Renfrew Hydro Inc.

Exhibit 2

EB-2016-0166 - 2017 Cost of Service

Contents

Overview of Rate Base

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

RHI's Rate Base is determined by taking the average of the net fixed asset balances at the beginning and the end of the Test Year, plus a working capital allowance which is 7.5% of the sum of the cost of power and controllable expenses. The use of a 7.5% rate is consistent with the Board's letter of June 03, 2015 and the Filing Requirements as issued by the Ontario Energy Board. At this time RHI has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this application using the default value of 7.5%.

RHI was not previously directed by the OEB to undertake a lead/lag study.

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

This exhibit will compare historical data with the 2016 Bridge Year and 2017 Test Year. RHI converted to International Financial Reporting Standards (IFRS) on January 1, 2015 and has prepared this application under IFRS. In order to make the comparisons meaningful, all comparisons will be made under IFRS.

RHI has calculated its 2017 test year rate base to be $6,933,996. This Rate Base is also used to determine the proposed revenue requirement. Table: 2.1 below shows RHI's Rate Base and Working Capital calculations for the test year and compares it to the last Board approved Rate Base in 2010.

Table 2.1: Test Year Rate Base and Working Capital

	CGAAP	MIFRS	
Particulars	**Last Board Approved**	**2017**	**Diff**
Net Capital Assets in Service:			
Avg Gross Asset	$12,436,805	$15,495,709	$3,058,904
Avg Accumulated Depr	-$7,893,818	-$9,556,595	-$1,662,777
Net Fixed Assets	$4,542,987	$5,939,114	$1,396,127
Working Capital Allowance	$1,473,670	$994,882	-$478,789
Total Rate Base	**$6,016,657**	**$6,933,995**	**$917,338**

	CGAAP	MIFRS	
Expenses for Working Capital	**Last Board Approved**	**2017**	**Diff**
Eligible Distribution Expenses:			
3500-Distribution Expenses - Operation	$235,909	$296,946	$61,037
3550-Distribution Expenses - Maintenance	$171,718	$196,759	$25,041
3650-Billing and Collecting	$328,238	$467,660	$139,422
3700-Community Relations	$1,000	$6,000	$5,000
3800-Administrative and General Expenses	$434,729	$581,915	$147,186
	-$21,765		$21,765
			$0
Total Eligible Distribution Expenses	$1,149,829	$1,549,280	$399,451
3350-Power Supply Expenses	$8,674,639	$11,715,807	$3,041,168
Total Expenses for Working Capital	$9,824,468	$13,265,087	$3,440,619
Working Capital factor	15%	7.50%	-7.50%
Total Working Capital	**$1,473,670**	**$994,882**	**-$478,789**

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

Table 2.2 below presents RHI's Rate Base calculations for all required years including the 2017 Test Year. Year over year variance analysis follows.

Table 2.2: Rate Base Trend

	CGAAP	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	
Particulars	**Last Board Approved**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	
Net Capital Assets in Service:										
Avg Gross Asset	$12,436,805	$12,444,931	$12,970,698	$13,449,629	$13,812,383	$14,104,271	$14,493,751	$14,929,292	$15,495,709	$3,058,904
Avg Accumulated Depr	-$7,893,818	-$8,018,135	-$8,415,112	-$8,806,458	-$9,074,512	-$9,232,899	-$9,426,136	-$9,613,703	-$9,556,595	-$1,662,777
Net Fixed Assets	$4,542,987	$4,426,796	$4,555,586	$4,643,170	$4,737,872	$4,871,372	$5,067,616	$5,315,589	$5,939,114	$1,396,127
Working Capital Allowance	$1,473,670	$1,416,578	$1,414,454	$1,453,218	$1,592,685	$1,646,134	$1,821,681	$1,541,791	$994,882	-$478,789
Total Rate Base	**$6,016,657**	**$5,843,374**	**$5,970,040**	**$6,096,388**	**$6,330,556**	**$6,517,506**	**$6,889,297**	**$6,857,380**	**$6,933,995**	**$917,338**

	CGAAP	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	
Expenses for Working Capital	**Last Board Approved**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	
Eligible Distribution Expenses:										
3500-Distribution Expenses - Operation	$235,909	$207,838	$222,809	$231,657	$228,491	$291,184	$311,428	$282,542	$296,946	$61,037
3550-Distribution Expenses - Maintenance	$171,718	$154,106	$147,176	$151,791	$190,006	$171,743	$171,109	$189,934	$196,759	$25,041
3650-Billing and Collecting	$328,238	$352,212	$335,087	$359,319	$400,546	$387,608	$417,963	$433,355	$467,660	$139,422
3700-Community Relations	$1,000	$2,022	$3,339	$1,684	$1,286	$2,853	$1,688	$3,000	$6,000	$5,000
3800-Administrative and General Expenses	$434,729	$324,920	$435,302	$457,589	$434,567	$386,773	$427,970	$519,091	$581,915	$147,186
Other taxes	-$21,765									$21,765
										$0
Total Eligible Distribution Expenses	$1,149,829	$1,041,099	$1,143,713	$1,202,039	$1,254,896	$1,240,159	$1,330,158	$1,427,921	$1,549,280	$399,451
3350-Power Supply Expenses	$8,674,639	$8,402,755	$8,285,984	$8,486,079	$9,363,001	$9,734,067	$10,814,383	$8,850,684	$11,715,807	$3,041,168
Total Expenses for Working Capital	$9,824,468	$9,443,854	$9,429,696	$9,688,118	$10,617,897	$10,974,226	$12,144,541	$10,278,605	$13,265,087	$3,440,619
Working Capital factor	15%	15%	15%	15%	15%	15%	15%	15%	7.50%	-7.50%
Total Working Capital	**$1,473,670**	**$1,416,578**	**$1,414,454**	**$1,453,218**	**$1,592,685**	**$1,646,134**	**$1,821,681**	**$1,541,791**	**$994,882**	**-$478,789**

The Rate Base for the 2017 Test Year has been forecasted to increase by $76,615, 1.12%, over the 2016 Bridge Year. Furthermore, the Rate Base for the 2017 Test Year has been forecasted to increase by $917,338, or 15% over the last Board Approved Rate Base. The reason for the variances between the 2017 Test Year and the 2010 last Board Approved is mainly attributed to:

<u>An increase in the average net fixed assets in service</u>

- Investments in the distribution system have surpassed the amortization expenses by $1,396,127 since the last Cost of Service Application. The details of the Renfrew Hydro Distribution System Plan are provided in detail at Ex.2/Tab 5/Sch.2.
- The inclusion of $558,932 in Smart Meter Related Capital expenditures into the 2017 Test Year's Rate Base.
- The capital assets added in the Test Year, exclusive of smart meters, total $740,500 which includes the replacement of 40 poles, new reclosers, and implementation of smart grid technology.
- In accordance with the OEB's letter of July 17, 2012, RHI adopted new extended useful lives for many asset categories in 2013. The extension of the typical useful lives of RHI's assets has caused the depreciation expense to decrease resulting in an increase in the value of the net fixed assets of the utility.

<u>A decrease in the working capital allowance</u>

- The working capital allowance has decreased by $478,789 caused by the reduced rate, down from 15% in 2010 to 7.5% in 2017, in accordance with the letter issued by the OEB on June 03, 2015.

<u>Increased Power Supply Expenses</u>

- RHI has forecasted an increase in the 2017 Power Supply Expenses of over $3M since the 2010 Cost of Service.

<u>Increased Distribution Expenses</u>

- The 2017 forecast for OM&A reflects an increase of $399,451 from the 2010 Board Approved. The details of the increases in OM&A are provided in Exhibit 4, but some of the highlights include:
    - increased labour rates
    - the addition of smart meter operational expenses

- increased billing expenses to change from a bi-monthly cycle to monthly
- increases to regulatory expenses
- increased rent for a new garage and office space

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

The following paragraphs and Tables 2.3 to Table 2.8 provide a narrative on the changes that have driven the increase in rate base since RHI's 2010 Board Approved Cost of Service Application.

RHI's materiality threshold is $50,000.

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

- 2017 Test Year (MIFRS) against 2016 Bridge Year (MIFRS)
- 2016 Bridge Year (MIFRS) against 2015 Actual (MIFRS)
- 2015 Actual (MIFRS) against 2014 Actual (CGAAP)
- 2014 Actual (CGAAP) against 2013 Actual (CGAAP)
- 2013 Actual (CGAAP) against 2012 Actual (CGAAP)
- 2012 Actual (CGAAP) against 2011 Actual (CGAAP)
- 2011 Actual (CGAAP) against 2010 Actual (CGAAP)
- 2010 Actual (CGAAP) against 2010 Board Approved (CGAAP)

2017 Test Year vs. 2016 Bridge Year:

Table 2.3: 2017-2016 Rate Base Variance

Particulars	**2016**	**2017**	**Var**	**%**
Gross Fixed Assets (average)	14,929,292	15,495,709	566,417	3.79%
Accumulated Depreciation (average)	(9,613,703)	(9,556,595)	57,108	-0.59%
Net Fixed Assets (average)	5,315,589	5,939,114	623,525	11.73%
Working Capital Allowance	1,541,791	994,882	(546,909)	-35.47%
Total Rate Base	**6,857,380**	**6,933,995**	**76,616**	**1.12%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**2016**	**2017**	**Var**	**%**
3500-Distribution Expenses - Operation	282,542	296,946	14,404	5.10%
3550-Distribution Expenses - Maintenance	189,934	196,759	6,825	3.59%
3650-Billing and Collecting	433,355	467,660	34,305	7.92%
3700-Community Relations	3,000	6,000	3,000	100.00%
3800-Administrative and General Expenses	519,091	581,915	62,824	12.10%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,427,921	1,549,280	121,359	8.50%
3350-Power Supply Expenses	8,850,684	11,715,807	2,865,123	32.37%
Total Expenses for Working Capital	10,278,605	13,265,087	2,986,482	29.06%
Working Capital factor	15%	8%	15%	-50.00%
Total Working Capital	**1,541,791**	**994,882**	**- 546,909**	**-35.47%**

The total projected Rate Base in 2017 of $6,933,995 is $76,616 or 1.12% higher than 2016.The main reasons for the variance is:

- The average net capital assets in service are projected to be approximately $623K higher than the prior year's average.
- In 2017, increased capital investment in the utility's distribution system is required in order to keep the system running in a safe and reliable manner. Details regarding capital planning can be found in the Distribution System Plan at Ex.2/Tab 5/Sch.2
- The inclusion of $558,932 in Smart Meter Related Capital expenditures into the 2017 Test Year's Rate Base.
- The capital assets added in the Test Year, exclusive of smart meters, total $740,500 which includes the replacement of 40 deteriorated poles, new reclosers replacing 60

year old breakers at the M1 substation, and implementation of smart grid technology.

- This increase is offset by the removal of stranded conventional meters from Fixed Assets in the 2017 Test Year.
- The working capital allowance saw a decrease of ($546K) due to the reduction in rate from 15% to 7.5%.

2016 Bridge Year vs. 2015 Actual:

Table 2.4: 2016-2015 Rate Base Variances

Particulars	**2015**	**2016**	**Var**	**%**
		-		
Gross Fixed Assets (average)	14,493,751	14,929,292	435,540	3.01%
Accumulated Depreciation (average)	(9,426,136)	(9,613,703)	(187,567)	1.99%
Net Fixed Assets (average)	5,067,616	5,315,589	247,973	4.89%
Working Capital Allowance	1,821,681	1,541,791	(279,890)	-15.36%
Total Rate Base	**6,889,297**	**6,857,380**	**(31,917)**	**-0.46%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**2015**	**2016**	**Var**	**%**
3500-Distribution Expenses - Operation	311,428	282,542	(28,886)	-9.28%
3550-Distribution Expenses - Maintenance	171,109	189,934	18,825	11.00%
3650-Billing and Collecting	417,963	433,355	15,392	3.68%
3700-Community Relations	1,688	3,000	1,312	77.71%
3800-Administrative and General Expenses	427,970	519,091	91,121	21.29%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,330,158	1,427,921	97,763	7.35%
3350-Power Supply Expenses	10,814,383	8,850,684	(1,963,698)	-18.16%
Total Expenses for Working Capital	12,144,541	10,278,605	- 1,865,936	-15.36%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,821,681**	**1,541,791**	**- 279,890**	**-15.36%**

The total projected Rate Base in 2016 of $6,857,380 is $31,917 or -0.46% less than 2015. The main contributors to the variance are:

- The 2016 net capital additions are projected to be approximately $234K higher than the amortization expense, causing an increase to the average net fixed assets of $247K.

- The utility is planning on replacing 30 deteriorated poles, 35 transformers and upgrading Argyle St. as a result of its asset assessment. Details regarding capital planning can be found in the Distribution System Plan at at Ex.2/Tab 5/Sch.2

2015 Actual vs. 2014 Actual:

Table 2.5: 2015-2014 Rate Base Variances

Particulars	**2014**	**2015**	**Var**	**%**
		-		
Gross Fixed Assets (average)	14,104,271	14,493,751	389,480	2.76%
Accumulated Depreciation (average)	(9,232,899)	(9,426,136)	(193,237)	2.09%
Net Fixed Assets (average)	4,871,372	5,067,616	196,243	4.03%
Working Capital Allowance	1,646,134	1,821,681	175,547	10.66%
Total Rate Base	**6,517,506**	**6,889,297**	**371,790**	**5.70%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**2014**	**2015**	**Var**	**%**
3500-Distribution Expenses - Operation	291,184	311,428	20,244	6.95%
3550-Distribution Expenses - Maintenance	171,743	171,109	(633)	-0.37%
3650-Billing and Collecting	387,608	417,963	30,355	7.83%
3700-Community Relations	2,853	1,688	(1,165)	-40.83%
3800-Administrative and General Expenses	386,773	427,970	41,197	10.65%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,240,159	1,330,158	89,999	7.26%
3350-Power Supply Expenses	9,734,067	10,814,383	1,080,316	11.10%
Total Expenses for Working Capital	10,974,226	12,144,541	1,170,315	10.66%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,646,134**	**1,821,681**	**175,547**	**10.66%**

The 2015 Rate Base of $6,889,297 is $371,790, or 5.7% more than 2014. The main contributors to the variance are:

- The 2015 net capital additions were approximately $261K higher than the amortization expense, causing an increase to the average net fixed assets of $196K.

- The 2015 capital investments included the replacement of 23 poles and upgrading the distribution system on Gillan Rd. The utility also had capital lease improvements at its new location and upgraded its billing software.
- The 2015 working capital allowance also increased by $175K, or 10%, mainly caused by the increase of $1M, or 11% in power supply expenses.

2014 Actual vs. 2013 Actual:

Table 2.6: 2014-2013 Rate Base Variances

Particulars	**2013**	**2014**	**Var**	**%**
		-		
Gross Fixed Assets (average)	13,812,383	14,104,271	291,888	2.11%
Accumulated Depreciation (average)	(9,074,512)	(9,232,899)	(158,387)	1.75%
Net Fixed Assets (average)	4,737,872	4,871,372	133,501	2.82%
Working Capital Allowance	1,592,685	1,646,134	53,449	3.36%
Total Rate Base	**6,330,556**	**6,517,506**	**186,950**	**2.95%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**2013**	**2014**	**Var**	**%**
3500-Distribution Expenses - Operation	228,491	291,184	62,692	27.44%
3550-Distribution Expenses - Maintenance	190,006	171,743	(18,263)	-9.61%
3650-Billing and Collecting	400,546	387,608	(12,939)	-3.23%
3700-Community Relations	1,286	2,853	1,567	121.86%
3800-Administrative and General Expenses	434,567	386,773	(47,794)	-11.00%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,254,896	1,240,159	(14,736)	-1.17%
3350-Power Supply Expenses	9,363,001	9,734,067	371,065	3.96%
Total Expenses for Working Capital	10,617,897	10,974,226	356,329	3.36%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,592,685**	**1,646,134**	**53,449**	**3.36%**

The 2014 Rate Base of $6,517,506 is $186,950, or 2.95% higher than 2013. The main contributors to the variance are:

- The 2014 net capital additions were approximately $130K higher than the amortization expense, causing an increase to the average net fixed assets of $133K.
- In 2014, the utility's capital investments included a major upgrade to the lower portion of Argyle St.; replacing 37 deteriorated poles as a result of its asset assessment; and a new vehicle was purchased for employee business travel in lieu of personal vehicle use and service calls
- The working capital allowance increased by $53K or 3.36% directly related to the increase in the power supply expenses of $371K, or 3.36%.

2013 Actual vs. 2012 Actual:

Table 2.7: 2013-2012 Rate Base Variance

Particulars	2012	2013	Var	%
		-		
Gross Fixed Assets (average)	13,449,629	13,812,383	362,755	2.70%
Accumulated Depreciation (average)	(8,806,458)	(9,074,512)	(268,053)	3.04%
Net Fixed Assets (average)	4,643,170	4,737,872	94,702	2.04%
Working Capital Allowance	1,453,218	1,592,685	139,467	9.60%
Total Rate Base	**6,096,388**	**6,330,556**	**234,168**	**3.84%**

Expenses for Working Capital				
Eligible Distribution Expenses:	2012	2013	Var	%
3500-Distribution Expenses - Operation	231,657	228,491	(3,165)	-1.37%
3550-Distribution Expenses - Maintenance	151,791	190,006	38,215	25.18%
3650-Billing and Collecting	359,319	400,546	41,227	11.47%
3700-Community Relations	1,684	1,286	(398)	-23.66%
3800-Administrative and General Expenses	457,589	434,567	(23,022)	-5.03%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,202,039	1,254,896	52,857	4.40%
3350-Power Supply Expenses	8,486,079	9,363,001	876,922	10.33%
Total Expenses for Working Capital	9,688,118	10,617,897	929,779	9.60%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,453,218**	**1,592,685**	**139,467**	**9.60%**

The 2013 Rate Base of $6,330,556 is $234,168, or 3.84% higher than 2012. The main contributors to the variance are:

- The 2013 net capital additions were approximately $136K higher than the amortization expense, causing an increase to the average net fixed assets of $139K. RHI adopted new extended useful lives for many asset categories in 2013. The extension of the typical useful lives of RHI's assets has caused the depreciation expense to decrease resulting in an increase in the value of the net fixed assets of the utility.
- In 2013, RHI's capital investments included replacing 35 deteriorated poles and the addition of a new subdivision at Hunters Gate.
- The working capital allowance increased by $139K or 9.6% directly related to the increase in the power supply expenses of $876K, or 10.33%.

2012 Actual vs. 2011 Board-Approved:

Table 2.8: 2012-2011 Rate Base Variance

Particulars	2011	2012	Var	%
		-		
Gross Fixed Assets (average)	12,970,698	13,449,629	478,930	3.69%
Accumulated Depreciation (average)	(8,415,112)	(8,806,458)	(391,346)	4.65%
Net Fixed Assets (average)	4,555,586	4,643,170	87,584	1.92%
Working Capital Allowance	1,414,454	1,453,218	38,763	2.74%
Total Rate Base	**5,970,040**	**6,096,388**	**126,347**	**2.12%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**2011**	**2012**	**Var**	**%**
3500-Distribution Expenses - Operation	222,809	231,657	8,847	3.97%
3550-Distribution Expenses - Maintenance	147,176	151,791	4,615	3.14%
3650-Billing and Collecting	335,087	359,319	24,232	7.23%
3700-Community Relations	3,339	1,684	(1,654)	-49.55%
3800-Administrative and General Expenses	435,302	457,589	22,287	5.12%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,143,713	1,202,039	58,326	5.10%
3350-Power Supply Expenses	8,285,984	8,486,079	200,095	2.41%
Total Expenses for Working Capital	9,429,696	9,688,118	258,422	2.74%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,414,454**	**1,453,218**	**38,763**	**2.74%**

The 2012 Rate Base of $6,096,388 is $126,347, or 2.12% higher than 2011. The main contributors to the variance are:

- The 2012 net capital additions were approximately $53K higher than the amortization expense, causing an increase to the average net fixed assets of $87K.
- In 2012, the utility's investment in its distribution system included a new subdivision at Coleraine Drive. RHI also replaced 34 deteriorated poles and purchased a 2009 utility dump and chipper truck to replace the 16 year-old truck.
- The working capital allowance increased by $258K or 2.74% directly related to the increase in the power supply expenses of $200K, or 2.41%, and increased distribution expenses of $58K or 5.1%.

2011 Actual vs. 2010 Board-Approved:

Table 2.8: 2011-2010 Rate Base Variance

Particulars	**2010**	**2011**	**Var**	**%**
		-		
Gross Fixed Assets (average)	12,444,931	12,970,698	525,767	4.22%
Accumulated Depreciation (average)	(8,018,135)	(8,415,112)	(396,978)	4.95%
Net Fixed Assets (average)	4,426,796	4,555,586	128,790	2.91%
Working Capital Allowance	1,416,578	1,414,454	(2,124)	-0.15%
Total Rate Base	**5,843,374**	**5,970,040**	**126,666**	**2.17%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**2010**	**2011**	**Var**	**%**
3500-Distribution Expenses - Operation	207,838	222,809	14,971	7.20%
3550-Distribution Expenses - Maintenance	154,106	147,176	(6,931)	-4.50%
3650-Billing and Collecting	352,212	335,087	(17,125)	-4.86%
3700-Community Relations	2,022	3,339	1,317	65.12%
3800-Administrative and General Expenses	324,920	435,302	110,382	33.97%
6105-Taxes other than Income Taxes	-	-	-	
Total Eligible Distribution Expenses	1,041,099	1,143,713	102,613	9.86%
3350-Power Supply Expenses	8,402,755	8,285,984	(116,771)	-1.39%
Total Expenses for Working Capital	9,443,854	9,429,696	- 14,157	-0.15%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,416,578**	**1,414,454**	**- 2,124**	**-0.15%**

The 2011 Rate Base of $5,970,040 is $126,666, or 2.17% higher than 2010. The main contributors to the variance are:

- The 2011 net capital additions were approximately $122K higher than the amortization expense, causing an increase to the average net fixed assets of $128K or 2.91%.
- In 2011, RHI's capital investments included a rebuild of the distribution system at Plaunt St.; 36 deteriorated poles replaced; and the purchase of a tension stringing trailer.

2010 Actual vs. 2010 Board-Approved:

Table 2.8: 2010-2010 Board Approved Rate Base Variance

Particulars	Last Board Approved	2010	Var	%
		-		
Gross Fixed Assets (average)	12,436,805	12,444,931	8,126	0.07%
Accumulated Depreciation (average)	(7,893,818)	(8,018,135)	(124,317)	1.57%
Net Fixed Assets (average)	4,542,987	4,426,796	(116,191)	-2.56%
Working Capital Allowance	1,473,670	1,416,578	(57,092)	-3.87%
Total Rate Base	**6,016,657**	**5,843,374**	**(173,283)**	**-2.88%**

Expenses for Working Capital				
Eligible Distribution Expenses:	**Last Board Approved**	**2010**	**Var**	**%**
3500-Distribution Expenses - Operation	235,909	207,838	(28,071)	-11.90%
3550-Distribution Expenses - Maintenance	171,718	154,106	(17,612)	-10.26%
3650-Billing and Collecting	328,238	352,212	23,974	7.30%
3700-Community Relations	1,000	2,022	1,022	102.21%
3800-Administrative and General Expenses	434,729	324,920	(109,809)	-25.26%
6105-Taxes other than Income Taxes	(21,765)	-	21,765	
Total Eligible Distribution Expenses	1,149,829	1,041,099	(108,730)	-9.46%
3350-Power Supply Expenses	8,674,639	8,402,755	(271,884)	-3.13%
Total Expenses for Working Capital	9,824,468	9,443,854	- 380,614	-3.87%
Working Capital factor	15%	15%	15%	0.00%
Total Working Capital	**1,473,670**	**1,416,578**	**- 57,092**	**-3.87%**

The 2010 Rate Base of $5,843,374 is $173,283 or 2.88% lower than 2010 Board Approved. The main contributors to the variance are:

- The working capital decreased by $57K or 3.87% caused by less than projected distribution expenses $(109K), and less than projected power supply expenses $(271K) in 2010 when compared to 2010 Board Approved. As detailed in Exhibit 4, RHI's new rates were approved in December 2010 so many of the items budgeted for 2010 were postponed and realized in 2011.
- The net average fixed assets were also 2.56%, or $116K lower than the 2010 Board Approved projections, attributed to depreciation expense being higher than originally calculated.

Ex.2/Tab 1/Sch.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 2010 Historic Year, 2011 Historic Year, 2012 Historic Year, 2013 Historic Year, 2014 Historic Year, 2015 Historic Year, 2016 Bridge Year, and 2017 Test Year.
RHI attests that the continuity statements reconcile with the calculated depreciation expenses, under Exhibit 4 – Operating Costs, and presented by asset account.

The following Tables are Board Appendix 2-BA for the 2011, 2012, 2103, 2014, 2015 Actuals, 2016 Bridge Year, and 2017 Test Year.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP (Old CGAAP)
Year: 2010

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 114,200	$ 6,445		$ 120,705	-$ 69,095	-$ 22,027		-$ 92,722	$ 27,903
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 17,374	$ 6,607		$ 23,981	-$ 16,712	-$ 340		-$ 17,052	$ 6,929
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -	$ -		$ -	$ 22,895
1	47	1808	Buildings	$ 154,129	$ 11,168		$ 165,297	-$ 81,477	-$ 2,835		-$ 84,312	$ 80,985
	13	1810	Leasehold Improvements	$ -			$ -				$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -				$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,146,264	$ 141,933		$ 1,288,197	-$ 619,535	-$ 33,853		-$ 653,388	$ 634,809
	47	1825	Storage Battery Equipment				$ -				$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,023,798	$ 130,865		$ 2,154,663	-$ 1,067,113	-$ 65,800		-$ 1,132,913	$ 1,021,750
1/47	47	1835	Overhead Conductors & Devices	$ 3,501,362	$ 139,070		$ 3,640,433	-$ 2,265,888	-$ 104,516		-$ 2,370,404	$ 1,270,029
1/47	47	1840	Underground Conduit	$ 45,129	$ 7,459		$ 52,588	-$ 15,876	-$ 1,956		-$ 17,831	$ 34,757
1/47	47	1845	Underground Conductors & Devices	$ 345,189	$ 42,023		$ 387,211	-$ 126,315	-$ 14,579		-$ 140,894	$ 246,318
1/47	47	1850	Line Transformers	$ 1,530,498	$ 15,440		$ 1,545,938	-$ 1,083,236	-$ 44,001		-$ 1,127,237	$ 418,701
1/47	47	1855	Services (Overhead & Underground)	$ 1,474,564	$ 21,176		$ 1,495,739	-$ 1,074,580	-$ 42,316		-$ 1,116,896	$ 378,843
1/47	47	1860	Meters	$ 587,713	$ 6,617		$ 594,329	$ 421,737	$ 17,320		$ 439,056	$ 155,273
47	47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	N/A	1905	Land				$ -				$ -	$ -
	47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	13	1910	Leasehold Improvements				$ -				$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	$ 31,034	$ 11		$ 31,045	$ 203
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -				$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 84,471	$ 4,448		$ 88,919	-$ 83,193	-$ 4,470		-$ 87,663	$ 1,256
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$				$	$
10	10	1930	Transportation Equipment	$ 909,406			$ 909,406	-$ 674,635	-$ 39,435		-$ 714,070	$ 195,336
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559			-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 184,605	-$ 3,233		-$ 187,837	-$ 984
8	8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	8	1950	Power Operated Equipment				$ -				$ -	$ -
8	8	1955	Communications Equipment				$ -				$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	47	1990	Other Tangible Property				$ -				$ -	$ -
47	47	1995	Contributions & Grants				$ -				$ -	$ -
		2440	Deferred Revenue[5]									
							$ -				$ -	$ -
			Sub-Total	**$ 12,178,306**	**$ 533,251**	**$ -**	**$ 12,711,556**	**-$ 7,819,389**	**-$ 397,490**	**$ -**	**-$ 8,216,880**	**$ 4,494,677**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$				$	$
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
			Total PP&E	**$ 12,178,306**	**533,251**	**$ -**	**$ 12,711,556**	**- 7,819,389.40**	**- 397,490**	**$ -**	**-$ 8,216,880**	**4,494,677**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**$ 397,490**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 397,490

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP — Old CGAAP
Year: 2011

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705			$ 120,705	-$ 92,722	-$ 23,471		-$ 116,193	$ 4,511
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981			$ 23,981	-$ 17,052	-$ 505		-$ 17,557	$ 6,423
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -	$ -		$ -	$ 22,895
1	47	1808	Buildings	$ 165,297	$ 36,537		$ 201,834	-$ 84,312	-$ 3,312		-$ 87,624	$ 114,210
	13	1810	Leasehold Improvements	$			$	$			$	$
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,200,197			$ 1,200,197	-$ 653,389	-$ 36,218		-$ 689,606	$ 510,591
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,154,663	$ 167,919		$ 2,322,583	-$ 1,132,913	-$ 70,265		-$ 1,203,178	$ 1,119,405
1/47	47	1835	Overhead Conductors & Devices	$ 3,640,433	$ 185,958		$ 3,826,390	-$ 2,370,404	-$ 107,491		-$ 2,477,894	$ 1,348,496
1/47	47	1840	Underground Conduit	$ 52,588	$ 1,982		$ 54,570	-$ 17,831	-$ 2,131		-$ 19,962	$ 34,608
1/47	47	1845	Underground Conductors & Devices	$ 387,211	$ 2,303		$ 389,514	-$ 140,894	-$ 15,345		-$ 156,239	$ 233,276
1/47	47	1850	Line Transformers	$ 1,545,938	$ 59,277		$ 1,605,215	-$ 1,127,237	-$ 40,860		-$ 1,168,098	$ 437,118
1/47	47	1855	Services (Overhead & Underground)	$ 1,495,739	$ 24,103		$ 1,519,843	-$ 1,116,896	-$ 41,498		-$ 1,158,395	$ 361,448
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 439,056	-$ 15,920		-$ 454,976	$ 139,353
47	47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$			$	$			$	$
13	13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,041			$ 30,041	-$ 31,045	$ -		-$ 31,045	-$ 203
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 88,919			$ 88,919	-$ 87,663	-$ 2,057		-$ 89,720	-$ 801
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment	$ 909,406	$ 40,204		$ 949,610	-$ 714,070	-$ 35,408		-$ 749,477	$ 200,133
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559			-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 187,837	-$ 1,984		-$ 189,821	-$ 2,968
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)	$			$	$			$	$
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
		2440	Deferred Revenue[5]	$ -				$ -				
				$ -			$ -				$ -	$ -
			Sub-Total	**$ 12,711,556**	**$ 518,284**	**$ -**	**$ 13,229,840**	**-$ 8,216,880**	**-$ 396,465**	**$ -**	**-$ 8,613,345**	**$ 4,616,495**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$				$	$
			Total PP&E	**$ 12,711,556**	**518,284**	**$ -**	**$ 13,229,840**	**-$ 8,216,880**	**- 396,465**	**$ -**	**-$ 8,613,345**	**$ 4,616,495**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 396,465**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 396,465

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Notes:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year 2012

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705			$ 120,705	-$ 116,193	-$ 1,289		-$ 117,482	$ 3,222
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981			$ 23,981	-$ 17,557	-$ 406		-$ 17,963	$ 6,018
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings	$ 201,834			$ 201,834	-$ 87,624	-$ 3,677		-$ 91,301	$ 110,533
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,288,197			$ 1,288,197	-$ 689,606	-$ 36,218		-$ 725,824	$ 562,373
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,322,583	$ 161,976		$ 2,484,559	-$ 1,203,178	-$ 75,360		-$ 1,278,538	$ 1,206,020
1/47	47	1835	Overhead Conductors & Devices	$ 3,826,390	$ 145,098		$ 3,971,488	-$ 2,477,894	-$ 110,606		-$ 2,588,500	$ 1,382,988
1/47	47	1840	Underground Conduit	$ 54,570	$ 8,500		$ 63,071	-$ 19,962	-$ 2,303		-$ 22,265	$ 40,806
1/47	47	1845	Underground Conductors & Devices	$ 389,514	$ 23,628		$ 413,143	-$ 156,239	-$ 15,520		-$ 171,759	$ 241,384
1/47	47	1850	Line Transformers	$ 1,605,215	$ 23,828		$ 1,629,043	-$ 1,168,098	-$ 39,245		-$ 1,207,343	$ 421,701
1/47	47	1855	Services (Overhead & Underground)	$ 1,519,843	$ 22,577		$ 1,542,420	-$ 1,158,395	-$ 40,635		-$ 1,199,030	$ 343,390
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 454,976	-$ 15,186		-$ 470,162	$ 124,168
47	47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	-$ 31,045	$ -		-$ 31,045	-$ 203
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 88,919	$ 6,705		$ 95,624	-$ 89,720	-$ 1,560		-$ 91,280	$ 4,344
	45	1920	Computer Equip.-Hardware(Post Mar 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment	$ 949,610	$ 47,264		$ 996,874	-$ 749,477	-$ 42,239		-$ 791,716	$ 205,158
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559	$ -		-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 189,821	-$ 1,984		-$ 191,805	-$ 4,952
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communications Equipment	$			$	$			$	$
8	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
		2440	Deferred Revenue[5]	$ -				$ -				
							$ -				$ -	$ -
			Sub-Total	$ 13,229,840	$ 439,577	$ -	$ 13,669,417	-$ 8,613,345	-$ 386,227	$ -	-$ 8,999,572	$ 4,669,845
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
			Total PP&E	$ 13,229,840	439,577	$ -	$ 13,669,417	-$ 8,613,345	- 386,227	$ -	-$ 8,999,572	$ 4,669,845
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						-$ 386,227			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 386,227

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP — Old CGAAP
Year: 2013

RHI CCA Class	OEB 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: Adj to Opening	Accumulated Depreciation: Closing Balance	Net Book Value
12	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705			$ 120,705	-$ 117,482	-$ 1,289			-$ 118,771	$ 1,933
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981			$ 23,981	-$ 17,963	-$ 390			-$ 18,353	$ 5,627
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -				$ -	$ 22,895
1	47	1808	Buildings	$ 201,834			$ 201,834	-$ 91,301	-$ 5,352			-$ 96,654	$ 105,181
	13	1810	Leasehold Improvements	$ -			$ -	$ -				$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -				$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,288,197			$ 1,288,197	-$ 725,824	-$ 36,218			-$ 762,042	$ 526,155
	47	1825	Storage Battery Equipment	$ -			$ -	$ -				$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,484,559	$ 109,813		$ 2,594,371	-$ 1,278,538	-$ 78,934		-$ 34,511	-$ 1,391,983	$ 1,202,388
1/47	47	1835	Overhead Conductors & Devices	$ 3,971,488	$ 64,843		$ 4,036,331	-$ 2,588,500	-$ 110,460		-$ 2,014	-$ 2,700,973	$ 1,335,358
1/47	47	1840	Underground Conduit	$ 63,071	$ 4,520		$ 67,591	-$ 22,265	-$ 2,541		$ 571	-$ 24,234	$ 43,357
1/47	47	1845	Underground Conductors & Devices	$ 413,143	$ 85,037		$ 498,180	-$ 171,759	-$ 17,493		$ 3,157	-$ 186,094	$ 312,085
1/47	47	1850	Line Transformers	$ 1,629,043	$ 41,356		$ 1,670,399	-$ 1,207,343	-$ 36,568			-$ 1,243,911	$ 426,488
1/47	47	1855	Services (Overhead & Underground)	$ 1,542,420	$ 34,966		$ 1,577,386	-$ 1,199,030	-$ 39,643		$ 29,792	-$ 1,208,881	$ 368,505
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 470,162	-$ 14,140		$ 407	-$ 483,895	$ 110,435
47	47	1860	Meters (Smart Meters)	$ -	$ 14,491		$ 14,491	$ -	-$ 483			-$ 483	$ 14,008
N/A	N/A	1905	Land	$ -			$ -	$ -				$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -				$ -	$ -
13	13	1910	Leasehold Improvements	$ -			$ -	$ -				$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	-$ 31,045			$ 203	-$ 30,841	$ -
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -				$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 95,624			$ 95,624	-$ 91,280	-$ 2,231		$ 3,915	-$ 89,596	$ 6,028
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -				$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -				$ -	$ -
10	10	1930	Transportation Equipment	$ 996,874	$ 2,500		$ 999,374	-$ 791,716	-$ 47,215		-$ 8	-$ 838,939	$ 160,435
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559				-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 191,805	-$ 1,825		$ 11,967	-$ 181,663	$ 5,190
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -				$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -				$ -	$ -
8	8	1955	Communications Equipment	$ -			$ -	$ -				$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -				$ -	$ -
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -				$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -				$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -				$ -	$ -
47	47	1980	System Supervisor Equipment	$ -			$ -	$ -				$ -	$ -
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -				$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -				$ -	$ -
		1995	Contributions & Grants - O/H Conductor	$ -	-$ 2,000		-$ 2,000	$ -	$ 40			$ 40	-$ 1,960
		1995	Contributions & Grants - Poles	$ -	-$ 15,100		-$ 15,100	$ -	$ 302			$ 302	-$ 14,798
		1995	Contributions & Grants - Transformers	$ -	-$ 7,500		-$ 7,500	$ -	$ 150			$ 150	-$ 7,350
		2440	Deferred Revenue[5]	$ -				$ -				$ -	
							$ -					$ -	$ -
			Sub-Total	$ 13,669,417	332,925	$ -	$ 14,002,342	-$ 8,999,572	- 394,289	$ -	13,479	-$ 9,380,382	$ 4,621,961
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
			Total PP&E	$ 13,669,417	$ 332,925	$ -	$ 14,002,342	-$ 8,999,572	-$ 394,289	$ -	$ 13,479	-$ 9,380,382	$ 4,621,961
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
			Total						-$ 380,810				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 380,810

Notes:

13,479.00 — Errors found on old Fixed Asset Continuity Schedules (Over depreciated) Adjusted Opening A/D for errors in past years.

