OVERVIEW (2.2.1.1)

The rate base used for the purpose of calculating the revenue requirement used in this Application follows Chapter 2 of the *Filing Requirements for Electricity Distribution Applications* issued by the Ontario Energy Board ("Board") on July 16, 2015 (the "Filing Requirements"). In accordance with the Filing Requirements, HHHI has calculated the rate base as the average of the net capital balances at the beginning and the end of the 2016 Test Year, plus a working capital allowance of 7.5% of the sum of the cost of power and controllable expenses.

In its 2012 Cost of Service Rate Application (EB-2011-0271), HHHI adopted the Revised CGAAP basis of reporting beginning January 1, 2012. As part of the change-over to Revised CGAAP in 2012, HHHI changed its depreciation rates and capitalization policy. HHHI also adjusted the CGAAP book value of its assets based on new useful lives provided in the HHHI specific Kinectrics report. The book value variance of assets between original CGAAP and Revised CGAAP was recorded in Deferral and Variance account 1575 and amortized from 2012 to 2016. The implementation of Revised CGAAP, the new useful lives of assets and capitalization policy were approved by the Board in HHHI's 2012 Cost of Service Rate Application (EB-2011-0271).

Net capital assets include in-service assets that are associated with activities that enable the conveyance of electricity for distribution purposes, minus accumulated depreciation and contributed capital from third parties. For the purposes of this Exhibit, distribution assets refer to those assets that are most directly related to the distribution system, such as poles, overhead and underground lines, and transformers. General plant refers to assets that support the operation of the distribution system such as computer hardware and software, vehicles, buildings, equipment. The rate base calculation excludes all non-distribution assets. HHHI has not applied for, nor received, any Incremental Capital Module ("ICM") adjustments.

Controllable expenses include operations and maintenance, billing and collecting, community relations and administration expenses.

HHHI has provided its rate base calculations for the years 2012 Board Approved, 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge Year and 2016 Test Year in Table 2-1 below:

Table 2-1: Summary of Rate Base

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Gross Fixed Assets, Opening Balance	52,728,694	51,414,622	61,628,381	67,278,598	75,569,434	82,837,245
Gross Fixed Assets, Closing Balance	59,628,695	61,628,381	67,278,598	75,569,434	82,837,245	91,048,205
Average Gross Fixed Assets	**56,178,694**	**56,521,502**	**64,453,490**	**71,424,016**	**79,203,340**	**86,942,725**
Accumulated Depreciation, Opening Balance	20,775,844	21,159,703	23,231,005	24,953,518	26,713,501	28,986,750
Accumulated Depreciation, Closing Balance	22,514,364	23,231,005	24,953,518	26,713,501	28,986,750	31,516,772
Average Accumulated Depreciation	**21,645,104**	**22,195,354**	**24,092,261**	**25,833,510**	**27,850,126**	**30,251,761**
Average Net Book Value	**34,533,590**	**34,326,148**	**40,361,229**	**45,590,506**	**51,353,214**	**56,690,964**
Working Capital	52,636,102	51,479,758	55,512,724	60,582,688	72,309,529	72,761,304
Working Capital Allowance (%)	15%	15%	15%	15%	15%	7.5%
Working Capital Allowance	7,895,415	7,721,964	8,326,909	9,087,403	10,846,429	5,457,098
Rate Base	42,429,005	42,048,112	48,688,137	54,677,910	62,199,643	62,148,062

HHHI has calculated its 2016 rate base as $62,148,062, an increase of $19,719,056 over the 2012 Board Approved rate base of $42,429,005. This increase in rate base is attributable to an increase in the average net book value of capital assets of $22,157,374 and a reduction in the working capital allowance of $2,438,318. HHHI has reinvested significantly in its distribution system since the 2012 Cost of Service application and this is reflected in the net book value variance.. Approximately 96% of the working capital increase of $20,125,202 is related to cost of power. Controllable OM&A expenses increased 13% over the 2012 Board-Approved amounts for working capital.

A summary of HHHI's working capital calculations, including cost of power and controllable expenses, for the years 2012 Board Approved, 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge Year and 2016 Test Year are shown in Table 2-2. Further details of HHHI's calculation of cost of power are provided in Table 2-31. The calculation of cost of power for the 2015 bridge year is based on forecasted data.

