this case)[23][24]

2.5.5 COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

CPUC attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its capital costs or in its Distribution System Plan.

As such, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement are not applicable in this case.[25]

CPUC is not considering incremental conservation initiatives in order to defer or avoid future infrastructure projects as part of distribution system planning processes [26] nor is it planning on applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs, etc. [27] Lastly, CPUC is not considering a generation facility. [28]

2.5.6 NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

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[23] MFR - Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any

[24] MFR - Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.

[25] MFR - If applicable, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include, initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments

[26] MFR - Description of how incremental conservation initiatives have been considered in order to defer or avoid future infrastructure projects as part of distribution system planning processes

[27] MFR - If applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs etc. the application must include a consideration of the projected affects to the distribution system on a long term basis and the projected expenditures. Distributors should explain the proposed program in the context of the distributors five year Distribution System Plan or explain any changes to its system plans that are pertinent to the program

[28] MFR - Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09:
- Appendices 2-FA through 2-FC identifying all eligible investments for recovery

CPUC is not proposing any special or different approach to funding its capital expenditure[29]

2.5.7 ADDITION OF ICM ASSETS TO RATE BASE

CPUC has never applied for a rate adder to recover an investment through the OEB's Incremental Capital Module.[30] And as such, CPUC does not need to balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue. At the time of the application, CPUC is not forecasting the need for an Advanced Capital Module or Incremental Capital Module. [31][32][33]

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[29] MFR - Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification

[30] MFR - Distributor with previously approved ICM(s) - schedule of ICM amounts, variances and explanation

[31] Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue

[32] MFR - Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information

[33] MFR - Complete Capital Module Applicable to ACM and ICM

2.5.8 SERVICE QUALITY AND RELIABILITY PERFORMANCE[34]

CPUC 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 CPUC 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.

CPUC's performance metrics are discussed in detail in Exhibit 1 and in the Business Plan.[35]

CPUC is not proposing any benchmarking metrics that are not already in place.[36]

[34] MFR - 5 historical years of ESQRs, explanation for any under-performance vs standard and actions taken
[35] MFR - 5 historical years of SAIDI and SAIFI - for all interruptions, all interruptions excluding loss of supply, and all interruptions excluding major events; explanation for any under-performance vs 5 year average and actions taken
[36] MFR - Explanation for any under-performance vs 5 year average and actions taken

Table 28 – OEB App 2-G ESQR Results[37][38]

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016	2017
Low Voltage Connections	90.0%	100	100	100	100	100	100
High Voltage Connections	90.0%	0	0	0	0	0	0
Appointment Scheduling	65.0%	100	100	100	100	100	100
Appointments Met	90.0%	100	100	100	100	100	100
Telephone Accessibility	80.0%	100	100	100	100	100	98.68
Rescheduling a Missed Appointment	80.0%	0	0	0	0	0	0
Telephone Call Abandon Rate	10.0%	0	0	0	0	0	0
Written Response to Enquires	80.0%	100	100	100	100	100	100
Emergency Urban Response	90.0%	0	0	0	0	0	0
Emergency Rural Response	100.0%	0	0	0	0	0	0
Reconnection Performance Standard	85.0%	100	100	100	100	100	100
Micro-embedded generation facilities	90.0%	0	0	0	0	0	0

- **No explanations are required as all results have exceeded the 5 year average.**

Table 29 – OEB App 2-G SAIFI SAIDI Results

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
SAIDI	2.320	5.090	14.720	16.480	16.740	2.180	0.280	4.750	1.820	0.940	2.320	5.090	14.720	16.480	16.740
SAIFI	2.850	2.460	3.960	2.880	3.210	2.580	0.380	1.070	0.630	0.690	2.850	2.460	3.980	2.880	3.210

5 Year Historical Average

Index	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	11.070	1.994	11.070
SAIFI	3.072	1.070	3.076

[37] MFR - Distributors may propose SAIDI and SAIFI benchmarks different than 5 year average; provide rationale
[38] MFR - Completed Appendix 2-G

APPENDIX

LIST OF APPENDICES

N/A	