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP Old CGAAP
Year: 2014

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705			$ 120,705	-$ 118,771	-$ 1,289		-$ 120,060	$ 644
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981			$ 23,981	-$ 18,353	-$ 390		-$ 18,744	$ 5,237
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings	$ 201,834			$ 201,834	-$ 96,654	-$ 3,677		-$ 100,331	$ 101,504
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,288,197			$ 1,288,197	-$ 762,042	-$ 33,386		-$ 795,429	$ 492,768
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,594,371	$ 127,370		$ 2,721,741	-$ 1,391,983	-$ 81,402		-$ 1,473,385	$ 1,248,356
1/47	47	1835	Overhead Conductors & Devices	$ 4,036,331	$ 114,905		$ 4,151,236	-$ 2,700,973	-$ 108,745		-$ 2,809,718	$ 1,341,518
1/47	47	1840	Underground Conduit	$ 67,591	$ 10,114		$ 77,705	-$ 24,234	-$ 2,764		-$ 26,998	$ 50,707
1/47	47	1845	Underground Conductors & Devices	$ 498,180	$ 24,717		$ 522,896	-$ 186,094	-$ 19,064		-$ 205,158	$ 317,738
1/47	47	1850	Line Transformers	$ 1,670,399	$ 28,523		$ 1,698,922	-$ 1,243,911	-$ 33,948		-$ 1,277,859	$ 421,063
1/47	47	1855	Services (Overhead & Underground)	$ 1,577,386	$ 14,548		$ 1,591,934	-$ 1,208,881	-$ 37,873		-$ 1,246,754	$ 345,180
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 483,895	-$ 13,368		-$ 497,262	$ 97,067
47	47	1860	Meters (Smart Meters)	$ 14,491	$ 10,278		$ 24,769	-$ 483	-$ 1,309		-$ 1,792	$ 22,977
N/A	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	-$ 30,841	$ -		-$ 30,841	$ -
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 95,624	$ 5,437		$ 101,061	-$ 89,596	-$ 2,774		-$ 92,370	$ 8,691
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment	$ 999,374	$ 21,744		$ 1,021,118	-$ 838,939	-$ 49,639		-$ 888,578	$ 132,540
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559			-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 181,663	-$ 1,570		-$ 183,234	$ 3,620
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - O/H Conductor	-$ 2,000			-$ 2,000	$ 40	$ 80		$ 120	-$ 1,880
		1995	Contributions & Grants - Poles	-$ 15,100			-$ 15,100	$ 302	$ 604		$ 906	-$ 14,194
		1995	Contributions & Grants - Transformers	-$ 7,500			-$ 7,500	$ 150	$ 300		$ 450	-$ 7,050
		2440	Deferred Revenue[5]	$ -				$ -			$ -	
							$ -				$ -	$ -
			Sub-Total	**$ 14,002,342**	**$ 357,636**	**$ -**	**$ 14,359,978**	**-$ 9,380,382**	**- 390,215**	**$ -**	**-$ 9,770,596**	**$ 4,589,382**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
			Total PP&E	**$ 14,002,342**	**$ 357,636**	**$ -**	**$ 14,359,978**	**-$ 9,380,381.7**	**-$ 390,215**	**$ -**	**-$ 9,770,596**	**$ 4,589,382**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 390,214.7**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 390,215

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP (Old CGAAP)
Year: 2015

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705	$ 39,417		$ 160,121	-$ 120,060	-$ 4,586		-$ 124,646	$ 35,475
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981	$ 4,321		$ 28,301	-$ 18,744	-$ 498		-$ 19,242	$ 9,059
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings	$ 201,834			$ 201,834	-$ 100,331	-$ 3,677		-$ 104,008	$ 97,826
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,288,197			$ 1,288,197	-$ 795,429	-$ 33,386		-$ 828,815	$ 459,382
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,721,741	$ 182,603		$ 2,904,344	-$ 1,473,385	-$ 85,500		-$ 1,558,885	$ 1,345,459
1/47	47	1835	Overhead Conductors & Devices	$ 4,151,236	$ 68,146		$ 4,219,382	-$ 2,809,718	-$ 107,503		-$ 2,917,221	$ 1,302,161
1/47	47	1840	Underground Conduit	$ 77,705			$ 77,705	-$ 26,998	-$ 2,957		-$ 29,955	$ 47,750
1/47	47	1845	Underground Conductors & Devices	$ 522,896			$ 522,896	-$ 205,158	-$ 19,470		-$ 224,628	$ 298,268
1/47	47	1850	Line Transformers	$ 1,698,922	$ 62,246		$ 1,761,168	-$ 1,277,859	-$ 33,587		-$ 1,311,446	$ 449,722
1/47	47	1855	Services (Overhead & Underground)	$ 1,591,934	$ 10,407		$ 1,602,341	-$ 1,246,754	-$ 36,006		-$ 1,282,760	$ 319,581
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 497,262	-$ 12,797		-$ 510,059	$ 84,270
47	47	1860	Meters (Smart Meters)	$ 24,769	$ 1,884		$ 26,653	-$ 1,792	-$ 1,714		-$ 3,506	$ 23,147
N/A	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	13	1910	Leasehold Improvements	$ -	$ 116,088		$ 116,088	$ -	-$ 5,804		-$ 5,804	$ 110,284
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841	$ 21,604		$ 52,446	-$ 30,841	-$ 1,080		-$ 31,922	$ 20,524
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 101,061	$ 1,918		$ 102,979	-$ 92,370	-$ 3,065		-$ 95,435	$ 7,544
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment	$ 1,021,118			$ 1,021,118	-$ 888,578	-$ 51,814		-$ 940,392	$ 80,726
8	8	1935	Stores Equipment	$ 3,559	$ 1,731		$ 5,290	-$ 3,559	-$ 87		-$ 3,646	$ 1,645
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854	$ 625		$ 187,479	-$ 183,234	-$ 1,416		-$ 184,649	$ 2,829
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - O/H Conductor				$ -				$ -	$ -
		1995	Contributions & Grants - Poles				$ -				$ -	$ -
		1995	Contributions & Grants - Transformers				$ -				$ -	$ -
		2440	Deferred Revenue[5]	-$ 24,600	-$ 18,266		-$ 42,866	$ 1,476	$ 1,374		$ 2,850	-$ 40,016
							$ -				$ -	$ -
			Sub-Total	**$ 14,359,978**	**$ 492,724**	**$ -**	**$ 14,852,702**	**-$ 9,770,596**	**- 403,574**	**$ -**	**-$ 10,174,170**	**$ 4,678,532**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
			Total PP&E	**$ 14,359,978**	**$ 492,724**	**$ -**	**$ 14,852,702**	**-$ 9,770,596.3**	**-$ 403,574**	**$ -**	**-$ 10,174,170**	**$ 4,678,532**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 403,573.9**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 403,574

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year 2016

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 160,121			$ 160,121	-$ 124,646	-$ 7,883		-$ 132,530	$ 27,592
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 28,301	$ 3,000		$ 31,301	-$ 19,242	-$ 681		-$ 19,923	$ 11,378
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings	$ 201,834		-$ 157,538	$ 44,297	-$ 104,008	-$ 781	$ 85,588	-$ 19,202	$ 25,095
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,288,197			$ 1,288,197	-$ 828,815	-$ 33,386		-$ 862,201	$ 425,996
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,904,344	$ 172,000		$ 3,076,344	-$ 1,558,885	-$ 90,501		-$ 1,649,387	$ 1,426,958
1/47	47	1835	Overhead Conductors & Devices	$ 4,219,382	$ 83,000		$ 4,302,382	-$ 2,917,221	-$ 105,646		-$ 3,022,868	$ 1,279,514
1/47	47	1840	Underground Conduit	$ 77,705	$ 7,400		$ 85,105	-$ 29,955	-$ 3,084		-$ 33,039	$ 52,066
1/47	47	1845	Underground Conductors & Devices	$ 522,896	$ 92,600		$ 615,496	-$ 224,628	-$ 21,141		-$ 245,769	$ 369,727
1/47	47	1850	Line Transformers	$ 1,761,168	$ 163,000		$ 1,924,168	-$ 1,311,446	-$ 37,044		-$ 1,348,490	$ 575,678
1/47	47	1855	Services (Overhead & Underground)	$ 1,602,341	$ 16,000		$ 1,618,341	-$ 1,282,760	-$ 34,143		-$ 1,316,902	$ 301,438
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 510,059	-$ 11,699		-$ 521,758	$ 72,572
47	47	1860	Meters (Smart Meters)	$ 26,653	$ 10,000		$ 36,653	-$ 3,506	-$ 2,110		-$ 5,616	$ 31,037
N/A	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	13	1910	Leasehold Improvements	$ 116,088	$ 10,000		$ 126,088	-$ 5,804	-$ 12,164		-$ 17,969	$ 108,119
8	8	1915	Office Furniture & Equipment (10 years)	$ 52,446			$ 52,446	-$ 31,922	-$ 2,160		-$ 34,082	$ 18,364
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 102,979	$ 3,000		$ 105,979	-$ 95,435	-$ 3,112		-$ 98,547	$ 7,432
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment	$ 1,021,118			$ 1,021,118	-$ 940,392	-$ 51,814		-$ 992,206	$ 28,912
8	8	1935	Stores Equipment	$ 5,290			$ 5,290	-$ 3,646	-$ 173		-$ 3,819	$ 1,472
8	8	1940	Tools, Shop & Garage Equipment	$ 187,479	$ 7,500		$ 194,979	-$ 184,649	-$ 1,555		-$ 186,205	$ 8,774
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - O/H Conductor	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - Poles	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - Transformers	$ -			$ -	$ -			$ -	$ -
		2440	Deferred Revenue[5]	-$ 42,866	-$ 20,000		-$ 62,866	$ 2,850	$ 2,165		$ 5,015	-$ 57,851
							$ -				$ -	$ -
			Sub-Total	**$ 14,852,702**	**$ 547,500**	**-$ 157,538**	**$ 15,242,665**	**-$ 10,174,170**	**- 416,915**	**$ 85,588**	-$ 10,505,498	**$ 4,737,167**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
			Total PP&E	**$ 14,852,702**	**$ 547,500**	**-$ 157,538**	**$ 15,242,665**	**############**	**-$ 416,915**	**$ 85,588**	**-$ 10,505,498**	**$ 4,737,167**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 416,915.2**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 416,915

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP — Old CGAAP
Year: 2017

RHI CCA Class	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	12	1611	Computer Software (Formally known as Account 1925)	$ 160,121			$ 160,121	-$ 132,530	-$ 7,883		-$ 140,413	$ 19,708
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 31,301			$ 31,301	-$ 19,923	-$ 696		-$ 20,620	$ 10,682
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings	$ 44,297			$ 44,297	-$ 19,202	-$ 781		-$ 19,983	$ 24,314
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Distribution Station Equipment <50 kV	$ 1,288,197	$ 300,000		$ 1,588,197	-$ 862,201	-$ 38,386		-$ 900,588	$ 687,609
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 3,076,344	$ 190,000		$ 3,266,344	-$ 1,649,387	-$ 95,300		-$ 1,744,687	$ 1,521,658
1/47	47	1835	Overhead Conductors & Devices	$ 4,302,382	$ 85,000		$ 4,387,382	-$ 3,022,868	-$ 103,311		-$ 3,126,178	$ 1,261,204
1/47	47	1840	Underground Conduit	$ 85,105			$ 85,105	-$ 33,039	-$ 3,195		-$ 36,234	$ 48,871
1/47	47	1845	Underground Conductors & Devices	$ 615,496	$ 10,000		$ 625,496	-$ 245,769	-$ 22,853		-$ 268,622	$ 356,874
1/47	47	1850	Line Transformers	$ 1,924,168	$ 40,000		$ 1,964,168	-$ 1,348,490	-$ 39,616		-$ 1,388,106	$ 576,062
1/47	47	1855	Services (Overhead & Underground)	$ 1,618,341	$ 15,000		$ 1,633,341	-$ 1,316,902	-$ 31,925		-$ 1,348,827	$ 284,514
1/47	47	1860	Meters	$ 36,583			$ 36,583	-$ 18,966	-$ 1,463		-$ 20,429	$ 16,154
47	47	1860	Meters (Smart Meters)	$ 36,653	$ 10,000		$ 46,653	-$ 5,616	-$ 2,777		-$ 8,393	$ 38,260
47	47	1860	Smart Meter - Additions	$ 558,932			$ 558,932	-$ 243,916	-$ 37,262		-$ 281,178	$ 277,754
N/A	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	13	1910	Leasehold Improvements	$ 126,088			$ 126,088	-$ 17,969	-$ 12,720		-$ 30,689	$ 95,399
8	8	1915	Office Furniture & Equipment (10 years)	$ 52,446			$ 52,446	-$ 34,082	-$ 2,160		-$ 36,242	$ 16,203
8	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 105,979	$ 3,000		$ 108,979	-$ 98,547	-$ 3,042		-$ 101,589	$ 7,390
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment	$ 1,021,118			$ 1,021,118	-$ 992,206	-$ 14,601		-$ 1,006,807	$ 14,311
8	8	1935	Stores Equipment	$ 5,290			$ 5,290	-$ 3,819	-$ 173		-$ 3,992	$ 1,298
8	8	1940	Tools, Shop & Garage Equipment	$ 194,979	$ 7,500		$ 202,479	-$ 186,205	-$ 2,305		-$ 188,510	$ 13,969
8	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	47	1980	System Supervisor Equipment	$ -	$ 100,000		$ 100,000	$ -	-$ 2,500		-$ 2,500	$ 97,500
47	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - O/H Conductor	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - Poles	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - Transformers	$ -			$ -	$ -			$ -	$ -
		2440	Deferred Revenue[5]	-$ 62,866	-$ 20,000		-$ 82,866	$ 5,015	$ 2,965		$ 7,980	-$ 74,886
							$ -				$ -	$ -
			Sub-Total	**$ 15,243,851**	**$ 740,500**	**$ -**	**$ 15,984,351**	**-$ 10,246,622**	**- 419,984**	**$ -**	-$ 10,666,606	**$ 5,317,745**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
			Total PP&E	**$ 15,243,851**	**$ 740,500**	**$ -**	**$ 15,984,351**	**############**	**-$ 419,984**	**$ -**	**-$ 10,666,606**	**$ 5,317,745**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 419,983.6**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 419,984

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP New CGAAP
Year 2014

RHI	OEB			Cost				Accumulated Depreciation				
CCA Class	**CCA Class**	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance with ADJ**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705			$ 120,705	-$ 118,771	-$ 1,289		-$ 120,060	$ 644
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981			$ 23,981	-$ 18,353	-$ 390		-$ 18,744	$ 5,237
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings - Brick	$ 157,538			$ 157,538	-$ 79,796	-$ 2,896		-$ 82,692	$ 74,846
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 12,706	-$ 781		-$ 13,487	$ 26,658
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 4,152			-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Transmission Lines	$ 9,092			$ 9,092	-$ 9,092			-$ 9,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 5,956	-$ 163		-$ 6,119	$ 3,744
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,068			$ 114,068	-$ 68,637	-$ 1,637		-$ 70,274	$ 43,793
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 63,436	-$ 1,363		-$ 64,799	$ 40,881
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 23,105			$ 23,105	-$ 9,495	-$ 567		-$ 10,062	$ 13,043
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrics Equipment	$ 14,283			$ 14,283	-$ 5,870	-$ 351		-$ 6,220	$ 8,063
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 70,435	-$ 4,207		-$ 74,641	$ 96,757
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 48,004	-$ 1,926		-$ 49,929	$ 69,321
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 2,031	-$ 99		-$ 2,129	$ 2,272
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 119,855	-$ 4,252		-$ 124,107	$ 139,249
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 42,592	-$ 1,859		-$ 44,451	$ 48,342
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,221	-$ 10		-$ 8,231	$ 223
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,439			$ 1,439	-$ 1,399	-$ 2		-$ 1,401	$ 38
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrics Equip	$ 4,265			$ 4,265	-$ 4,148	-$ 5		-$ 4,153	$ 112
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,477	-$ 56		-$ 47,533	$ 1,285
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,971			$ 35,971	-$ 34,983	-$ 42		-$ 35,025	$ 946
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 17,193	-$ 207		-$ 17,400	$ 4,767
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,355	-$ 28		-$ 2,384	$ 653
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrics Equip	$ 15,084			$ 15,084	-$ 11,699	-$ 141		-$ 11,840	$ 3,244
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 102,845	-$ 1,240		-$ 104,085	$ 28,514
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 89,074			$ 89,074	-$ 69,087	-$ 833		-$ 69,920	$ 19,154
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,571,043	$ 127,370	-$ 30,939	$ 2,667,474	-$ 1,332,136	-$ 40,717	$ 22,622	-$ 1,350,231	$ 1,317,243
1/47	47	1835	Overhead Conductors & Devices	$ 4,028,207	$ 114,905	-$ 15,028	$ 4,128,084	-$ 2,615,565	-$ 34,121	$ 9,467	-$ 2,640,219	$ 1,487,865
1/47	47	1840	Underground Conduit	$ 67,591	$ 10,114		$ 77,705	-$ 22,784	-$ 1,237		-$ 24,020	$ 53,685
1/47	47	1845	Underground Conductors & Devices	$ 498,180	$ 24,717		$ 522,896	-$ 175,964	-$ 8,460		-$ 184,424	$ 338,472
1/47	47	1850	Line Transformers	$ 1,663,239	$ 28,523	-$ 5,446	$ 1,686,316	-$ 1,218,657	-$ 19,035	$ 5,218	-$ 1,232,474	$ 453,842
1/47	47	1855	Sevices - Overhead	$ 1,423,773	$ 9,808	-$ 8,380	$ 1,425,201	-$ 1,114,248	-$ 11,504	$ 6,648	-$ 1,119,105	$ 306,097
1/47	47	1855	Services - Underground	$ 145,233	$ 4,739		$ 149,972	-$ 62,812	-$ 3,330		-$ 66,142	$ 83,830
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 483,895	-$ 13,368		-$ 497,262	$ 97,067
47	47	1860	Meters (Smart Meters)	$ 14,491	$ 10,278		$ 24,769	-$ 483	-$ 1,309		-$ 1,792	$ 22,977
	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
	13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	-$ 30,841			-$ 30,841	$ -
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 95,624	$ 5,437		$ 101,061	-$ 89,596	-$ 2,774		-$ 92,370	$ 8,691
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 735,621	-$ 37,512		-$ 773,133	$ 87,588
10	10	1930	Transportation Equipment <3 ton	$ 138,653	$ 21,744		$ 160,397	-$ 103,318	-$ 12,127		-$ 115,446	$ 44,952
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559			-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 181,663	-$ 1,570		-$ 183,234	$ 3,620
	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	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - O/H Conductor	-$ 2,000			-$ 2,000	$ 17	$ 33		$ 50	-$ 1,950
		1995	Contributions & Grants - Poles	-$ 15,100			-$ 15,100	$ 168	$ 336		$ 503	-$ 14,597
		1995	Contributions & Grants - Transformers	-$ 7,500			-$ 7,500	$ 94	$ 188		$ 281	-$ 7,219
		2440	Deferred Revenue[5]	$ -				$ -			$ -	
							$ -				$ -	$ -
			Sub-Total	**$ 13,955,350**	**$ 357,636**	**-$ 59,793**	**$ 14,253,192**	**-$ 9,149,451**	**-$ 210,850**	**$ 43,955**	**-$ 9,316,345**	**$ 4,936,847**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as				$ -				$ -	$ -
			Total PP&E	**$ 13,955,350**	**$ 357,636**	**-$ 59,793**	**$ 14,253,192**	**-$ 9,149,451**	**-$ 210,850**	**$ 43,955**	**-$ 9,316,345**	**$ 4,936,847**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 210,850**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 210,850

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

2

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP New CGAAP
Year 2015

RHI	OEB			Cost				Accumulated Depreciation					
CCA Class	**CCA Class**	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Adj**	**Closing Balance**	**Net Book Value**
12	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705	$ 39,417		$ 160,121	-$ 120,060	-$ 4,586			-$ 124,646	$ 35,475
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981	$ 4,321		$ 28,301	-$ 18,744	-$ 498			-$ 19,242	$ 9,059
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -				$ -	$ 22,895
1	47	1808	Buildings - Brick	$ 157,538			$ 157,538	-$ 82,692	-$ 2,896			-$ 85,588	$ 71,950
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 13,487	-$ 781			-$ 14,268	$ 25,877
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 4,152				-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -				$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -				$ -	$ -
1/47	47	1820	Transmission Lines	$ 9,092			$ 9,092	-$ 9,092				-$ 9,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 6,119	-$ 156		$ 7	-$ 6,269	$ 3,595
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,068			$ 114,068	-$ 70,274	-$ 1,580		$ 57	-$ 71,798	$ 42,270
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 64,799	-$ 1,320		$ 42	-$ 66,076	$ 39,603
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 23,105			$ 23,105	-$ 10,062	-$ 544		$ 23	-$ 10,583	$ 12,522
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrics Equipment	$ 14,283			$ 14,283	-$ 6,220	-$ 337		$ 14	-$ 6,543	$ 7,741
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 74,641	-$ 4,039		$ 168	-$ 78,512	$ 92,887
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 49,929	-$ 1,875		$ 51	-$ 51,754	$ 67,497
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 2,129	-$ 95		$ 4	-$ 2,220	$ 2,180
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 124,107	-$ 4,130		$ 123	-$ 128,113	$ 135,242
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 44,451	-$ 1,793		$ 67	-$ 46,178	$ 46,616
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,231	-$ 9		$ 1	-$ 8,239	$ 214
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,439			$ 1,439	-$ 1,401	-$ 2		$ 1	-$ 1,402	$ 37
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrics Equip	$ 4,265			$ 4,265	-$ 4,153	-$ 5			-$ 4,158	$ 108
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,533	-$ 54		$ 2	-$ 47,585	$ 1,234
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,971			$ 35,971	-$ 35,025	-$ 40		$ 2	-$ 35,063	$ 909
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 17,400	-$ 199		$ 8	-$ 17,591	$ 4,576
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,384	-$ 27		$ 1	-$ 2,410	$ 627
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrics Equip	$ 15,084			$ 15,084	-$ 11,840	-$ 135		$ 6	-$ 11,970	$ 3,114
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 104,085	-$ 1,190		$ 50	-$ 105,225	$ 27,373
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 89,074			$ 89,074	-$ 69,920	-$ 799		$ 33	-$ 70,686	$ 18,388
	47	1825	Storage Battery Equipment	$ -			$ -	$ -				$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,667,474	$ 182,603	-$ 8,564	$ 2,841,513	-$ 1,350,231	-$ 42,349	$ 340	$ 1,770	-$ 1,390,470	$ 1,451,043
1/47	47	1835	Overhead Conductors & Devices	$ 4,128,084	$ 68,146	-$ 207	$ 4,196,023	-$ 2,640,219	-$ 35,320	$ 9	$ 87	-$ 2,675,442	$ 1,520,580
1/47	47	1840	Underground Conduit	$ 77,705			$ 77,705	-$ 24,020	-$ 1,311		$ 25	-$ 25,306	$ 52,399
1/47	47	1845	Underground Conductors & Devices	$ 522,896			$ 522,896	-$ 184,424	-$ 8,496		$ 206	-$ 192,714	$ 330,182
1/47	47	1850	Line Transformers	$ 1,686,316	$ 62,246	-$ 1,364	$ 1,747,198	-$ 1,232,474	-$ 18,807	$ 90	$ 1,301	-$ 1,249,890	$ 497,309
1/47	47	1855	Sevices - Overhead	$ 1,425,201	$ 3,839	-$ 815	$ 1,428,225	-$ 1,119,105	-$ 11,174	$ 30	$ 478	-$ 1,129,771	$ 298,454
1/47	47	1855	Services - Underground	$ 149,972	$ 6,568	-$ 656	$ 155,884	-$ 66,142	-$ 3,268	$ 30	$ 171	-$ 69,209	$ 86,675
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 497,262	-$ 12,797			-$ 510,059	$ 84,270
47	47	1860	Meters (Smart Meters)	$ 24,769	$ 1,884		$ 26,653	-$ 1,792	-$ 1,714			-$ 3,506	$ 23,147
	N/A	1905	Land	$ -			$ -	$ -				$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -				$ -	$ -
	13	1910	Leasehold Improvements	$ -	$ 116,088		$ 116,088	$ -	-$ 5,804			-$ 5,804	$ 110,284
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841	$ 21,604		$ 52,446	-$ 30,841	-$ 1,080			-$ 31,922	$ 20,524
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -				$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 101,061	$ 1,918		$ 102,979	-$ 92,370	-$ 3,065			-$ 95,435	$ 7,544
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -				$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -				$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 773,133	-$ 37,512			-$ 810,645	$ 50,076
10	10	1930	Transportation Equipment <3 ton	$ 160,397			$ 160,397	-$ 115,446	-$ 14,302			-$ 129,747	$ 30,650
8	8	1935	Stores Equipment	$ 3,559	$ 1,731		$ 5,290	-$ 3,559	-$ 87			-$ 3,646	$ 1,645
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854	$ 625		$ 187,479	-$ 183,234	-$ 1,416			-$ 184,649	$ 2,829
	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	$ -			$ -	$ -				$ -	$ -
		2440	Contributions & Grants - O/H Conductor	-$ 2,000			-$ 2,000	$ 50	$ 33			$ 83	-$ 1,917
		2440	Contributions & Grants - Poles	-$ 15,100	-$ 4,452		-$ 19,552	$ 503	$ 385			$ 888	-$ 18,663
		2440	Contributions & Grants - Transformers	-$ 7,500	-$ 11,930		-$ 19,430	$ 281	$ 337			$ 618	-$ 18,812
		2440	Contributions & Grants - Meters	$ -	-$ 1,884		-$ 1,884	$ -	$ 63			$ 63	-$ 1,821
		2440	Deferred Revenue[5]	$ -				$ -				$ -	
							$ -					$ -	$ -
			Sub-Total	**$14,253,192**	**$ 492,724**	**-$ 11,606**	**$14,734,310**	**-$ 9,316,345**	**-$ 224,774**	**$ 500**	**$ 4,695**	**-$ 9,535,925**	**$ 5,198,385**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as				$ -					$ -	$ -
			Total PP&E	**$14,253,192**	**$ 492,724**	**-$ 11,606**	**$14,734,310**	**-$ 9,316,345**	**-$ 224,774**	**$ 500**	**$ 4,695**	**-$ 9,535,925**	**$ 5,198,385**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
			Total						**-$ 224,774**				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 224,774

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS MIFRS
Year 2014

RHI	OEB			Cost				Accumulated Depreciation				
CCA Class	**CCA Class**	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance with ADJ**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705			$ 120,705	-$ 118,771	-$ 1,289		-$ 120,060	$ 644
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981			$ 23,981	-$ 18,353	-$ 390		-$ 18,744	$ 5,237
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings - Brick	$ 157,538			$ 157,538	-$ 79,796	-$ 2,896		-$ 82,692	$ 74,846
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 12,706	-$ 781		-$ 13,487	$ 26,658
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 4,152			-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Transmission Lines	$ 9,092			$ 9,092	-$ 9,092			-$ 9,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 5,956	-$ 163		-$ 6,119	$ 3,744
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,068			$ 114,068	-$ 68,637	-$ 1,637		-$ 70,274	$ 43,793
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 63,436	-$ 1,363		-$ 64,799	$ 40,881
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 23,105			$ 23,105	-$ 9,495	-$ 567		-$ 10,062	$ 13,043
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrics Equipment	$ 14,283			$ 14,283	-$ 5,870	-$ 351		-$ 6,220	$ 8,063
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 70,435	-$ 4,207		-$ 74,641	$ 96,757
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 48,004	-$ 1,926		-$ 49,929	$ 69,321
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 2,031	-$ 99		-$ 2,129	$ 2,272
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 119,855	-$ 4,252		-$ 124,107	$ 139,249
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 42,592	-$ 1,859		-$ 44,451	$ 48,342
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,221	-$ 10		-$ 8,231	$ 223
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,439			$ 1,439	-$ 1,399	-$ 2		-$ 1,401	$ 38
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrics Equip	$ 4,265			$ 4,265	-$ 4,148	-$ 5		-$ 4,153	$ 112
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,477	-$ 56		-$ 47,533	$ 1,285
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,971			$ 35,971	-$ 34,983	-$ 42		-$ 35,025	$ 946
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 17,193	-$ 207		-$ 17,400	$ 4,767
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,355	-$ 28		-$ 2,384	$ 653
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrics Equip	$ 15,084			$ 15,084	-$ 11,699	-$ 141		-$ 11,840	$ 3,244
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 102,845	-$ 1,240		-$ 104,085	$ 28,514
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 89,074			$ 89,074	-$ 69,087	-$ 833		-$ 69,920	$ 19,154
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,571,043	$ 127,370	-$ 30,939	$ 2,667,474	-$ 1,332,136	-$ 40,717	$ 22,622	-$ 1,350,231	$ 1,317,243
1/47	47	1835	Overhead Conductors & Devices	$ 4,028,207	$ 114,905	-$ 15,028	$ 4,128,084	-$ 2,615,565	-$ 34,121	$ 9,467	-$ 2,640,219	$ 1,487,865
1/47	47	1840	Underground Conduit	$ 67,591	$ 10,114		$ 77,705	-$ 22,784	-$ 1,237		-$ 24,020	$ 53,685
1/47	47	1845	Underground Conductors & Devices	$ 498,180	$ 24,717		$ 522,896	-$ 175,964	-$ 8,460		-$ 184,424	$ 338,472
1/47	47	1850	Line Transformers	$ 1,663,239	$ 28,523	-$ 5,446	$ 1,686,316	-$ 1,218,657	-$ 19,035	$ 5,218	-$ 1,232,474	$ 453,842
1/47	47	1855	Sevices - Overhead	$ 1,423,773	$ 9,808	-$ 8,380	$ 1,425,201	-$ 1,114,248	-$ 11,504	$ 6,648	-$ 1,119,105	$ 306,097
1/47	47	1855	Services - Underground	$ 145,233	$ 4,739		$ 149,972	-$ 62,812	-$ 3,330		-$ 66,142	$ 83,830
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 483,895	-$ 13,368		-$ 497,262	$ 97,067
47	47	1860	Meters (Smart Meters)	$ 14,491	$ 10,278		$ 24,769	-$ 483	-$ 1,309		-$ 1,792	$ 22,977
	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
	13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	-$ 30,841			-$ 30,841	$ -
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 95,624	$ 5,437		$ 101,061	-$ 89,596	-$ 2,774		-$ 92,370	$ 8,691
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 735,621	-$ 37,512		-$ 773,133	$ 87,588
10	10	1930	Transportation Equipment <3 ton	$ 138,653	$ 21,744		$ 160,397	-$ 103,318	-$ 12,127		-$ 115,446	$ 44,952
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559			-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854			$ 186,854	-$ 181,663	-$ 1,570		-$ 183,234	$ 3,620
	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	$ -			$ -	$ -			$ -	$ -
		1995	Contributions & Grants - O/H Conductor	-$ 2,000			-$ 2,000	$ 17	$ 33		$ 50	-$ 1,950
		1995	Contributions & Grants - Poles	-$ 15,100			-$ 15,100	$ 168	$ 336		$ 503	-$ 14,597
		1995	Contributions & Grants - Transformers	-$ 7,500			-$ 7,500	$ 94	$ 188		$ 281	-$ 7,219
		2440	Deferred Revenue[5]	$ -				$ -			$ -	
							$ -				$ -	$ -
			Sub-Total	**$ 13,955,350**	**$ 357,636**	**-$ 59,793**	**$ 14,253,192**	**-$ 9,149,451**	**-$ 210,850**	**$ 43,955**	**-$ 9,316,345**	**$ 4,936,847**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as				$ -				$ -	$ -
			Total PP&E	**$ 13,955,350**	**$ 357,636**	**-$ 59,793**	**$ 14,253,192**	**-$ 9,149,451**	**-$ 210,850**	**$ 43,955**	**-$ 9,316,345**	**$ 4,936,847**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 210,850**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 210,850

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2015

RHI CCA Class	OEB 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: Adj	Accumulated Depreciation: Closing Balance	Net Book Value
12	12	1611	Computer Software (Formally known as Account 1925)	$ 120,705	$ 39,417		$ 160,121	-$ 120,060	-$ 4,586			-$ 124,646	$ 35,475
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,981	$ 4,321		$ 28,301	-$ 18,744	-$ 498			-$ 19,242	$ 9,059
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -				$ -	$ 22,895
1	47	1808	Buildings - Brick	$ 157,538			$ 157,538	-$ 82,692	-$ 2,896			-$ 85,588	$ 71,950
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 13,487	-$ 781			-$ 14,268	$ 25,877
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 4,152				-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -				$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -				$ -	$ -
1/47	47	1820	Transmission Lines	$ 9,092			$ 9,092	-$ 9,092				-$ 9,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 6,119	-$ 156		$ 7	-$ 6,269	$ 3,595
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,068			$ 114,068	-$ 70,274	-$ 1,580		$ 57	-$ 71,798	$ 42,270
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 64,799	-$ 1,320		$ 42	-$ 66,076	$ 39,603
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 23,105			$ 23,105	-$ 10,062	-$ 544		$ 23	-$ 10,583	$ 12,522
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrics Equipment	$ 14,283			$ 14,283	-$ 6,220	-$ 337		$ 14	-$ 6,543	$ 7,741
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 74,641	-$ 4,039		$ 168	-$ 78,512	$ 92,887
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 49,929	-$ 1,875		$ 51	-$ 51,754	$ 67,497
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 2,129	-$ 95		$ 4	-$ 2,220	$ 2,180
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 124,107	-$ 4,130		$ 123	-$ 128,113	$ 135,242
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 44,451	-$ 1,793		$ 67	-$ 46,178	$ 46,616
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,231	-$ 9		$ 1	-$ 8,239	$ 214
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,439			$ 1,439	-$ 1,401	-$ 2		$ 1	-$ 1,402	$ 37
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrics Equip	$ 4,265			$ 4,265	-$ 4,153	-$ 5			-$ 4,158	$ 108
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,533	-$ 54		$ 2	-$ 47,585	$ 1,234
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,971			$ 35,971	-$ 35,025	-$ 40		$ 2	-$ 35,063	$ 909
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 17,400	-$ 199		$ 8	-$ 17,591	$ 4,576
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,384	-$ 27		$ 1	-$ 2,410	$ 627
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrics Equip	$ 15,084			$ 15,084	-$ 11,840	-$ 135		$ 6	-$ 11,970	$ 3,114
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 104,085	-$ 1,190		$ 50	-$ 105,225	$ 27,373
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 89,074			$ 89,074	-$ 69,920	-$ 799		$ 33	-$ 70,686	$ 18,388
	47	1825	Storage Battery Equipment	$ -			$ -	$ -				$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,667,474	$ 182,603	-$ 8,564	$ 2,841,513	-$ 1,350,231	-$ 42,349	$ 340	$ 1,770	-$ 1,390,470	$ 1,451,043
1/47	47	1835	Overhead Conductors & Devices	$ 4,128,084	$ 68,146	-$ 207	$ 4,196,023	-$ 2,640,219	-$ 35,320	$ 9	$ 87	-$ 2,675,442	$ 1,520,580
1/47	47	1840	Underground Conduit	$ 77,705			$ 77,705	-$ 24,020	-$ 1,311		$ 25	-$ 25,306	$ 52,399
1/47	47	1845	Underground Conductors & Devices	$ 522,896			$ 522,896	-$ 184,424	-$ 8,496		$ 206	-$ 192,714	$ 330,182
1/47	47	1850	Line Transformers	$ 1,686,316	$ 62,246	-$ 1,364	$ 1,747,198	-$ 1,232,474	-$ 18,807	$ 90	$ 1,301	-$ 1,249,890	$ 497,309
1/47	47	1855	Sevices - Overhead	$ 1,425,201	$ 3,839	-$ 815	$ 1,428,225	-$ 1,119,105	-$ 11,174	$ 30	$ 478	-$ 1,129,771	$ 298,454
1/47	47	1855	Services - Underground	$ 149,972	$ 6,568	-$ 656	$ 155,884	-$ 66,142	-$ 3,268	$ 30	$ 171	-$ 69,209	$ 86,675
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 497,262	-$ 12,797			-$ 510,059	$ 84,270
47	47	1860	Meters (Smart Meters)	$ 24,769	$ 1,884		$ 26,653	-$ 1,792	-$ 1,714			-$ 3,506	$ 23,147
	N/A	1905	Land	$ -			$ -	$ -				$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -				$ -	$ -
	13	1910	Leasehold Improvements	$ -	$ 116,088		$ 116,088	$ -	-$ 5,804			-$ 5,804	$ 110,284
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841	$ 21,604		$ 52,446	-$ 30,841	-$ 1,080			-$ 31,922	$ 20,524
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -				$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 101,061	$ 1,918		$ 102,979	-$ 92,370	-$ 3,065			-$ 95,435	$ 7,544
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -				$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -				$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 773,133	-$ 37,512			-$ 810,645	$ 50,076
10	10	1930	Transportation Equipment <3 ton	$ 160,397			$ 160,397	-$ 115,446	-$ 14,302			-$ 129,747	$ 30,650
8	8	1935	Stores Equipment	$ 3,559	$ 1,731		$ 5,290	-$ 3,559	-$ 87			-$ 3,646	$ 1,645
8	8	1940	Tools, Shop & Garage Equipment	$ 186,854	$ 625		$ 187,479	-$ 183,234	-$ 1,416			-$ 184,649	$ 2,829
	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	$ -			$ -	$ -				$ -	$ -
		2440	Deferred Revenue - O/H Conductor	-$ 2,000			-$ 2,000	$ 50	$ 33			$ 83	-$ 1,917
		2440	Deferred Revenue - Poles	-$ 15,100	-$ 4,452		-$ 19,552	$ 503	$ 385			$ 888	-$ 18,663
		2440	Deferred Revenue - Transformers	-$ 7,500	-$ 11,930		-$ 19,430	$ 281	$ 337			$ 618	-$ 18,812
		2440	Deferred Revenue - Meters	$ -	-$ 1,884		-$ 1,884	$ -	$ 63			$ 63	-$ 1,821
		2440	Deferred Revenue[5]	$ -				$ -				$ -	
							$ -					$ -	$ -
			Sub-Total	**$ 14,253,192**	**$ 492,724**	**-$ 11,606**	**$ 14,734,310**	**-$ 9,316,345**	**-$ 224,774**	**$ 500**	**$ 4,695**	**-$ 9,535,925**	**$ 5,198,385**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as				$ -					$ -	$ -
			Total PP&E	**$ 14,253,192**	**$ 492,724**	**-$ 11,606**	**$ 14,734,310**	**-$ 9,316,345**	**-$ 224,774**	**$ 500**	**$ 4,695**	**-$ 9,535,925**	**$ 5,198,385**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
			Total						**-$ 224,774**				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 224,774

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	MIFRS
Year	2016

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 160,121			$ 160,121	-$ 124,646	-$ 7,883		-$ 132,530	$ 27,592
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 28,301	$ 3,000		$ 31,301	-$ 19,242	-$ 681		-$ 19,923	$ 11,378
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings - Brick	$ 157,538		-$ 157,538	$ -	-$ 85,588		$ 85,588	$ -	$ -
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 14,268	-$ 781		-$ 15,050	$ 25,095
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 4,152			-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Transmission Lines	$ 9,092			$ 9,092	-$ 9,092			-$ 9,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 6,269	-$ 156		-$ 6,425	$ 3,438
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,068			$ 114,068	-$ 71,798	-$ 1,580		-$ 73,378	$ 40,690
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 66,076	-$ 1,320		-$ 67,396	$ 38,283
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 23,105			$ 23,105	-$ 10,583	-$ 544		-$ 11,128	$ 11,977
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrics Equipment	$ 14,283			$ 14,283	-$ 6,543	-$ 337		-$ 6,879	$ 7,404
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 78,512	-$ 4,039		-$ 82,551	$ 88,848
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 51,754	-$ 1,875		-$ 53,628	$ 65,622
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 2,220	-$ 95		-$ 2,315	$ 2,086
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 128,113	-$ 4,130		-$ 132,243	$ 131,113
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 46,178	-$ 1,793		-$ 47,971	$ 44,823
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,239	-$ 9		-$ 8,249	$ 205
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,439			$ 1,439	-$ 1,402	-$ 2		-$ 1,403	$ 35
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrics Equip	$ 4,265			$ 4,265	-$ 4,158	-$ 5		-$ 4,162	$ 103
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,585	-$ 54		-$ 47,638	$ 1,180
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,971			$ 35,971	-$ 35,063	-$ 40		-$ 35,102	$ 869
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 17,591	-$ 199		-$ 17,790	$ 4,377
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,410	-$ 27		-$ 2,437	$ 599
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrics Equip	$ 15,084			$ 15,084	-$ 11,970	-$ 135		-$ 12,105	$ 2,979
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 105,225	-$ 1,190		-$ 106,415	$ 26,183
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 89,074			$ 89,074	-$ 70,686	-$ 799		-$ 71,486	$ 17,588
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,841,513	$ 172,000		$ 3,013,513	-$ 1,390,470	-$ 46,289		-$ 1,436,759	$ 1,576,754
1/47	47	1835	Overhead Conductors & Devices	$ 4,196,023	$ 83,000		$ 4,279,023	-$ 2,675,442	-$ 36,580		-$ 2,712,022	$ 1,567,001
1/47	47	1840	Underground Conduit	$ 77,705	$ 7,400		$ 85,105	-$ 25,306	-$ 1,385		-$ 26,690	$ 58,415
1/47	47	1845	Underground Conductors & Devices	$ 522,896	$ 92,600		$ 615,496	-$ 192,714	-$ 9,422		-$ 202,136	$ 413,360
1/47	47	1850	Line Transformers	$ 1,747,198	$ 163,000		$ 1,910,198	-$ 1,249,890	-$ 21,623		-$ 1,271,513	$ 638,686
1/47	47	1855	Sevices - Overhead	$ 1,428,225	$ 11,000		$ 1,439,225	-$ 1,129,771	-$ 11,298		-$ 1,141,069	$ 298,156
1/47	47	1855	Services - Underground	$ 155,884	$ 5,000		$ 160,884	-$ 69,209	-$ 3,412		-$ 72,621	$ 88,263
1/47	47	1860	Meters	$ 594,329			$ 594,329	-$ 510,059	-$ 11,699		-$ 521,758	$ 72,572
47	47	1860	Meters (Smart Meters)	$ 26,653	$ 10,000		$ 36,653	-$ 3,506	-$ 2,110		-$ 5,616	$ 31,037
	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
	13	1910	Leasehold Improvements	$ 116,088	$ 10,000		$ 126,088	-$ 5,804	-$ 12,164		-$ 17,969	$ 108,119
8	8	1915	Office Furniture & Equipment (10 years)	$ 52,446			$ 52,446	-$ 31,922	-$ 2,160		-$ 34,082	$ 18,364
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 102,979	$ 3,000		$ 105,979	-$ 95,435	-$ 3,112		-$ 98,547	$ 7,432
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 810,645	-$ 37,512		-$ 848,157	$ 12,564
10	10	1930	Transportation Equipment <3 ton	$ 160,397			$ 160,397	-$ 129,747	-$ 14,302		-$ 144,049	$ 16,348
8	8	1935	Stores Equipment	$ 5,290			$ 5,290	-$ 3,646	-$ 173		-$ 3,819	$ 1,472
8	8	1940	Tools, Shop & Garage Equipment	$ 187,479	$ 7,500		$ 194,979	-$ 184,649	-$ 1,555		-$ 186,205	$ 8,774
	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	$ -			$ -	$ -			$ -	$ -
		2440	Deferred Revenue - O/H Conductor	-$ 2,000			-$ 2,000	$ 83	$ 33		$ 116	-$ 1,884
		2440	Deferred Revenue - Poles	-$ 19,552			-$ 19,552	$ 888	$ 434		$ 1,323	-$ 18,229
		2440	Deferred Revenue - Transformers	-$ 19,430	-$ 20,000		-$ 39,430	$ 618	$ 736		$ 1,354	-$ 38,076
		2440	Deferred Revenue - Meters	-$ 1,884			-$ 1,884	$ 63	$ 126		$ 188	-$ 1,696
		2440	Deferred Revenue[5]	$ -				$ -			$ -	
							$ -				$ -	$ -
			Sub-Total	**$ 14,734,310**	**$ 547,500**	**-$ 157,538**	**$ 15,124,273**	**-$ 9,535,925**	**-$ 241,142**	**$ 85,588**	**-$ 9,691,480**	**$ 5,432,793**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as				$ -				$ -	$ -
			Total PP&E	**$ 14,734,310**	**$ 547,500**	**-$ 157,538**	**$ 15,124,273**	**-$ 9,535,925**	**-$ 241,142**	**$ 85,588**	**-$ 9,691,480**	**$ 5,432,793**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 241,142**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 241,142