Table 2-2: Summary of Working Capital Calculations

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Distribution Expenses - Operation	1,122,101	797,619	800,456	791,622	1,419,193	1,355,647
Distribution Expenses - Maintenance	808,985	1,905,957	742,555	615,219	341,000	374,125
Billing and Collecting	1,548,690	1,072,259	1,210,087	1,203,346	1,584,893	1,890,937
Community Relations	-	-	-	-	-	-
Administrative and General Expenses	2,313,625	2,036,642	2,331,334	2,568,754	2,917,017	3,122,070
Donations - LEAP	-	4,875	2,975	24,054	12,000	12,027
Taxes Other than Income Taxes	106,600	99,638	90,207	100,799	101,896	104,440
Less Allocated Depreciation		(184,231)	(159,509)	(131,339)	(153,830)	(173,580)
Total Eligible Distribution Expenses	5,900,000	5,732,759	5,018,105	5,172,456	6,222,169	6,685,666
Power Supply Expenses	46,736,102	45,746,999	50,494,619	55,410,232	66,099,360	66,075,638
Total Working Capital Expenses	**52,636,102**	**51,479,758**	**55,512,724**	**60,582,688**	**72,321,529**	**72,761,304**

Steeles Avenue Capital Addition Variance Account

In HHHI's 2012 Cost of Service Rate Application, Partial Settlement Agreement, Section 2, Rate Base, Item 2.1 states;

> *"There shall be an asymmetrical sharing arrangement with respect to capital expenditures for two projects forecast for 2012: (a) the Steeles Avenue – Trafalgar Rd to 5th Line South (Phase 2 – Stage 2)(capital cost of $496,638); and (b) Pole Relocations on Steeles Avenue between Winston Churchill Boulevard and Trafalgar Road (capital cost of $1,047,701) (collectively the "Steeles Avenue Projects"). The Parties have agreed to include the impact of the Steeles Avenue Projects in the Test Year revenue requirement. However, the Parties have also agreed that, in the event that the Steeles Avenue Projects are not closed to rate base in the Test Year, or if the overall capital cost is less than the amount forecasted, the revenue requirement impact will be credited to the asymmetrical variance account established for this purpose (the "Steeles Avenue Capital Addition Variance Account"). This account would provide for the return to customers of the revenue requirement impact related to the difference between the*

$1,544,339 of forecast capital expenditures on these two projects, and the actual capital expenditures of these two projects closed to rate base in 2012. The Steeles Ave Capital Additions Variance Account would record the difference in all components of annual revenue requirement (including, but not limited to, depreciation, interest, return on equity and PILs) resulting from any under-spending on capital expenditures for these two projects closed to rate base in the Test Year. That is, if the capital expenditures closed to rate base in 2012 are less than $1,544,339 on these two projects, the revenue requirement impact of the shortfall will be calculated and credited to the variance account in each year (between 2012 and HHH's next rebasing application) that the underspending on these two projects persists. For example, if the projects are completed in 2012 but come in under budget by $300,000, then the variance account will capture the revenue requirement impact of removing that $300,000 of capital spending from 2012, including the impact in 2013 to 2015. The account would be subject to disposition in accordance with the Board's normal policies from time to time on the disposition of applicable variance accounts."

The Steeles Avenue Projects referenced in the partial settlement agreement were started in 2012. The Steeles Avenue – Trafalgar Rd to 5th Line South (Phase 2 – Stage 2) project was completed in 2014 and the Pole Relocations on Steeles Avenue between Winston Churchill Boulevard and Trafalgar Road was completed in 2013. The actual costs of both projects were greater than the approved amounts of $496,638 and $1,047,701 respectively.

Upon request by the Region of Halton, the scope of both projects was changed and HHHI was required to make the necessary adjustments. The changes to the projects resulted in completion dates extending beyond 2012 and increased the total cost of the projects. Given that the actual cost of Steeles Avenue Projects was greater in totality than the Board Approved amount, HHHI is proposing that there be no adjustment to revenue requirement and to close the asymmetrical variance account established for this purpose. Table 2-3 provides a summary of the costs for the Steeles Avenue Projects.

Table 2-3: Summary of Costs for Steeles Avenue Projects

Description	Amount as per Partial Settlement Agreement	2012 Actual	2013 Actual	2014 Actual	Total Actual	Variance
Steeles Avenue – Trafalgar Rd to 5th Line South (Phase 2 – Stage 2)	496,638	1,507	4,401	435,955	441,864	(54,774)
Pole Relocations on Steeles Avenue between Winston Churchill Boulevard and Trafalgar Road (collectively the "Steeles Avenue Projects")	1,047,701	765,414	935,311		1,700,725	653,024
Total	1,544,339	766,922	939,712	435,955	2,142,589	598,250

Variance Analysis of Rate Base

In accordance with the Filing Requirements, HHHI has calculated a materiality threshold of $62,364 HHHI's proposed rate base of $62,148,062 for 2016. HHHI has elected to use a materiality threshold of $65,000. The materiality calculation is summarized in Table 2-4 below:

Table 2-4: Materiality Threshold

Description	2016 Test Year
Distribution Revenue Requirement	12,472,736
Materiality Threshold	0.50%
Materiality Calculated	62,364
Materiality Used	**65,000**

Table 2-5 details HHHI's rate base and working capital calculations for the 2016 Test Year, 2015 Bridge Year, 2014 Actual, 2013 Actual, 2012 Actual, and Board Approved and the following variances:

- 2016 Test Year against 2015 Bridge Year;
- 2015 Bridge Year against 2014 Actual;
- 2014 Actual against 2013 Actual;
- 2013 Actual against 2012 Actual; and
- 2012 Actual against 2012 Board Approved.