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2017

RHI CCA Class	OEB 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	12	1611	Computer Software (Formally known as Account 1925)	$ 160,121			$ 160,121	-$ 132,530	-$ 7,884		-$ 140,414	$ 19,708
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 31,301			$ 31,301	-$ 19,923	-$ 696		-$ 20,620	$ 10,682
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -			$ -	$ 22,895
1	47	1808	Buildings - Brick	$ -			$ -	$ -			$ -	$ -
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 15,050	-$ 782		-$ 15,831	$ 24,314
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 4,152			-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1/47	47	1820	Transmission Lines	$ 9,092			$ 9,092	-$ 9,092			-$ 9,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 6,425	-$ 156		-$ 6,581	$ 3,283
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,068	$ 300,000		$ 414,068	-$ 73,378	-$ 5,330		-$ 78,708	$ 335,360
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 67,396	-$ 1,320		-$ 68,716	$ 36,963
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 23,105			$ 23,105	-$ 11,128	-$ 544		-$ 11,672	$ 11,433
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrics Equipment	$ 14,283			$ 14,283	-$ 6,879	-$ 337		-$ 7,216	$ 7,067
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 82,551	-$ 4,039		-$ 86,589	$ 84,809
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 53,628	-$ 1,875		-$ 55,503	$ 63,748
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 2,315	-$ 95		-$ 2,410	$ 1,991
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 132,243	-$ 4,130		-$ 136,373	$ 126,983
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 47,971	-$ 1,793		-$ 49,764	$ 43,029
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,249	-$ 10		-$ 8,258	$ 195
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,439			$ 1,439	-$ 1,403	-$ 2		-$ 1,405	$ 34
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrics Equip	$ 4,265			$ 4,265	-$ 4,162	-$ 5		-$ 4,167	$ 98
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,638	-$ 54		-$ 47,692	$ 1,126
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,971			$ 35,971	-$ 35,102	-$ 39		-$ 35,141	$ 830
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 17,790	-$ 199		-$ 17,990	$ 4,178
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,437	-$ 27		-$ 2,465	$ 572
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrics Equip	$ 15,084			$ 15,084	-$ 12,105	-$ 135		-$ 12,240	$ 2,844
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 106,415	-$ 1,190		-$ 107,605	$ 24,994
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 89,074			$ 89,074	-$ 71,486	-$ 800		-$ 72,286	$ 16,788
	47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 3,013,513	$ 190,000		$ 3,203,513	-$ 1,436,759	-$ 50,311		-$ 1,487,070	$ 1,716,443
1/47	47	1835	Overhead Conductors & Devices	$ 4,279,023	$ 85,000		$ 4,364,023	-$ 2,712,022	-$ 37,979		-$ 2,750,001	$ 1,614,021
1/47	47	1840	Underground Conduit	$ 85,105			$ 85,105	-$ 26,690	-$ 1,458		-$ 28,148	$ 56,956
1/47	47	1845	Underground Conductors & Devices	$ 615,496	$ 10,000		$ 625,496	-$ 202,136	-$ 10,448		-$ 212,584	$ 412,913
1/47	47	1850	Line Transformers	$ 1,910,198	$ 40,000		$ 1,950,198	-$ 1,271,513	-$ 24,160		-$ 1,295,673	$ 654,525
1/47	47	1855	Sevices - Overhead	$ 1,439,225	$ 10,000		$ 1,449,225	-$ 1,141,069	-$ 11,473		-$ 1,152,542	$ 296,683
1/47	47	1855	Services - Underground	$ 160,884	$ 5,000		$ 165,884	-$ 72,621	-$ 3,538		-$ 76,159	$ 89,725
1/47	47	1860	Meters	$ 36,583			$ 36,583	-$ 18,966	-$ 1,463		-$ 20,429	$ 16,154
47	47	1860	Meters (Smart Meters)	$ 36,653	$ 10,000		$ 46,653	-$ 5,616	-$ 2,777		-$ 8,393	$ 38,260
47	47	1860	Smart Meter - additions	$ 558,932			$ 558,932	-$ 243,916	-$ 37,262		-$ 281,178	$ 277,754
	N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
	13	1910	Leasehold Improvements	$ 126,088			$ 126,088	-$ 17,969	-$ 12,720		-$ 30,689	$ 95,399
8	8	1915	Office Furniture & Equipment (10 years)	$ 52,446			$ 52,446	-$ 34,082	-$ 2,160		-$ 36,242	$ 16,203
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 105,979	$ 3,000		$ 108,979	-$ 98,547	-$ 3,042		-$ 101,589	$ 7,390
	45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
	45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 848,157	-$ 5,026		-$ 853,183	$ 7,538
10	10	1930	Transportation Equipment <3 ton	$ 160,397			$ 160,397	-$ 144,049	-$ 9,575		-$ 153,624	$ 6,773
8	8	1935	Stores Equipment	$ 5,290	$ 7,500		$ 12,790	-$ 3,819	-$ 173		-$ 3,992	$ 8,798
8	8	1940	Tools, Shop & Garage Equipment	$ 194,979			$ 194,979	-$ 186,205	-$ 2,305		-$ 188,510	$ 6,469
	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	$ -	$ 100,000		$ 100,000	$ -	-$ 2,500		-$ 2,500	$ 97,500
	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
	47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
	47	2440	Deferred Revenue - O/H Conductor	-$ 2,000			-$ 2,000	$ 116	$ 33		$ 149	-$ 1,851
	47	2440	Deferred Revenue - Poles	-$ 19,552			-$ 19,552	$ 1,323	$ 434		$ 1,757	-$ 17,794
	47	2440	Deferred Revenue - Transformers	-$ 39,430	-$ 20,000		-$ 59,430	$ 1,354	$ 1,236		$ 2,589	-$ 56,841
	47	2440	Deferred Revenue - Meters	-$ 1,884			-$ 1,884	$ 188	$ 126		$ 314	-$ 1,570
	47	2440	Deferred Revenue[5]	$ -				$ -			$ -	
							$ -				$ -	$ -
			Sub-Total	**$ 15,125,459**	**$ 740,500**	**$ -**	**$ 15,865,959**	**-$ 9,432,604**	**-$ 247,981**	**$ -**	**-$ 9,680,585**	**$ 6,185,374**
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
			Less Other Non Rate-Regulated Utility Assets (input as				$ -				$ -	$ -
			Total PP&E	**$ 15,125,459**	**$ 740,500**	**$ -**	**$ 15,865,959**	**-$ 9,432,604**	**-$ 247,981**	**$ -**	**-$ 9,680,585**	**$ 6,185,374**
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
			Total						**-$ 247,981**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 247,981

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

OLD CGAAP

Year			2010Old		2011Old		2012Old		2013Old		2014Old		2015 Old		2016 Old		2017 Old	
Add Smart Meters (added to open balance)																	558,932	1
																	- 557,746	2
Gross Assets	**Opening**		12,178,306		12,711,556		13,229,840		13,669,417		14,002,342		14,359,978		14,852,702		15,243,851	
	Add		533,251		518,284		439,577		332,925		357,636		492,724		547,500		740,500	
	Ret		-		-		-		-		-		-		- 157,538		-	
	Closing		12,711,556		13,229,840		13,669,417		14,002,342		14,359,978		14,852,702		15,242,665		15,984,351	

Year			2010Old		2011Old		2012Old		2013Old		2014Old		2015 Old		2016 Old		2017 Old	
Add Smart Meters (added to open balance)																	- 243,916	3
																	502,792	4
Accumulated Depreciation	**Opening**		- 7,819,389		- 8,216,880		- 8,613,345		- 8,999,572		- 9,380,382		- 9,770,596		- 10,174,170		- 10,246,622	
Adjust.									13,479	9								
	Add		- 397,490		- 396,465		- 386,227		- 394,289		- 390,215		- 403,574		- 416,915		- 419,984	
	Ret		-		-		-		-		-		-		85,588		-	
	Closing		- 8,216,880		- 8,613,345		- 8,999,572		- 9,380,382		- 9,770,596		- 10,174,170		- 10,505,498		- 10,666,606	
			4,494,677		**4,616,495**		**4,669,845**		**4,621,961**		**4,589,382**		**4,678,532**		**4,737,167**		**5,317,745**	
Net Book Value Integrity Check			***4,494,677***		***4,616,495***		***4,669,845***		***4,621,961***		***4,589,382***		***4,678,532***		***4,737,167***		***5,317,745***	
Net Book Value Integrity Check - diff			-		-		-		-		-		-		-		-	
Depreciation Exp Integrity Check			***397,644***		***396,631***		***386,405***		***392,780***		***390,214***		***403,574***		***416,915***		***419,984***	
Depreciation Exp Integrity Check - diff			$ 154.06	5	$ 165.49	6	$ 177.72	7	-$ 1,508.78	8	-$ 0.28		-$ 0.27		-$ 0.28		$ 0.33	

1 Additions of Smart Meters to opening balances
2 Removal of Stranded Meters from opening balance
3 Addition of depreciation related to smart meters
4 Removal of depreciaiton related to Stranded Meters
5 Small building was not properly depreciated in 2010
6 Small building was not properly depreciated in 2011
7 Small building was not properly depreciated in 2012
8 Correction for the depreciation missed in previous years (small building)
9 $13,479 correction for prior year's over depreciated assets (reduced depreciation expense)

2

New CGAAP

Year									2013 New		2014 New						
Gross Assets	**Opening**								13,669,417		13,955,350						
	Add								332,925		357,636						
	Ret								- 46,993		- 59,793						
	Closing								13,955,350		14,253,192						

Year									2013 New		2014 New						
Accumulated Depreciation	**Opening**								- 8,999,572		- 9,149,451						
Adjust.									13,479	**9**							
	Add								- 203,897		- 210,850						
	Ret								40,538		43,955						
	Closing								- 9,149,451		- 9,316,345						
									4,805,899		**4,936,847**						
Net Book Value Integrity Check									***4,805,899***		***4,936,847***						
Net Book Value Integrity Check - diff									***-***		***-***						
Depreciation Exp Integrity Check									203,898		210,848						
Depreciation Exp Integrity Check - diff									$ 1.20		-$ 1.36						

$13,479 correction for prior year's over depreciated assets (reduced depreciation expense)

1

MIFRS

Year		2014 MIFRS	2015 MIFRS		2016 MIFRS	2017 MIFRS	
Add Smart Meters (added to open balance)						558,932	1
						- 557,746	2
Gross Assets	**Opening**	13,955,350	14,253,192		14,734,310	15,125,459	
	Add	357,636	492,724		547,500	740,500	
	Ret	- 59,793	- 11,606		- 157,538	-	
	Closing	14,253,192	14,734,310		15,124,273	15,865,959	

Year		2014 MIFRS	2015 MIFRS		2016 MIFRS	2017 MIFRS	
Add Smart Meters (added to open balance)						- 243,916	3
						502,792	4
Accumulated Depreciation	**Opening**	- 9,149,451	- 9,316,345		- 9,535,925	- 9,432,604	
Adjust.			4,695	10			
	Add	- 210,850	- 224,774		- 241,142	- 247,981	
	Ret	43,955	500		85,588	-	
	Closing	- 9,316,345	- 9,535,925		- 9,691,480	- 9,680,585	
		4,936,847	**5,198,385**		**5,432,793**	**6,185,374**	
Net Book Value Integrity Check		*4,936,847*	*5,198,385*		*5,432,793*	*6,185,374*	
Net Book Value Integrity Check - diff		*-*	*-*		*-*	*-*	
Depreciation Exp Integrity Check		*210,848*	*229,470*		*241,175*	*210,752*	
Depreciation Exp Integrity Check - diff		-$ 1.36	$ 4,695.78	10	$ 32.55	-$ 37,228.51	11

Additions of Smart Meters to opening balances

Removal of Stranded Meters from opening balance

Addition of depreciation related to smart meters

Removal of depreciaiton related to Stranded Meters

Too much depreciation was taken on several accounts over 2013 and 2014 (errors found in new continuity schedules for IFRS)-corrected for 2015

Depreciation calculated on smart meters (not additions, added to opening balance), yet model does not calculate on change to opening.

1

FINAL CONTINUITY SCHEDULE

Year		2010Old		2011Old		2012Old		2013 New		2014 New		2015 MIFRS		2016 MIFRS		2017 MIFRS	
Add Smart Meters																558,932	1
Removal of Stranded Meters																- 557,746	2
Gross Assets	Opening	12,178,306		12,711,556		13,229,840		13,669,417		13,955,350		14,253,192		14,734,310		15,125,459	
	Add	533,251		518,284		439,577		332,925		357,636		492,724		547,500		740,500	
	Ret	-		-		-		- 46,993		- 59,793		- 11,606		- 157,538		-	
	Closing	12,711,556		13,229,840		13,669,417		13,955,350		14,253,192		14,734,310		15,124,273		15,865,959	

Year		2010Old		2011Old		2012Old		2013 New		2014 New		2015 MIFRS		2016 MIFRS		2017 MIFRS	
Add Smart Meters																- 243,916	3
Removal of Stranded Meters																502,792	4
Accumulated Depreciation	Opening	- 7,819,389		- 8,216,880		- 8,613,345		- 8,999,572		- 9,149,451		- 9,316,345		- 9,535,925		- 9,432,604	
Adjust.								13,479	9			4,695	10				
	Add	- 397,490		- 396,465		- 386,227		- 203,897		- 210,850		- 224,774		- 241,142		- 247,981	
	Ret	-		-		-		40,538		43,955		500		85,588		-	
	Closing	- 8,216,880		- 8,613,345		- 8,999,572		- 9,149,451		- 9,316,345		- 9,535,925		- 9,691,480		- 9,680,585	
		4,494,677		**4,616,495**		**4,669,845**		**4,805,899**		**4,936,847**		**5,198,385**		**5,432,793**		**6,185,374**	
Net Book Value Integrity Check		*4,494,677*		*4,616,495*		*4,669,845*		*4,805,899*		*4,936,847*		*5,198,385*		*5,432,793*		*6,185,374*	
Net Book Value Integrity Check - diff		*-*		*-*		*-*		*-*		*-*		*-*		*-*		*-*	
Depreciation Exp Integrity Check		397,644		396,631		386,405		203,898		210,848		229,470		241,175		210,752	
Depreciation Exp Integrity Check - diff		$ 154.06	5	$ 165.49	6	$ 177.72	7	$ 1.20	8	-$ 1.36		$ 4,695.78	10	$ 32.55		-$ 37,228.51	11

1 Additions of Smart Meters to opening balances
2 Removal of Stranded Meters from opening balance
3 Addition of depreciation related to smart meters
4 Removal of depreciaiton related to Stranded Meters
5 Small building was not properly depreciated in 2010
6 Small building was not properly depreciated in 2011
7 Small building was not properly depreciated in 2012
8 Correction for the depreciation missed in previous years (small building)
9 13,479 correction for prior year's over depreciated assets (reduced depreciation expense)
10 Too much depreciation was taken on several accounts over 2013 and 2014 (errors found in new continuity schedules for IFRS)-corrected for 2015
11 Depreciation calculated on smart meters (not additions, added to opening balance), yet model does not calculate on change to opening.

1

Gross Assets

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

RHI chose to break down and explain variances under the RRFE functions; System Access (Table 2.9), System Renewal (Table 2.10), System Services (Table 2.11) and General Plant (2.12). 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

Table 2.9: Appendix 2-AA System Access Variances

Reporting Basis	Reporting Basis		CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2010	2011	2012	2013	2014	2015	2016	2017
System Access	**System Access**									
	Underground		$3,041	$12,837	$10,518		$4,739	$4,321		$15,000
	New Coleraine Subdivision				$85,502					
	Riverview extension					$19,282				
	Coleraine Subdivision					$26,320				
	RVH - building 2					$16,291				
	Hunter Gate - phase 3					$82,050				
	OPG new office						$25,804			
	O'Brien Office						$10,166			
	Hunter Gate - phase 4								$102,000	
	Easement								$3,000	
Contributed Capital	Capital Contributions - Coleraine					-24600				
									-$10,000	-$10,000
	Sub-Total System Access - Contributed Capital									
Sub-Total System Access	**Sub-Total System Access**		**3,041**	**12,837**	**96,020**	**119,343**	**40,709**	**4,321**	**95,000**	**5,000**

Asset Breakdown

<u>2010 – 2015 System Access</u> investments are modifications (including asset relocation) a distributor is obligated to perform to provide a customer access to electricity services. Renfrew is a slow growth area and residential developments are installed in phases to match the need. As such, system access expenditures for residential growth do not happen every year. Coleraine development was done in 2012/2013 and Hunters Gate Phase 3 in 2013 and Hunters Gate Phase 4 in 2016. The System Access for General Service customers are low growth as well. General Service projects were: RVH – building 2 in 2013, OPG office in 2014, O'Brien office in 2014. The Riverview extension in 2013 allowed the connection of 2 load transfer customers in Renfrew Hydro territory. Specifics can be found in the Distribution System Plan at Ex.2/Tab 5/Sch.2.

Table 2.10: Appendix 2-AA System Renewal Variances

System Renewal	System Renewal		2010	2011	2012	2013	2014	2015	2016	2017
	General replacement and renewal		172,629	97,635	126,672	109,634	104,269	165,992	176,000	154,000
	MS-4 pole fire		$169,188							
	MS-2 transformer		$141,933							
	Plaunt St. rebuild			$323,519						
	Bonnechere Feeder				$159,271					
	Moore St. Rebuild					$40,191				
	Stevenson Crescent					$46,767				
	Argyle St. rebuild						$109,292			
	Dominion/Barr St.						$65,905			
	Gillan Rd - 44kv poles							$147,003		
	Argyle St.								$256,000	
	Raglan St N									$171,000
	MS-1 Reclosures									$300,000
Contributed Capital										
	Capital Contribution - Mac's Convenience							-$16,382	-10000	-10000
	Sub-Total System Renewal - Contributed Capital									
Sub-Total System Renewal	**Sub-Total System Renewal**		**483,750**	**421,154**	**285,943**	**196,592**	**279,467**	**296,613**	**422,000**	**615,000**

2010 – 2017 System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. The System Renewal expenditures include annual costs for replacement of poles, conductors, and transformers that have reached their useful life and occasional costs for replacement of major distribution equipment. The Municipal Substation No: 2 transformer was replaced in 2010 and there is a $300,000 expenditure in 2017 to replace breakers that are over 60 years old. 2010 expenditures included pole and conductor replacement at MS-4 substation to repair damage caused by a pole fire. 2011 expenditures include the rebuild of a main overhead feeder on Plaunt Street repairing damage caused by a major windstorm. 2012 expenditures include pole and conductor replacement on the Bonnechere feeder which required the replacement of deteriorated cedar poles adjacent to a high school. 2013 expenditures include the replacement of deteriorated poles on a three phase overhead circuit – Moore Street and a single phase residential circuit – Stevenson Crescent. The System renewal expenditures in 2013 are lower than the norm but are offset by the System access expenditures for Coleraine and Hunters Gate developments. 2014 expenditures include replacement of deteriorated poles on Argyle street and Barr street. The Barr street job included the removal of a single phase line and transformer from the Fair Grounds for public safety reasons. 2015 expenditures included the replacement of poles on Gillan road which carries both 44 kv and 4.16kv circuits. The rebuild of the Gillan circuit was prioritized after a pole fire on this section of legacy construction. 2016 expenditures include the rebuild of Argyle street which feeds the back of the main street commercial area for the Town. This rebuild will eliminate 50 year old deteriorated cedar poles and will bring the construction standards and clearances to current standards. 2017 expenditures include the rebuild of Raglan St. North. This investment supports the new Pole Replacement Program which is described in the Distribution System Plan.

Table 2.11: Appendix 2-AA System Service Variances

System Service	System Service		2010	2011	2012	2013	2014	2015	2016	2017
	General		$11,176	$7,551				$10,407		
	Meters		$6,617			$14,491	$10,278	$1,884	$10,000	$10,000
	Install inline switch				$3,645					
	Substation Monitoring									$100,000
Contributed Capital										
			$0	$0	$0	$0	$0	$0	$0	$0
	Capital Contribution - Mac's Convenience							-$1,884		
	Sub-Total System Service - Contributed Capital									
Sub-Total System Service	Sub-Total System Service		17,793	7,551	3,645	14,491	10,278	10,407	10,000	110,000

<u>2010 – 2017 System Service</u> investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. The historical years show little investment in System services other than new meters. 2017 expenditures include the provision for substation monitoring to improve outage management and system optimization. Specifics can be found in the Distribution System Plan at Ex.2/Tab 5/Sch.2.

Table 2.12: Appendix 2-AA General Plant Variances

General Plant	General Plant		2010	2011	2012	2013	2014	2015	2016	2017
	Computer		$4,448							
	Software		$6,445							
	Office renovation		$11,168							
	Land rights/easements		$6,606							
	Line Tension Stringer			$40,204						
	Office renovation			$15,365						
	MS1 - replace roof			$21,172						
	2009 Ford F550				$47,264					
	New Computer Server				$6,705					
	Box for 2009 Ford					$2,500				
	Dodge Journey						$21,744			
	Computers						$5,437	$1,918	$3,000	$3,00
	New location - Leasehold Improvements							$116,088	$10,000	
	New office equipment and furniture							$21,604		
	Tools							$625	$7,500	$7,50
	CIS - Software upgrade							$39,417		
	Stores equipment							$1,731		
	Project Description									
Contributed Capital										
	Sub-Total General Plant - Contributed Capital									
Sub-Total General Plant	Sub-Total General Plant		28,667	76,741	53,969	2,500	27,181	181,383	20,500	10,50
Total Capital Expenditures			533,251	518,283	439,577	332,925	357,635	492,724	547,500	740,50
Reconciliation to yearly additions			533,251	518,284	439,577	332,925	357,636	492,724	547,500	740,50
Variance to yearly additions			0	-1	0	0	-1	0	0	

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

2010 – 2011: The purchase of a Line Tension stringer trailer to work with our pole boss line puller added $40,204 to the Plant expenditures. The roof on the MS-1 switchgear roof was replaced after a major windstorm lifted the roof.

2011 – 2012: The purchase of a used Ford F550 – crew cab work truck with dump to replace an existing crew cab that could not pass the CVOR inspection. $47,264.

2012 – 2013: No major additions in 2013.

2013 – 2014: The purchase of a Dodge Journey vehicle to be used for employee business travel in lieu of personal vehicle use and service calls. $21,744

2014 – 2015: A new location was found for our operations department after an extensive search of property in Renfrew. The move from the Renfrew Power Generation facility was requested by the owner not by Renfrew Hydro. Leasehold improvements to the new location at 499 Obrien road cost $116,088 and are distributed over the life of the ten year lease. There was also a major upgrade to the billing software with an expenditure of $39,417. This upgrade allows the introduction of electronic billing to our customers.

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

Table 2.13: Breakdown by Traditional Function

Function	USOA	Description	CGAAP 2010 BA	CGAAP 2010 Actual	CGAAP 2011 Actual	CGAAP 2012 Actual	CGAAP 2013 Actual	IFRS 2014 Actual	IFRS 2015 Actual	IFRS 2016 Projected	IFRS 2017 Projected
General Plant/Intangible	1611	Computer Software (Formally known as Account 1925)	13,800	6,445					39,417		
General Plant/Intangible	1612	Land Rights (Formally known as Account 1906 and 1806)		6,607					4,321	3,000	
Distribution Plant	1805	Land									
Distribution Plant	1808	Buildings	23,000	11,168	36,537						
Distribution Plant	1820	Distribution Station Equipment <50 kV	131,173	141,933							300,000
Distribution Plant	1830	Poles, Towers and Fixtures	133,624	130,866	167,920	161,976	109,813	127,370	182,603	172,000	190,000
Distribution Plant	1835	Overhead Conductors and Devices	118,990	139,070	185,958	145,098	64,843	114,905	68,146	83,000	85,000
Distribution Plant	1840	Underground Conduit	-	7,459	1,982	8,500	4,520	10,114	-	7,400	
Distribution Plant	1845	Underground Conductor and Devices	25,272	42,023	2,303	23,628	85,037	24,717	-	92,600	10,000
Distribution Plant	1850	Line Transformers	35,066	15,440	59,277	23,828	41,356	28,523	62,246	163,000	40,000
Distribution Plant	1855	Services	21,354	21,176	24,103	22,577	34,966	14,548	10,407	16,000	15,000
Distribution Plant	1860	Meters	5,520	6,617			14,491	10,278	1,884	10,000	10,000
General Plant	1905	Land									
General Plant	1906	Land Rights									
General Plant	1908	Buildings and Fixtures									
General Plant	1910	Leasehold Improvements							116,088	10,000	
General Plant	1915	Office Furniture and Equipment						5,437	21,604		
General Plant	1920	Computer Equipment - Hardware	4,600	4,448		6,705			1,918	3,000	3,000
General Plant	1925	Computer Software									
General Plant	1930	Transportation Equipment			40,204	47,264	2,500	21,744			
General Plant	1935	Stores Equipment							1,731		
General Plant	1940	Tools, Shop and Garage Equipment	4,600						625	7,500	7,500
General Plant	1980	System Supervisor Equipment									100,000
General Plant	1995	Contributions and Grants - Credit					- 24,600		- 18,266	- 20,000	- 20,000
			516,999	**533,251**	**518,284**	**439,577**	**332,925**	**357,636**	**492,724**	**547,500**	**740,500**

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2017*

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2012			**2013**			**2014**			**2015**			**2016**			**2017**	**2018**	**2019**	**2020**	**2021**
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual[2]**	**Var**					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	10,000	12,837	28.4%	80,000	96,020	20.0%	140,000	143,943	2.8%	40,000	40,709	1.8%	5,000	4,321	-13.6%	95,000	5,000	35,000	129,000	10,000
System Renewal	360,000	421,154	17.0%	297,537	285,943	-3.9%	265,000	196,592	-25.8%	339,500	279,467	-17.7%	368,000	296,613	-19.4%	422,000	615,000	335,000	380,000	385,000
System Service	5,000	7,551	51.0%	3,500	3,645	4.1%	25,000	14,491	-42.0%	15,000	10,278	-31.5%	17,000	10,407	-38.8%	10,000	110,000	20,000	5,000	5,000
General Plant	85,000	76,741	-9.7%	57,700	53,969	-6.5%	-	2,500	--	42,000	27,181	-35.3%	100,000	181,383	81.4%	20,500	10,500	360,500	10,500	10,500
General Plant	-	-	--	-	-	--	-	-24,600	--	-	-	--	-	-	--					
TOTAL EXPENDITURE	460,000	518,283	12.7%	438,737	439,577	0.2%	430,000	357,526	-16.9%	436,500	357,635	-18.1%	490,000	492,724	0.6%	547,500	740,500	750,500	524,500	410,500
System O&M		$1,143,713	--		$1,202,039	--		$1,254,896	--		$1,240,159	--		$1,330,158	--	$1,427,921	$1,549,280			

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

RHI has adopted depreciation rates based on the Kinectrics Asset Depreciation Study. The rates used are presented below and the Continuity Schedules of the Accumulated Depreciation are presented at Ex.2/Tab 1/Sch 4.

RHI's Accumulated Depreciation is presented in a continuity schedule filed with its application. While RHI's accumulated depreciation generally increases at the same pace as the utility capital investment, the annual depreciation has now decreased beginning in 2013 as a result of the extended useful lives.

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

Table 2.14: Comparison of Depreciation Rates

Account	Description	CGAAP	Modified CGAAP 2013
1611	Computer Software (Formally known as Account 1925)	5.00	5.00
1612	Land Rights (Formally known as Account 1906)	20.00	20.00
1808	Buildings	50.00	50.00
1820	Distribution Station Equipment <50 kV	30.00	40.00
1830	Poles, Towers & Fixtures	25.00	45.00
1835	Overhead Conductors & Devices	25.00	60.00
1840	Underground Conduit	25.00	50.00
1845	Underground Conductors & Devices	25.00	50.00
1850	Line Transformers	25.00	40.00
1855	Services – Overhead	25.00	60.00
1855	Services – Underground	25.00	40.00
1860	Meters	25.00	25.00
1860	Meters (Smart Meters)	25.00	15.00
1915	Office Furniture & Equipment (10 years)	10.00	10.00
1920	Computer Equipment – Hardware	5.00	5.00
1930	Transportation Equipment – under 3 Tons	5.00	5.00
1930	Transportation Equipment – 3 Tons & Over	8.00	8.00
1935	Stores Equipment	10.00	10.00
1940	Tools, Shop & Garage Equipment	10.00	10.00
1980	System Supervisor Equipment	20.00	20.00

Allowance for Working Capital

Ex.2/Tab 3/Sch.1 - Derivation of Working Capital

RHI 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). RHI attests that the Cost of Power is determined by split between RPP and non-RPP customers based on actual data, using most current RPP price, using current UTR. Table 2.15 presented below show RHI's calculations in determining its Allowance for Working Capital.

Table 2.15: Allowance for Working Capital

	CGAAP	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	NEWGAAP	NEWGAAP	NEWGAAP
Expenses for Working Capital	**Last Board Approved**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Eligible Distribution Expenses:									
3500-Distribution Expenses - Operation	$235,909	$207,838	$222,809	$231,657	$228,491	$291,184	$311,428	$282,542	$296,946
3550-Distribution Expenses - Maintenance	$171,718	$154,106	$147,176	$151,791	$190,006	$171,743	$171,109	$189,934	$196,759
3650-Billing and Collecting	$328,238	$352,212	$335,087	$359,319	$400,546	$387,608	$417,963	$433,355	$467,660
3700-Community Relations	$1,000	$2,022	$3,339	$1,684	$1,286	$2,853	$1,688	$3,000	$6,000
3800-Administrative and General Expenses	$434,729	$324,920	$435,302	$457,589	$434,567	$386,773	$427,970	$519,091	$581,915
	-$21,765								
Total Eligible Distribution Expenses	$1,149,829	$1,041,099	$1,143,713	$1,202,039	$1,254,896	$1,240,159	$1,330,158	$1,427,921	$1,549,280
3350-Power Supply Expenses	$8,674,639	$8,402,755	$8,285,984	$8,486,079	$9,363,001	$9,734,067	$10,814,383	$8,850,684	$11,715,807
Total Expenses for Working Capital	$9,824,468	$9,443,854	$9,429,696	$9,688,118	$10,617,897	$10,974,226	$12,144,541	$10,278,605	$13,265,087
Working Capital factor	15%	15%	15%	15%	15%	15%	15%	15%	7.50%
Total Working Capital	**$1,473,670**	**$1,416,578**	**$1,414,454**	**$1,453,218**	**$1,592,685**	**$1,646,134**	**$1,821,681**	**$1,541,791**	**$994,882**

Ex.2/Tab 3/Sch.2 – Determination of Cost of Power

(This section is also presented in Exhibit 9)

RHI calculated the cost of power for the 2016 Bridge Year and the 2017 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 Report – May 1 2016 to April 31, 2017 issued by the Ontario Energy Board on April 14, 2016. Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, RHI will update the electricity prices in the forecast.

Energy

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 by component are presented in Table 9.15 below. RHI 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 RHI's cost of power are;

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2016)

RPP Supply Cost Summary for the period from May 1, 2016 through April 30, 2017		
Forecast Wholesale Electricity Price		$16.86
Load-Weighted Price for RPP Consumers ($ / MWh)		$18.59
Impact of the Global Adjustment ($ / MWh)	+	$90.86
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$0.97
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$111.41**

	Last Actual kWh's		
Customer Class Name	**Last Actual kWh's**	**non-RPP**	**RPP**
Residential	29,589,162	990,906	28,598,256
General Service < 50 kW	10,843,312	1,873,494	8,969,818
General Service > 50 to 4999 kW	45,095,566	45,095,566	0
Unmetered Scattered Load	155,364	155,364	0
Street Lighting	1,123,682	1,123,682	0
TOTAL	**86,807,086**	**49,239,012**	**37,568,074**
%	*100.00%*	*56.72%*	*43.28%*

Forecast Price

HOEP ($/MWh)			$18.59	
Global Adjustment ($/MWh)			$90.86	
Adjustments				
TOTAL ($/MWh)			**$109.45**	**$111.41**
$/kWh			***$0.10945***	***$0.11141***
%			56.72%	43.28%
WEIGHTED AVERAGE PRICE	**$0.1103**		**$0.0621**	**$0.0482**

		2016			2017		
Customer							
Class Name		Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	31,702,863	0.0796	$2,523,548	31,273,344	$0.11030	$3,449,395
General Service < 50 kW	kWh	12,876,365	0.0796	$1,024,959	12,701,406	$0.11030	$1,400,943
General Service > 50 to 4999 kW	kWh	46,673,960	0.0796	$3,715,247	46,953,684	$0.11030	$5,178,909
Unmetered Scattered Load	kWh	163,375	0.0796	$13,005	161,766	$0.11030	$17,842
Street Lighting	kWh	1,181,622	0.0796	$94,057	1,169,982	$0.11030	$129,047
TOTAL		**92,598,185**		**$7,370,815**	**92,260,183**		**$10,176,136**

The Commodity share of the Cost of Power is calculated in the same manner as has been previously approved by the OEB in RHI'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 Price Report – May 1 2016 to April 31, 2017 issued by the Ontario Energy Board on April 14, 2016.

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 2017 Load Forecast to determine the commodity to be included in the Cost of Power.

Transmission Network

		2016			2017		
Customer							
Class Name		Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	31,702,863	0.0064	$202,898	31,273,344	0.0064	$200,314
General Service < 50 kW	kWh	12,876,365	0.0058	$74,683	12,701,406	0.0058	$73,729
General Service > 50 to 4999 kW	kW	117,445	2.3668	$277,970	118,024	2.3687	$279,569
Unmetered Scattered Load	kWh	163,375	0.0058	$948	161,766	0.0058	$939
Street Lighting	kW	3,037	1.7849	$5,421	3,007	1.7864	$5,372
TOTAL	0	**44,863,085**		**$561,920**	**44,257,548**		**$559,923**

The Transmission Network charges are calculated in the OEB's RTSR model. The Rates are applied to the 2017 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application.

Transmission Connection

		2016			2017		
Customer							
Class Name		Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	31,702,863	0.0033	$104,619	31,273,344	0.0035	$108,472
General Service < 50 kW	kWh	12,876,365	0.0031	$39,917	12,701,406	0.0033	$41,385
General Service > 50 to 4999 kW	kW	117,445	1.1566	$135,837	118,024	1.2157	$143,478
Unmetered Scattered Load	kWh	163,375	0.0031	$506	161,766	0.0033	$527
Street Lighting	kW	3,037	0.8941	$2,716	3,007	0.9398	$2,826
TOTAL	0	**44,863,085**		**$283,596**	**44,257,548**		**$296,688**

The Transmission Connection charges are also calculated in the OEB's RTSR model. The Rates are applied to the 2017 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application.

<u>Wholesale Market</u>

		2016			2017		
Customer			**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	31,702,863	0.00360	$114,130	31,273,344	0.00360	$112,584
General Service < 50 kW	kWh	12,876,365	0.00360	$46,355	12,701,406	0.00360	$45,725
General Service > 50 to 4999 kW	kWh	46,673,960	0.00360	$168,026	46,953,684	0.00360	$169,033
Unmetered Scattered Load	kWh	163,375	0.00360	$588	161,766	0.00360	$582
Street Lighting	kWh	1,181,622	0.00360	$4,254	1,169,982	0.00360	$4,212
TOTAL	0	**92,598,185**		**$333,353**	**92,260,183**		**$332,136**

On November 19, 2015 the OEB released Decision and Order for the Wholesale Market Service (WMS) for 2016. The Board's decision is summarized as follows:

- The WMS rate used by rate-regulated distributors to bill their customers shall be 0.36 cents per kilowatt-hour, effective January 1, 2016. This unit rate shall apply to a customer's metered energy consumption adjusted by the distributor's Board-approved Total Loss Factor.

In compliance with this order, RHI has applied the Board Approved $0.0036/kWh to its 2017 Load Forecast in order to include $332,136 in its Cost of Power.

<u>Rural Rate</u>

		2016			2017		
Customer			**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	31,702,863	0.00130	$41,214	31,273,344	0.00130	$40,655
General Service < 50 kW	kWh	12,876,365	0.00130	$16,739	12,701,406	0.00130	$16,512
General Service > 50 to 4999 kW	kWh	46,673,960	0.00130	$60,676	46,953,684	0.00130	$61,040
Unmetered Scattered Load	kWh	163,375	0.00130	$212	161,766	0.00130	$210
Street Lighting	kWh	1,181,622	0.00130	$1,536	1,169,982	0.00130	$1,521
TOTAL	0	**92,598,185**		**$120,378**	**92,260,183**		**$119,938**

On November 19, 2015 the OEB released Decision and Order for the Rural or Remote Electricity Rate Protection (RRRP) for 2016. The Board's decision is summarized as follows:

- The RRRP charge used by rate-regulated distributors to bill their customers shall continue to be 0.13 cents per kilowatt-hour, effective January 1, 2016. This unit rate shall apply to a customer's metered energy consumption adjusted by the distributor's Board-approved Total Loss Factor.

Smart Meter Entity

		2016			2017		
Customer			**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	3,807	0.79000	$36,089	3,835	0.79000	$36,356
General Service < 50 kW	kWh	422	0.79000	$3,998	414	0.79000	$3,921
General Service > 50 to 4999 kW	kW	61	0.79000	$578	61	0.79000	$576
TOTAL	0	**4,290**		**$40,666**	**4,309**		**$40,853**

OESP

		2016			2017		
Customer			**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		Volume		Amount	Volume		Amount
Residential	kWh	31,702,863	0.00110	$34,873	31,273,344	0.00110	$34,401
General Service < 50 kW	kWh	12,876,365	0.00110	$14,164	12,701,406	0.00110	$13,972
General Service > 50 to 4999 kW	kWh	117,445	0.00110	$129	46,953,684	0.00110	$51,649
Unmetered Scattered Load	kWh	163,375	0.00110	$180	161,766	0.00110	$178
Street Lighting	kWh	3,037	0.00110	$3	1,169,982	0.00110	$1,287
TOTAL	0	**44,863,085**		**$49,349**	**92,260,183**		**$101,486**

Low Voltage Charges

Table 9.16 below presents the derivation of proposed retail rates for Low Voltage ("LV") service. The 2017 estimates of total LV charges were calculated based on an average of the last 2 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 2017 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. 2017 LV rates appear on a distinct line item on the proposed schedule of rates.

Table 9.16: Low Voltage Charges

				2010	2011	2012	2013	2014	2015	2016	2017
4075-Billed - LV				-111,446	-93,005	-88,827	-82,682	-85,641	-84,969	-91,095	- 91,095
4750-Charges - LV				111,446	93,005	88,827	82,682	85,641	84,969	91,095	91,095

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Uplifted Volumes**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0035**	31,273,344	$108,472	36.56%
General Service < 50 kW	kWh	**$0.0033**	12,701,406	$41,385	13.95%
General Service > 50 to 4999 kW	kW	**$1.2157**	118,024	$143,478	48.36%
Unmetered Scattered Load	kWh	**$0.0033**	161,766	$527	0.18%
Street Lighting	kW	**$0.9398**	3,007	$2,826	0.95%
TOTAL			**44,257,552**	**$296,688**	**100%**

Low Voltage Charges Rate Rider Calculations

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	36.56%	33,305	31,273,344	$0.0011	kWh
General Service < 50 kW	13.95%	12,707	12,701,406	$0.0010	kWh
General Service > 50 to 4999 kW	48.36%	44,053	118,024	$0.3733	kW
Unmetered Scattered Load	0.18%	162	161,766	$0.0010	kWh
Street Lighting	0.95%	868	3,007	$0.2885	kW
TOTAL	**100.00%**	**91,095**	**44,257,552**		

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

Customer		**Revenue**	**Expense**	**2016**				**2017**		
Class Name		USA #	USA #	Volume	Rate	Amount		Volume	Rate	Amount
Residential	kWh	4075	4750	31,702,863	$0.0011	$34,873.15		28,929,066	$0.0011	$31,821.97
General Service < 50 kW	kWh	4075	4750	12,876,365	$0.0010	$12,876.36		11,749,297	$0.0010	$11,749.30
General Service > 50 to 4999 kW	kW	4075	4750	117,445	$0.3564	$41,857.53		118,024	$0.3733	$44,058.36
Unmetered Scattered Load	kWh	4075	4750	163,375	$0.0010	$163.38		149,640	$0.0010	$149.64
Street Lighting	kW	4075	4750	3,037	$0.2754	$836.49		3,007	$0.2885	$867.62
TOTAL		**0**	**0**	**44,863,085**		**$90,607**		**40,949,038**		**$88,646.89**

Ex.2/Tab 3/Sch.3 - Lead Lag Study

RHI 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 providing two approaches for the calculation of the allowance for working capital:

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

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

Smart Meter Deployment and Stranded Meters

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

Introduction:

RHI is seeking recovery of costs incurred while implementing the Province of Ontario's Smart Meter Initiative.

As of December 31, 2012, 100% of RHI's conventional meters were replaced with Smart Meters. Customers with interval meters remain unchanged. The Total Smart meter Initiative costs claimed in this application are $ 642,828 as indicated in Table 2.19 below. These costs can be offset by the disposition of the Smart Meter Funding Adder.

The SMFA was introduced by the Board in RHI's 2006 rates and continued until April 30, 2012.
RHI's 2012, 2013 and 2014 rates do not include the SMFA or any other rates associated with the Smart Meter Initiative.

Table 2.19 - Summary of Cost Claim

Smart Meter – Capital Costs	$ 558,932
Smart Meter – O&M Costs	$ 83.896
Total Smart Meter Costs	$ 642,828

The costs of the Smart Meter Initiative (to December 31, 2012) are partially offset by the SMFA, in the amount $ 217,198. This includes accumulated interest. RHI is proposing to follow the allocation methodology applied by the Board in the Smart Meter Initiative proceedings of other distributors. The resulting rate riders being proposed are displayed in Table 2.20 below.

Table 2.20 - Summary of Cost Claim

Rate Rider	Residential	GS<50 kW	GS>50kW
Smart Meter Disposition Rate Rider (SMDR)	$1.42	$3.10	$11.60

According to the Board's Guideline, the Smart Meter Disposition Rider ("SMDR") recovers, over a specified time period, the variance between: 1) the deferred revenue requirement for the Smart Meter Initiative up to the time of disposition, and 2) the SMFA revenues collected from May 2006 through April 2012 and associated carrying charges until January 31, 2016.

The Applicant's costs of the Smart Meter Initiative were $135.24 average capital cost per meter and $155.54 average total cost per meter as set out in Tables 2.21 and 2.22 below.

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

Table 2.21 - Average Capital Cost per Meter

Smart Meter Capital Costs	$ 558,932
Number of Meters Installed	4133
Average Cost per Meter	$135.24

Table 2.22 - Average Total Cost per Meter

Smart Meter Capital Costs	$ 558,932
Smart Meter OM&A Costs	$ 83,896
Total Smart Meter Costs	$ 642,828
Number of Meters Installed	4,133
Average Cost per Meter	$ 155.54

As illustrated in Table 2.23, the Applicant was able to implement the Smart Meter Initiative below the provincial average. Consequently, RHI's customers will pay approximately 24.9% less for their smart meters, than the Board's benchmark for the industry. This was due in large part to the partnering of four local utilities namely: Hydro 2000 Inc., Co-Operative Embrun, Renfrew Hydro Inc. and Ottawa River Power Corporation. Together they operated as one under the London RFP and to this day they continue to share software and computer hardware.

Table 2.23 - Comparison with Sector Averages

	Renfrew Hydro Inc.	Ontario	Variance$	Variance%
Average Capital Cost	$135.24	$186.76	($51.52)	(27.6%)
Average Total Cost	$155.54	$207.37	($51.83)	(24.90%)

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

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

Procurement and London RFP:

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

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

As part of the London Hydro RFP, RHI attempted to contact and do business with the proponent in the London Hydro RFP that received the best score based on the RHI's criteria in accordance with the prescribed process. After this failed, RHI contacted the Fairness Commissioner. Approval to purchase the smart meter infrastructure from its second proponent, Elster Metering was received in April 2009. A copy of this correspondence is included at the end of this schedule.

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

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

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

	2009	2010	2011	2012	Total
Smart Meter Installation					
Residential	0	3,323	342	0	3,665
General Service < 50 Kw	0	389	42	0	431
Total Residential & GS<50 - Installed	0	3,712	384	0	4,096
% Res. & GS<50 - Complete	0%	90%	100%	0	
GS>50 installed	0	37	0	0	37
Total Smart Meter installed	0	3,749	384	0	4,133

RHI installed a total of 4,133 smart meters as at December 31, 2012 which represented 100% of its conventional meters (Interval meters not included).

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

Cost:

The Board's Guideline, section 3.5, states that, "The Board expects the majority (i.e. 90% or more) of the total program costs for which the distributor is seeking recovery will be audited."

RHI has included costs up to and including those captured in its audited financial statements as at December 31, 2012. As such, all of the costs for which RHI is seeking recovery were incurred in years for which an external financial audit has been completed and thus exceeds the 90% threshold set in the Board's Guideline.

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

Table 2.25 - Smart Meter Costs Claimed for Recovery

Cost	Cost Sub-Element		Total Costs
Capital	1.	Advanced Metering Communications Devices (AMCD)	$537,893
	1.	Advanced Metering Regional Collector (AMRC) (Includes	$21,038
	1.	Advanced Metering Control Computer (AMCC)	
	1.	Wide Area Network (WAN)	
	1.	Other AMI Capital Costs Related to Minimum Functionality	
	1.	Capital Costs Beyond Minimum Functionality	
	Total Smart Meter Capital Costs		$558,932
OM&A	2.	Incremental AMCD OM&A Costs	$7,208
	2.	Incremental AMRC OM&A Costs	
	2.	Incremental AMCC OM&A Costs	
	2.	Incremental AMRC OM&A Costs	
	2.	Other AMI OM&A Costs Related to Minimum Functionality	$76,688
	2.	OM&A Costs Beyond Minimum Functionality	
	Total Smart Meter OM&A Costs		$83,896
Total	**Total Smart Meter Costs**		**$ 642,828**

As presented in Tables 2.21 and 2.22 and 2.23 and discussed in the introduction, all costs incurred in completing the Smart Meter Initiative have been prudently incurred as is evidenced by a $135.24 average capital cost per meter and a $155.54 average total cost per meter. These costs are lower than the Ontario benchmarks of $186.76 average capital cost per meter and $207.37 average total cost per meter.

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

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

Rate Riders:

(SMFA)

In the Board's 2006 Decision (RP-2005-0020, EB-2005-0413) setting RHI's 2006 rates, a $0.30 SMFA was applied to all metered customers namely residential, less than 50 KW and greater than 50 KW customers. The $0.30 SMFA amount was changed on May 1, 2007 to $0.26 by order under EB-2007-057 until the Board's 2009 Decision and Order (EB-2009-0146).

In that Decision, the Board increased the SMFA to $2.05 per metered customer per month effective January 1, 2011. The SMFA of $2.05 continued until May 1, 2012. Since that date, no SMFA has been charged.

Table 2.26 below shows the SMFA revenues collected from each class of customer. These SMFA revenues directly attributable to class were input in sheet 10A of the Smart Meter model.

Table 2.26 - Smart Meter Funding Adder Revenue Allocation

Rate Class	SMFA ($)	SMFA (%)
Residential	$175,405	88%
GS<50	$21,594	10.5%
GS >50	$2,905	1.5%
Total	**$199,904**	**100%**

Rate Riders:

(SMDR)

RHI is seeking Board approval for a Smart Meter Disposition Rate Rider in the amount of $1.42 per Residential customer per month and $3.10 per GS< 50 and $11.16 per GS>50 customer per month for a 4 year period commencing January 1, 2017.

The Calculation was made utilizing the Board's Smart Meter Model v6.01.

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

Table 2.27 - WACC and Tax Rate Inputs

Year	2009 IRM	2010 COS	2011 IRM	2012 IRM	2013 IRM	2014 IRM	2015 IRM	2016 IRM	2017 COS
WACC	8.01%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	6.28%
Tax Rates	18.62%	16%	15.5%	15.5%	15.5%	15.5%	15.5%	15.00%	15.00%

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

- Deferred and forecasted Smart Meter Incremental Revenue Requirement from 2008 to December 31, 2016

  Plus

- Interest on deferred and forecasted OM&A and amortization expenses 2008 to December 31, 2016

  Less

- SMFA revenues collected from May 1, 2006 to April 30, 2012 and carrying charges from May 1, 2006 to December 31, 2016.

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

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

Component of Revenue Requirement	**Residential**	**GS < 50**	**GS > 50**	**Total**
Return, Amortization and Related Interest	$159,060.87	$33,267.63	$15,594.20	$207,922.71
OM&A	$272,625.16	$50,158	$20,136.70	
PILs	$17,878.68	$3,455.15	$1479.83	$22,813.66
Total Revenue Requirement	$449,564.72	$86,880.78	$37,210.74	$573,656.24
SMFA Revenue including Carrying Charges	$191,133.86	$22,805.74	$3257.96	$217,197.57
Net Deferred Revenue Requirement	$258,430.86	$64,075.04	$33,952.77	$356,458.67
Number of Metered Customers	3,779	430	61	
Calculation of Smart Meter Disposition Rider – 4 year	$1.42	$3.10	$11.60	

Table 2.29 – Smart Meter Revenue Requirement Calcs.

Allocator		**Residential**	**GS < 50**	**GS>50**	**Total**
Capital costs of Meters Installed - AMCD 1.1	$	$411,488	$86,063	$40,342	$537,893
	%	**76.5%**	**16.0%**	**7.5%**	**100.0%**

It is respectfully submitted that the costs for smart metering requested for recovery in this application have been prudently incurred to fulfill the Applicant's obligations under the Provincially-mandated Smart Meter Initiative and have been prudently incurred in accordance with Board's guidelines. Moreover, the proposed rate riders are just and reasonable and the associated customer bill impacts are reasonable. It is therefore appropriate that the Board approve the proposed rate riders for implementation effective January 1, 2017.

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

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

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

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

RHI has acted in accordance with Option B. Until now, the stranded meters have resided in Account 1860 - Meters .

The table below (excerpt from Appendix 2-S of the Board's Appendices) shows the net book value of RHI's stranded smart meters.

Table 2.30a) - Summary of Proposed Charge Parameters (App 2-S)

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$530,756	$365,186	$0.00	$165,570	$0.00	$165,570
2007		$551,801	$380,925	$0.00	$170,877	$0.00	$170,877
2008		$557,746	$396,901	$0.00	$160,844	$0.00	$160,844
2009		$557,746	$412,878	$0.00	$144,868	$0.00	$144,868
2010		$557,746	$428,867	$0.00	$128,879	$0.00	$128,879
2011		$557,746	$443,324	$0.00	$114,422	$0.00	$114,422
2012		$557,746	$457,047		$100,699		$ 100,699
2013		$557,746	$469,317		$88,429		$88,429
2014		$557,746	$481,222		$76,524		$76,524
2015		$557,746	$492,556		$65,191		$65,191
2016		$557,746	$502,792		$54,954		$54,954

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

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

    a. Thus far, stranded meters were included in Account 1860 and therefore were treated in accordance with CGAAP with the same accounting rules as standard meters.

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

    a. The amount of pooled residual net book value as of December 31st, 2016 is in the amount of $54,954.

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2012.

    a. Although no depreciation expenses were recorded for the years 2010 and 2011, this Model was calculated as if we had recorded depreciation for the entire period.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2016.

    a. N/A Please see response in 3.

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

    a. The net residual amount at the end of 2016 will be $54,594.

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

   a. The applicant intends to recover the cost of the Stranded Meters through a Rate Rider. The proposed recovery period is 5 years. Calculations of the proposed rate rider are presented at Table 1 below.

Table 2.30b) - Stranded Meter Rate Rider

Customer Class Name	**Net Book Value**	**% share**	**Annual $**	**Customer**	**Rate**	**per month**
Residential	$31,323.78	57.00%	6264.76	3835	$1.63	$0.14
General Service < 50 kW	$6,044.94	11.00%	1208.99	414	$2.92	$0.24
General Service > 50 to 4999 kW	$17,585.28	32.00%	3517.06	61	$57.87	$4.82
		100.00%				
	TOTAL	100.00%				

Total for Recovery			**54,954**
Recovery Period (years)		**5**	
Annual Recovery			**10,991**

(1) The utility used the 2010 Cost Allocation model - Meter Capital, as a basis for the allocation

PRP International, Inc.

Fairness Advisory Services

April 29, 2009

Renfrew Hydro Inc.
29 Bridge Avenue, West
Renfrew, Ontario K7V 3K3

Dear Mr. Freemark:

Subject: Attestation Letter (Negotiations) of the Fairness Commissioner
Renfrew Hydro – Elster Metering Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Attestation Letter (Negotiations) of the Fairness Commissioner for the noted negotiations and contracting phase of the London Hydro AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Renfrew Hydro Inc., in its administration of the contract awarded to its #2 ranked Proponent, Elster Metering following unsuccessful negotiations with its #1 ranked Proponent, Silver Spring Networks.

"It is the judgment of PRP International, Inc.(as the Fairness Commissioner engaged by Renfrew Hydro *for the phase of negotiations and contract award) that the successful conclusion of negotiations and contract award to* Elster Metering, *was undertaken in accordance with the principles for such negotiations and contract award set out in the RFP, issued August 14, 2007 and the Fairness Protocol, issued August 2008."*

A backgrounder and summary of the Fairness Protocol is attached and forms part of this Attestation Letter (Negotiations).

Yours truly,

Peter Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairness@telus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14[1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

---

[1] 7.5.14 Final Contract Negotiations

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding, nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of the final contract.

London Hydro has scheduled no more than two weeks for contract negotiations (if necessary), and expects the successful bidder to maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period. If contract negotiations exceed an interval acceptable to London Hydro, London Hydro retains the option to terminate negotiations and continue to the next apparent successful bidder, at the sole discretion of London Hydro. Said interval shall in no event be less than three weeks.

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
  - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation[2]:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Renfrew Hydro Inc.
29 Bridge Avenue, West
Renfrew, Ontario K7V 3K3

Attention: Tom Freemark, P.Eng., President

---

[2] **Conditions on the rendering of this Confirmation /Attestation.**

- The two Negotiations Agenda were provided by RHI via Ottawa River Power;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between RHI and either of their #1 or #2 ranked Proponents;
- The successful contract award was based on the RHI criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by RHI via Ottawa River Power.

Capital Expenditures

Ex.2/Tab 5/Sch.1 – Introduction to Distribution System Plan

Introduction

RHI's distribution system strategy is the set of long-term policies, rules, guidelines, etc. that RHI 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.

RHI has pursued the best practices of the electricity distribution industry for many years. This has included adhering to the OEB's Distribution System Code that sets out both good utility practice and minimal performance standards for electricity distribution systems in Ontario, and inspection requirements for distribution equipment. Over the years RHI has diligently maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. The diligent maintenance of its equipment has permitted RHI to extract an extended useful working life from its assets; moreover, while the age of the distribution equipment has increased, the reliability of the equipment has also often improved to meet the expectations of RHI's customers. Historically, this has been achieved with only a moderate increase in the customers' bills over many years.
By carefully controlling renewal expenditures and therefore moderating any increases in its customers' bills, the distribution system has evolved into an array of equipment of different vintages spanning a number of technological eras; that is, funds were not spent on replacing functioning equipment in order to simply have more modern technologies in place.

The future distribution system will be designed to deliver power at the quality and reliability levels required by customers and will minimize the lifetime cost by balancing preventive maintenance, life-extending refurbishment and end-of-life replacement; in short, the system will meet the customers' needs for quality and reliability of power at the minimal cost to the customer.

The future system should have sufficient capital available to it to permit the lowest cost solution to be implemented. In order to leverage the efficiencies that are possible through emerging new technologies equipment.

The following are the actions that RHI plans to take over the next 5-10 years in order to bring about the desired future. Priority will be given to RHI's legislated/mandatory requirements; for example:

- System access including the obligation to connect customers - Residential, Commercial and Industrial. Accommodate Town, Region, Ministry, etc. mandatory project requirements.
- Embrace demand side management for the accommodation of renewable generation, and the CDM conditions of license, in order to fully support public policy directives.
- Meet the OEB's – and other regulatory bodies' – quality, reliability, health, safety, environmental, etc. performance standards. Generally, funds will be spent to maintain current reliability levels; where a higher level of reliability is genuinely required, the additional cost will be allocated to specific customers or customer class by some appropriate mechanism.
- In order to safeguard the major investments already made in its key assets, continue to maintain and upgrade as necessary. Similarly, to ensure public safety and system security, maintain and refurbish the substations as required.
- Continue to invest prudently in modern information technology in order to provide customers with clear meaningful bills that are able to assist them in managing their electricity usage.
- Intensify condition monitoring to minimize uncertainty regarding decisions relating to equipment maintenance, renewal and replacement.

- Where the optimal life has already been reached and to the extent that funding is available, undertake an accelerated replacement of the over-aged items; e.g. RHI's wood poles and, to a lesser degree, transformers.
- Prudently acquire smart grid equipment where there will be direct economic/efficiency benefits.
- Continue with the cost effective replacement of service vehicles to ensure the utility has a reliable fleet for maintenance and for response to system outages.

RHI's Distribution System Plan is designed to present a fully integrated approach to capital expenditure planning. This includes a comprehensive documentation of its asset management process that supports its future 5 year capital expenditure plan while detailing the history of its past 5 years' activities. It recognizes its responsibilities to provide its customers with reliable service that is acknowledged as excellent value for money, by ensuring that its asset management activities maintain a focus on customers, operational effectiveness, public policy responsiveness and financial performance.

RHI has 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 at the next page. The Distribution System Plan follows at Ex.2/Tab 5/Sch. 2.

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

The Distributions System Plan is presented at the next page

Renfrew Hydro Inc.

Distribution System Plan

Date

May 20, 2016

TABLE OF CONTENTS

Table of Figures

Appendix Listing

Appendix A	OPA Letter of Comment
Appendix B	Draft Needs Screening Report

Executive Summary

This Consolidated Distribution System Plan (DS Plan) has been prepared by Renfrew Hydro Inc. (RHI) in accordance with Chapter 5 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission Distribution Applications, Consolidated Distribution System Plan Filing Requirements dated March 28 ("Chapter 5"), 2013.

RHI's DS Plan is an integrated document that supports the cost-effective planning and operation of its electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for its customers. The DS Plan documents the practices, policies and processes that are in place to ensure that investment decisions support RHI's desired outcomes in a cost-effective manner and provides value to the customer. RHI is committed to adhering to its DS Plan in order to provide valued outcomes to its customers. Electricity distributors are capital intensive in nature, and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network.

RHI has followed the best practices of the electricity distribution industry for many years including OEB's Distribution System Code (DSC) which sets out good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with best practices, RHI has diligently maintained its equipment in safe and reliable working order, and only when economically justified, upgraded or replaced its equipment.

In developing its long-term DS Plan, RHI's objective is to make timely investments in infrastructure and technology to ensure its distribution system continues to deliver power at the quality and reliability levels required by its customers. RHI will continue to adopt technological improvements that will improve its system, and at the same time, maximize the life of system parts using scheduled and preventative maintenance without compromising safety or reliability. RHI will continue to advance conservation and demand management.

INTRODUCTION

On March 28, 2013, the Ontario Energy Board ("OEB" or the "Board") issued Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5 Consolidated Distribution System Plan Filing Requirements (Chapter 5 Requirements). Chapter 5 Requirements provide a standard approach to a distributor's filing of asset management and capital expenditure plan information in support of a rate application and a distributor's Distribution System Plan (DS Plan).

RHI has compiled its consolidated DS Plan in accordance with the Chapter 5 Requirements.

The DS Plan reflects RHI's integrated approach to planning, prioritizing, and managing assets, and includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations. RHI has completed this DS Plan with a focus on customer preferences and operational effectiveness while achieving optimal value for capital spending.

RHI has organized the required information using the section headings in the DS Plan Filing Requirements. Investment projects and activities have been grouped into one of the four OEB defined investment categories: system access, system renewals, system service, and general plant.

Utility overview

The Town of Renfrew is an historic community located on the Bonnechere River at the convergence of Highway 60, Highway 132 and the Trans-Canada Highway (Highway 17). The Town of Renfrew is one of Renfrew County's primary urban settlements. Given its strategic location, the Town serves as a commercial and transportation hub within the County. Renfrew has a population of 8, 218, an increase of 4% since 2006. Primary industries include health and social services, retail and manufacturing.

RHI is an electricity distributor licensed by the OEB. In accordance with its Distribution License ED-2002-0577, RHI provides electricity distribution services in the Town of Renfrew. RHI is responsible for maintaining distribution and infrastructure assets deployed within the Renfrew service area. RHI currently serves approximately 4,200 electricity distribution customers across its service area.

RHI is an embedded utility in Hydro One and as such, is supplied power from Hydro One's Stewartville Transformer Station via the 10M3 feeder at 44kV, and has backup feeders via the 10M1 feeder at Stewartville TS and from Hydro One's Cobden TS via the 23M2 feeder.

RHI distributes electricity to the Town of Renfrew at primary distribution voltages of 4kV (through five 4kV substations and 18 feeders) and 2400V. RHI does not host any utilities.

RHI's licensed service area is 12.77 square kilometres of urban service area. RHI's distribution system is made up of seventy-two kilometres of overhead lines, eight kilometres of underground lines, and 645 transformers. Revenue is earned by RHI by delivering electric power to homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the OEB.

RHI also maintains the town's street and traffic light system. RHI is incorporated under the Ontario Business Corporations Act. The Corporation of the Town of Renfrew is its sole shareholder.

Strategic priorities

RHI's strategic priorities are defined in its corporate goals and reflect its mission and value statements:

- To form partnerships and alliances with other local distribution companies for economies of scale and cost-sharing opportunities. This is being accomplished by participating in the Cornerstone Hydro Electric Concept ("CHEC") group, and CDM programs with Hydro Ottawa
- To invest in the development of our staff to provide an employee-oriented, high performance culture of organizational effectiveness that emphasizes empowerment, quality, productivity, goal attainment and ongoing development of a superior workforce
- To stay current with industry, sector and regulatory changes
- To pursue new business opportunities, partnerships and best management practices in our quest to meet or exceed financial expectations of our community by cost sharing, efficiency gains, cost savings, improve reliability, superior customer service and protecting the environment
- To investigate roles and opportunities that RHI can pursue in generation and promoting conservation and demand management initiatives

Our vision

RHI will strive to be acknowledged as a leader among electric utilities in the areas of safety, reliability, customer service, and least cost service.

Our mission

RHI will deliver a dependable supply of electricity safely to its customers and achieve the highest level of customer service.

Leadership team

The RHI Leadership Team consists of:

Bill Nippard, President

with the following direct reports:

1. Cindy Marshall, Secretary/Treasurer
2. James Riopelle, Crew Leader
3. Jordy Leavoy, Billing Supervisor

The President has direct responsibility for system operation, asset management and capital expenditure plans. The plans and associated budget requirements are presented and vetted by the Leadership Team, and are ultimately included in the proposed corporate budget, as modified by the Leadership Team to a final form, which is in turn, presented to the RHI Board of Directors annually for approval.

Background

RHI's distribution system strategy is based on a set of long-term policies, rules and guidelines that RHI utilizes to transition its current system into its desired future system. The strategy, described in this DS Plan, provides the rationale for the capital expenditures and supporting activities planned for the 2017-2021 period.

An effective strategy requires a clear recognition of the strengths and weaknesses of the current system together with a realistic vision of the desired future system. In order to provide context and rationale for the strategy, it is necessary to describe the current and future distribution systems together with the key drivers and other major influencers expected to impact the transition.

The current distribution system

RHI has followed the best practices of the electricity distribution industry for many years. This has included adhering to the OEB's DSC that sets out both good utility practice, minimal performance standards for electricity distribution systems in Ontario, and minimal inspection requirements for distribution equipment. Consistent with best practices, RHI has diligently maintained its equipment in safe and reliable working order and, when economically justifiable, upgrades or replaces its equipment. The diligent maintenance of its equipment has permitted RHI to extract an extended useful working life from its assets. Historically, this has been achieved with only a moderate increase in customers' bills. RHI has been careful when incurring costs given repeated customer satisfaction survey results in which customers place a high value on maintaining a low price for electricity.

The desired distribution system

The future distribution system will be designed to deliver power at the quality and reliability levels required by customers, and will minimize the lifetime cost by balancing preventative maintenance, life-extending refurbishment and end-of-life replacement; in short, the system will *meet customers'* needs for quality and reliability of power in the most efficient and cost-effective way.

The envisaged system in 10 to 20 years will be one where there is even greater emphasis on condition monitoring in order to direct preventive maintenance to specific at-risk equipment and further extend the safe reliable useful life of all equipment. Consequently, equipment is expected to have longer in-service life. This is evident from the longer asset depreciation schedules for many of the distribution system assets listed in the revised capitalization policies.

The future distribution system should have sufficient capital available to it to permit the best solution to be implemented. This will involve adjusting the annual investment levels to allow renewal projects to proceed and remain within the construction capabilities of RHI. While extending the useful working life of equipment is intuitively desirable, life-extension "at any cost" (e.g., necessitated by shortage of capital) produces a sub-optimal, more costly solution.

In order to leverage the efficiencies that are possible through emerging new technologies, the distribution system would judiciously employ additional smart grid equipment. Underground connections in most new residential subdivisions reflect RHI's Conditions of Service which in turn reflect the current Township By-Laws.

Distribution-connected renewable generation is expected to be much more commonplace based on applications received to date in RHI's service area. Conservation and demand management will continue to be an integral part of the system as required by RHI's condition of license.

In order to achieve the desired distribution system, sufficient well-trained and well-equipped staff is required. This may require an increase in staff levels in some departments to accommodate apprenticeship schedules to replace retiring employees.

Drivers and influencers

- Customer demand
- System reliability
- Municipal driven
- Developer driven (growth-related)
- Capacity requirements
- Asset management capital expenditures (regulatory and legislative requirements)
- Infrastructure renewal
- Smart metering/Smart Grid

Strategy

RHI's DS Plan is designed to present a fully integrated approach to capital expenditure planning. This includes comprehensive documentation of its asset management process to support its future five-year capital expenditure plan, and detailing the history of its past five years' activities. RHI recognizes its responsibilities to provide its customers with reliable service that is acknowledged as excellent value for money, by ensuring that its asset management activities maintain alignment with RRFE objectives – customer focus, operational effectiveness, public policy responsiveness and financial performance.

RHI has relied on the OEB's Filing Requirements for Electrical Transmission and Distribution Applications Chapter 5 (March 28, 2013) to guide its presentation of its policies, practices and decision-making processes.

(5.2) Distribution System Plan

RHI's integrated approach to planning, prioritizing, and managing assets includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations. RHI has completed this DS Plan with a focus on customer preferences and operational effectiveness while achieving optimal value for capital spending.

RHI has organized the required information using the section headings in the DS Plan Filing Requirements. Investment projects and activities have been grouped into one of the four OEB defined investment categories listed below, based on the 'trigger' driver of the expenditure:

System access—investments are modifications (including asset relocation) to the distribution system RHI is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via RHI's distribution system.

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 RHI's distribution system to provide customers with electricity services.

System service—investments are modifications to RHI's distribution system to ensure the distribution system continues to meet RHI operational objectives while addressing anticipated future customer electricity service requirements.

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

The purpose of this DS Plan is to present RHI's Asset Management Strategy and to provide justifications for the capital investments required to maintain its core business: supplying reliable electrical services to its customers at a reasonable cost. This requires

- a thorough understanding of the age, condition and performance of its assets,
- documenting its inspection practices in accordance with the DSC,
- describing its maintenance activities in accordance with good utility practice,
- ensuring that all aspects of employee and public safety are addressed in compliance with all regulatory and legal obligations,
- forecasting and planning for the future growth of load customers and renewable generation facilities,
- recognizing and addressing constraints in the current distribution system and anticipating future capacity requirements,
- reviewing four historical years plus the current year of capital expenditures and reporting on variances from the 2010 Board-approved cost of service applications,
- demonstrating that the asset management process recognizes the above items and prioritizes projects to accommodate customers and system requirements, and
- developing a five-year forward looking capital expenditure plan that anticipates the future growth, capacity and performance of the distribution system while remaining flexible to accommodate the unknown requirements of its customer base.

In striving to achieve the corporate vision and asset management objectives, RHI is guided by the OEB's four key target objectives referenced in the Renewed Regulatory Framework for Electricity Distributors (RRFE)

- Customer focus,
- Operational effectiveness,
- Public policy responsiveness and
- Financial performance.

This requires conformance with all applicable laws, regulations, codes, and standards. To help achieve the foregoing, RHI's overall guiding principle for asset management is to meet all regulated requirements and performance standards and minimize the cost to RHI customers when staff acquire and subsequently maintain assets.

(5.2.1) Distribution System Plan Overview

The electric distribution system is capital intensive. Prudent capital investments are documented within RHI's DS Plan asset management and capital expenditure plan for the 2017-2021 period. The DS Plan documents the practices, policies and processes that ensure investment decisions support RHI's desired outcomes in a responsible, cost-effective manner and provides value to the customer. The DS Plan integrates qualitative and quantitative information which results in an optimal investment plan and includes:

- Customer value considerations
- Alignment with public policy objectives
- Regional planning considerations
- Smart grid considerations
- Renewable generation considerations
- System expansion considerations
- System renewal considerations

a) (5.2.1a) Key elements of the DS Plan that affect the rate proposal

(Key elements of the DS Plan that affect its rates proposal especially business conditions driving the size and mix of capital investments needed to achieve planning priorities)

RHI's DS Plan documents the capital and maintenance activities that RHI has completed or plans to complete in the 2012-2016 historical period, plans for the 2017 Test Year and plans for the 2018-2021 forecast period. The current date for information contained in this Consolidated DS Plan is March 31, 2016.

This is the first DS Plan filed by RHI and as such there are no changes from any previously filed plan.

As per Section 2.4.5 of the Chapter 2 filing requirements, RHI's revenue requirement is less than $10 Million and therefore is using $50,000 as the default materiality threshold. RHI will be reporting on investments or variances above this value.

It is expected that the operational and service requirements driving RHI's capital expenditures, and found within its DS Plan, will generally remain consistent through the 2017 to 2021 planning window. The projected expenditures for 2016 and going forward reflect

- the typical spending needs of a distribution electric utility serving a mature and stable customer base, and
- focused planned capital sustainment investments required to replace the aging assets found in RHI's distribution system.

Specific investment category spending requirements include:

- System Access spending due to customer connection needs and 3rd party infrastructure needs requiring non-discretionary plant relocation
- System Renewal investments required to replace end of life assets including poles and transformers, and other renewal needs such as the 1953 English bulk oil breakers at MS1
- System Service investments that promote the development of RHI's based Smart Grid/Smart Map: better use of Elster smart meters for outage reporting
- System Service investments such as remote monitoring of substations for loading and outages, and feeder and phase balancing, and a potential load management program for conservation demand management
- General plant investments to meet the fleet and IT needs

RHI's planning and investment processes follow good utility practices that are executed through the Distribution System Plan. Good utility practices have inherent cost savings through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. There are a number of key elements that contribute to the planning of investments through the period of the DS Plan:

- Customer service
- Outputs of RHI's asset management program – including maintenance and EOL replacement
- Coordination with municipally (town and county) planned projects
- Regulatory obligation
- Industrial load growth
- Residential load growth

In order to maintain current and accurate information in its database, RHI has conducted a condition assessment of the plant in its system. This information is resident in its GIS system that serves as a centralized data repository for asset information. This information is updated from time to time and as maintenance and capital projects are completed.

A capital investment prioritization process, aligned with corporate and asset management objectives, has been developed to prioritize discretionary capital investments. This occurs during the budgeting part of the planning process. During the budget process, capital investments are identified and investment justifications are put together for each one that identifies the cost of the project and its expected benefits. A value and risk deferral assessment of the investment is performed. Investment scores determine priority of the investment for current or future budget periods.

RHI has adopted good utility practices of the electricity distribution industry. This has included adhering to the OEB's DSC that sets out both good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, over the years RHI has maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. Consistent maintenance of its equipment has permitted RHI to, in some circumstances, extract an extended useful working life from certain assets. Historically, this has been achieved with only a moderate increase in the customers' bills. RHI has been prudent when incurring costs since customer satisfaction survey results indicate that the low price of electricity is an important factor to customers.

By prudently controlling all expenditures and therefore moderating any increases in its customers' bills, the distribution system has evolved into an array of operational equipment of different vintages spanning a number of technological eras. Funds were not spent on replacing functioning equipment in order to simply have more modern technologies in place. RHI's DS Plan ensures that the current and future distribution system can deliver power at the quality and reliability levels desired by customers and the lifetime usage is extended by balancing preventative maintenance, life-extending refurbishment, and end-of life replacements. In short, the system will meet the customers' needs for quality and reliability of power at a reasonable and affordable cost.

RHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the distribution system.

RHI's DS Plan demonstrates prudence and rate mitigation consideration in the pacing and prioritizing of non-discretionary investments, specifically those related to replacement or renewal of end-of-life plant.

b. (5.2.1 b) Sources of Cost Savings

(Sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution)

RHI planning, prioritization and investment processes follow good utility practices that are executed through the DS Plan. Good utility practices have inherent cost savings through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. Some specific RHI Distribution System Plan cost savings are expected to be achieved using the following:

- Asset condition inspections and comprehensive data collection provides a better understanding of each asset's stage in its lifecycle which will lead to more cost effective decisions with respect to maintenance, refurbishment and replacement decisions.
- Proactive maintenance and replacement of plant reduces reactive maintenance costs and improves service to the customer resulting in fewer and shorter duration outages, which in turn has a beneficial impact on the cost of outages to customers. A structured program of maintenance and renewal with planned rate increases will avoid disruptive rate spikes when addressing the volume of plant reaching end of life.
- Improved use of GIS to capture/access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, etc.) aids in cost control through optimization of the asset's lifecycle.
- Prudent investment in distribution automation as part of Smart Grid development will improve day-to-day switching operations and have a positive

impact on improving outage restoration times, and mitigate customer outage costs.

- Coordination of plant inspection with maintenance reduces operating costs. Employees performing tree trimming and infra-red testing also carry out visual inspections of adjacent plant. Exception reports are generated, as required, for follow-up remediation efforts by RHI crews.

c. (5.2.1 c) Period covered by DS Plan

The DS Plan covers the historical period of 2012 to 2016 with 2016 being the bridge year and a forecast period of 2017 to 2021 with 2017 being the test year. The data for 2016 will be three months actual and nine months of forecast spending.

d. (5.2.1 d) Currency of Information

Unless otherwise noted, all information contained in the DS Plan is current as of March 31, 2016.

e. (5.2.1 e) Changes to Asset Management Processes

As this is the first DS Plan to be filed by RHI, there are no changes to report.

f. (5.2.1 f) Contingent Aspect

At this time, there are no planned activities that are contingent upon the outcome of ongoing or future activities.

While RHI has and will continue to consult with third parties, the information presented in the DS Plan is based on best available information.

(5.2.2) Coordinated Planning with Third Parties

(To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate)

a. (5.2.2a) Description of the Consultations

(The purpose of the consultation e.g. Regional Planning Process; whether the distributor initiated the consultation or was invited to participate in it; the other participants in the consultation process e.g. customers; transmitter; OPA; the nature and prospective timing of the final deliverables, if any, that are expected to result from or otherwise be informed by the consultation(s) e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan; and will the consultation(s) have or are they expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.)

In preparing this DS Plan, RHI has considered the needs of its customers, as well as Hydro One, the Town of Renfrew, and the IESO.

Customer Engagement

"Putting the Consumer First" was part of the title of the *Report of the Ontario Distribution Sector Review Panel*. Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer focus is primarily on the overall costs of their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

Commercial Customers

As of the latest discussions, commercial customers within the service area are not planning any significant or material modifications within the service period. Planning and consultation is conducted with customers on a regular basis primarily to engage and promote participation in CDM programs. In addition to this, RHI uses this opportunity to discuss power quality, other reliability issues and future system planning.

Residential Customers

RHI values its customers and regularly seeks feedback to ensure that their needs are met and to receive suggestions on how RHI can improve their overall customer experience and include

- person to person communication,
- inserts in hydro bills,
- website interaction,
- community meetings and events, and
- surveys.

RHI is one of the few electric utilities to operate a full service customer counter with daily customer interaction. Customers who want to open a new account, move, pay bills, or have concerns or comments can come to our office or contact us by telephone, email, and fax. Customers appreciate the opportunity to deal with a local person and know that their concerns are treated with urgency and respect. RHI also uses mail inserts to provide customers with information about hydro, energy conservation including coupons, and demand management.

RHI will be launching a new user friendly website in 2016. It will be easier to read, feature greater emphasis on conservation, demand management and how to reduce their energy costs, and provide information about RHI, and responses to customers' questions and concerns. Our customers already can access their accounts 24/7 to view energy consumption which is updated nightly via smart meters, and check their account balance and payment history.

RHI participates in a number of community events throughout the year raising awareness of conservation and promoting discussion about infrastructure investment. Programs such as SaveOnEnergy and the Home Assistance program have been vital to conservation education; our participation at events such as the myFM Radio Home, Garden & Leisure Show also provide opportunities for RHI utility to interact with customers in a less formal environment.

Renfrew completed a Customer Satisfaction Survey in 2014, an Electrical Safety Awareness Survey in 2016, and is completing another Customer Satisfaction survey using a third party survey company on its behalf in 2016. It is anticipated the survey will be completed and results known in the second half of 2016.

In the 2014 customer satisfaction survey that RHI commissioned, the utility received a 10.8% response from the community. The survey covered a wide range of issues relating to customer satisfactions, service levels, business operations, reliability, conservations and smart grid. The survey completed in 2014 contained separate questionnaires for residential and for commercial customers.

Of the respondents, 89% were residential customers with the balance belonging to other customer classes. The results of the survey showed that more than 97% of RHI customers rated the service they receive from the LDC as between good and excellent. From a reliability perspective, 98% rated RHI's performance as good to excellent. In the area of Customer Service, 87% indicated that the received good to excellent service from RHI's CSRs. When it comes to communications, 84% believed that RHI was between good and excellent in communicating with them. Commercial customer consisted of 11% of the respondents overall. RHI participated in the Electrical Safety Authority Public Awareness Survey in 2016. The survey was conducted by a third party media company through CHEC to determine the awareness of electrical safety through the ratepayers in the service area. RHI achieved a Public Safety Awareness Score of 82.6%. This score is in line with other Ontario LDCs that participated in the survey and reflects the general electrical safety awareness among ratepayers in the service area.