Table 2-5: Rate Base Variances

Description	2012 Board Approved	2012 Actual	Variance from 2012 Board Approved	2013 Actual	Variance from 2012 Actual	2014 Actual	Variance from 2013 Actual	2015 Bridge Year	Variance from 2014 Actual	2016 Test Year	Variance from 2015 Bridget Year
Average Gross Fixed Assets	56,178,694	56,521,502	342,807	64,453,490	7,931,988	71,424,016	6,970,526	79,203,340	7,779,324	86,942,725	7,739,385
Average Accumulated Depreciation	21,645,104	22,195,354	550,249	24,092,261	1,896,908	25,833,510	1,741,248	27,850,126	2,016,616	30,251,761	2,401,635
Average Net Book Value	34,533,590	34,326,148	- 207,442	40,361,229	6,035,080	45,590,506	5,229,278	51,353,214	5,762,707	56,690,964	5,337,750
Working Capital	52,636,102	51,479,758	- 1,156,344	55,512,724	4,032,965	60,582,688	5,069,964	72,309,529	11,726,842	72,761,304	451,775
Working Capital Allowance (%)	15%	15%		15%		15%		15%		7.5%	
Working Capital Allowance	7,895,415	7,721,964	- 173,452	8,326,909	604,945	9,087,403	760,495	10,846,429	1,759,026	5,457,097.80	- 5,389,332
Rate Base	42,429,005	42,048,112	- 380,894	48,688,137	6,640,025	54,677,910	5,989,772	62,199,643	7,521,734	62,148,062	- 51,582

HHHI offers the following comments in respect of the variances shown in Table 2-5.

2016 Test Year

As shown in Table 2-6, the total rate base for the 2016 Test Year is forecast to be $62,148,062. Average net fixed assets account for $56,690,964 of this total. The allowance for working capital totals $5,457,098 of which $4,955,673 (or 91%) is related to cost of power expenses.

Table 2-6: 2016 Rate Base Calculation

Description	2016 Test Year
Gross Fixed Assets, Opening Balance	82,837,245
Gross Fixed Assets, Closing Balance	91,048,205
Average Gross Fixed Assets	**86,942,725**
Accumulated Depreciation, Opening Balance	28,986,750
Accumulated Depreciation, Closing Balance	31,516,772
Average Accumulated Depreciation	**30,251,761**
Average Net Book Value	**56,690,964**
Working Capital	72,761,304
Working Capital Allowance (%)	7.5%
Working Capital Allowance	5,457,098
Rate Base	**62,148,062**

2016 Test Year vs. 2015 Bridge Year

As indicated in Table 2-7, the total rate base is expected to be $51,582 lower in the 2016 Test Year than in the 2015 Bridge Year. An increase in average net book value of $5,337,750 is offset by a decrease in working capital allowance of $5,389,332. The addition to gross fixed assets in 2016 is forecasted to be $8,210,959. Table 2-7 provides a more detailed variance of year over year changes to gross assets. Details with respect to HHHI's 2016 capital expenditure program are provided in HHHI's Distribution System Plan ("DSP"), found in Appendix 2-A. The decrease in working capital allowance of $5,389,332 is the result of a reduction in working capital allowance percentage from 15% to 7.5%. Detailed calculations of the cost of power expense for the 2016 Test Year can be found in Table 2-32.

Table 2-7: Variance - 2016 Test Year vs. 2015 Bridge Year

Description	2016 Test Year	2015 Bridge Year	Variance from 2015 Bridge Year
Gross Fixed Assets	91,048,205	82,837,245	8,210,959
Accumulated Depreciation	31,516,772	28,986,750	2,530,022
Net Book Value	59,531,433	53,850,495	5,680,938
Average Net Book Value	**56,690,964**	**51,353,214**	**5,337,750**
Working Capital	72,761,304	72,309,529	451,775
Working Capital Allowance	5,457,098	10,846,429	(5,389,332)
Rate Base	62,148,062	62,199,643	- 51,582

2015 Bridge Year vs. 2014 Actual

Total rate base for the 2015 Bridge Year is expected to be $62,199,643; an increase of $7,521,734 over the 2014 Actual amount. The increase is attributable primarily to an increase of $5,762,707 in the average net book value. The total variance of $7,267,811 in gross fixed assets is related to increases of $8,086,812 and $629,136 for distribution and general plant assets respectively. The increases are offset by contributed capital of ($1,448,137). Table 2-8 provides a more detailed explanation of the year over year change in gross assets. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

Approximately 91% of the increase in the 2015 working capital allowance can be attributed to the increase in cost of power expenses from 2014.