Hydro One

RHI is an embedded utility in Hydro One and as such, is supplied power from Hydro One's Stewartville Transformer Station via the 10M3 feeder at 44kV, and has backup feeders via the 10M1 feeder at Stewartville TS and from Hydro One's Cobden TS via the 23M2 feeder.

RHI distributes electricity to the Town of Renfrew at primary distribution voltages of 4kV (through five 4kV substations and 18 feeders) and 2400V. RHI does not host any utilities.

As RHI is an embedded distributor, it does not participate in planning at the regional level, rather Hydro One participates in the Regional Planning and then RHI coordinates its planning with Hydro One. To date there have been no constraints identified by Hydro One regarding any of the feeders that service and supply RHI.

RHI last participated in the Regional Planning process three years ago.. No constraints were or have since been identified with transmission capacity for the foreseeable planning future.

Operations coordination between RHI and Hydro One happens where necessary. Hydro One identifies planned outages, switching plans, and in some cases asks to wheel power through Renfrew to accommodate transmission system outages. Hydro One also supply a weekly Ontario Grid Control Centre update to inform customers of significant events associated with its transmission and distribution systems.

RHI assist applicants from Renewable Energy Generators (REG) in its service territory as part of the Condition Impact Assessment process for FIT applicants through Hydro One.

Town of Renfrew

RHI maintains a close relationship with the Town of Renfrew and its Department of Development and Works Planning. Discussions include planned activities that can affect budgets, and scheduling and coordination on a per project basis and during construction season.

The town is mature and stable with respect to growth and development. New residential subdivisions are added to the town every few years. Commercial growth is minimal and is primarily outside the boundaries of the service area.

Neighboring utilities

RHI is embedded in Hydro One which is the only neighboring utility.

b. (5.2.2b) Integrated regional resource planning

RHI is a member of the Renfrew Regional Planning Group. From a Hydro One and IESO perspective, Renfrew Region is located within the Group 3 Region. A needs assessment was to be conducted for the Renfrew region by September of 2015. A draft Needs Screening/Assessment Report has been completed. This draft indicates that there are no major capacity related modifications required in the RHI service area.

RHI is also a member of the Greater Ottawa Regional Planning Group area (Group 1 from a Hydro One and IESO perspective). An Integrated Regional Resource Report for this region was published in April 2015. There were no needs identified that would affect RHI.

c. (5.2.2c) Comment letter from IESO regarding REG investments

Although there are a number of customer-owned substations, these customers are connected directly to the 44kV system. There are 8 fenced enclosures and three “tamper resistant” installations. RHI conducts an annual visual inspection for these substations but does not provide any additional services.

RHI has 10 microFIT and 4 FIT projects connected. In addition to this, there are also two hydro power generation facilities connected to RHI’s 4160V system and a third hydro power generation facility connected to its 44 kV system. These three hydro powered generating stations on the Bonnechere River System are owned by Renfrew Power Generation.

RHI has determined that the distribution system as currently constructed and configured will accommodate REG investments anticipated in the forecast period covered by this DSP. RHI’s REG investment plan was forwarded to the IESO and the comment letter from the IESO is attached in the Appendix to this DSP.

(5.2.3) Performance Measurement for Continuous Improvement

(Good distributor planning is an essential element of the Board’s performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning

objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.)

a. (5.2.3a) Metrics used to monitor DS planning performance

(Identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

- *customer oriented performance (e.g. consumer bill impacts; reliability; power quality);*
- *cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and*
- *asset and/or system operations performance).*

Based on Chapter 5 filing guidelines that indicate that the LDC shall identify and define methods and metrics used to monitor distribution system planning, and in conjunction with Report of the Board – Performance Measurement for Electricity Distributors a Scorecard Approach (EB-2010-0379) dated 5 March 2014, the OEB asks distributors to focus on the one measure that they believe most effectively reflects their performance in system plan implementation.

RHI proposes to report on the ratio of its cumulative actual annual spending to its cumulative budgeted annual spending.

Monitoring system performance provides RHI with the information required to appropriately adjust its plans or to identify remedial steps to ensure that distribution assets achieve their design life and are capable of serving under peak demand conditions. Performance monitoring is geared to achieve desired results on its four

target performance outcomes:

- Customer focus
- Operational effectiveness
- Public policy responsiveness
- Financial performance

The Service Quality Requirements within Section 7 of the DSC indicate a prescribed measurement and expected level of performance that defines a baseline for the quality of service delivered by electricity distributors. In addition to these and other metrics mandated by the OEB, RHI monitors a number of performance measures that may assist in the utility's continuous improvement activities and in satisfying customer requests.

Customer-oriented performance

- Feedback
- Service reliability
- Bill impacts
- Billing accuracy

- Power quality
- O&M cost per customer

Feedback

As a utility serving a small community, customer concerns are communicated quite easily just by interaction and customer feedback. That said, RHI has also commissioned or participated in three independent customer surveys since 2014 as part of its commitment to put its customers first. The top three needs identified through customer interaction were:

1. Price- customers are very concerned about price and increased utility bills. Most seniors need more education on the support programs available to assist low income households.

2. Reliability- Customers are pleased at our level of reliability as it is an important issue to them. Customers equate safety with reliability as electricity is an essential service.

3. Confusing hydro bills- most customers, especially seniors, are confused with the billing format and the information as presented.

Bill Impacts

In the annual budgeting process, RHI takes care to avoid large swings in costs by planning gradual changes to capital expenditures which subsequently minimizes the impact on customer bills. The key factors used in reviewing proposed budget increases include: quality of service improvements to customers, improvements in reliability, changes in revenue requirements year over year, and impacts on RHI resources.

RHI rebased its rates through a cost of service application in 2010 (EB-2009-0146). In subsequent years IRM or Annual IR applications were filed resulting in the approval of adjustments to rates. The annual distribution rate impacts through the historical period are shown in the table below:

Class	2012	2013	2014	2015
Residential	-4.5%	4.27%	3.61%	-2.08%
GS < 50 kW	-3.13%	4.53%	3.01%	-2.06%
GS > 50 kW	-1.98%	4.99%	1.10%	0.47%

Figure 1: Historical Annual Distribution Rate Adjustment Impacts

Service reliability

Guidance provided by the OEB in the recently published *Report of the Board: Electricity Distribution System Reliability Measures and Expectations* (EB-2014-0189), indicates that it would like to use the average or arithmetic mean of the previous five years (or historical period) of data to establish performance expectations for the forecast period.

Specifically, the OEB referred to SAIDI and SAIFI as the two reliability indicators that would benefit from using targeted goals.

RHI uses the CAIDI, SAIDI and SAIFI reliability indexes to monitor system reliability performance.

RHI collects a variety of statistics and analyzes the data to assess system performance and to act as inputs to its asset management program and capital prioritization processes. The data is also used as a tool to improve restoration time and drive/support policy.

RHI monitors the reliability performance of its system. While no one wants to have power interruptions, the customers have not raised any special concerns in this area of performance. Power quality is not and has not been an issue raised by the public in the RHI service area. RHI continues to work proactively to monitor the power quality to ensure it does not adversely affect the customers in the service area.

Efficiency and cost-effectiveness

RHI measures efficiency and cost effectiveness through the progress of projects in the current year capital program. RHI regularly meets and includes staff members from Finance, Operations and Engineering to review the progress and implementation of projects and to compare it against the plan presented in the budget. This review typically determines if work needs to be expedited and if year-end forecasts will be met.

Asset and/or systems operations performance

RHI does not have a formal worst performing feeder analysis, but it does monitor the number and types of outages on particular feeders to be able to generate and prioritize capital projects.

RHI monitors safety and safety related incidents within the service area. Contact with distribution equipment by the general public in addition to employees is tracked. RHI is anticipating a customer engagement campaign to raise the level of awareness of electrical safety.

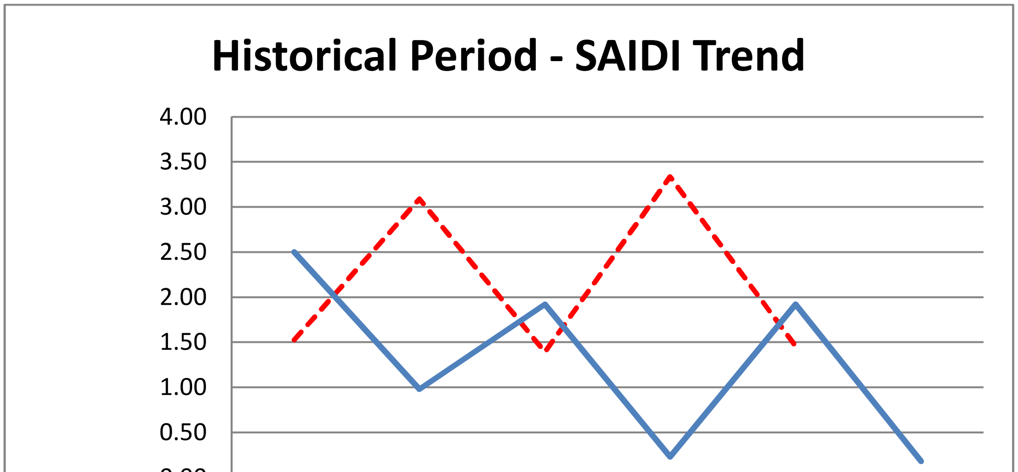
RHI monitors its compliance with Ontario Regulation 22/04 for design, construction and maintenance. Practices are audited by a third party on an annual basis and RHI tracks the non-compliances and Needs Improvements comments.

b (5.2.3b) Summary of performance trends

(Provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index. Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

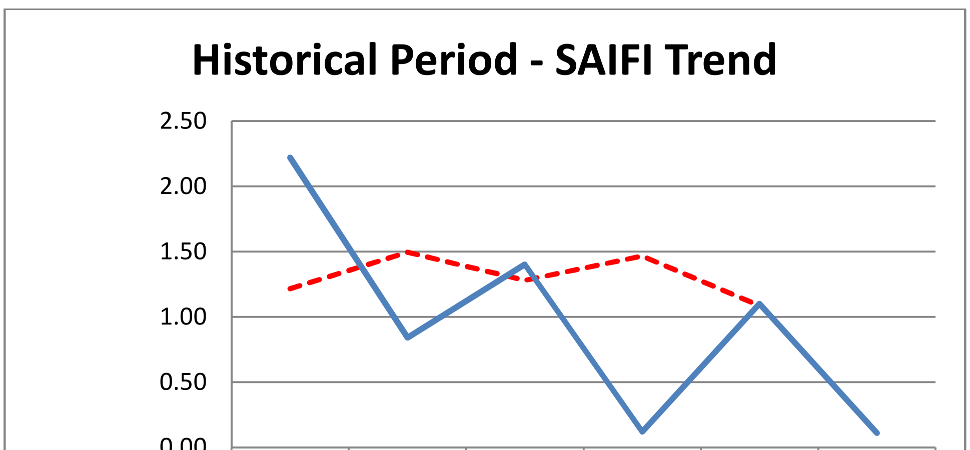
Service reliability

RHI uses the CAIDI, SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain a tight control over their capital and maintenance spending. The Maintenance Program is primarily condition based. The maintenance component addresses statutory requirements such as inspection per the DSC, as well as prudent "testing" of the plant to help identify end of life conditions for poles or overheating problems for load carrying devices on the system.



	2010	2011	2012	2013	2014	2015
Industry	1.53	3.09	1.39	3.33	1.45	
RHI	2.50	0.98	1.92	0.23	1.92	0.18

Figure 2: Historical Period - SAIDI Trend



	2010	2011	2012	2013	2014	2015
Industry	1.22	1.49	1.28	1.47	1.09	
RHI	2.22	0.84	1.40	0.12	1.10	0.11

Figure 3: Historical Period – SAIFI Trend

RHI collects and reports outage data using the standard format and codes specified in the RRR document. The data is transferred to an Excel spreadsheet for ease of producing standard and custom reliability reports. Calculations are made to determine the reliability indices SAIDI, SAIFI, and CAIDI. The data are also sorted to determine frequency and duration for each individual feeder, and also sorted to determine cause and affected components.

Reliability statistics for the historical period are presented as follows:

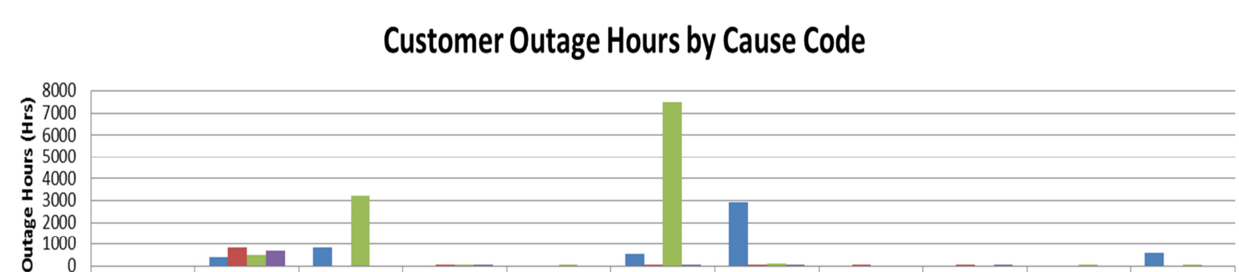
	2010	2011	2012	2013	2014	2015
CAIDI	1.12	1.17	1.37	1.91	1.27	1.73
SAIDI	2.50	0.98	1.92	0.23	1.92	0.18
SAIFI	2.22	0.84	1.40	0.12	1.10	0.11

Figure 4: Reliability Statistics for the Historical Period

(2010 – 2013 are adjusted for loss of supply as presented in the yearbook; 2013 indices include ice storm outages; 2014 is loss adjusted based on outage coding provided)

Outage causes

Outages are categorized by cause codes; the number of customers affected and the duration of a given outage are collected and reported. As RHI continues with its capital replacement and infrastructure renewal programs, the number of outages due to equipment and vegetation has been reduced. RHI believes that by continuing its steady improvements to the system, the reduced outages trend will continue.



	Description	Scheduled	Loss of Supply	Tree Contact	Lightning	Defective Equipment	Weather	Adverse Environment	Human Element	Animal	Other
2011	0	381.3	836.4	0	0	566.5	2943.1	0			608.5
2013	0	827	0	23.25	0	68	28.25	4	15		
2014	0	515	3206	9	24	7518	103			4	22
2015	0	695.86	0	2	0	73.88	4.5	0	5.7	0	0

The majority of outages in the historical period have been caused by scheduled outages, loss of supply, defective equipment or weather. As a result of the outages in 2014, RHI replaced defective equipment in the system to ensure a continued reliable supply of electricity to its customers. Subsequently, few outages have been caused by defective equipment. RHI's maintenance and inspection program has been an effective means of replacing infrastructure at EOL. RHI has control over neither weather nor loss of supply but has effectively managed its outages through the historical period. RHI will continue to diligently maintain, inspect and service its equipment so that useful life is maximized.

Standard performance indicators - ESQRs

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90%	100	100	100	100	100
High Voltage Connections	90%	N/A	N/A	100	N/A	N/A
Telephone Accessibility	65%	90.30	79.3	87.8	89.4	95.8
Appointments Met	90%	100	100	100	100	96.9
Written Response to Enquiries	80%	N/A	N/A	100	100	100
Emergency Urban Response	80%	100	100	100	100	100
Emergency Rural Response	80%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10%	7.0	10.6	9.6	6.1	4.2
Appointment Scheduling	90%	100	100	100	96.1	95.8
Rescheduling Missed Appointments	100%	N/A	N/A	N/A	N/A	N/A
Reconnection Performance Standard	85%	100	100	100	100	100

Figure 5: Standard Performance Indicators

Standard performance indicators – Scorecard

RHI's belief in continuous improvement is reflected in all areas of its operations. Similar to most utilities in Ontario, RHI must replace aging distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to strategic replacement of aging assets, RHI continues to focus on core maintenance activities, such as transformer maintenance, distribution station maintenance, and vegetation control, including tree trimming activities, to reduce the disruption of electricity distribution to our customers.

RHI focuses on short and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

			2010	2011	2012	2013	2014	2015	Industry Target	RHI Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected On Time	100%	100%	100%	100%	100%	100%	90%	100%
		Scheduled Appointments Met On Time	100%	100%	100%	100%	100%	96.90%	90%	100%
		Telephone Calls Answered On Time	85.50%	90.30%	79.30%	87.80%	89.40%	95.80%	65%	100%
	Customer Satisfaction	First Contact Resolution					87%	99.60%		100%
		Billing Accuracy					99.82%	99.54%	98.00%	99.50%
		Customer Satisfaction Survey Results					92%	92.00%		99%

Figure 6: Scorecard – Customer Focus

Year over year, RHI has consistently exceeded the OEB targets for customer satisfaction and service quality as part of the customer focus section of the scorecard. When corporate and asset management objectives are aligned with OEB performance outcomes and when RHI involves customers in discussions to understand their preferences and concerns, the result is an increased level of satisfaction. RHI's customer service representatives answer a changing number of phone calls per year within the 30 second window prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of RHI's dedication to being an organization focused on customer service.

			2010	2011	2012	2013	2014	2015	Industry Target	RHI Target
Operational Effectiveness	Safety	Level of Public Awareness								
		Level of Compliance with Ontario Regulation 22/04	C	NI	C	C	C	C	C	C
		Serious Electrical Incident Index - Number of General Public Incidents	0	0	0	0	0	0	0	0
		Serious Electrical Incident Index - rate per 10,100, 1000 km of line	0	0	0	0	0	0	0	0
	System Reliability	Average number of Hours that Power to a Customer is Interrupted	2.5	0.98	1.92	0.23	1.92	0.18		0.23 - 2.50
		Average Number of Times that Power to a Customer is Interrupted	2.22	0.84	1.4	0.12	1.1	0.11		0.12 - 2.22
	Asset Management	Distribution System Plan Implementation Progress					82%	75.00%		
	Cost Control	Efficiency Assessment			4	4	4	4		
		Total Cost per Customer	$529	$559	$561	$561	$559			
		Total Cost per km of Line	$39,941	$42,516	$42,980	$39,493	$30,047			

Figure 7: Scorecard – Operational Effectiveness

The operational effectiveness portion of the scorecard shows RHI's continuous improvement in productivity and cost performance including reliability and quality objectives. RHI has exceeded the targets in each category in addition to demonstrating an improvement trend in its reliability statistics. This is attributed to prudent management of the system, its asset management process, and method of capital project prioritization. For four consecutive years, RHI was placed in Group 4 in terms of efficiency. Group 4 is considered "fair" and is defined as having actual costs within 10% to 25% of predicted costs. RHI's forward looking goal is to be a more efficient group; management's expectation is that its efficiency performance will not decline. RHI notes that its total cost per customer has increased by 6% since 2010. Going forward RHI will continue to implement productivity and efficiency improvements to help offset some of the costs associated with distribution system enhancements, while maintaining the reliability and quality of its distribution system.

			2010	2011	2012	2013	2014	2015	Industry Target	RHI Target
Public Policy Responsiveness	Conservation & Demand Management	Net Annual Peak Demand Savings (% of Target)		17.07%	27.11%	34.28%	52.29%	52.29%		1.05 MW
		Net Cumulative Energy Savings (% of Target)		42.30%	69.31%	79.69%	96.36%	96.46%		4.86 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100%		100%	100%		100%
		New Embedded Generation Facilities Connected On Time				100%		100%	90%	100%

Figure 8: Scorecard – Public Policy Responsiveness

In response to public policy, although RHI has not managed to attain its CDM targets through the historical period, it has managed to excel in the area of renewable connections. In the historical period RHI had one CIA and no micro-embedded connections. All of the work was completed within the prescribed time limits. With respect to conservation programs, typically the prime candidates for demand savings programs are large industrial and manufacturing customers. The Renfrew region has a very light industrial and manufacturing customer base, so the opportunities for significant demand savings in Renfrew are minimal. However, RHI is continuing to offer a number of provincial initiatives to further reduce the peak demand requirements.

			2010	2011	2012	2013	2014	2015	Industry Target	RHI Target
Financial Performance	Financial Ratios	Liquidity: Current Ratio	1	2.26	2.12	1.71	1.65	1.64		
		Leverege: Debt Ratio	0.89	0.84	0.81	0.78	0.77	0.76		
		Profitability: Deemed ROE		9.85%	9.85%	9.85%	9.85%	9.85%		
		Profitability: Achieved ROE		8.39%	5.36%	4.50%	2.92%	-0.92%		

Figure 9: Scorecard – Financial Performance

RHI reports on financial ratios to ensure that financial viability of the utility is maintained and to demonstrate that savings achieved in the operational effectiveness portion are sustainable. The ratios provide a perspective regarding liquidity, the degree of leveraging and profitability. While RHI's current ratio is in a declining trend, its current ratio is that of a healthy organization. This reflects the RHI's financial obligations created by capital projects financed through both cash flow and through its line of credit. RHI's degree of leveraging is decreasing because regular payments are being made to pay down financing of capital programs. RHI has typically achieved profitability within the OEB approved earning threshold of the deemed or expected return on equity. In 2012, 2013, 2014 and 2015, RHI achieved a profitability that was outside of the OEB range allowed of distributors. RHI plans to return to performing within the acceptable OEB range for profitability through the rebasing of its rates.

Cost effectiveness and efficiency

RHI's historical five-year cost per customer has averaged $554 per customer.

RHI's past 5-year cost per kilometer of line has averaged $38,995 per km of line.

RHI's Efficiency Assessment rating is 4.

c. (5.2.3c) Impact on performance and the DS Plan

Explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

Customer service feedback

RHI completed three customer surveys since 2014. Customers are surveyed to solicit high level feedback regarding their perception of RHI's performance and where they think RHI could improve service. The survey results indicate customer satisfaction is high but daily customer interactions show a trend that indicates that there is concern in the service area over price that reliability is a key factor and that customers are satisfied with RHI's reliability and that bills are confusing and should be simplified. RHI does its best to ensure that there is education within the community regarding pricing, conservation programs and ways and means to reduce power bills.

Customer-oriented performance: service reliability

RHI calculates and monitors reliability statistics for all customers within the service area. These statistics are calculated based both on all outages and also for all interruptions excluding loss of supply. RHI capital project planning and implementation will assist in shortening the duration and reducing the frequency of outages in the service area.

Customer-oriented performance: power quality

RHI will continue to ensure that ratepayers in the service area and supplied with reliable and quality power.

Cost efficiency and effectiveness – Project Progress

RHI measures and tracks the progress of projects in the current year capital program. This measure is internal and allows RHI to respond sooner to project deviations and to ensure successful project completion by year end.

Asset/Systems Operations Performance: safety

RHI monitors safety related incidents. RHI has a steady track record of safety through the historical period. We meet our safety target and compliance requirements with zero serious general safety incidents. RHI is planning to assess and raise the public level of electrical safety awareness and will identify further requirements in this area as needed.

Asset/Systems Operations Performance: Reg. 22/04

RHI monitors and tracks its compliance with Ontario Regulation 22/04 for design, construction and maintenance. RHI has a steady track record through the historical period and met targets for zero non-compliances during audits and due diligence inspections.

(5.3) Asset Management Process

(5.3.1) Asset Management Process Overview

(This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates.)

Key elements of the process that drive the composition of RHI's proposed capital investments are highlighted along with RHI's asset management philosophy. The relationship between RRFE outcomes, corporate goals, asset management objectives, and the linkage to the selection and prioritization of RHI's planned capital investments is explained.

The components of the asset management process that RHI has used to prepare its capital expenditure plan are identified, including inputs, the data sets, primary process steps and outputs. The information generally used throughout the DS Plan is based on available information established between early-2015 to mid-2015, and should be considered as current.

This is the first DS Plan to be filed by RHI, and as such, there are no important changes to the asset management process identified from a previously filed DS Plan.

Looking forward, the next steps planned to improve RHI's asset management process have also been identified in as much detail as is available.

The RHI asset management plan for 2017-2021 proposes annual investments to

- upgrade or replace aging breakers, conductors, insulators, transformers, wooden poles, and a bucket truck,
- service new subdivisions with underground connections
- invest in more smart technology
- make better use of smart meters to quickly pinpoint the source of power outages and deploy crews
- reduce energy waste and losses by using technology to monitor and manage remote substations for loading and outages, feeder and phase balancing, voltage reduction and load management
- handle the increased demand created by digital, computer equipment and technology in homes and businesses
- invest in staff through training, and
- ensure sufficient capacity for future growth.

a. (5.3.1a) RHI's asset management objectives

(A description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments)

RHI's asset management objectives form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan necessary to sustain RHI's electrical distribution system. The objectives provide guidance to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets. The objectives identify an initial starting point and are developed, enhanced, or adjusted so that they are aligned with RHI's business environment. The qualitative asset management objectives have been integrated into RHI's Capital Investment Process (CIP) to prioritize investments for five years including the bridge and test years.

RHI's asset management objectives are linked to the corporate vision and mission. Asset management objectives describe the specific and measureable outcomes required of the asset management system and are used to measure the success of the Asset Management Plan.

RHI's multi-level commitment to its stakeholders is reflected in these asset management objectives:

- to construct, maintain and operate all assets in a condition safe to staff, contractors and the public
- to actively manage distribution assets to optimally balance system investments and reliability
- to align asset investments with customer expectations of cost, reliability and service performance
- to continually seek out, develop and deliver sustainable cost efficiencies relating to asset deployment, operations and maintenance
- to manage the pace and magnitude of asset investments over the long term, to level customer rate impacts while maintaining corporate financial stability and continuing to deliver economically reliable power to customers
- to ensure that environmental considerations are taken into account in the design and management of the distribution system
- to satisfy growth and loading needs by managing capacity and asset utilization;
- to incorporate and leverage the benefits of new technology

The goals and objectives are used throughout RHI's asset management approach and are embedded within the asset management policy, strategies, and plan. Key tactical initiatives are included to achieve the objectives. The goals and objectives will have targets established to determine the measure of success of the asset management programs and practices. Conceptually, objectives will most likely revolve around, but not be limited to safety, reliability and cost efficiency.

The table below shows the linkages between RRFE Outcomes, corporate objectives and asset management objectives:

RRFE Outcomes	Corporate Objectives	Asset Management Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Safety first	Construct, maintain and operate all assets in a safe manner	1. Lost/non-lost time 2. ESA Non-Compliance	1. WSIB rate class 10 year benchmarks 2. Zero (Max 1 N)
Operational Effectiveness	Reliability in electricity delivery	Actively manage distribution assets to optimally balance system investments and reliable supply of electricity delivery	1. SAIDI 2. SAIFI	1. SAIDI within range of past 5 year performance 2. SAIFI within range of past 5 year performance
Customer Focus	Excellence in customer service	Align asset investments with customer expectations of cost, reliability and service performance	1. Customer Survey	1. Customer survey results => previous year for : a) Customer Care b) Company Image c) Mgmt Operations
Financial Performance	Financial integrity	Manage the pace and magnitude of asset investments over the long term, to level customer rate impacts while maintaining corporate financial stability and continuing to deliver economically reliable power to customers	1. Investment spending 2. Investment scheduling	1. OM&A expenditure +/- 15% to estimate; Capital expenditure +/- 15% to estimate 2.>80% annual projects/ programs completed on time
Public Policy Responsiveness	CDM	Ensure that conservation programs are implemented and effective.	1. Cumulative Energy Savings 2. Peak Demand Savings	1. RHI target of 4.86 GWh cumulative 2. RHI target of 1.05 MW net Annual Peak Demand

Figure 10: Linkages between Corporate Objectives and RRFE Outcomes

b. (5.3.1b) Asset Management Components

(Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments)

- *asset register*
- *asset condition assessment*

- *asset capacity utilization/constraint assessment*
- *historical period data on customer interruptions caused by equipment failure*
- *reliability-based 'worst performing feeder' information and analysis*
- *reliability risk/consequence of failure analyses)*

Asset management process

In KPMG's March 10, 2009 report to the Board, titled Review of Asset Management Practices in the Ontario Electricity Distribution Sector (the "KPMG Report"), KPMG referred to a concise definition of asset management to highlight the main elements as: a process to optimize performance, costs and risks relevant to service delivery. This summary definition was supplemented, by five main processes

- inspection,
- maintenance,
- capital planning,
- capital financing, and
- information management.

Four to six key practices for each process describe an ideal asset management approach, referred to as the "maturity model".

RHI's approach to asset planning covers the five key processes identified in the KPMG Report and meets the requirements of the OEB. RHI's review begins with a review of system performance and whether that performance meets management objectives.

The conditions of assets are assessed based on field inspections, life expectancy, fault frequency, maintenance costs and customer service impacts. Assets are replaced when required to maintain distribution service and system reliability (non-discretionary expenditures) or when replacement is determined to be more economic from a ratepayer perspective than asset refurbishment and/or ongoing maintenance (discretionary sustainment capital).

RHI uses several sources of data to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. The sources of data feeding into the asset management process include

- customer engagement activities,
- inspection and maintenance programs,
- Geographic Information System,
- system loading vs. capacity,
- reliability information,
- internal and external drivers,
- asset condition assessment, and
- outage information.

There are a number of internal and external drivers which have an impact and contribute to the asset management process. Within most driver categories, there can be two distinct needs types: non-discretionary requiring RHI to address them, and discretionary for which RHI has to make a decision—whether or not the need must be addressed immediately, at some future time, or not at all. Drivers include

- safety,
- customer considerations,
- regulatory initiatives,
- elimination of safety or environmental/health risks,
- system reliability,
- municipally-driven projects,
- infrastructure renewal projects,
- fleet/tools, and
- information technology and corporate administration.

In general, the overall approach used to select the candidate capital projects to be considered in any year has been consistent. The criteria considered encompasses

- employee, contractor, and public safety,
- system reliability,
- service quality,
- rate impact,
- operational efficiency,
- cost effectiveness,
- environmental effects,
- project interdependencies
- regulatory compliance, and
- stakeholder' concerns.

Although safety and compliance are prerequisites for all projects, the weighting of the other criteria can vary depending on the current system requirements and the relative impact of each project. While judgment is required when operating under either the current or the proposed planning approach, the decision-making process has been improved through enhanced access to system and asset data.

Capital spending is driven by capital needs' identification. Projects are identified as potential candidates for the annual budget, and the total projected capital expenditures for the year are assessed with regard to

- previous spending levels,
- rate impacts,
- customer service value,
- shareholder investment and,
- the requirement to proceed with non-discretionary projects.

The budgeting process involves both a bottom-up and top-down approach. Once assessed against the factors, the capital plan and the finance plan is submitted to the RHI Board of Directors for discussion and approval. The accompanying finance plan is assessed to ensure that the OEB deemed equity structure is maintained and there are no adverse impacts on the debt service coverage ratios. The approved capital budget sets the spending envelope for the current year.

RHI's overall capital budget spend envelope is set during the annual budget review but capital spending within the envelope may be adjusted throughout the year to meet changing capital requirements on an as-required basis through quarterly reviews.

These reviews identify any material dollar reallocations, both increases and decreases to individual approved capital project budgets while maintaining the overall approved capital budget spend envelope. For example, capital funds may be required for a non-discretionary spend due to storm damage from extreme weather conditions, or a road relocation project that had not been previously identified by municipal or county road authorities. Any capital project in which detailed engineering design identified a difference between the preliminary planning estimate and the detailed engineering design would be reviewed. Project interdependencies, resource availability, cost and risk assessments, and capital availability could cause a reconsideration. Over the last four years, RHI's adapted Capital Investment Process (CIP) has been used to effectively manage its assets and capital expenditures. Similar to the process in the KPMG report, the current CIP meets RHI's regulatory, safety, operational and customer needs.

Non-Discretionary vs. Discretionary Capital Projects

Non-discretionary capital projects are automatically included in the capital budget based on their need and include:

- emergency replacement of failed equipment (system renewal)
- safety-related projects (system service)
- new/enhanced customer service connections (system access)
- plant relocation projects necessitate by road construction (system access)
- mandated service obligations—regulatory, legal, or road authority (system access)
- renewable energy projects (system access)

All other projects not mandated are deemed discretionary. Evaluating the absolute or relative importance of these proposed investments in distribution assets can be an intricate task. There are often competing requirements for available resources in any year. The decision to recommend an individual project in the current year is made by senior management based upon consultation with stakeholders, established criteria and the best information available at the time.

RHI uses a combined needs and risk-based approach to considering discretionary capital projects. This evaluation generally takes into account a range of criteria including: health and safety concerns, load and customer growth projections, regulatory and environmental requirements, system reliability, life expectancy, operational efficiency, and optimal lifecycle costs.

	Criteria	Weighting
1	Safety	25.00%
2	Regulatory	15.00%
3	Environmental	15.00%
4	Quality/Reliability	15.00%
5	Customer Considerations	10.00%
6	Financial	10.00%
7	Operational	10.00%
	Total	**100.00%**

Figure 11: Discretionary Project Criteria Weighting

The criteria below, applied to discretionary candidate capital projects, is used to convert subjective (qualitative) issues into objective (quantitative) results to aid in project to project comparisons.

Public safety considers whether there is any impact on public safety, or, is the project very likely to reduce risk of a public injury or damage over the next 10 years. Where the risk of public safety is known and the probability of occurrence and degree of harm are unacceptable, remedial action is taken and the investment is treated as non-discretionary.

Worker safety considers whether there is any impact on worker safety, or is the project likely to reduce risk of a worker injury. The same approach is used as in the response to public safety concern described above.

Regulatory considers to what extent the project relates to the OEB requirements including RRFE objectives, and to what extent the license or business may be affected

Environment impairment considers the impact on risk of environmental impairment, and whether or not the project would reduce the risk of an environmental incident once every 10 years. The degree of harm, probability of occurrence and financial impact of deferred remediation are assessed.

Environment footprint considers the project impact on RHI's environmental footprint, or whether it will reduce the company's GHG (losses, emissions, wastes, etc.). As a leader in conservation and energy efficiency, RHI must be true to its values in this area and as it sets a high standard for its customers to encourage CDM, energy efficiency and renewable generation.

Reliability considers to what extent the project impacts the power system reliability and customer service. If it will definitely eliminate a sustained feeder outage, the economic benefit can be quantified. If the reliability improvement is more global as with redundancy investments, then the benefit is qualitative.

Power quality considers the project impact on the power quality. RHI must deliver a specific quality of power (voltage, regulation, etc.); and investments required to maintain this level of service can range from non-discretionary where the power standard is not maintained to discretionary when the quality is acceptable.

Customer satisfaction considers the project impact on RHI's ability to maintain or improve Electricity Service Quality Requirements (ESQRs). At a certain level, investment in this area may be considered non-discretionary when a distributor is ordered to improve its service quality and an asset investment is required. Where the distributor is performing at an acceptable ESQR level, increased investment to enhance service would normally be considered as discretionary spending.

Customer perception considers whether the project has a perceived value to the public. A project may be perceived as having a negative impact on the public, the immediate area or an individual customer. In each case, while customer perception must be considered and appropriately managed as part of any project, perception will not be the only deciding factor.

Financial considers whether a project will have a positive impact or return on investment.

End of Life (EOL) considers whether the asset in question has more than 50% remaining expected life, or, if it is within two years of expected or predicted useful operability. The closer an asset is to its expected obsolescence and/or end of life, the higher the need to replace in order to avoid a service disruption or a safety issue. The replacement of critical assets that have exceeded their life expectancy could be considered as non-discretionary investments in certain situations if there are safety or reliability concerns.

Maintainability considers whether workers will be able to continue to maintain the system or the equipment, and whether actions will improve the ease, degree, and frequency of maintenance. Investments that facilitate maintenance, improve employee morale and/or lower maintenance costs are classified as discretionary sustainment.

Operability considers whether workers will be able to continue to operate the system or the equipment, and if it will improve the ease and flexibility of system operations. Investments that facilitate system operations, improve employee morale and/or lower operating costs are classified as discretionary sustainment.

Asset management components

Asset register

RHI's GIS is the database for all of its distribution assets and serves to be an accurate model of RHI's physical electrical distribution system. The asset source data in the GIS feeds the ACA process. Details of each asset is collected and updated accordingly. Asset data is input from a multitude of sources including, but not limited to: construction as built records, legacy records, annual inspection and maintenance program results, trouble calls, fault information, etc. As the asset is visited through planned inspections or maintenance, the asset data is verified, corrected or updated. The information in the GIS, such as location, asset ratings or specifics of the asset, installation date, manufacturer or supplier, asset style, last inspection date, last maintenance date, etc., in whole will describe the asset.

Search and filter functions will allow specific fields to identify specific assets based on search criteria.

Asset condition assessment

RHI maintains a full schedule of distribution asset inspection and maintenance programs operating on a three-to-six year rotation as required by the OEB's DSC (DSC). In-field inspection, maintenance, testing, operational data, and action taken is collected and recorded by the company and is used to maintain and update the asset source data and support RHI's operating and capital expenditure plans.

Completion of the inspection and maintenance programs is not only a matter of compliance, but results from the inspection and maintenance programs allow a continual update of the asset database. The programs mean that assets are visited regularly and their condition assessed so any necessary actions are taken as promptly as possible in a proactive approach based on what is found, in particular if any safety hazard or concern is identified. As with every other Ontario distributor, RHI's inspection and maintenance programs are audited on a yearly basis as required by Ontario Regulation 22/04. RHI has achieved compliance in this portion of the audit each year, except for 2012, since the regulation came into effect in 2004.

An asset condition assessment process (ACA) is used which involves the collection and interpretation of condition and performance data of key assets, evaluates the condition of the asset, detects and quantifies long-term degradation of the asset, serves as an aid in prioritizing and allocating sustainment resources in order to be able to make informed capital investment decisions. The ACA model receives inputs from a variety of sources in the asset management lifecycle. The result of the ACA is an optimized lifecycle plan based on asset sustainability.

RHI has demarcated the inspection zones as follows:

Zone 1: South of Hall Avenue, East of Raglan St. S.

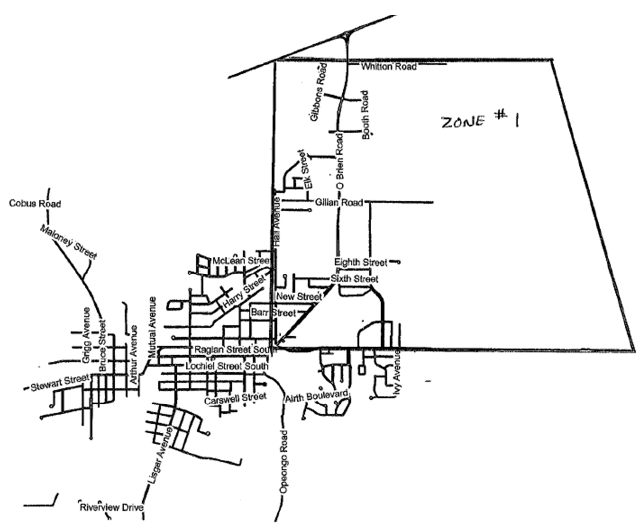


Figure 12: Vegetation Management and Inspection Zones – Zone 1

Zone 2: South of Opeongo Road, West of Raglan St. S.

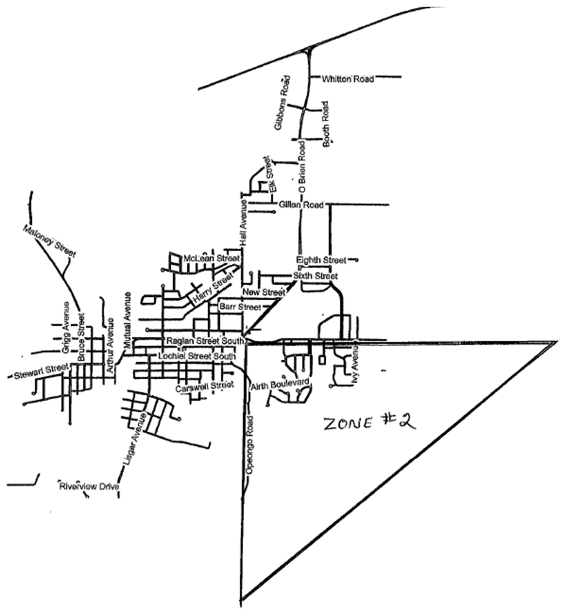


Figure 13: Vegetation Management and Inspection Zones – Zone 2

Zone 3: area bounded by Opeongo Road, Raglan St. S.