Table 2-8: Variance - 2015 Bridge Year vs. 2014 Actual

Description	2015 Bridge Year	2014 Actual	Variance from 2014 Actual
Gross Fixed Assets	82,837,245	75,569,434	7,267,811
Accumulated Depreciation	28,986,750	26,713,501	2,273,249
Net Book Value	53,850,495	48,855,933	4,994,562
Average Net Book Value	**51,353,214**	**45,590,506**	**5,762,707**
Working Capital	72,309,529	60,582,688	11,726,842
Working Capital Allowance	10,846,429	9,087,403	1,759,026
Rate Base	62,199,643	54,677,910	7,521,734

2014 Actual vs. 2013 Actual

The 2014 Actual rate base of $54,677,910 increased by $5,989,772 over 2013 Actuals. The variance is driven by an increase of $5,229,278 in the average net book value. The total change of $8,290,836 in gross fixed assets results from increases of $8,254,726 and $1,231,176 to distribution and general plant assets respectively. This increase to gross fixed assets is offset by contributed capital of ($1,195,066). Table 2-9 provides a more detailed explanation of the year over year change in gross assets. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

The primary driver of the increase in working capital of $5,069,964 is related to an increase in cost of power expense of $4,915,613. A summary of the cost of power expenses for 2012 through 2016 can be found in Table 2-31.

Table 2-9: Variance - 2014 Actual vs. 2013 Actual

Description	2014 Actual	2013 Actual	Variance from 2013 Actual
Gross Fixed Assets	75,569,434	67,278,598	8,290,836
Accumulated Depreciation	26,713,501	24,953,518	1,759,983
Net Book Value	48,855,933	42,325,080	6,530,852
Average Net Book Value	**45,590,506**	**40,361,229**	**5,229,278**
Working Capital	60,582,688	55,512,724	5,069,964
Working Capital Allowance	9,087,403	8,326,909	760,495
Rate Base	54,677,910	48,688,137	5,989,772

2013 Actual vs. 2012 Actual

The rate base of $48,688,137 for 2013 Actual increased over 2012 Actual by $6,640,025. This increase is due to capital expenditures resulting in a change in average net assets of $6,035,080.

The total change of $5,650,217 in gross fixed assets results from increases of $6,036,638 and $521,201 to distribution and general plant assets respectively. This increase to gross fixed assets is offset by contributed capital of ($907,623). Table 2-10 provides a more detailed explanation of the year over year change in gross assets. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

The primary driver of the increase in working capital is related to an increase in cost of power expense of $4,032,965. A summary of the cost of power expenses for 2012 through 2016 can be found in Table 2-31.

Table 2-10: Variance - 2013 Actual vs. 2012 Actual

Description	2013 Actual	2012 Actual	Variance from 2012 Actual
Gross Fixed Assets	67,278,598	61,628,381	5,650,217
Accumulated Depreciation	24,953,518	23,231,005	1,722,514
Net Book Value	42,325,080	38,397,377	3,927,703
Average Net Book Value	**40,361,229**	**34,326,148**	**6,035,080**
Working Capital	55,512,724	51,479,758	4,032,965
Working Capital Allowance	8,326,909	7,721,964	604,945
Rate Base	48,688,137	42,048,112	6,640,025

2012 Actual vs. 2012 Board Approved

The rate base of $42,048,112 for 2012 Actual is less than the 2012 Board Approved amount by $380,894. The decrease is a result of a change in Working Capital Allowance of $173,452 and the Average Net Book Value of $207,442. The lower 2012 Actual Working Capital Allowance over the 2012 Board Approved amount is a result of lower 2012 Actual cost of power than the 2012 Board Approved amount.

Distribution assets of $9,307,002 were added in 2012, as well as general plant assets of $906,758 for a total amount of $10,213,760 in gross fixed assets. Table 2-26 provides a more detailed explanation of the change in gross assets, year over year.

Included in the 2012 capital addition amount of $10,213,759 is $3,860,771 for smart meter disposition. This amount was transferred from the Deferral and Variance Account 1555 into Accounts 1860, 1920 and 1925 as a result of Board approved smart meter disposition in HHHI's 2012 Cost of Service Rate Application, EB-2011-0271.

Table 2-11: Variance - 2012 Actual vs. 2012 Board Approved

Description	2012 Actual	2012 Board Approved	Variance from 2012 Board Approved
Gross Fixed Assets	61,628,381	59,628,695	1,999,687
Accumulated Depreciation	23,231,005	22,514,364	716,640
Net Book Value	38,397,377	37,114,330	1,283,047
Average Net Book Value	**34,326,148**	**34,533,590**	(207,442)
Working Capital	51,479,758	52,636,102	(1,156,344)
Working Capital Allowance	7,721,964	7,895,415	(173,452)
Rate Base	42,048,112	42,429,005	(380,894)

Fixed Asset Continuity Schedules, Including Work in Progress

Tables 2-13 through 2-17 provide the Fixed Asset Continuity Schedules, including Work In Progress ("WIP") for 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge, and 2016 Test Years. For the years 2012, 2013 and 2014, actuals are based on Revised CGAAP. The 2015 Bridge and 2016 Test Years are based on MIFRS.