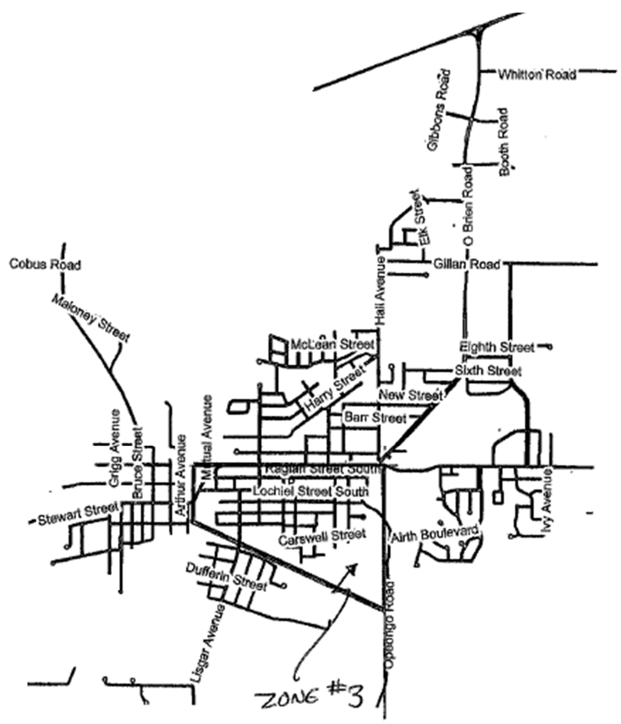


Figure 14: Vegetation Management and Inspection Zones – Zone 3

Zone 4: Arthur Avenue, Zone 3 and service area boundary

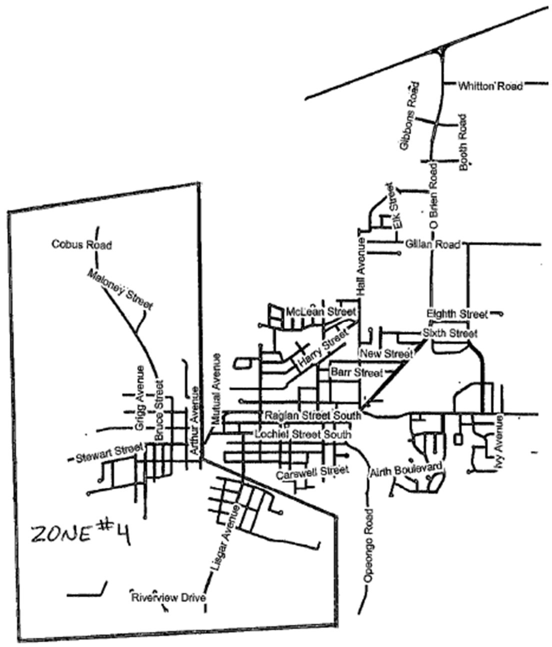


Figure 15: Vegetation Management and Inspection Zones – Zone 4

Zone 5: Ball Avenue, Raglan St. S., Mutual Avenue

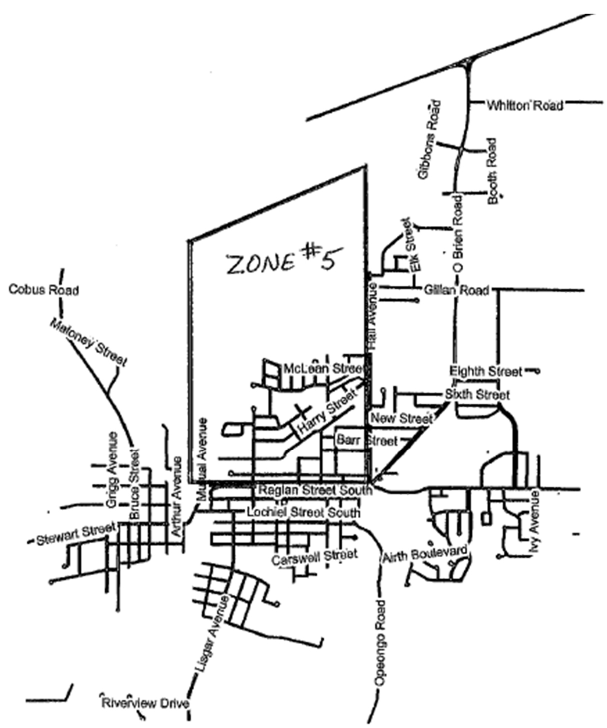


Figure 16: Vegetation Management and Inspection Zones – Zone 5

Asset capacity utilization/constraint assessment

The design of RHI's distribution system reflects industry practices and safety standards. RHI places a high level of importance on ensuring its distribution system reliability meets the expectations of its customers. RHI strives to continually improve its processes for collecting, measuring, analyzing and utilizing outage information in order to effectively manage distribution system reliability in its service territories.

When there has been a failure of an asset, root cause analysis is used to determine the cause of the failure and if failure trending exists, targeted plant replacements are made to try to mitigate any future failures. The failure of the asset is recorded, and the cause inputs to maintain and update the asset source data for assets in the GIS.

Outages are monitored by a third party and mostly on a reactive basis. As RHI does not have a SCADA system or a formal OMS system, it relies upon an after-hours phone system linked to local first responders within the Town of Renfrew to provide outage notification and smart meter outage data to provide sequence of events information. Due to the nature of the service area, RHI is quickly apprised of the condition of the distribution system.

Historical period data on customer interruptions

After the outages in 2014, RHI endeavored to replace defective equipment on the system to ensure the continued reliable supply of electricity to its customers. Subsequent to this effort, few outages have been caused by defective equipment. RHI's maintenance and inspection program has been an effective means of replacing infrastructure at EOL.

(5.3.2) Overview of Assets Managed

(Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed.

(a description and explanation of the features of the distribution service area e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan)

a. (5.3.2a) Service area

The service area that RHI operates in is entirely an urban area with no rural portions. This is shown in the map in Figure 17: Town of Renfrew Service Area.

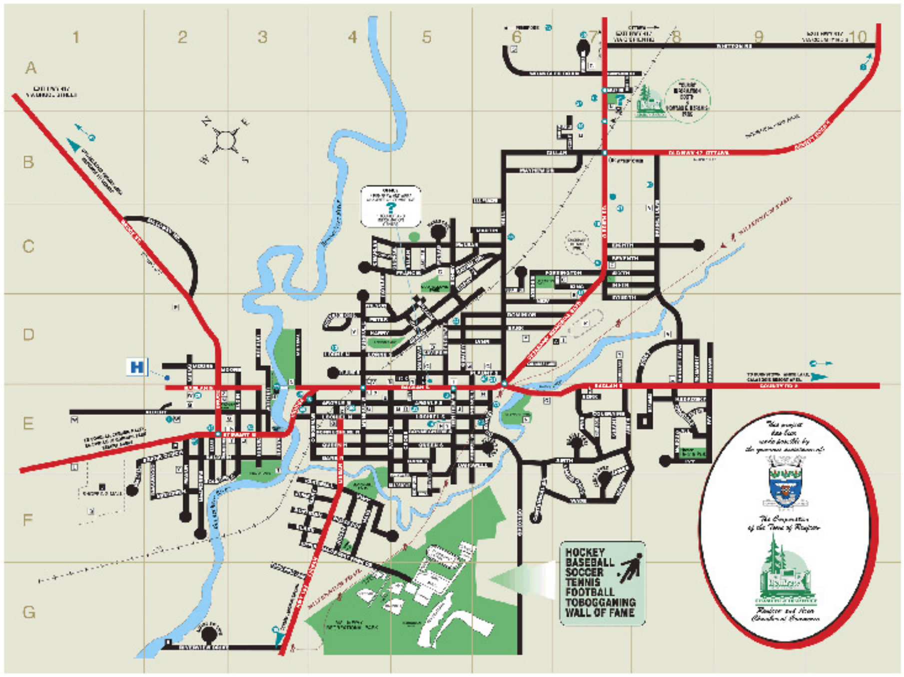


Figure 17: Town of Renfrew Service Area

RHI serves approximately 3,700 residential customers and 500 (GS type) customers and provides service to approximately 1100 street lights and 7 traffic control lights. Renfrew's population has increased by 4% to 8,218 since 2006, and has experienced only modest infrastructure growth.

The climate in the RHI service area is a humid continental climate (Köppen *Dfb*) with four distinct seasons, warm summers, cold snowy winters and no dry season. The average annual temperature in Renfrew is 11C with a range between -18C and 27C. Extreme temperatures are possible and the extremes range from -44C to 38C. The average annual precipitation is 811mm, with rain in the summer months and snow in the winter months. Average monthly precipitation is 68mm.

b. (5.3.2b) Description of system configuration

(a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations)

RHI is supplied power from two transformer stations and three 44kV breakers, all owned and operated by Hydro One Networks Inc. RHI distributes electricity to the Town of Renfrew at primary distribution voltages of 4kV and 2400V (through five 4kV substations). RHI's licensed service area is 12.8 square kilometres of urban service area. RHI's distribution system is made up of approximately 72 kilometres of overhead lines, eight kilometres of underground lines, and 645 distribution transformers. There are no significant drivers for expansion and growth in the area.

Stations

RHI's service area is supplied by several 44 kV feeders from a Hydro One owned transformer station. This voltage is stepped down to provide electricity service within the service area. Currently RHI operates primarily at 4.16 kV and 2400V through the service area.

RHI conducts monthly inspections of each of the its five owned substations while maintaining a substation maintenance program. This program includes annual transformer oil testing at all sites and a routine rotating maintenance shutdown every five years at each substation. Shutdown activities include load interrupter switch maintenance, general cleaning and inspections, and electrical diagnostic testing such as transformer insulation resistance and ratio. Routine protection relay re-verification and circuit breaker maintenance are also scheduled. The utility employs a qualified contractor to perform annual thermal scanning of our substations.

During each of the scheduled activities, defects are repaired or an action plan for future repairs is created.

Station	Voltage	Capacity (MVA)	Feeders
MS 1	44/4 kV	5/6.67	Argyle, Lochiel, Bonnechere
MS 2	44/4 kV	5/6.67	Raglan N., Hinks, Mutual
MS 3	44/4 kV	5/6.67	Plaunt, Hall West, Hall East, Gillan
MS 4	44/4 kV	5/6.67	Raglan N., Baldwin, Mall, Mateway
MS 5	44/4 kV	5/6.67	Raglan S., Scapa, Eighth, Ivy

Figure 18: RHI Feeder Listing by MS

Substation power transformers

Substation power transformers are not usually proactively replaced based solely on their age. Other factors such as power transformer condition (i.e. degree of corrosion, evidence of leaking gaskets), transformer loading, insulating oil condition and the impact of an unplanned transformer failure are also considered. In the event of a catastrophic power transformer failure, RHI has the ability to parallel all stations to supply capacity to customers with only four transformers while replacing a failed unit with a spare kept on hand.

Station	Name	Station Vintage	TX Vintage	Oil Condition	Loading (MVA)	Recommendations
MS 1	Opeongo Road	1920	2004	Acceptable	2.4	Retest annually, diagnostics within limits
MS 2	Mutual Ave	1997	2010	Acceptable	1.7	Retest annually, diagnostics within limits
MS 3	Hall Ave	1975	2000	Acceptable	3.0	Elevated CO, CO2 indicative of overheated cellulose insulation. Retest Annually
MS 4	McAndrew St.	1979	1979	Acceptable	2.6	Retest annually, diagnostics within limits
MS 5		1990	1990	Acceptable	2.3	Elevated CO, CO2 indicative of overheated cellulose insulation; elevated TDCG indicative of fault activity. Retest quarterly.

Figure 19: RHI Power Transformer Condition

Switchgear

As switchgear approach end of useful life, they are evaluated to determine if replacement is warranted or if life extension is more suitable. Factors such as load capacity, breaker type, level of automation, and future expansion capability are evaluated to determine if replacement is the best option. Safety and reliability also play a factor. For instance, arc rated switchgear is very cost effective when purchasing new switchgear and provides tremendous gains to operator safety over decades-old technology. Where oil recloser technology exists, cost-effective opportunities exist for substation automation initiatives.

Station	Switchgear	Switchgear Vintage	Manufacturer	Type/rating	Recommendations
MS 1	Main	1953	English Electric	1GB-C/1200A	Replacement planned for 2017
	Argyle	1953	English Electric	IFR/600A	Replacement planned for 2017
	Lochiel	1953	English Electric	IFR/600A	Replacement planned for 2017
	Bonnechere	1953	English Electric	IFR/600A	Replacement planned for 2017
MS 2	Raglan N	1997	Cooper	Recloser Type W/400A	Acceptable condition
	Hinks	1997	Cooper	Recloser Type W/400A	Acceptable condition
	Mutual	1997	Cooper	Recloser Type W/400A	Acceptable condition
MS 3	Plaunt	2008	Cooper	Recloser Type W/400A	Acceptable condition
	Hall West	2008	Cooper	Recloser Type W/400A	Acceptable condition
	Hall East	2008	Cooper	Recloser Type W/400A	Acceptable condition
	Gillan	2005	Cooper	Recloser Type W/400A	Acceptable condition
MS 4	Raglan N.	1979	S&C	Outdoor Fused/400A	Acceptable condition
	Baldwin	1979	S&C	Outdoor Fused/400A	Acceptable condition
	Mall	1979	S&C	Outdoor Fused/400A	Acceptable condition
	Mateway	1979	S&C	Outdoor	Acceptable condition

				Fused/400A	
MS 5	Raglan S.	1990	S&C	Outdoor Fused/400A	Acceptable condition
	Scapa	1990	S&C	Outdoor Fused/400A	Acceptable condition
	Eighth	1990	S&C	Outdoor Fused/400A	Acceptable condition
	Ivy	1990	S&C	Outdoor Fused/400A	Acceptable condition

Figure 20: RHI MS Switchgear Recommendations

RHI has an active station battery maintenance program. RHI does not anticipate replacing any battery systems in its stations in the forecast period. The rectifier/charger system and batteries are inspected on a quarterly basis and internal resistance checks are performed. Cells that show an accelerated rate of aging may trigger a load discharge test to be performed. This type of test is used to predict battery end of life and aid in budgeting for replacements. The rectifier/charger system requires little maintenance other than periodically ensuring proper operation. If the charging system fails, it is repaired based on the manufacturer's guidance.

c. (5.3.2c) Description of system profile and condition

(Information in tables and/or figures by asset type where available on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled)

RHI conducts regular line patrols. As part of these periodic visual inspections, the patrols look at visible overhead plant including poles, conductor, switches and cutouts as examples. Any anomalies are noted and flagged for more in-depth inspection and investigation. All overhead plant is inspected at periodic intervals based on the DSC. Typical useful lives can be summarized in the table below:

Description	Useful Life (yrs.)	Quantity in System	Strategy
Poles	50	1750	Risk-based replacement
Conductor	50	80	Condition-based replacement
Pole Mount Transformers	40	645	Condition-based replacement
Reclosers	40	7	Strategic replacement

Figure 21: Overhead Asset Strategy

Poles

RHI currently has approximately 1750 poles across its service area. Poles regularly undergo visual inspection during periodic line patrol inspections. This condition assessment is correlated with risk parameters based on the location and use of the pole to determine which poles require replacement in a year.

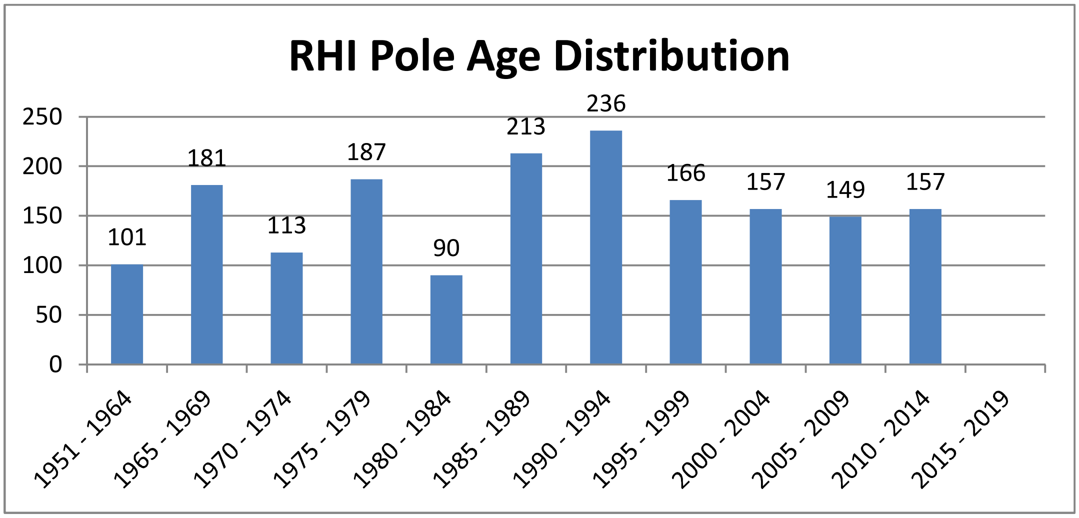


Figure 22: Pole Age Distribution

Conductor

With approximately 80 km of installed line on the system, the 4 kV infrastructure within the Town of Renfrew consists of recently installed conductor. There are no current plans to implement voltage conversions, the condition of distribution circuits at all the voltage classes is monitored and conductor is replaced as the condition warrants. Typically older spacer cable and conductor is also replaced when pole replacements are done. RHI is planning to incorporate thermography as part of its regular maintenance program. RHI believes this type of monitoring and analysis will provide key information to locate and maintain trouble locations in the system.

Transformers, switches and protection

RHI currently has approximately 645 distribution transformers in service across the voltage classes. This is complemented by approximately five power transformers that form the core of the distribution station network in the system. Power transformers are inspected regularly according to DSC, and pole and pad-mount transformers are inspected by line patrol and during condition assessments.

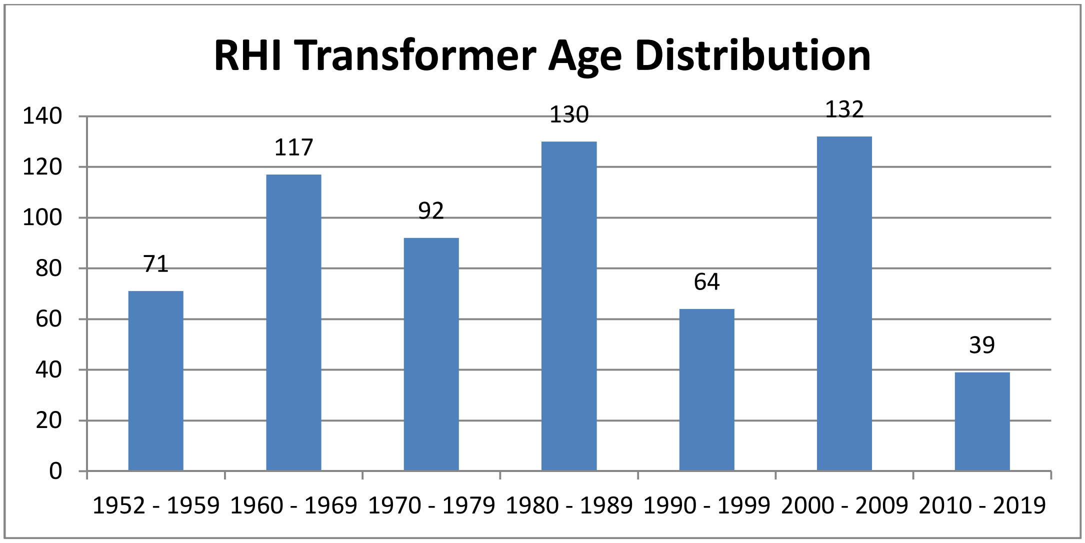


Figure 23: Transformer Age Distribution

Underground Asset Details

While primarily overhead, RHI has and operates underground plant, primarily in newer residential areas. This underground plant typically involves XLPE cable installed in direct-buried (DB) or concrete-encased (CE) ducts. Voltage is transformed and maintained through the use of pad-mount transformers.

d. (5.3.2d) System Asset Utilization

(An assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets)

RHI system losses are monitored on an annual basis. System design and operations is managed such that system losses are maintained within OEB thresholds as defined in the OEB Practices Relating to Management of System Losses. RHI ensures that the OEB threshold of 5% is not exceeded.

(5.3.3) Asset lifecycle optimization policies and practices

(An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment)

a. (5.3.3a) Asset lifecycle optimization policies and practices

(A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

• a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and

scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;

• a description of maintenance planning criteria and assumptions; and

• a description of routine and preventative inspection and maintenance policies, practices and programs (can include references to the DSC).

RHI has practices that reflect practical and prudent business approaches to implementing its Vision and Core Values. The following description of the practices demonstrates that RHI follows documented steps in the management of its assets, all of which aid in the reliable delivery of power to its customers.

RHI owns all the distribution assets within its service area. RHI is responsible for the management of all its distribution assets.

The GIS is the designated asset register for field assets and serves to be an accurate model of RHI's physical electrical distribution system. Asset data is input from a multitude of sources including construction as built records and legacy records. The system will be expanded in the future to store annual inspection and maintenance program results including inspection dates, transformer maintenance records, third-party attachments for poles, etc. As the asset is visited through planned inspections or maintenance, the asset data is verified or corrected. The information in the GIS, such as location, asset ratings or specifics of the asset, and installation date describes the asset.

The asset register is intended to hold asset attribute information as well as historical financial information over each asset's lifecycle. Currently, the GIS holds locational data, attribute data and historical non-financial information (i.e. inspection history, tests, etc.). It is the intent of RHI, over time, to continue to populate the GIS with additional non-financial and historic financial data.

The GIS System contains the relevant information for ongoing development and optimization of assets inspection, maintenance, refurbishment and replacement programs, assists with asset planning, assists in meeting regulatory/legislative compliance and IFRS accounting standards. The asset register will aid in cost control through optimization of the asset's lifecycle.

RHI maintains the efficiency and reliability of its distribution system through an active inspection, maintenance and asset management program that focuses on customer service, employee safety and cost-effective maintenance, refurbishment and replacement of assets that can no longer meet acceptable utility standards.

Maintenance planning

In the course of fulfilling its asset management responsibilities, RHI engages in the following type of maintenance programs:

- Predictive maintenance

Inspections address risk management by actively assessing condition of plant visually. Inspections are required to meet regulatory requirements, and are performed on a rotation—one-third of the system each year.

- Testing addresses risk management by actively assessing condition of plant. It is more detailed and more focused than inspection and typically involves the measurement of some aspect of the asset. This is done on an interval basis determined by the rate of deterioration of the asset.

- Preventative maintenance

Maintenance activities to extend the trouble-free operation of assets, making the activity economical and reliable, are performed on a cyclical basis and usually coincide with the inspection cycle.

- Condition-based or reactive maintenance

Corrective action and follow-up activities are necessary when a plant malfunctions or is out of specification. Occasionally, replacement is the most cost-effective way to remedy the situation.

RHI completes inspections as prescribed in the DSC, and in a manner and frequency that addresses public safety and cost efficiency. Predefined geographical areas are designated for inspection based on a three-year cycle. The individual areas to be inspected are produced by GIS and are printed for the inspection crews.

After the inspections are completed, the maps and deficiency reports are returned, processed and converted into a form to document follow-up and ensure completion within a reasonable time period.

The information is retained and available for review or verification if needed.

Predictive maintenance of overhead distribution assets

Inspections

Asset condition is determined using visual inspection. This is driven by the requirements of the DSC and ‘Appendix C’ in particular. The entire service area is inspected on a three-year cycle. The overhead and underground assets inspection areas are identified on maps—one set of maps for a particular inspection year. The overhead area uses a street map since the plant is visible when inspecting. The underground maps show the type of plant and the location of the plant to aid in the inspection. The process identifies what to inspect, how to record deficiencies, document what needs to be corrected, and when the inspection is completed.

There are separate databases containing the information of transformers and switches with pertinent device information such as nameplate data and device characteristics, and location. This information is currently resident in the GIS system.

There are five distribution stations in the service area and these stations are visually inspected on a regular basis by RHI. Detailed technical inspection and maintenance activities for RHI substations are carried out on contract by Eaton Services. RHI performs regular visual inspection only for the customer-owned stations within the service area.

In general, the condition of assets is determined to ensure that

- they are safe for the public and for competent knowledgeable staff to work on using approved procedures, and
- they are working within specifications:
  - within the device current and voltage capabilities,
  - with no deterioration to impair the ‘normal’ function of the asset, and
  - are as secure as it was when initially installed properly.

Assets must meet the requirements of the DSC, Ontario Regulation 22/04 and the relevant environmental standards such as the regulations addressing the use, storage and handling of PCBs.

The Minimum Inspection Requirements (Appendix ‘C’ of the OEB’s DSC), details the inspection standards and cycles required within the Code. Appendix ‘C’ Table C-1 defines Patrol inspection and identifies the maximum intervals for the inspection cycle patrols, which for most urban facilities including RHI is three years.

RHI’s supply area is served by a mostly urban distribution system supplying the Town of Renfrew. Its supply area consists of a single contiguous geographical zone which RHI divides into five vegetation management/inspection zones. Systematic and routine visual patrols are conducted to comply with the OEB inspection requirements (at a minimum). RHI inspects the overhead distribution system in each inspection zone, completing approximately one-quarter of the distribution system each year, as per DSC’s ‘Minimum Inspection Requirements. The visual inspections of the major distribution facilities meet the level of detail for the patrol inspection definition in the DSC.

The visual patrol inspects and assesses the condition of overhead assets, including wood poles and their supports and attachments, pole-mount distribution transformers, switches and surrounding vegetation. A lengthier description is described later. Historically, the line patrol would only produce a Line Inspection Deficiency Report highlighting deficiencies. Today, RHI uses a line inspection record to document the completion/date of inspection, the name of the inspector; when a defect is identified during the inspection, the equipment, location and condition details are listed. Line inspection records are submitted to supervisors for review. Follow-up maintenance is prioritized and scheduled, and a line advice notice is issued to a crew to correct defects. Data from inspection activities are compiled and used for reporting.

In addition to fulfilling the requirements of the DSC, the inspections allow for deficiencies and the general condition of system components and related peripheral equipment and hardware, including vegetation growth, to be realized and documented with sufficient lead time and for subsequent analysis in support of maintenance and capital planning activities.

Poles

Scheduled visual inspections of RHI poles are conducted on a three-year cycle satisfying the inspection requirements of the DSC. The condition-based assessment allows RHI to monitor and identify defects such as the integrity of the pole, concerning the condition of the pole, supports and attachments including conductor, cross arms, guys and guy guards, cable dips, etc. Defects and concerns are identified on the Line Inspection Record and detailed further through commentary on the Trouble Report.

Conductors

During the annual visual inspections, the conductors are inspected for obvious signs of deterioration. Concerns are noted on the inspection sheets and followed up.

Overhead distribution transformers, switches, protective devices and vegetation growth

Inspections of pole-mounted transformers, switches and vegetation growth are also completed as part of the cyclical visual patrol of the overhead distribution system. Deficiencies related to the transformers, switches and excess vegetation are noted on the Line Inspection Record and addressed through reactive maintenance programs.

The condition of overhead system assets is also inspected during preventative maintenance activities, mainly as a result of vegetation management.

Overhead transformers are inspected visually and problems are corrected. The strategy for this asset class is to replace based on asset condition. Feeder rebuilds and service connections trigger a review of transformer loading and sizing, and units are upgraded and/or replaced.

Overhead switches are inspected as per DSC requirements and are maintained as per the manufacturer's recommendations.

Overhead fused switches or cutouts are inspected as per DSC requirements and are also inspected when they are operated manually or after they operate automatically. Damaged cutouts are replaced.

In 2016 RHI is planning to institute an annual thermography scan of plant in the inspection zones to detect hot spots before they become issues or problems.

Transformer oil testing for PCB contamination

RHI has tested a significant number of its distribution transformers, specifically those manufactured prior to 1982, as they were returned from the field, prior to being returned to stock. "Contaminated" transformers were set aside and handled according to environmental guidelines.

Ministry of Environment guidelines define contamination as oil containing more than 50 ppm of PCB.

In 2015. RHI tested 200 transformers in its fleet. Twenty-nine of the transformers were identified as having a PCB content greater than 50 ppm. The replacement and handling of these transformers, and oil removal and disposal are included in the DS Plan.

RHI will continue to test transformers as they return from the field and handle them according to the appropriate guidelines.

Preventative maintenance of overhead assets

Vegetation management

Vegetation management, or tree trimming, is a preventative maintenance program scheduled on a five-year cycle, in which one of each of the five vegetation management zones of the distribution system is completed each year by RHI staff. Patrol inspections occur on a weekly basis and any areas requiring attention are documented and scheduled.

RHI staff monitor vegetation growth which can vary because of weather conditions and by plant species. In an exceptional growing season due to frequent rain, certain areas may be vulnerable to tree contacts two to three years from now, requiring earlier action. Since some species of plants/trees grow faster than others, RHI uses a shorter trimming cycle particularly because trimming would be too severe if left for the regular cycle. Vegetation management including tree-trimming can also be scheduled as part of preparation for a capital project.

Staff also responds to requests from the citizens to trim or remove trees in proximity to power lines.

Condition-based maintenance of overhead assets

Following pole inspections and line inspections

Trouble reports are completed for poles requiring attention and identified during the inspection program. The Trouble Reports are prioritized based on safety and risk for follow-up repair; repairs are tracked, documented and signed off when complete as per the ESA requirements.

Following vegetation management

Vegetation management, while separate from any inspections, does place RHI staff at a specific site on the distribution system. It is prudent to observe and report any defects discovered regardless of the reason. All items of concern that are observed when performing vegetation management are recorded on Trouble Reports. The Trouble Reports are prioritized based on safety and risk for follow-up repair; repairs are tracked, documented and signed off when complete as per the ESA requirements.

Predictive maintenance of underground assets

Underground inspections

Similar to the general overhead process of inspection and condition assessment, the underground distribution system is also inspected on a three-year cyclical basis to assess the condition of underground assets including pad-mount transformers, submersible transformers, underground switches, transformer vaults and civil structures. The buried assets cannot be totally inspected visually like the overhead assets, but care is taken to inspect all assets that can be seen to assess their condition. The Line Inspection Record documents the inspection completion, date of inspection and the inspector. The equipment, location and condition details of defects identified are documented in the Trouble Report. The Line Inspection Record and the Trouble Report are reviewed by supervisors. Maintenance is prioritized and scheduled, and the Trouble Report is issued to a crew to correct the defect(s). Data from inspection activities are compiled and used for reporting.

Underground distribution transformers

Inspections of pad-mount transformers occur within the visual patrol of the underground distribution system and are therefore inspected on a three-year cycle. Approximately one-third of the transformers within RHI's distribution system are inspected on an annual basis. Enclosures are opened to allow a visual check of the condition of the plant. The Line Inspection Record is used to document deficiencies such as broken bushings, oil leaks or paint chips, and condition of the concrete base—bases with cracks or deteriorated are identified for replacement.

Underground system switchgear

Inspections of pad-mounted switches occur as part of the visual patrol of the underground distribution system and on a three year cycle. Approximately one-third of the switches within RHI's distribution system are inspected on an annual basis. Inspection includes opening the enclosures so a visual check can be made of the condition of the plant. Deficiencies such as broken bushings, oil leaks or paint chips, among others, are noted on the Line Inspection Record.

Underground cable

Underground primary cable has not failed in RHI's system. Cable terminations are inspected visually in switching units and in transformers. Unless specific issues are identified, they are run to failure.

Underground secondary cable terminations are visually inspected at the transformer when the transformer inspection is carried out. Unless specific issues are identified, they are run to failure.

Condition-based maintenance of underground assets

RHI uses the inspection form for items that are discovered in visual inspections. The inspection form identified defect is classified as needing attention immediately or in a less time critical manner. Trouble reports are completed and recorded in the database. The work is dispatched to the appropriate crew(s) and the work is completed. Once the work is completed appropriate sign-offs are made to ensure the distribution system is safe for the public and staff and that the system is restored to proper working order. The original inspection forms are filed by year and are available for review if needed. The signed off trouble reports are logged in the electronic database and the paper copy signed off is retained by year and report number.

Inspection and condition assessment of distribution stations

RHI owns five municipal distribution stations in the Town of Renfrew. Regular monthly inspections are carried out on the distribution station yard and equipment and these are recorded on forms. In addition, regular planned maintenance is carried out by a specialized contractor on a two-year cycle. Any defects or deficiencies discovered are corrected as part of planned maintenance activities. If a major deficiency is discovered as a result of the monthly inspection process, this is addressed based on the risk.

Preventative and condition-based maintenance for distribution stations

RHI contracts with a specialized contractor to have the stations maintained on a five year cycle and includes a thorough condition review and correction of all deficiencies.

Any deficiencies reported as a result of the monthly inspections are addressed when the report is submitted. Minor repairs such as light bulb replacements are completed as part of the inspection. Other aspects relating to the security and the appearance of the station, such as the perimeter fence, building access integrity, vegetation within the fenced enclosure and any other work, is scheduled based on urgency and crew availability. The same urgency classification scheme is used as with overhead or underground asset deficiencies.

Maintenance of customer substations

There are 11 customer-owned substations–eight are traditional fenced enclosures and three are tamper-resistant installations. These are all 44 kV stations and are inspected visually by RHI staff as requested.

The Substation Inspection Form is the form utilized for customer-owned transformers at customer-owned substations and identifies, at a minimum, items at the substation enclosure requiring inspection. If deficiencies are found, the customer is notified and is responsible to address deficiencies. If not rectified, the Electrical Safety Authority is notified.

b. (5.3.3b) Lifecycle risk management policies and practices

(A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures).

Risk is managed by being aware of the failures that can occur on the power system and by being aware of their consequences. The replacement and mitigation of such hazards begins in more populated areas and finishes in areas where there are least likely to be people. Similarly, pole replacement is scheduled to take place at a steady pace beginning with the poles in the worst condition. Capital expenditure selection generally is based on the following in priority order:

- Safety impact on the public and staff
- Regulatory requirement or obligation
- Reliability impact
    - outage causes and frequency
    - restoration capability
    - power quality

The timing and pace of the work is determined by the following:

- Capability to complete the work
- Financial ability to pay for the work
- Completing the expenditures that provide the greatest benefit

Operations

If a major deficiency is discovered as a result of the monthly inspection process, the deficiency is addressed based on safety and risk.

The Line Inspection Record documents inspection completion, date of inspection and the person completing the inspection. The record can also indicate the equipment, location and condition details if a defect is identified. This information is also documented on RHI's Trouble Report; the latter notes the location of the defect and allows for the inspector to comment on the condition of the underground asset(s). The Line Inspection Record and the Trouble Report are submitted to supervisors for review. Follow-up reactive maintenance is prioritized based on safety and risk and scheduled, and a Trouble Report issued to a crew to correct the defect(s). Data from inspection activities are compiled and used for reporting. Repairs are tracked and when completed, signed off as per the ESA requirements.

The signed-off trouble reports are logged into the electronic database and the paper copy signed off is retained by year and report number.

Items of concern are reviewed and discussed by RHI staff or more formally through regular departmental meetings in which maintenance activities are addressed. These and other meetings also serve as the general forum for addressing distribution network items that may impact system performance and result in additional maintenance or capital investments.

RHI regularly reviews the industry standard reliability performance indices namely SAIFI, SAIDI and CAIDI. Outages are reviewed and actions are taken to address the causes of outages that have a common root.

Risk management and capital projects

The inclusion of performance data in the preparation of the capital budget is the result of direct involvement and information about system performance. It takes place as a matter of course because of the knowledge and experience of the senior leadership team. Feedback from customers is also used when considering projects for the capital budget.
Similarly for maintenance and inspection processes, detailed instructions are revised based on experience and history.

(5.4) Capital Expenditure Plan

(A distributor's DS Plan details the program of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.)

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

(5.4.1) Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';

b) total annual capital expenditures over the forecast period, by investment category (see section 5.4);

c) a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

d) a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;

e) information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

f) a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

• in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);

• to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and

• to study or demonstrate innovative processes, services, business models, or technologies.

a. (5.4.1a) Capability to connect new load or generation

As RHI is embedded in Hydro One, the upstream capacity will depend on the allocation that Hydro One provides on the given feeders.

Within its distribution system, RHI is not aware of any constraints to connecting renewable generation.

b. (5.4.1b) Forecasted capital expenditures

RHI's customer base is mature and stable. There are no new developments anticipated in the service territory nor are there any significant changes to the customer base whether residential, commercial or industrial. Consequently there is no real growth driver for capital plant. The system peak load is approximately 16 000 kW and the system has served this load adequately. Therefore there is no new plant planned or required to support the current load.

The current capital expenditures over the forecast period are shown below. These are only the following projects that exceed the materiality threshold:

OEB Category	2017	2018	2019	2020	2021
System Access	0	35	120	0	0
System Renewal	471	229	200	260	350
System Service	100	0	0	0	0
General Plant	0	350	0	0	0

Figure 24: Forecasted Material Capital Expenditures by Investment Category

- Pole replacement program
- Vehicle replacement program
- Hunters Gate subdivision developments
- Smart Grid technology implementation
- MS1 Breaker replacement

c. (5.4.1c) Effect of planning on capital expenditures

RHI has a developed a prudent capital budgeting process combined with a system of capital project prioritization that takes into account customer preferences, business performance and accountability. This system reflects its long term strategy and addresses the need for RHI to remain flexible enough to respond to priority shifts as they occur. The capital budget process takes into account the relative priorities of the proposed investments including both non-discretionary and discretionary budget items.

Non-Discretionary items include:

- Load growth and the utility obligation to connect new customers
- Projects to accommodate the Town of Renfrew, Renfrew County or other regional and Ministerial requirements
- Projects or expenditures to satisfy regulatory initiatives, environmental or health and safety risks and the company's conditions of service

Discretionary items include:

- EOL plant renewal projects
- Distribution automation
- Fleet/tools

System Access

The planned annual capital expenditures during the forecast period for connecting new customers and providing system access are in the $10,000 to $30,000 range. This is consistent through the forecast period.

- There is one material project initiated in this category. There are no projects initiated by other authorities, nor by system expansion requirements nor by renewable energy generation. There are only small customer service type activities.
- Hunters Gate Subdivision

System Renewal

The main driver of system renewal projects is the aging infrastructure within the service area

- There are a few material projects in this category:
  - pole replacement program
  - transformer replacement program
  - feeder rebuilds – Raglan St. N., McAndrew St., Raglan St., Lisgar St.
  - MS1 switchgear replacement 2017
- This program resulted from the visual inspection of distribution plant as part of the asset management program and the analysis of the age distribution of poles.

System Service

Expenditures in this category reflect the main requirement in the forecast period of the preparation for the data gathering for the forecasted OMS system through the installation of substation and feeder monitoring. Planned expenditures range from $10,000 to $100,000.

- There is only one material project in this category: Smart Map monitoring.

General Plant

The main driver behind general plant expenditures in the forecast period is the retirement of a number of vehicles to the fleet. Vehicular replacement is required and has been primarily scheduled for 2019. General plant expenditures range from $10,000 to $350,000 through the forecast period.

- There is only one material project in this category: the Vehicle Replacement Program.
- This program resulted from the visual inspection of distribution plant as part of the asset management program and the analysis of the age distribution of vehicles

RHI expects its load and customer base to remain essentially constant over the forecast period. It only anticipates minor investments for REG or smart grid based on historical experience.

d. (5.4.1d) Material capital investment projects

Materiality Threshold

Based on Section 2.4.5 of the Chapter 2 filing requirements, the materiality threshold is set based on the revenue requirement of the utility. For utilities with a revenue requirement of less than $10 Million, the materiality threshold is set at $50,000. Consequently, RHI will be reporting on all projects, variations or variances that are above this limit. The tables below provide a list of material capital projects and their costs planned for the forecast period.