The total gross asset balances in HHHI's Fixed Asset Continuity Statements do not balance to the opening and closing balances of gross assets used to calculate the fixed asset component of rate base. WIP has been removed from the fixed asset continuity schedule balances for rate base calculation purposes, as mandated by the Board. A reconciliation of year-end NBV by year is provided in Table 2-12 below. The opening and closing balances of accumulated depreciation used to calculate the fixed asset component of rate base correspond to the fixed asset continuity schedule. As such there is no reconciliation required for accumulated depreciation.

1 **Table 2-12: Reconciliation of Year End Net Book Value Balances**

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Total Gross Assets for Rate Base	59,628,695	61,628,381	67,278,598	75,569,434	82,837, 245	91,048,205
Work in Progress	2,596,729	1,570,979	3,144,067	3,133,245	86,420,491	94,631,450
Total Gross Assets Including WIP	**62,225,424**	**63,199,360**	**70,422,665**	**78,702,679**	**169,257,736**	**185,679,655**
Total Accumulated Depreciation, including WIP	**22,514,364**	**23,231,005**	**24,953,518**	**26,713,501**	**28,986,750**	**31,516,772**
Total Net Book Value for Rate Base	37,114,330	38,397,377	42,325,080	48,855,933	53,850,495	59,531,433
Work in Progress	2,596,729	1,570,979	3,144,067	3,133,245	3,583,245	3,583,245
Total Net Book Value Including WIP	**39,711,059**	**39,968,356**	**45,469,147**	**51,989,178**	**57,433,740**	**63,114,678**

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Table 2-13: Fixed Asset Continuity Schedule as at December 31, 2012 - Revised CGAAP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	591,591	- 250		591,341	-	-		0	591,341
CEC	1806	Land Rights	4,738	0		4,738	-	-		0	4,738
47	1808	Buildings and Fixtures	3,233,684	356,930		3,590,614	672,969.82	82,159.87		755,130	2,835,484
13	1810	Leasehold Improvements	-	-		-	-	-		0	0
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-		-	-	-		0	0
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	5,145,637	567,968		5,713,606	1,117,450.68	88,876.98		1,206,328	4,507,278
47	1825	Storage Battery Equipment	-	-		-	-	-		0	0
47	1830	Poles, Towers and Fixtures	17,179,058	1,896,201		19,075,259	12,881,790.53	230,102.75		13,111,893	5,963,365
47	1835	Overhead Conductors and Devices	6,240,894	688,861		6,929,755	761,222.23	170,996.58		932,219	5,997,536
47	1840	Underground Conduit	970,548	107,128		1,077,676	98,676.81	20,487.77		119,165	958,511
47	1845	Underground Conductors and Devices	5,875,827	648,566		6,524,393	607,731.08	217,241.33		824,972	5,699,420
47	1850	Line Transformers	7,238,728	799,001		8,037,729	790,428.09	221,002.12		1,011,430	7,026,298
47	1855	Services	2,730,647	301,405		3,032,052	418,500.09	-		418,500	2,613,552
47	1860	Meters	1,179,057	3,790,635		4,969,692	76,329.25	391,135.78		467,465	4,502,227
N/A	1865	Other Installations on Customer's Premises	-	-		-	-	-		0	0
N/A	1905	Land	-	-		-	-	-		0	0
CEC	1906	Land Rights	-	-		-	-	-		0	0
47	1908	Buildings and Fixtures	-	-		-	-	-		0	0
13	1910	Leasehold Improvements	-	-		-	-	-		0	0
8	1915	Office Furniture and Equipment	384,354	42,424		426,778	255,488.75	10,289.90		265,779	161,000
10	1920	Computer Equipment - Hardware	1,086,223	266,567		1,352,790	1,025,028.18	242,838.92		1,267,867	84,923
12	1925	Computer Software	1,236,063	190,042		1,426,105	1,108,834.35	237,177.52		1,346,012	80,093
10	1930	Transportation Equipment	2,485,912	274,392		2,760,304	1,481,219.10	184,230.63		1,665,450	1,094,654
8	1935	Stores Equipment	53,152	5,867		59,018	52,043.13	-		52,043	6,975
8	1940	Tools, Shop and Garage Equipment	584,699	64,538		649,237	350,101.59	52,039.65		402,141	247,096
8	1945	Measurement and Testing Equipment	-	-		-	-	-		0	0
8	1950	Power Operated Equipment	-	-		-	-	-		0	0
8	1955	Communication Equipment	-	-		-	6,507.30	51,625.33		58,133	(58,133)
8	1960	Miscellaneous Equipment	-	-		-	-	-		0	0
47	1970	Load Management Controls - Customer Premises	570,108	62,928		633,035	298,141.02	-		298,141	334,894
47	1975	Load Management Controls - Utility Premises	-	-		-	-	-		0	0
47	1980	System Supervisory Equipment	1,009,299	111,405		1,120,704	425,242.32	-		425,242	695,462
47	1985	Sentinel Lighting Rentals	-	-		-	-	-		0	0
47	1990	Other Tangible Property	-	-		-	-	-		0	0
47	1995	Contributions and Grants	- 6,385,598	39,153		- 6,346,445	- 1,268,001.70	- 128,903.20		(1,396,905)	(4,949,540)
	2005	Property under Capital Lease	-	-		-	-	-		0	0
		Total before Work in Process	51,414,622	10,213,759	-	61,628,381	21,159,703	2,071,302	0	23,231,005	38,397,377
WIP	2055	Work in Process	1,088,850	482,129		1,570,979		-		0	1,570,979
	2070	Other Utility Plant - assets not in use				-				0	0
		Total after Work in Process	52,503,472	10,695,889	-	63,199,360	21,159,703	2,071,302	0	23,231,005	39,968,356

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Table 2-14: Fixed Asset Continuity Schedule as at December 31, 2013 - Revised CGAAP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2013

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	591,341	250		591,591	-	-		-	591,591
CEC	1806	Land Rights	4,738	-		4,738	-	-		-	4,738
47	1808	Buildings and Fixtures	3,590,614	-		3,590,614	755,130	82,317		837,447	2,753,167
13	1810	Leasehold Improvements	-	-		-	-	-		-	-
47	1815	Transformer Station Equipment - Normally Prim	-	-		-	-	-		-	-
47	1820	Distribution Station Equipment - Normally Prima	5,713,606	-		5,713,606	1,206,328	91,165		1,297,492	4,416,114
47	1825	Storage Battery Equipment	-	-		-	-	-		-	-
47	1830	Poles, Towers and Fixtures	19,075,259	3,191,693		22,266,952	13,111,893	293,107		13,405,000	8,861,952
47	1835	Overhead Conductors and Devices	6,929,755	1,079,885		8,009,640	932,219	187,415		1,119,633	6,890,006
47	1840	Underground Conduit	1,077,676	73,112		1,150,788	119,165	21,655		140,820	1,009,968
47	1845	Underground Conductors and Devices	6,524,393	619,154		7,143,546	824,972	246,926		1,071,899	6,071,647
47	1850	Line Transformers	8,037,729	694,253		8,731,981	1,011,430	232,734		1,244,164	7,487,817
47	1855	Services	3,032,052	22,489		3,054,541	418,500	-		418,500	2,636,041
47	1860	Meters	4,969,692	339,265		5,308,957	467,465	159,421		626,886	4,682,071
N/A	1865	Other Installations on Customer's Premises	-	-		-	-	-		-	-
N/A	1905	Land	-	-		-	-	-		-	-
CEC	1906	Land Rights	-	-		-	-	-		-	-
47	1908	Buildings and Fixtures	-	-		-	-	-		-	-
13	1910	Leasehold Improvements	-	-		-	-	-		-	-
8	1915	Office Furniture and Equipment	426,778	3,137		429,916	265,779	12,406		278,184	151,731
10	1920	Computer Equipment - Hardware	1,352,790	144,237		1,497,027	1,267,867	115,155		1,383,023	114,005
12	1925	Computer Software	1,426,105	156,819		1,582,924	1,346,012	179,415		1,525,427	57,498
10	1930	Transportation Equipment	2,760,304	67,746		2,828,050	1,665,450	159,509		1,824,959	1,003,091
8	1935	Stores Equipment	59,018	-		59,018	52,043	-		52,043	6,975
8	1940	Tools, Shop and Garage Equipment	649,237	48,101		697,339	402,141	54,524		456,666	240,673
8	1945	Measurement and Testing Equipment	-	-		-	-	-		-	-
8	1950	Power Operated Equipment	-	-		-	-	-		-	-
8	1955	Communication Equipment	633,035	-		633,035	58,133	4,634		62,767	570,268
8	1960	Miscellaneous Equipment	-	-		-	-	-		-	-
47	1970	Load Management Controls - Customer Premise	-	101,160		101,160	298,141	-		298,141	-196,981
47	1975	Load Management Controls - Utility Premises	-	-		-	-	-		-	-
47	1980	System Supervisory Equipment	1,120,704	16,538		1,137,242	425,242	47,811		473,053	664,189
47	1985	Sentinel Lighting Rentals	-	-		-	-	-		-	-
47	1990	Other Tangible Property	-	-		-	-	-		-	-
47	1995	Contributions and Grants	-6,346,445	-907,623		-7,254,067	-1,396,905	-165,680		-1,562,585	-5,691,482
	2005	Property under Capital Lease	-			-	-	-		-	-
		Total before Work in Process	**61,628,381**	**5,650,217**	**-**	**67,278,598**	**23,231,005**	**1,722,514**	**-**	**24,953,518**	**42,325,080**
WIP	2055	Work in Process	1,570,979	1,573,088		3,144,067	-			-	3,144,067
	2070	Other Utility Plant - assets not in use	-			-					-
		Total after Work in Process	**63,199,360**	**7,223,305**	**-**	**70,422,665**	**23,231,005**	**1,722,514**	**-**	**24,953,518**	**45,469,147**

Table 2-15: Fixed Asset Continuity Schedule as at December 31, 2014 - Revised CGAAP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2014