Material Projects – Drivers

- EOL infrastructure replacement
- Asset condition assessment
- New load

System Access

Project	2017	2018	2019	2020	2021
Hunters Gate – Phase 5		35,000	120,000		
Total System Access	0	35,000	120,000	0	0

Figure 25: Material System Access Projects

Hunters Gate Phase 5: New Services includes supplying electrical equipment and materials to residential, commercial and industrial accounts where no electrical supply currently exists. Metering includes supplying metering equipment and materials to residential, commercial and industrial accounts

System Renewal

Project	2017	2018	2019	2020	2021
Raglan Street N	171,000				
MS-1 Reclosers	300,000				
McAndrew		229,000			
Raglan Street S.			200,000		
Lisgar Street				260,000	
Total System Renewal	471,000	229,000	200,000	260,000	

Figure 26: Material System Renewal Projects

Raglan Street – Overhead rebuild

MS-1 Reclosers – Replacement of EOL station breakers

McAndrew Street – Overhead rebuild

Raglan Street S. – Overhead rebuild

Lisgar Street – Overhead rebuild

System Service

Project	2017	2018	2019	2020	2021
Substation Monitoring	100,000				
Total System Service	100,000				

Figure 27: Material System Service Projects

Substation Monitoring: New substation feeder monitoring to accompany the breaker/recloser replacements at MS-1. These online feeder monitors will help to enable outage detection and monitoring which allows RHI to better respond to outages.

General Plant

Project	2017	2018	2019	2020	2021
Vehicle Replacement – Single Bucket Truck		350,000			
Total General Plant		350,000			

Figure 28: Material General Plant Projects

Vehicle Replacement: RHI plans to replace vehicles that are at the end of their useful life and has spread these costs across the forecast period.

e. (5.4.1e) Material impacts of IRRP

RHI serves the Town of Renfrew located in northeastern Ontario. As RHI is embedded within Hydro One, it was not invited to participate in the Regional Planning. RHI is within the Renfrew Regional Planning Group area. From a Hydro One and IESO perspective, Renfrew Region is within the Group 3 Region. A needs assessment was scheduled for the Renfrew Region in September of 2015. RHI does not anticipate any planned regional modifications that would materially affect the service area. RHI is also within the Greater Ottawa Regional Planning Group area which, from a Hydro One and IESO perspective would put it within the Group 1 Region. An IRRP Report for these regions was published in April 2015. There were no needs identified that would affect RHI.

f. (5.4.1f) Customer engagement activities

RHI continually engages its customers in various forms and assesses the effectiveness of these activities. Historically, customer interaction has identified the preference of high reliability of the system as an important feature to customers. Survey results indicate satisfaction with current service performance levels. That is an indication that plan efforts to maintain historical levels are reasonable thereby supporting system operational efforts and prudent smart grid development outlined in the plan. Concern about rates supports the need to consider rate mitigation efforts while managing risk. Survey results are implicitly considered in the development of the asset management strategy, objectives and plans.

RHI regularly engages with its customers on its website.

g. (5.4.1g) System development

In developing its five year forecast, RHI must balance the requirements of non-discretionary obligations with discretionary projects that have been evaluated and prioritized. Current levels of expenditure on system renewal and distribution automation projects have maintained reliability of the distribution system.

h. (5.4.1h) Capital Costs – customer driven projects

RHI, in direct response to customer requests has implemented a number of features on its website. Customers had requested access to their usage and billing data and in response, RHI provided customers, once registered, to log into the system and view their usage and billing data. RHI further combined this access with bill explanations to ensure that customers had an understanding of the different parts of their electricity bill.

In addition to providing online access to information, RHI has also made information and resources related to conservation programs accessible by customers through their website. This includes links to the IESO, OEB and CDM reports for those customers who wish a deeper understanding of the programs implemented by RHI.

i. (5.4.1i) Capital costs – technology based opportunities

There is one capital project in particular that is technology based and that is the installation of Smart meter based substation monitoring as part of the MS1 switchgear replacement activities.

(5.4.2) Capital expenditure planning process overview

(The information a distributor should provide includes, but need not be restricted to:

a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information; and

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).)

With its corporate emphasis on business performance and accountability, RHI has developed a prudent capital budget process and system of prioritization. This system reflects its long term investment strategy, recognizes shorter term requirements, and is capable of addressing the ongoing need for RHI to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, RHI's corporate strategies and regulatory requirements.

a. (5.4.2a) Capital Objectives – criteria and assumptions

The following high level inputs are investigated and evaluated in detail and collectively contribute to a final capital investment budget:

- Regulatory initiatives e.g., Smart meters and the *Green Energy and Green Economy Act*
- Elimination of safety or environmental/health risks
- System reliability
- Municipally-driven projects
- Infrastructure renewal projects
- Fleet/tools
- Information technology and corporate administration

These drivers align with corporate goals which are aligned with the RRFE outcomes.

New load growth and development projects

RHI connects between 0 – 50 new customers per year. RHI anticipates that this rate will continue through the forecast period and has budgeted for this in its capital plan under System Access projects. RHI does not consider load growth to be a significant driver of capital projects and spending.

Municipally-driven projects

RHI works closely with the Town of Renfrew Department of Development, Works and Planning to ensure that municipally-driven and RHI-driven projects are coordinated and executed safely and efficiently.

System reliability

With pockets of aging infrastructure and areas of mixed use adjacent to residential areas, RHI looks to design resilience into its distribution system which, in turn results in reliability for the customer. Through infrastructure renewal and system service projects, RHI expects to see a steady evolution of its measures of system reliability. In areas that experience sustained or frequent outages, RHI targets these sections for improvement and has allocated funding for projects within the overall budget envelope for forecast years.

Distribution Automation

RHI continues to replace aging infrastructure to maintain system reliability and increase resilience. As switches and load interrupters approach the end of their useful life, RHI evaluates and schedules their safe and economical replacement.

MS1 Breaker Replacement

RHI is planning to replace the switchgear at MS1 in 2017. The existing set of English electric breakers has a nameplate vintage of 1953. The 63 year-old breakers have reached the end of their useful life and replacement is scheduled for the 2017 year. RHI will be replacing them with three-phase reclosers; this will result in lower overall substation maintenance costs and consistent reliability.

Pole replacement Program

RHI has had a pole replacement program in place for a number of years. Following a condition assessment and inspection performed at the beginning of 2015, RHI has prioritized and effectively focused its efforts on the poles in worst condition. RHI has formally instituted a replacement program allocating a significant portion of its system renewal budget to the replacement of poles in poor condition before they result in an outage. RHI has planned for the replacement of approximately 40 poles/year each year for the entire forecast period.

Transformer Replacement

In conjunction with its pole replacement program, RHI has also started to monitor and track the performance and condition of its transformers. Those transformers on poles being replaced will likely be replaced especially if the transformer is old or in poor condition. In addition to this, additional transformers—pole-mount or pad-mount—have been identified by condition and performance for replacement. This condition-based replacement is an attempt to perform work under controlled conditions thereby reducing costs and passing on saving to the ratepayers. RHI has planned for the replacement of 15 pole-mounted transformers per year and one to two pad-mounted transformers per year for the forecast period.

Elimination of environmental/health or safety risks

RHI adheres to its strict safety code thereby preventing incidents and near misses. These actions cannot always remove the risks inherent on the system or due to the nature of the work. Any system state requiring the mitigation of a safety risk would be immediately moved to the forefront of implementation, and the projects within the capital spending envelope would be adjusted to account for this expenditure.

Fleet/tools

RHI currently has a number of vehicles in its fleet. Included in this list are two bucket trucks, a derrick truck, a dump truck and a pickup truck. The bucket trucks are 2000 vintage and are approaching the end of their useful life. Replacement of one of the bucket trucks is planned for the forecast period, and the second just beyond the horizon of the forecast period.

RHI has planned for the replacement of a truck in the 2018 year. Due to the aging of its assets, this replacement became a necessity to continue safe operations.

Information Technology and Services

RHI currently has a GIS system that it keeps up to date. There are no plans for implementing SCADA, and no wholesale plans for distribution automation. Through modern equipment installation as part of infrastructure renewal, RHI will be examining how to capitalize on its smart meters and other distribution automation through the use of Smart Map technology. The investment in this technology in the forecast period will enable outage management, power quality notifications, feeder and system studies, and open the door to more active management of the distribution system with data available to make real time decisions and collect pertinent data for regulatory reporting.

Renewable generation

RHI continues to perform connection impact assessments for FIT applicants in addition to connecting customers with approved FIT contracts. These projects are captured under the system access portion of the capital program. RHI anticipates approximately one to two new FIT connections over the forecast period.

Impact on customer bills

RHI has a modest capital plan that has a relatively small impact on customers' power bills. RHI is sensitive to impacts and attempts to only do what is necessary and to smooth the capital expenditures.

b. (5.4.2b) Non-distribution system alternatives

RHI does not have any specific policy or procedure related to utilizing non-distribution system alternatives for system capacity or operational constraint relief. RHI's activities in this area are delivered through the RHI 2017-2021 CDM programs in accordance with the CDM requirement included in RHI's licence as issued by the OEB. RHI's total 2017 – 2021 CDM target is 4,170 MWh.

RHI's 2017-2021 CDM programs are consistent with OEB policy and the OEB's 2015 CDM Guidelines of putting conservation first into distribution planning. RHI's CDM programs are designed to reduce electricity consumption and draw from the grid upstream of the customer. RHI's CDM program consists of IESO-funded programs.

c. (5.4.2c) Prioritization and pacing of investments

Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet customer or developer requirements. A system of project prioritization is applied that takes into account growth rates, safety, reliability and performance, condition and age, and other drivers internal or external to RHI. Other projects are selected and prioritized based on value and risk assessments for each project. System renewal projects are prioritized based on the selection criteria identified through the asset management system. System service and general plant projects are prioritized based on safety, reliability, customer preferences and internal optimization. In determining reliability priorities, RHI considers the following characteristics of its distribution system:

- Failure of one 4.16 kV feeder line interrupts approximately 5.5% of total system load
- Overhead lines take hours to repair while underground cables may take days

Project pace for System Access projects is generally determined by external schedules and needs. Although System Renewal, System Service and General Plant projects tend to be lumpy in nature and most are paced to begin and be completed within a particular budget year, RHI takes efforts to smoothen the effect on the budget within a given fiscal year. These three investment types are paced with regard to available resources and managing the program cost impacts on the customer's bill.

d. (5.4.2d) Customer engagement

RHI regularly seeks customer feedback to help shape the direction and development of community investment and outreach as well as preferred methods of communication. It is important to connect with customers to ensure that their expectations are being met and to receive suggestions on how RHI can improve their overall customer experience.

Renfrew completed a customer survey in 2014 and is completing another survey using a third party survey company on its behalf in 2016. It is anticipated the survey will be completed and results known in the second quarter of 2016.

RHI is one of the few electric utilities to still operate a full service customer counter with daily customer interaction. Customers who want to start a new account or move, pay bills, or have concerns or comments can come to the office and our Customer Service Reps will handle their problem or bring the problem to the attention of management for resolution. This face to face communication is much more informative than a survey and customers really appreciate the opportunity to deal with someone locally and know that their concerns are treated with urgency and respect.

RHI is also creating a new user friendly website for customer service interaction that will be easier to read, use, and contains all the relevant information a consumer would require. RHI also recently completed an Electrical Safety Awareness survey which confirmed RHI customers are well educated on the hazards associated with the electrical system.

RHI participated in the Electrical Safety Authority Public Awareness Survey in 2016. The survey was conducted by a third party media company through CHEC to determine the awareness of electrical safety through the ratepayers in the service area. RHI achieved a Public Safety Awareness Score of 82.6%. This score is in line with other Ontario LDCs that participated in the survey and reflects the general electrical awareness among ratepayers in the service area.

RHI participates in a number of community events throughout the year raising awareness of conservation and promoting bidirectional dialogue with its customers regarding infrastructure investment. While programs such as SaveOnEnergy and the Home Assistance program have been vital to conservation education, events such as the myFM Radio Home, Garden & Leisure Show also provides opportunities for the utility to interact with customers in a less formal environment.

"Putting the Consumer First" was part of the title of the Report of the Ontario Distribution Sector Review Panel. Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer is primarily concerned about their overall costs for their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity

In the 2014 and 2016 customer surveys that RHI commissioned, the utility received a 10.8% response from the community. The survey covered a wide range of issues relating to customer satisfactions, service levels, business operations, reliability, conservations, public safety and smart grid. The survey completed in 2014 contained separate questionnaires for residential and for commercial customers.

Of the respondents, 89% were residential customers with the balance belonging to other customer classes. The results of the survey showed that more than 97% of RHI customers rated the service they receive from the LDC as between good and excellent. From a reliability perspective, 98% rated RHI's performance as good to excellent. In the area of Customer Service, 87% indicated that they received good to excellent service from RHI's CSRs. When it comes to communications, 84% believed that RHI was between good and excellent in communicating with them. Commercial customer consisted of 11% of the respondent overall.

As a result of the feedback, the importance of maintaining a high level of reliability in the service area was identified by customers. This feedback was subsequently reflected in the current capital expenditure plan.

e. (5.4.2e) Prioritization of REG investments

RHI does not anticipate the need for additional renewable enabling investments in the distribution system through the forecast period.

(5.4.3) System Capability Assessment for Renewable Energy Generation

(This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;

b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and *e) constraints for an embedded distributor that may result from the connections.)*

As RHI is embedded within Hydro One, ultimately Hydro One will have to allocate the capacity. Based on the available information, it appears as though there is available capacity on the feeders to RHI, but the available charts do not indicate prospective or planned allocations.

a. (5.4.3a) Applications for renewable generation connection

As of March 31, 2016, RHI has connected 0.638 MW of renewable generation to its distribution system including:

- MicroFIT PV Solar: 10 projects totaling 80 kW
- Small FIT Solar: 4 projects totaling 558 kW

The renewables integration program is supported by a flow of FIT and microFIT projects in RHI's service area for the next five years. The mix of projects is forecast as microFIT and small FIT distributed generation (DG) projects.

b. (5.4.3b) Renewable generation connection forecast

RHI is expecting to maintain the current level of FIT and microFIT applications in the coming years. This forecast is based on the existing connected projects, applications currently under consideration and any capacity restraints on existing feeders. Currently, the following projects are anticipated:

- MicroFIT - It is anticipated that two microFIT projects will apply for connection over the next five years. This forecast is based on the number of connections in 2014 and 2015 to date.
- Small FIT (<250 kW connected to <15 kV; or up to 500 kW connected at >15kV) – it is anticipated that one project will request connection over the next five years.
- Large FIT – it is anticipated that 0 large FIT project will request connection per year over the next five years.
- There are currently no RESOP nor any CHPSOP projects that are planned or anticipated in the service area for the forecast period.

RHI believes projections are consistent with the rate of applications and connections that have occurred over the previous years. This includes the periods of time that the FIT program was suspended while under review by Ontario.

c. (5.4.3c) Capacity to connect REG

Currently the Hydro One Stewartville TS has the following capacity across feeders M1, M3, M4:

Short Circuit: 450 MVA

Thermal: 28.2 MW

Currently the Hydro One Cobden TS has the following capacity for RHI's backup feeder 23M2:

Short Circuit: 1298 MVA

Thermal: Thermally Constrained

Supply Station Ratings

Station Name	Min Load (MW) Note 1	SC Available (MVA) Note 1	Thermal Available (MVA) Note 1
Stewartville TS (M1) QZ Bus	8.2	450.3	28.2
Stewartville TS (M3) QZ Bus	8.2	450.3	28.2
Stewartville TS (M4) QZ Bus	8.2	450.3	28.2
Cobden TS T2 (23M2)	2.0	1298.1	TC

Note 1: These values are supplied by Hydro One at:

http://www.hydroone.com/Generators/Documents/HONI_LSC.PDF

http://www.hydroone.com/Generators/Documents/HONI_LA.pdf

for Hydro One owned stations

Figure 29: Supply Station Ratings

Analysis of station capacity

RHI's main supply is through one HONI owned transformer station, Stewartville TS. HONI has maintained this TS, and as of the last discussions with Hydro One, has no plans to further modify the station specifically for renewable generation capacity. According to Hydro One's online Capacity Evaluation Tool, there is significant capacity on the existing feeders to accommodate the planned renewable generation connections. The current and planned level of REG is well within the capacity of stations based on published ratings. Future requests will need to be evaluated to ensure that ratings are not exceeded.

Supply feeder ratings and capacity

RHI is supplied via both 10M1 and 10M3. The information available provides data for the buss in the station which feeds more than just the feeders supplying RHI.

Looking at the FIT or microFIT applications we note the following:

M1 Applications: 1553 kW of proposed REG

M3 Applications: 6540 kW of proposed REG

It is not clear how many of these applications are within the RHI service territory.

RHI has 23M2 as a back-up feeder.

Looking at the FIT or microFIT applications we note the following:

M2 Applications: 4310 kW of proposed REG

Feeder Name	Rating (AMPS)	Max Line Loading (AMPS)	Max Line Loading (MW)	Existing Generation (MW)	Pending Generation (MW)
M1	600	400	30.5	5.05	1.523
M2	600	400	30.5	0.80	4.908
M3	600	400	30.5	2.0	5.657

Figure 30: Supply Feeder Ratings

Analysis of feeder capacity

The M1 and M3 feeders from Stewartville have ample capacity for addition renewable connections, subject to capacity allocation by Hydro One. No additional projects are required to augment the available capacity to connect renewables through the forecast period.

d. (5.4.3d) Constraints Related to Renewable Generation Connection

RHI does not anticipate material costs to be incurred due to the connection of or the facilitation of connection of renewable generation projects.

Renewable connections

To date, 10 microFIT and 4 FIT projects have been connected to the system. FIT connections are sent to Hydro One for Connection Impact Assessment (CIA) and local CIA is performed by Rodan. In addition to this, in 2015 a 4MW hydro-electric project owned by Renfrew Power Generation was connected to the 44 kV system.

Summary of forecast expenditures/planned development

To date there have been no constraints to renewable generation connection identified in the system and hence no planned investment for capacity increases.

(5.4.4) Capital Expenditure Summary

The Capital Expenditure Summary provides a snapshot of RHI's capital expenditures over the ten year DS Plan window. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories on the basis of the primary driver for the investment. All historical expenditures up to 2015, in the bridge year (2016), and proposed for the 2017 to 2021 Capital Expenditure Plan are categorized as follows:

1. System Access
2. System Renewal
3. System Service
4. General Plant

Project listings and descriptions for material projects in 2017 to 2021 are described in Section 4.5.2 [5.4.5.2] Material Investments and have been allocated to the relevant investment categories.

All proposed expenditures in 2015, the test year (2017), and 2017 to 2021 Capital Expenditure Plan are categorized as follows:

System Access

- There are only a small number of projects in this category (Hunters Gate- 2 projects 2016 and 2019)

System Renewal

- There are three main projects in this category – the pole replacement program, the transformer replacement program and the 2017 MS1 switchgear replacement in addition to a number of feeder rebuilds

System Service

- There is only one project in this category related to the Smart Map feature and OMS capabilities being installed in conjunction with the MS1 breaker replacements in 2017. The sensors and software will allow RHI to record outages with greater granularity and allow analysis into outage prevention and will contribute to capital project prioritization.

General Plant

- There are only a few projects in this category above the threshold – the Vehicle Replacement Program indicates a new truck is required in 2018.

These are described in Section [5.4.5.2] Material Investments. Project listings and descriptions for 2017 to 2021 are included.

The categorization is derived from the capital expenditure planning process that prioritizes items based on whether they are discretionary or non-discretionary. These, in turn, were developed from RHI's annual performance reporting, asset management strategy and the regional planning process. RHI's systems planning for new load and forecasts for renewable generation are captured within this DS Plan.

As previously indicated, RHI does not anticipate major expenditures to accommodate renewable energy generation projects.

Figure 19 includes the historical 2012 to 2015 expenditures, as well as the current year (2016), the test year (2017), as well as the forecast expenditures from 2018 to 2021.

	Historical					Forecast				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Actual	Actual	Actual	Actual	Budget	Budget	Budget	Budget	Budget	Budget
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Access	96	119	41	4.3	95	5	35	129	10	10
System Renewal	286	197	279	296	422	615	335	380	385	350
System Service	4	14	10	10	10	110	20	5	5	10
General Plant	54	2.5	27	181	20.5	10.5	360.5	10.5	10.5	20
Total	440	333	357	492	547.5	740.5	750.5	524.5	410.5	390

Figure 31: Capital Expenditure Summary

Notes to Capital Expenditure Summary

2016 is the RHI budget as approved by its Board of Directors and includes no actual spending.

Explanatory Notes on Variances
Notes on shifts in forecast vs. historical budgets by category System Access – new customer connections are expected to remain constant through the forecast period System Renewal – involves a paced program including renewal of the distribution system System Service – General plant – vehicle replacements are scheduled for the forecast period OM&A -
Notes on year over year Plan vs. Actual variances for Total Expenditures RHI has not previously filed a DS Plan.
Notes on Plan vs. Actual variance trends for individual expenditure categories RHI has not previously filed a DS Plan.

(5.4.5) Justifying capital expenditures

The capital expenditures of RHI are modest and consequently there are few distinct projects to be reported on. Budgeting is typically done using the financial account structure, but reported using the OEB investment categories. There are only a few projects that exceed the materiality threshold in the forecast period, primarily pole replacement, pole-mount transformer replacement and feeder rebuilds. In addition to this, RHI has the need to replace vehicles in the forecast period and allowance has been made for required fleet replacement to be completed by 2022.

(5.4.5.1) Overall plan

(To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

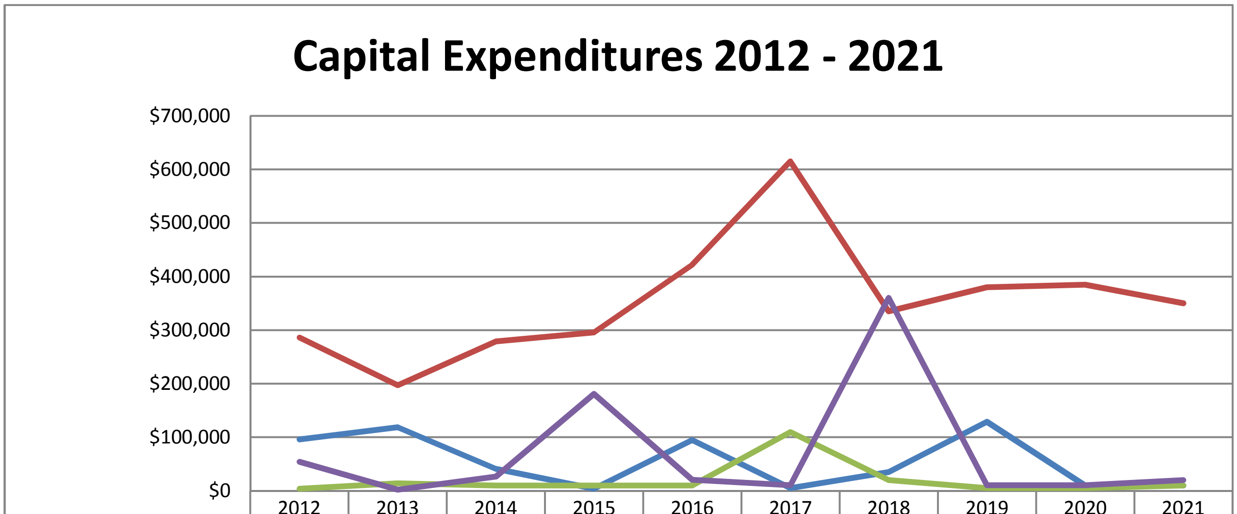
• comparative expenditures by category over the historical period;

• the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;

• the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);

• information related to the distributor's system capability assessment (see section 5.4.3))

The comparative expenditures by investment category through the entire DS Plan period made by RHI are shown in the figure below. Historical plan data has not been provided since a DS Plan has not been previously filed with the OEB.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
System Access	$96,000	$119,000	$41,000	$4,300	$95,000	$5,000	$35,000	$129,000	$10,000	$10,000
System Renewal	$286,000	$197,000	$279,000	$296,000	$422,000	$615,000	$335,000	$380,000	$385,000	$350,000
System Service	$4,000	$14,000	$10,000	$10,000	$10,000	$110,000	$20,000	$5,000	$5,000	$10,000
General Plant	$54,000	$2,500	$27,000	$181,000	$20,500	$10,500	$360,500	$10,500	$10,500	$20,000

Figure 32: Comparative Capital Expenditures over DS PLAN Period

Historical spending and variance information is provided below.

System Access

System Access investments are projects required in order for RHI to meet its obligations under the DSC and whose timetables are driven by others. RHI is obligated to connect new load and new renewable generation. The scheduling of investment needs is usually coordinated to meet the needs of third parties. RHI is also required to respond to the road authorities by obligations under the Public Service Works on Highways Act. The Act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the "cost of labour and labour saving devices" towards the relocation costs.

The level of System Access expenditures in each of the historical years has varied from $10,000 to $120,000.

- 2013 actuals were $49,457 net of capital contributions of $24,600.
- 2014 actuals were $20,086 net of capital contributions of $0. The decrease from 2013 was primarily due to two new subdivisions that were completed in 2013.
- 2015 actuals were $4,321 net of capital contributions of $18,266. The decrease from 2014 was primarily due to new service connections.

Key material spending is shown in the table below:

Project	2012	2013	2014	2015	2016
Hunters Gate	82,000	0	0	0	102,000

Figure 33: Historical Period – Key System Access Projects

System Renewal

System renewal is a mix of projects related to assets nearing end of life and projects to replace equipment that has reached end of life (emergency replacement). The former group of projects are identified and prioritized in the Asset Management system.

The level of System Renewal spending in each of the historical years has varied between $196,000 and $437,000.

- 2013 actuals were $305,569.
- 2014 actuals were $310,368. The increase from 2013 was primarily due to the larger rebuild projects executed.
- 2015 actuals were $312,995. The increase from 2014 was primarily due to work completed on the 44 kV system.
- 2016 actuals were $432,000. The increase from 2015 was primarily due to increased work on pole and transformer replacement programs.

Project	2012	2013	2014	2015	2016
Feeder Rebuilds (OH & UG)		80,957	175,198	179,000	256,000
Piecemeal Replacements		109,634	104,269	110,000	176,000

Figure 34: Historical Period – Key System Renewal Projects

System Service

System Service investments are required to provide for continued service reliability and to meet operational objectives.

- There were no material System Service projects executed during the historical period.

Project	2012	2013	2014	2015	2016
Smart Map					

Figure 35: Historical Period – Key System Service Projects

General Plant

General Plant investments are not part of its distribution system (e.g. fleet, tools, land, etc.). These projects provide system support and improve operational efficiencies.

- The only material spending under General Plant was to effect leasehold improvements at the RHI offices.

Project	2012	2013	2014	2015	2016
Leasehold Improvements				116,088	

Figure 36: Historical Period – Key General Plant Projects

Impact of System Investment on O&M

System investments will result in

- the addition of incremental plant,
- the relocation/replacement of existing plant,
- the replacement of end of life plant with new plant, and
- new/replacement system support expenditures.

In general, incremental plant additions (e.g. new DS c/w transformer, switchgear, land, etc.) will be integrated into the asset management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs. Forecast O&M costs for the 2017 – 2021 period are:

2017	2018	2019	2020	2021
494,400	428,600	432,900	438,400	442,000

Figure 37: Forecasted O&M Costs

Replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the DSC). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall, the plan system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end of life plant with new plant will still require the allocation of resources for ongoing O&M purposes.

Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair-related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair-related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions.

In a few areas, cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital).

If assets approaching end of life are replaced at a rate that maintains equipment class average condition then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year).

Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall, this is expected to put downward pressure on O&M repair related costs.

System support expenditures (e.g. GIS, ACA studies) are expected to provide a better overall understanding of RHI's assets that will lead to more efficient and optimized design, maintenance and investment activities going forward. ACA studies have been conducted and data gaps have been identified. To improve the quality of data used in the ACA studies, increased data collection efforts (i.e. testing program for poles) will be required which will increase pressure on O&M costs. Collected data will be input into the GIS as attribute information for each piece of plant. Improved asset information will allow existing resources to partially compensate for growth-related increases in O&M activities.

Fleet replacement expenditures will result in reduced O&M for new units however this will be offset by increasing O&M of remaining units as they get older.

In summary, the system investments will result in some upward growth-related and support-related O&M pressures, and downward repair related O&M pressures. Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period. RHI's forecast O&M increases during the plan period are predicted to be approximately 1% per year.

Investment Drivers

The following high level inputs are investigated and evaluated in detail and collectively contribute to a final capital investment budget

- regulatory initiatives e.g., Smart meters and the *Green Energy and Green Economy Act,*
- elimination of environmental/health or safety risks,
- system reliability,
- infrastructure renewal projects,
- fleet/tools, and
- information technology and corporate administration

Their input result in three main drivers of RHI's capital investments. These drivers align with corporate goals which are aligned with the RRFE Outcomes.

1. Obligation to connect a customer in accordance with Section 28 of the Electricity Act, 1998, Section 7 of RHI's Electricity Distribution License and the DSC.

2. System implementation activity to ensure maintenance of system reliability.

3. Planned system renewal spending to proactively replace plant at end of life in order to meet LUI's commitment to maintain a safe and reliable supply of electricity to its customers.

The specific investments drivers for each category are described below.

System Access

Customer service requests: continued development of the Town of Renfrew requiring new customer connections (site redevelopment; subdivisions). The historical trend has seen decreasing investments due to economic conditions. Forecasts assume decreasing investment needs due to market saturation.

System Renewal

There are three main drivers of System Renewal Projects:

- Failure risk: multiyear planned transformer and pole replacement programs that address assets in "very poor" and "poor" condition. The historical trend has seen increasing investments due to aging infrastructure. Forecast investments will remain at relatively high levels as equipment replacements and feeder rebuilds are completed.
- High Performance risks: overhead line rebuilds. Historical investments have been a combination of line sections that require complete rebuild (poles, conductors, insulators, etc.) and dispersed pole replacement work. Forecast investments will target specific sections of line requiring complete rebuild.
- Emergency needs: emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

System renewal spending will continue to focus on planned proactive transformer and pole replacement programs at increased levels to that seen in the historical period. Specific high performance risk areas will be prioritized during the 2017-2021 period at levels similar to that in the historical period.

System Service

- System constraints: new system investments, line extensions and feeder interconnections to accommodate grid load growth. Historical investments have focused on overhead and underground infrastructure replacement. Forecast investments will focus on equipment and data required for an OMS system in addition to the corresponding distribution automation
- System operational objectives: investments to maintain system reliability and efficiency of distribution stations. Historical investments needs related to station modifications have been relatively consistent and low. Forecast investment needs related to station modifications are expected to be of similar magnitude.

System service spending will continue to focus on maintaining operational performance and capacity.

General Plant

- System Maintenance support: replacement of rolling stock; tools. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to be a high cost in a particular investment year when compared to the replacement costs of small fleet units. Forecast investments include the replacement of major fleet units in 2019.

In summary, general plant spending will continue to focus on ensuring fleet asset performance meets RHI operational and reliability needs.

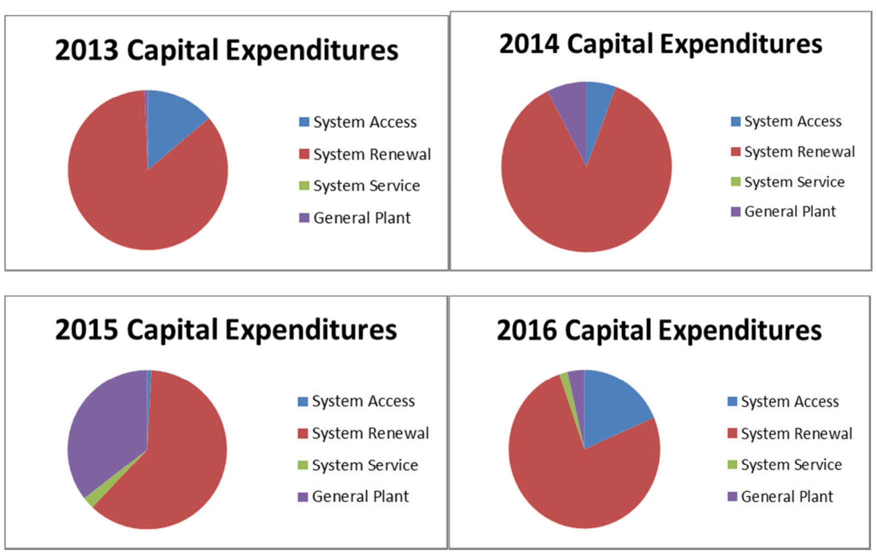


Figure 38: 2013 – 2016 Capital Expenditure Charts

System Capability Assessment

(5.4.5.2) Material investments and justification

(The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

• total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates

• related customer attachments and load, as applicable

• start date, in-service date and expenditure timing over the planning horizon

• the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated

• if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available

• information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities

• where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular) 1. Efficiency, Customer Value, Reliability)

a. (5.4.5.2a) General information on the project/activity

(Identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment)

b. (5.4.5.2b) Evaluation criteria and information requirements for each project activity

(Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c) c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)

Efficiency, Customer value, reliability
Safety
Cyber-security, privacy
Co-ordination, interoperability
Economic development
Environmental benefits

c. (5.4.5.2.c) Categoric-specific requirements for each project/ activity

(Explain the effect of the investment on system operation efficiency and cost-effectiveness, the net benefits accruing to customers as a result of the investment, the impact of the investment on reliability performance including on the frequency and duration of outages; where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives, and .Where a distributor's choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a 'trigger' driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.)

2. Safety

Provide information on the effect of the investment on health and safety protections and performance

3. Cyber-security, Privacy

Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. Co-ordination, Interoperability

a) where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

b) describe how the investment potentially enables future technological functionality and/or addresses future operational requirements

5. Economic Development

Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. Environmental Benefits:

Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

This section lists material projects for the forecast period, 2016-2020. As the service area has a stable and mature customer base with little residential, commercial or industrial growth, the only projects that meet the materiality threshold are the pole replacement program and the vehicle replacement program. In addition to this, it is worth mentioning that RHI also has a transformer replacement program, however it does not exceed the materiality threshold. Maintenance work such as substation maintenance and oil testing of power transformers is contracted to third parties, and recloser maintenance is performed by RHI through O&M work orders. All of the infrastructure renewal programs are captured under "System Renewal" investment category.

Pole Replacement Program

RHI has had a pole replacement program in place for a number of years. Following a condition assessment and inspection at the beginning of 2015, RHI has to prioritize and effectively focused its efforts on the poles in worst condition. Subsequent to the condition assessment, RHI has formally instituted a replacement program allocating a significant portion of its system renewal budget to the replacement of aging poles in poor condition before they result in an outage. With the current condition of RHI infrastructure, RHI has planned for the replacement of approximately 40 poles/year each year for the entire forecast period.

- Investment category
- Total capital and O&M
- Evaluation criteria

The main driver for the pole replacement program is the risk of plant failing in service and creating long outages for customers and added O&M costs for the utility. This is intensified if there are simultaneous failures, especially if the failures are the result of weather stressors such as high winds. RHI only has two line crews to respond to outage and emergency situations.

The pole replacement program has been spread out over the five year forecast period. RHI believes that regular investment in its infrastructure will minimize lumpy investment programs which are typically the result of reactive maintenance programs.

There are safety benefits to executing the pole replacement program. The execution of the program implies the replacement of plant in a planned and pre-determined manner when the conditions are best for RHI thereby making an efficient investment. Additional to this is the reduction of the possibility of poles falling in adverse weather and causing accidents or damage to property in conjunction with safety related to minimizing the potential loss of power during extreme cold periods.

Transformer Replacement Program

In conjunction with its pole replacement program, RHI has also started to monitor and track the performance and condition of its transformers. Those transformers on poles being replaced will likely be replaced especially if the transformer is old or in poor condition. In addition to this, additional transformers – pole-mount or pad - mount have been identified by condition and performance for replacement. This condition-based replacement is an attempt to perform work under controlled conditions thereby reducing costs and passing on saving to the ratepayers. RHI has planned for the replacement of 15 pole-mounted transformers per year and one to two pad-mounted transformers per year each year for the entire forecast period.

- Investment category
- Total capital and O&M
- Evaluation criteria

The main driver for the transformer replacement program is the risk of plant failing in service and creating long outages for customers and added O&M costs for the utility. This is intensified if there are simultaneous failures, especially if the failures are the result of weather stressors such as high winds and severe weather. RHI only has one line crew on call to respond to outage and emergency situations.

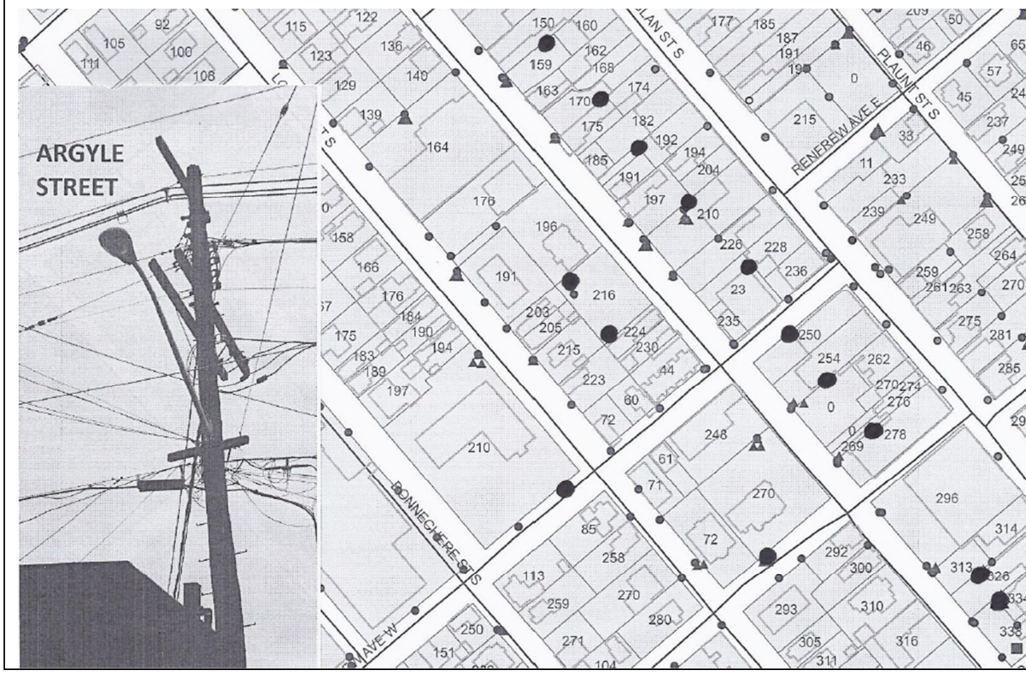
The transformer replacement program has been spread out over the five year forecast period. RHI believes that regular investment in its infrastructure will minimize investment programs which are typically the result of reactive maintenance.

There are safety benefits to executing the transformer replacement program. The execution of the program implies the replacement of plant in a planned and pre-determined manner when the conditions are best for RHI thereby making an efficient investment. Additional to this is the reduction of the possibility of transformers failing in adverse weather and causing accidents or damage to property in conjunction with safety related to minimizing the potential loss of power during extreme cold periods.