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	591,591	-		591,591	-	-		-	591,591
CEC	1806	Land Rights	4,738	-		4,738	-	-		-	4,738
47	1808	Buildings and Fixtures	3,590,614	43,442		3,634,056	837,447	80,998		918,444	2,715,611
13	1810	Leasehold Improvements	-	-		-	-	-		-	-
47	1815	Transformer Station Equipment - Normally Prima	-	-		-	-	-		-	-
47	1820	Distribution Station Equipment - Normally Prima	5,713,606	40,422		5,754,028	1,297,492	78,714		1,376,207	4,377,821
47	1825	Storage Battery Equipment	-	-		-	-	-		-	-
47	1830	Poles, Towers and Fixtures	22,266,952	4,605,229		26,872,181	13,405,000	370,688		13,775,687	13,096,493
47	1835	Overhead Conductors and Devices	8,009,640	688,985		8,698,625	1,119,633	200,128		1,319,761	7,378,863
47	1840	Underground Conduit	1,150,788	40,463		1,191,251	140,820	22,918		163,737	1,027,514
47	1845	Underground Conductors and Devices	7,143,546	1,048,667		8,192,213	1,071,899	266,116		1,338,015	6,854,198
47	1850	Line Transformers	8,731,981	1,703,294		10,435,275	1,244,164	238,026		1,482,190	8,953,085
47	1855	Services	3,054,541	-		3,054,541	418,500	-		418,500	2,636,041
47	1860	Meters	5,308,957	81,419		5,390,375	626,886	167,243		794,129	4,596,247
N/A	1865	Other Installations on Customer's Premises	-	-		-	-	-		-	-
N/A	1905	Land	-	-		-	-	-		-	-
CEC	1906	Land Rights	-	-		-	-	-		-	-
47	1908	Buildings and Fixtures	-	-		-	-	-		-	-
13	1910	Leasehold Improvements	-	-		-	-	-		-	-
8	1915	Office Furniture and Equipment	429,916	1,040		430,956	278,184	40,381		318,566	112,390
10	1920	Computer Equipment - Hardware	1,497,027	46,162		1,543,189	1,383,023	35,621		1,418,644	124,545
12	1925	Computer Software	1,582,924	772,756		2,355,680	1,525,427	232,948		1,758,374	597,306
10	1930	Transportation Equipment	2,828,050	385,211		3,213,261	1,824,959	131,339		1,956,298	1,256,963
8	1935	Stores Equipment	59,018	-		59,018	52,043	-		52,043	6,975
8	1940	Tools, Shop and Garage Equipment	697,339	23,530		720,869	456,666	37,616		494,282	226,587
8	1945	Measurement and Testing Equipment	-	-		-	-	-		-	-
8	1950	Power Operated Equipment	-	-		-	-	-		-	-
8	1955	Communication Equipment	633,035	2,477		635,513	62,767	2,576		65,343	570,170
8	1960	Miscellaneous Equipment	-	-		-	-	-		-	-
47	1970	Load Management Controls - Customer Premise	101,160	-		101,160	298,141	-		298,141	- 196,981
47	1975	Load Management Controls - Utility Premises	-	-		-	-	-		-	-
47	1980	System Supervisory Equipment	1,137,242	2,806		1,140,049	473,053	45,158		518,212	621,837
47	1985	Sentinel Lighting Rentals	-	-		-	-	-		-	-
47	1990	Other Tangible Property	-	-		-	-	-		-	-
47	1995	Contributions and Grants	- 7,254,067	- 1,195,066		- 8,449,133	- 1,562,585	- 190,487		- 1,753,072	- 6,696,061
	2005	Property under Capital Lease	-	-		-	-	-		-	-
		Total before Work in Process	**67,278,598**	**8,290,836**	**-**	**75,569,434**	**24,953,518**	**1,759,983**	**-**	**26,713,501**	**48,855,933**
WIP	2055	Work in Process	3,144,067	- 10,822		3,133,245	-			-	3,133,245
	2070	Other Utility Plant				-					-
		Total after Work in Process	**70,422,665**	**8,280,014**	**-**	**78,702,679**	**24,953,518**	**1,759,983**	**-**	**26,713,501**	**51,989,178**