Argyle Street Feeder Rebuild

Project Justification				
Project Name	Argyle Street Feeder Rebuild		Cost Category	Capital
			Project Type	Replacement
			Investment Driver	System Renewal
Project Information				
Project Description	The project involves rebuilding a pole line along Argyle Street to support the back lot fed commercial area between Opeongo Road and Railway Avenue. The project involves EOL replacement for poles, conductor and transformers. This type of project is aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers			
Project Details	Age of Plant:	50 – 60 Years	Construction Standards:	USF
	Primary Voltage:	4 kV	Primary Conductor:	336 ASC
	Pole No/Type:	14/Wood	Secondary Conductor:	4/0
	Area Description:	Residential	Transformers:	29
Capital Investment	Gross Capital:	$256,000	**Implementation Schedule:**	2016
	Customer	0		

	Contribution:	
		$256,000
	Net Capital:	
	O&M:	



Raglan St N Feeder Rebuild

Project Justification			
Project Name	Raglan Street N. Feeder Rebuild	Cost Category	Capital
		Project Type	Replacement
		Investment Driver	System Renewal
Project Information			
Project Description	The project involves rebuilding a pole line along Raglan Street N. to support the overhead infrastructure between Monroe Ave E. and Mutual Avenue. The project involves EOL replacement for poles, conductor and transformers. This type of project is aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers		

Project Details	Age of Plant:	50 – 60 Years	Construction Standards:	USF
	Primary Voltage:	4 kV	Primary Conductor:	336 ASC
	Pole No/Type:	15/Wood	Secondary Conductor:	4/0

	Area Description:	Residential	Transformers:	4
Capital Investment	Gross Capital:	$171,000	**Implementation Schedule:**	2017
	Customer Contribution:	0		
	Net Capital:	$171,000		
	O&M:			

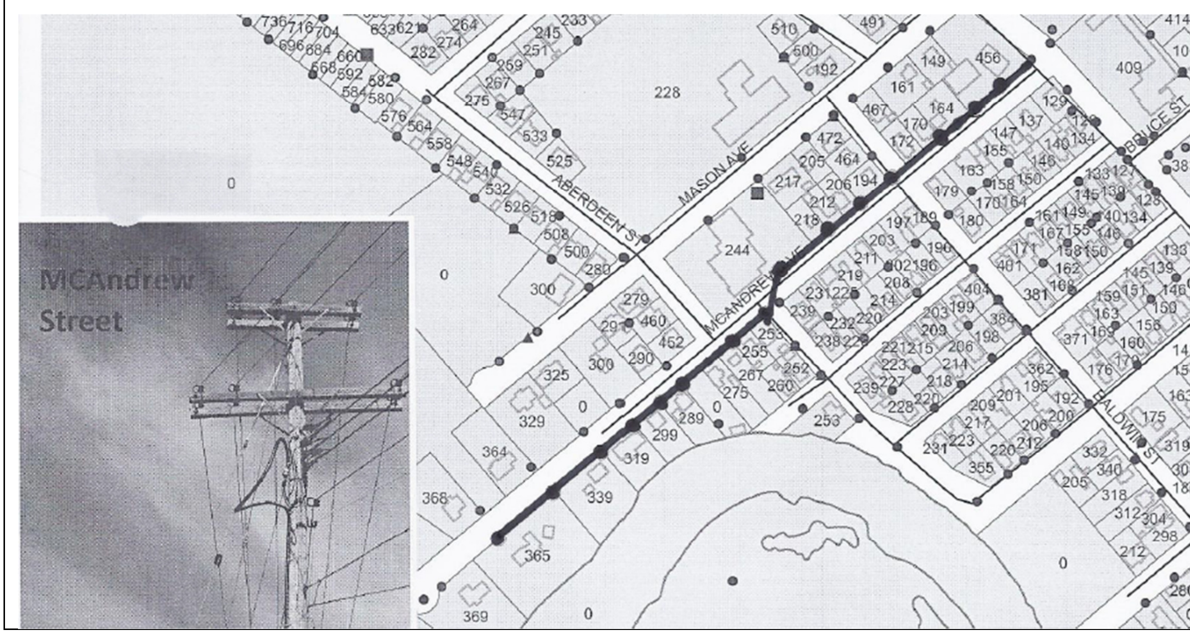
McAndrew Street Feeder Rebuild

Project Justification			
Project Name	McAndrew Street Feeder Rebuild	Cost Category	Capital
		Project Type	Replacement

		Investment Driver	System Renewal

Project Information

Project Description	The project involves rebuilding a pole line along McAndrew Street to support the overhead infrastructure between Stewart Street past Aberdeen Street. The project involves EOL replacement for poles, conductor and transformers. This type of project is aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers			
Project Details	Age of Plant:	50 – 60 Years	Construction Standards:	USF
	Primary Voltage:	4 kV	Primary Conductor:	336 ASC
	Pole Num/Type:	16/Wood	Secondary Conductor:	4/0
	Area Description:	Residential	Transformers:	6
Capital Investment	Gross Capital:	$229,000	**Implementation Schedule:**	2018
	Customer Contribution	0		
	Net Capital:	$229,000		
	O&M:			

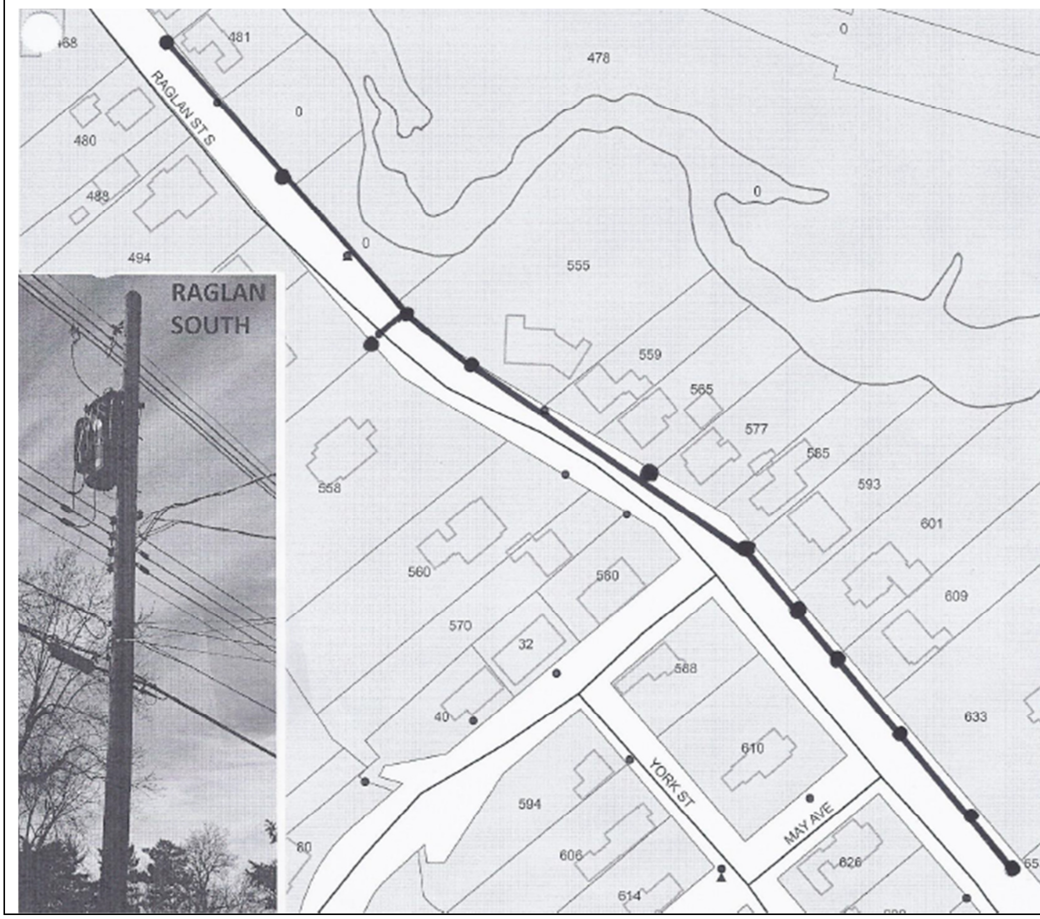


Raglan Street S Feeder Rebuild

Project Justification

Project Name	Raglan Street S. Feeder Rebuild	Cost Category	Capital

			Project Type	Replacement
			Investment Driver	System Renewal
		Project Information		
Project Description	The project involves rebuilding a pole line along Raglan Street S to support the overhead infrastructure between 473 Raglan Street S and 653 Raglan Street S. The project involves EOL replacement for poles, conductor and transformers. This type of project is aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers			
Project Details	Age of Plant:	50 – 60 Years	Construction Standards:	USF
	Primary Voltage:	4 kV	Primary Conductor:	336 ASC
	Pole Num/Type:	15/Wood	Secondary Conductor:	4/0
	Area Description:	Residential	Transformers:	4
Capital Investment	Gross Capital:	$200,000	**Implementation Schedule:**	2019
	Customer Contribution:	0		
	Net Capital:	$200,000		
	O&M:			



Lisgar Street Feeder Rebuild

Project Justification			
Project Name	Lisgar Street Feeder Rebuild	Cost Category	Capital
		Project Type	Replacement
		Investment Driver	System Renewal
Project Information			
Project Description	The project involves rebuilding a pole line along Lisgar Street to support the overhead infrastructure between Ma-Te-Way Park Drive and Lochiel Street N. The project involves EOL replacement for poles, conductor and transformers. This type of project is aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers		
Project Details	Age of Plant: 50 – 60 Years	Construction Standards:	USF

	Primary Voltage:	4 kV	Primary Conductor:	336 ASC
	Pole Num/Type:	28/Wood	Secondary Conductor:	4/0
	Area Description:	Residential	Transformers:	5
Capital Investment	Gross Capital:	$260,000	**Implementation Schedule:**	2020
	Customer Contribution:	0		
	Net Capital:	$260,000		
	O&M:			

Vehicle Replacement Program

RHI currently has a number of vehicles in its fleet. Included in this list are two bucket trucks, a derrick truck, a dump truck and a pickup truck. The bucket trucks are 2000 vintage and therefore are approaching the end of their useful life. Replacement for one of the bucket trucks will be planned for the forecast period and for the second, just beyond the horizon of the forecast period.

RHI has planned for the replacement of a bucket truck in year 2018. Due to the aging of its assets, this replacement became a necessity to continue safe operations.

The main driver for the vehicle replacement program is the risk of vehicles failing in service and creating hazardous situations for workers, long outages for customers, and added O&M costs for the utility. This is intensified if there are simultaneous failures, especially if the failures are during outages or severe weather. RHI only has one line crew on call to respond to outage and emergency situations.

MS1 Breaker Replacement

RHI MS1 on Opeongo Road was constructed in 1920. RHI purchased the station from Ontario Hydro in 1970 and subsequently replaced the transformer in 2004. The station still operates using a series of English Electric bulk oil breakers dated 1953. As these breakers are approaching the end of their useful life and since MS1 carries about 1/5 of the utility load, RHI has scheduled EOL replacement in 2017. The plan is to remove the main 1200A breaker in addition to replacing the three 600A feeder breakers with more modern three-phase recloser style switchgear. As part of this infrastructure renewal, RHI will also install SmartMap substation and feeder monitoring including sensors to assist RHI with outage detection and management.

Hunters Gate Subdivision

Hunters Gate subdivision in Renfrew is being developed by a local company and consists of 300 fully serviced residential lots in the north end of Renfrew. RHI will provide electric service to these residential lots as part of its obligations which is reflected in System Access projects in the Capital Expenditure Summary.

APPENDIX A

OPA Letter of Comment

IESO Letter of Comment

Renfrew Hydro Inc.

Renewable Energy Generation Plan

April 4, 2016

Independent Electricity System Operator

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.

Renfrew Hydro Inc. – Distribution System Plan

On March 3, 2016, the IESO received REG investments information ("Plan") of Renfrew Hydro Inc. ("RHI") as part of its Distribution System Plan which will be filed with the OEB when RHI files its 2017 Rate Application. The IESO has reviewed the REG investments information and provides the following comments.

OPA FIT/microFIT Applications Received

The Plan shows that 10 microFIT projects representing 80 kW of capacity and 2 FIT projects totalling 340 kW of capacity are connected to RHI's distribution system. Beyond FIT, the Plan indicates that RHI has connected a 4 MW hydro-electric project owned by Renfrew Power Generation.

According to the IESO's information, as of February 29, 2016, the IESO has offered contracts to 10 microFIT projects totalling 90 kW of capacity, and 5 FIT projects totalling 908 kW of capacity. Of the 908 kW, 340 kW represents FIT projects that are already connected to RHI's distribution system, with the remaining 568 kW representing FIT projects that are still undergoing the connection process. In addition, the IESO has contracted for a 4 MW expansion of an existing hydro-electric project under its Hydroelectric Contract Initiative (HCI) which is the project referenced by RHI. The renewable energy generation connections information in Renfrew Hydro's Plan is therefore consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine 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 Regional Plans

The IESO notes that RHI's distribution system is fully embedded in the Hydro One Networks Inc. ("Hydro One") distribution system in two of the planning regions in Ontario - the Greater Ottawa Region, and the Renfrew Region. Under the new regional planning process endorsed by the OEB in August 2013, while the host distributor is required to gather information from their respective embedded LDCs, it is not required that embedded LDCs be directly involved.

Greater Ottawa Region

Regional planning for the Ottawa area (a sub-region of the Greater Ottawa Region (Group 1)) was underway prior to the new regional planning process in 2013. The service area of RHI was not part of this study area. The Ottawa area Integrated Regional Resource Plan ("IRRP") was published on April 28, 2015.

Regional planning for the remaining area within the Greater Ottawa Region (the Outer Ottawa sub-region) commenced with the development of the Needs Assessment which was completed by Hydro One on July 28, 2014. As determined by the Needs Assessment study team, no further regional coordination is required as the need identified for Outer Ottawa sub-region can be addressed directly by the transmitter and area LDCs. Hydro One also published its Local Planning report on September 22, 2015 for the load restoration need identified in the Needs Assessment. In this case, information that was required was provided by the host LDC, Hydro One Distribution.

Renfrew Region

Renfrew Hydro Inc. also serves customers in the Renfrew Region (Group 3), along with Hydro One (Distribution and Transmission) and Ottawa River Power Corporation. Regional Planning for the Renfrew Region started in October 2015 and was complete with the publishing of the Needs Assessment by Hydro One on March 11, 2016. In this case, RHI participated in the regional planning meetings and was a part of the study team which determined that no further regional coordination is required for the Renfrew Region at this time. Therefore, the regional planning process for this region is complete and will be undertaken again when the next 5-year review cycle commences, unless there is sufficient load growth or an event that triggers the requirement to initiate the regional planning process before then.

The IESO looks forward to working with RHI on regional planning, and will include RHI in its relevant communications for both the Renfrew and Greater Ottawa Regions. The IESO appreciates the opportunity to comment on the REG investments information provided as part of Renfrew Hydro Inc.'s Distribution System Plan.

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

APPENDIX B

Draft Needs Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS SCREENING REPORT

Region: Renfrew

Revision: Draft
Date: February 2, 2016

Prepared by: Renfrew Study Team

Peterborough to Renfrew Region Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

Disclaimer

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

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Screening 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 Screening Report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the Needs Screening 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 Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

REGION	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	February 22, 2016

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the Renfrew Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Screening for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Renfrew Region belongs to Group 3. The Needs Screening for this Region was triggered on October 23, 2015 and was completed on February 22, 2016.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information was collected for 2015-2024, as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal, and voltage analysis, system reliability, operational issues such as load restoration, and assets approaching end-of--life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required.

Full load transfers for restoration purposes are not considered as mandatory in the Region. Restorations of load between Chenaux TS and Des Joachims TS via load transfers are performed to the extent possible and there are no plans to enhance this discretionary capability.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.
- There is no guarantee and also not a requirement that all loads in the area can be supplied radially from Des Joachims 115kV terminal under emergency operation.

System Reliability, Operation and Restoration Needs

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

The Region is prone to storms. Load can be restored within eight hours typically with some exceptions when trees falling to radial 115kV circuits under severe storms.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities.

7. RECOMMENDATIONS

Based on the findings of this Needs Screening assessment, the study team's recommendations are as follows:

- No transmission capacity expansion is required for the study period. No further planning efforts are required for this area.
- Continue to monitor and assess the load restoration performance under X1P and D6 outages

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

Deleted: 11

1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the Renfrew Region (the Region) over the next ten years. The development of the Needs Screening report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Screening report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by the Renfrew Region Needs Screening study team and led by the transmitter, Hydro One Networks Inc (Table 1). The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Screening for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Screening for this Region was triggered on October 23, 2015 and was completed on February 22, 2016.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Screening includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Screening.

3.1 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region.

The electricity supply to the region is mainly through three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). The circuits are supplied by 230/115 kV autotransformers at Chenaux Transformer Station (TS) from the East and Des Joachims TS from the West. A normally opened 115kV switch at Pembroke TS isolates the East and the West sides of the region. The Renfrew Region is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

.

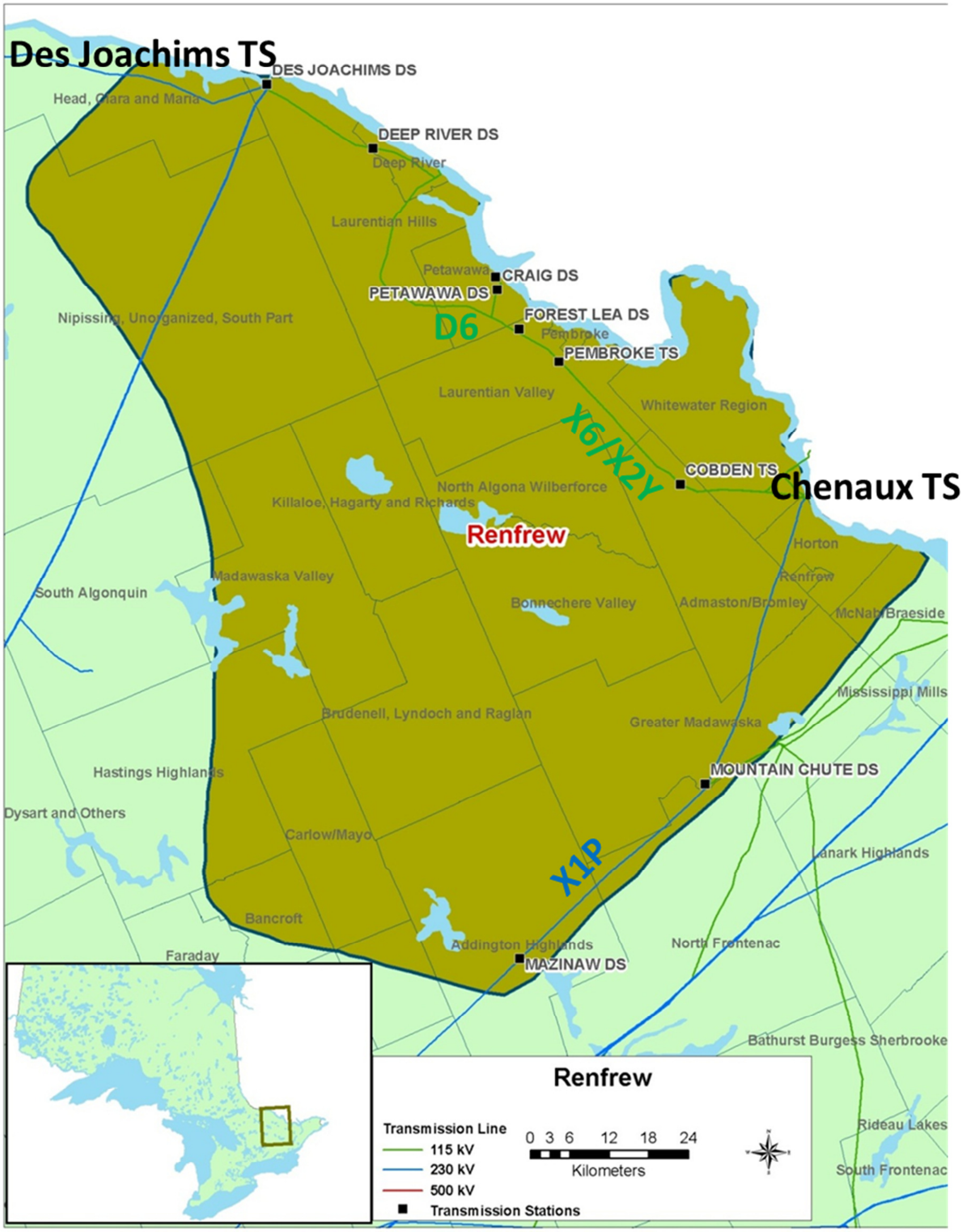


Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des Joachim TS is a major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.

- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Chalk River Customer Transformer Station (CTS).

- Chenaux TS is the other major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y.

- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker.

- All the 115kV circuits D6/X6/X2Y, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew Region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region. The DS typically has load less than 1MW.

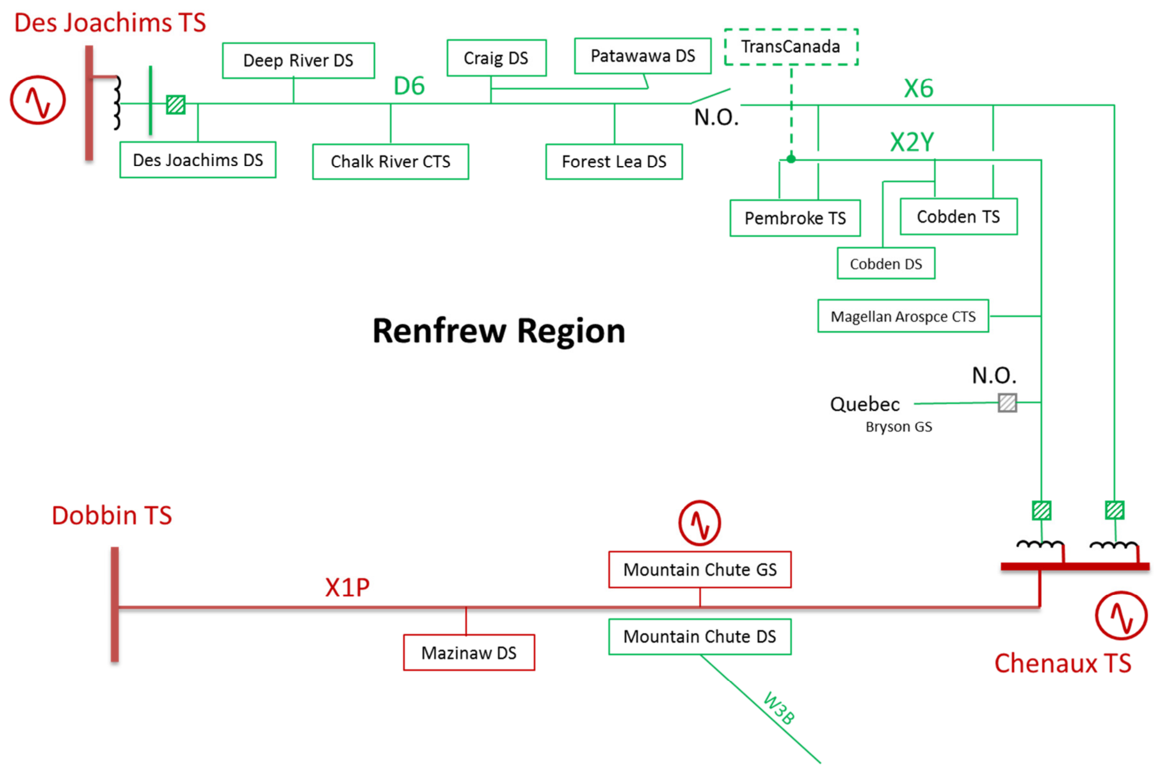


Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life. The rating will be changed from 10MVA to 12.5MVA.

- Mountain Chute DS transformer will be upgraded from 3MVA to 12.5MVA due to end-of-life.

- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life. The new T3/T4 will have continuous rating of 125MVA. The existing units are rated 78MVA and 115MVA respectively.

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information to Hydro One:

- IESO provided:
  i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. Therefore it is assumed the loads at these two stations would not increase in the study period.
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Screening assessment:

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC's load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year's coincidental peak load.

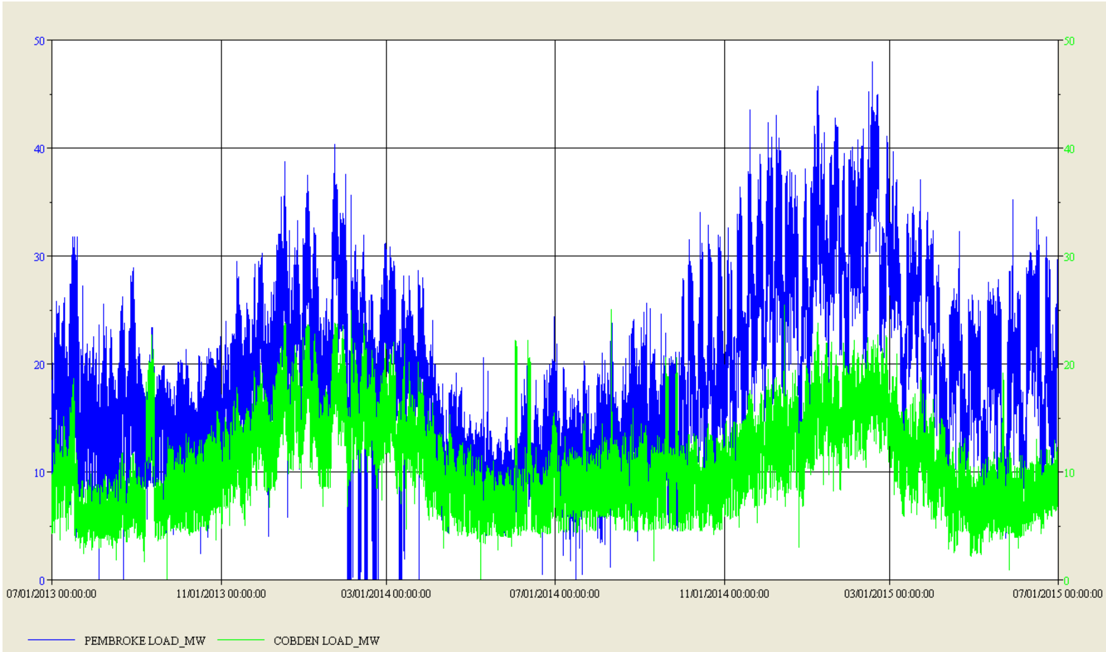


Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

   - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Screening assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range. Projected coincidental peak loads are used in such assessment.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not considered as mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible and there are no plans to enhance this discretionary capability.

6 RESULTS

This section summarizes the results of the Needs Screening in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MVA)	Transformer Rating/LTR* (MVA)
Cobden DS	T3	7.5	12.5
Cobden TS	T1/T2	30.0	41.7
Craig DS	T1/T2	12.7	16.7
Deep River DS	T1/T2/T3	11.7	12.5
Des Joachims DS	T1	3.7	12.5
Forest Lea DS	T1/T2	10.2	11
Mazinaw DS	T1	3.8	6
Mountain Chute DS	T1	1.1	12.5
Pembroke TS	T1/T2	51.5	41.7/52.5@20°C
Petawawa DS	T1/T2	14.6	12.5/15.6 Summer, 19.3 Winter
Chalk River CTS***		11	
Magellan Aerospace CTS***		3.4	
Chenaux TS	T3/T4	113**	125
Des Joachims TS	T6/T7	63.4	125

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.
- The projected regional peak loads can be supplied safely even if the local generations at Des Joachims GS and Chenaux GS are out of service. Voltage stability can be maintained if the region loads are scaled up by 10%.
- In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit.

Under emergency conditions where the D6-X6 in-line switch is closed by operating action, the study found that:

- Under D6 terminal outage at the Des Joachims terminal, D6 loads can be transferred to Chenaux 115kV via X6 supply. No voltage instability was identified when the loads increase by 10% pre-contingency or increase 5% post-contingency (loss of X2Y). The new Chenaux autotransformer tap changers adjustment can ensure the voltages across X6-D6 corridor within acceptable limits based on the *coincidental* peak load forecast. However, if D6 loads increase beyond the expected load forecast for the area, full back up may not be guaranteed under peak load conditions.

- Des Joachims cannot radially supply all the loads in the Region via D6-X6 when X1P is out of service. Sufficient Chenaux generation and import from Bryson GS in Quebec are necessary to respect contingency of losing a Chenaux generation step-up transformer.

It should be pointed out that full load restoration via D6-X6 transfer is not considered as a planning requirement. Therefore there is no plan to enhance this discretionary capability. The load restoration goal is to meet the timeframe defined in ORTAC through other efforts.

6.2 System Reliability, Operation and Restoration Review

- The entire Region does not have coincidental peak load greater than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storm, extended outages on D6 were experienced in the past (in 2011 for example). Further outage survey shows that the most common cause for sustained outages was tree contact under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. Improved vegetation management and outage responses have reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact

2011	4	7792	Tree Contact

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Screening assessment, the study team's recommendations are as follows:

a) No transmission capacity expansion is required for the study period. No further planning efforts are required for this area.

b) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Monitor and assess the load restoration performance under X1P and D6 outages.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: January 2016 – June 2017
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NS	Needs Screening
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Ex.2/Tab 5/Sch.3 - Capitalization Policy

Capitalization Policy under CGAAP:

RHI records fixed assets at cost with depreciation taken at various rates in accordance with the Accounting Procedures Handbook and Uniform System of Accounts (USoA). Contributions in aid of construction are not included in the rate base, as they are recorded as an offset to the capital asset and amortized (as an offset to depreciation) at the same rate as the capital assets, thereby providing net depreciation amount for assets.

RHI's constructed assets are capitalized using actual labour rates plus a burden for payroll, engineering, vehicle usage (where applicable) and direct materials.

RHI capitalizes expenditures that are capital in nature and are expected to provide future benefits for a period in excess of one year. RHI uses the following minimum threshold for capitalizing expenditures:

- $500 for tools and equipment
- $1000 for constructed assets
- $1000 for rebuilding of facilities or vehicles when the life of the equipment or facility will be extended

Where a group of like assets are acquired that are individually valued below $500, but meet the capitalization criteria above and are in total cost in excess of $500, they are capitalized.

Material Direct Cost:
The material direct cost is comprised of all the eligible material that is used on a capital project, including its freight to destination.

Labour Direct Cost:
The labour direct cost is comprised of all the eligible salaries for staff as well of their supervisors on a capital project.

Capitalization Policy under IFRS:

Capitalization Policy Overview

RHI's current capitalization policies and principles are based on IFRS and guidelines set about by the Ontario Energy Board, where applicable. RHI converted to IFRS January 1, 2015 and as such the capitalization policy in effect for the 2016 Bridge Year and 2017 Test Year is compliant with MIFRS.

RHI reviewed its capitalization policy in anticipation of transitioning to IFRS; componentization of assets, depreciation changes and overheads were the focus of the review in light of the July 17, 2012 Board letter indicating that changes to depreciation expense and capitalization policies were required in 2013. RHI confirms that the changes to its capitalization policy are consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinetrics Report dated July 8, 2010, and the APH, effective January 1, 2013.

PP&E includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour and other costs directly attributable to bringing the asset to a working condition of its intended use.

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

Guidelines for Capitalization

Capital assets include property, plant, and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital asset's and are defined as assets that lack physical substance.

Materiality Limit

RHI's threshold for capitalization is:

- $500 for tools and equipment
- $1000 for constructed assets
- $1000 for rebuilding of facilities or vehicles when the life of the equipment or facility will be extended

Betterment

A betterment is a cost which enhances the service potential of a capital asset and/or increases its value, and is therefore capitalized. A betterment includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an assets current value.

Repairs

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

Capitalization by Component

When parts or components of an item of property, plant, and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant, and equipment. Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which:

a) are significant in relation to the total cost of the item; and
b) have different depreciation methods or useful life.

Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually significant (remainder of the items) are combined and categorized as a single component best suited for the sum of the parts.

Exclusions

RHI confirms it does not capitalize certain costs that are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training);
d) Administration and other general overhead costs; and
e) Day-to-day servicing costs.

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

Capital Stand-by Spare Equipment

Transformers and meters when received from the supplier are accounted for as inventory. As referenced in Article 410 of the Accounting Procedures Handbook for Electricity Distributors, at the fiscal yearend these assets are moved to capital accounts as stand-by equipment as they form an integral part of the reliability program for the distribution system.

No depreciation is applied until the assets are in service and fully operational as intended by management.

Amortization

As of January 1, 2013 RHI adopted the “Typical Useful Life (TUL)” depreciation rates set out in the Kinetrics Inc. Report prepared for the Ontario Energy Board July 8, 2010. Capital assets are amortized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant, and equipment. Land is not depreciated. Construction in progress and capital spare equipment are not amortized until they are in service. The half year rule is utilized for amortization purposes, with a half year of amortization being recorded in the year of acquisition and a half year being recorded in the year of disposal. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated.

Disposals and Write-Offs

For assets taken out of service, the asset cost and the related accumulated amortization is removed from the records. Any difference between the proceeds and the net book value of the asset including removal costs are recorded as a gain or loss in the year of disposal.

General Policy for Capitalization and Depreciation:

RHI's capital assets, and their designated service life, should be categorized as follows in the Appendix 2-BB from the Chapter 2 Appendices.

		Asset Details			Useful Life			USoA #	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category	Component	Type	MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers & Fixtures	25	4%	45	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	O/H Conductor and Devices	25	4%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment	30	3%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								

	16	Station Metal Clad Switchgear	Overall	30	40	60									
			Removable Breaker	25	40	60									
	17	Station Independent Breakers		35	45	65									
	18	Station Switch		30	50	60									
	19	Electromechanical Relays		25	35	50									
	20	Solid State Relays		10	30	45									
	21	Digital & Numeric Relays		15	20	20									
	22	Rigid Busbars		30	55	60									
	23	Steel Structure		35	50	90									
	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75									
	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									
	29	Primary TR XLPE Cables in Duct		35	40	55		1845	UG Conductors and Devices	25	4%	50	2%	No	No
	30	Secondary PILC Cables		70	75	80									
	31	Secondary Cables Direct Buried		25	35	40									
	32	Secondary Cables in Duct		35	35	60									
UG	33	Network Tranformers	Overall	20	35	50									
			Protector	20	35	40									
	34	Pad-Mounted Transformers		25	40	45									
	35	Submersible/Vault Transformers		25	35	45									
	36	UG Foundation		35	55	70									
	37	UG Vaults	Overall	40	60	80									
			Roof	20	30	45									
	38	UG Vault Switches		20	35	50									
	39	Pad-Mounted Switchgear		20	30	45									
	40	Ducts		30	50	85		1840	UG Conduit	25	4%	50	2%	No	No
	41	Concrete Encased Duct Banks		35	55	80									

	42	Cable Chambers	50	60	80								
S	43	Remote SCADA	15	20	30								

Table F-2 from Kinetrics Report[1]

#	Asset Details		Useful Life Range			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type							Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15		1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15		1930	Transportation Equipment - Trucks/Buckets	8	13%	8	13%	No	No
		Trailers	5	20		1930	Transportation Equipment - Trailers	8	13%	8	13%	No	No
		Vans	5	10		1930	Transportation Equipment - Pickup/Cars	5	20%	5	20%	No	No
3	Administrative Buildings		50	75		1808	Buildings - Office	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent										
5	Station Buildings	Station Buildings	50	75		1808	Brick Building at MS #1	50	2%	50	2%	No	No
		Parking	25	30									
		Fence	25	60									
		Roof	20	30									
6	Computer Equipment	Hardware	3	5		1920	Computer Hardware	5	20%	5	20%	No	No
		Software	2	5		1925	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10									
		Stores	5	10		1935	Stores Equipment	10	10%	10	10%	No	No

		Tools, Shop, Garage Equipment	5	10		1940	Tools, Shop, Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10									
8	Communication	Towers	60	70									
		Wireless	2	10									
9	Residential Energy Meters		25	35		1860	Stranded Meters	25	4%	25	4%	No	No
10	Industrial/Commercial Energy Meters		25	35		1860	Industrial/Commercial Energy Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30				25					
12	Current & Potential Transformer (CT & PT)		35	50									
13	Smart Meters		5	15		1860	Smart Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15									
15	Data Collectors - Smart Metering		15	20									

Account 1830 to 1860 – Poles, OH Conductors, Transformers, UG Conduit, Meters, etc.

The capitalized expenditures for these accounts include:

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

Material and Supplies Direct Costs:
The material and supplies direct cost is comprised of all the eligible material that is used on a capital project, including its freight to destination.

Labour Direct Cost:
The labour direct cost consists of all the eligible salaries for staff as well as their supervisors on a capital project.

Labour Burden:
The Labour Burden is comprised of employee benefits including:

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

The Labour Burden rate is a percentage calculated every year and based on the actual employee rates and benefits costs divided by 2,080 hrs (regular hours worked in a year). Then all employee rates are added together and divided by the number of employees to get the average overhead percentage hourly rate for the year. The Labour Burden rate is then allocated to capital based upon the Labour Direct Cost charged to capital.

In 2015, the labor burden percentage rate was established at 52%. In 2016 it was recalculated to 57%. The increase was directly attributable to higher health and dental benefit rates for 2016.

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

- Vehicle Maintenance
- Vehicle Insurance
- Fuel

<u>Account 1905 - Land Acquisition</u>

The recorded cost of land includes:

- The purchase price;
- Costs of closing the transaction and obtaining title, which includes but are not limited to legal fees, survey costs and land transfer taxes:
- The cost for preparing the land for its particular use such as clearing and grading. If the land is purchased for the purpose of constructing a building, all costs incurred up to the excavation for the new building should be considered land costs. Removal of an old building, clearing, grading and filling are considered land costs because they are necessary to get the land in condition for its intended purpose. Any proceeds obtained in the process of getting the land ready for its intended use, such as salvage receipts on the demolition of the old building or the sale of cleared timber, are treated as reductions in the price of the land.

Expenditures for land acquisition usually do not deteriorate with use or passage of time, therefore the cost of land is generally not exhaustible, and therefore not depreciable.

Account 1908 – Building

Capitalization of Building costs include, but are not limited to, the following:

- Original contract price of asset;
- Expenses for remodeling, repairing or changing a purchased building to make it available for the purpose for which it was acquired;
- Interest charges until building acquisition, renovation project, improvement or alteration is complete;
- Architects and engineers fees for design as well as expenses for the preparation of plans, specifications, blueprints, etc.;
- Cost of building permits.

Each building is divided into 4 major building components. The components are as follows:

1. Building Structure
2. Building Outside / Fence
3. Interior Construction
4. Roof

The total cost of the building or additional square footage is then allocated among the 4 major building components.

Building Renovations/Rehabilitation:
A building renovation is defined as enhancements made to a previously existing building component. The total expenditure capitalized is based on the invoice or contract price. No administrative charges are added.

Building Outside / Fence improvements:
Building Outside / Fence improvements include items such as landscaping, driveways, sidewalks, parking lots, fencing, outdoor lighting, and other non-building improvements. Please note that Land improvements can be further categorized as non-exhaustible under account

1905 – Land acquisitions. The total project cost must meet the set minimum threshold and shall be recorded as capital based on the invoice or contract price. No administrative charges are added.

Account 1915 to 1955 – Office Furniture, Computer, Vehicles, Tools and Other Equipment

For capitalization of expenditures with a service life of more than one year, the total invoice or contract price is used, including its freight to destination. No administrative charges are added.

Changes to Capitalization Policy

RHI reviewed its capitalization policy in anticipation of transitioning to IFRS; componentization of assets, depreciation changes and overheads were the focus of the review in light of the July 17, 2012 Board letter indicating that changes to depreciation expense and capitalization policies were required in 2013. RHI confirms that the changes to its capitalization policy are consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinetrics Report dated July 8, 2010, and the APH, effective January 1, 2013. RHI extended the useful lives of certain asset categories in line with the typical useful lives summarized in the Kinetrics Report. No further changes to the capitalization policy have been made since the last COS Application.

Ex.2/Tab 5/Sch.4 - Capitalization of Overhead

Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset are not capitalized.

Appendix 2-D is not applicable therefore it has not been included in this evidence.

Ex.2/Tab 5/Sch.5 - Costs of Eligible Investments for Connection of Qualifying Generation Facilities

RHI 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, OEB Appendices App.2-FB Calcs of REG Improvements and App.2-FC Calcs of REG Expansion have not been included as evidence.

Ex.2/Tab 5/Sch.6 - New Policy Options for the Funding of Capital

RHI has not used in the past nor does it foresee making use of the new policy options for funding of capital in the future.

Ex.2/Tab 5/Sch.7 - Addition of ICM Assets to Rate Base

RHI has never applied for a rate adder to recover an investment through the OEB's Incremental Capital Module and does not foresee using an ACM mechanism model in the future.

Ex.2/Tab 5/Sch.8 - Service Quality and Reliability Performance

RHI 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 RHI 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.

Appendix 2-G Service Reliability Indicators

2011-2015

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
SAIDI	1.18	2.42	0.23	2.67	0.18	0.98	1.92	0.23	1.92	0.18
SAIFI	1.77	2.39	0.12	2.10	0.10	0.84	1.40	0.12	1.1	0.10

5 Year Historical Average

Index	Includes outages caused by loss of supply	Excludes outages caused by loss of supply
SAIDI	1.34	1.05
SAIFI	1.30	0.71

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90.0%	100	100	100	100	100
High Voltage Connections	90.0%	N/A	N/A	100	N/A	N/A
Telephone Accessibility	65.0%	90.3	79.3	87.8	89.4	95.8
Appointments Met	90.0%	100	100	100	100	96.9
Written Response to Enquires	80.0%	N/A	N/A	100	100	100
Emergency Urban Response	80.0%	100	100	100	100	100
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	7	10.6	9.6	6.10	4.2
Appointment Scheduling	90.0%	100	100	100	96.10	95.8
Rescheduling a Missed Appointment	100.0%	N/A	N/A	N/A	N/A	100
Reconnection Performance Standard	85.0%	100	100	100	100	100