Table 2-16: Fixed Asset Continuity Schedule as at December 31, 2015 – MIFRS

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2015

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	591,591	933,000		1,524,591	-	-		-	1,524,591
CEC	1806	Land Rights	4,738			4,738	-	-		-	4,738
47	1808	Buildings and Fixtures	3,634,056	150,000		3,784,056	918,444	65,813		984,258	2,799,798
13	1810	Leasehold Improvements	-			-	-	-		-	-
47	1815	Transformer Station Equipment - Normally Prim	-			-	-	-		-	-
47	1820	Distribution Station Equipment - Normally Prima	5,754,028	267,445		6,021,473	1,376,207	61,228		1,437,434	4,584,038
47	1825	Storage Battery Equipment	-			-	-	-		-	-
47	1830	Poles, Towers and Fixtures	26,872,181	2,877,676		29,749,857	13,775,687	419,333		14,195,021	15,554,836
47	1835	Overhead Conductors and Devices	8,698,625	1,223,235		9,921,860	1,319,761	210,006		1,529,767	8,392,092
47	1840	Underground Conduit	1,191,251	364,390		1,555,641	163,737	24,714		188,451	1,367,190
47	1845	Underground Conductors and Devices	8,192,213	498,591		8,690,804	1,338,015	286,513		1,624,528	7,066,276
47	1850	Line Transformers	10,435,275	794,064		11,229,339	1,482,190	256,704		1,738,894	9,490,445
47	1855	Services	3,054,541	342,263		3,396,804	418,500	4,278		422,778	2,974,025
47	1860	Meters	5,390,375	343,186		5,733,561	794,129	154,835		948,963	4,784,598
N/A	1865	Other Installations on Customer's Premises	-			-	-	-		-	-
N/A	1905	Land	-			-	-	-		-	-
CEC	1906	Land Rights	-			-	-	-		-	-
47	1908	Buildings and Fixtures	-			-	-	-		-	-
13	1910	Leasehold Improvements	-			-	-	-		-	-
8	1915	Office Furniture and Equipment	430,956	51,136		482,092	318,566	30,332		348,897	133,194
10	1920	Computer Equipment - Hardware	1,543,189	121,500		1,664,689	1,418,644	178,182		1,596,826	67,863
12	1925	Computer Software	2,355,680	85,500		2,441,180	1,758,374	648,404		2,406,779	34,401
10	1930	Transportation Equipment	3,213,261	329,000		3,542,261	1,956,298	153,830		2,110,127	1,432,133
8	1935	Stores Equipment	59,018			59,018	52,043	-		52,043	6,975
8	1940	Tools, Shop and Garage Equipment	720,869	30,000		750,869	494,282	36,802		531,084	219,785
8	1945	Measurement and Testing Equipment	-	5,000		5,000	-	-		-	5,000
8	1950	Power Operated Equipment	-			-	-	-		-	-
8	1955	Communication Equipment	635,513	7,000		642,513	65,343	4,365		69,708	572,805
8	1960	Miscellaneous Equipment	-			-	-	-		-	-
47	1970	Load Management Controls - Customer Premis	101,160			101,160	298,141	-		298,141	- 196,981
47	1975	Load Management Controls - Utility Premises	-			-	-	-		-	-
47	1980	System Supervisory Equipment	1,140,049	292,962		1,433,011	518,212	-		518,212	914,799
47	1985	Sentinel Lighting Rentals	-			-	-	-		-	-
47	1990	Other Tangible Property	-			-	-	-		-	-
47	1995	Contributions and Grants	- 8,449,133			- 8,449,133	- 1,753,072	-		- 1,753,072	- 6,696,061
	2005	Property under Capital Lease	-			-	-	-		-	-
47	2440	Deferred Revenue	-	- 1,448,137		- 1,448,137	-	- 262,091		- 262,091	- 1,186,046
		Total before Work in Process	75,569,434	7,267,811	-	82,837,245	26,713,501	2,273,249	-	28,986,751	53,850,495
	2070	Other utility plant	-			-					-
WIP	2055	Work in Process	3,133,245	450,000		3,583,245	-			-	3,583,245
		Total after Work in Process	78,702,679	7,717,811	-	86,420,490	26,713,501	2,273,249	-	28,986,751	57,433,740

Table 2-17: Fixed Asset Continuity Schedule as at December 31, 2016 - MIFRS

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2016

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,524,591	-		1,524,591	-	-		-	1,524,591
CEC	1806	Land Rights	4,738	-		4,738	-	-		-	4,738
47	1808	Buildings and Fixtures	3,734,056	285,000		4,069,056	984,258	70,992		1,055,249	3,013,806
13	1810	Leasehold Improvements	-	-		-	-	-		-	-
47	1815	Transformer Station Equipment - Normally Prim	-	-		-	-	-		-	-
47	1820	Distribution Station Equipment - Normally Prima	6,021,473	1,008,609		7,030,082	1,437,434	93,129		1,530,563	5,499,518
47	1825	Storage Battery Equipment	-	-		-	-	-		-	-
47	1830	Poles, Towers and Fixtures	29,749,357	3,706,539		33,456,396	14,195,021	485,175		14,680,196	18,776,199
47	1835	Overhead Conductors and Devices	9,921,860	1,501,254		11,423,114	1,529,767	240,278		1,770,046	9,653,068
47	1840	Underground Conduit	1,555,641	546,812		2,102,453	188,451	33,826		222,277	1,880,176
47	1845	Underground Conductors and Devices	8,690,804	208,164		8,898,968	1,624,528	296,064		1,920,592	6,978,376
47	1850	Line Transformers	11,229,339	893,285		12,122,624	1,738,894	278,906		2,017,801	10,104,823
47	1855	Services	3,396,804	387,911		3,784,715	422,778	13,405		436,184	3,348,531
47	1860	Meters	5,733,561	294,710		6,028,271	948,963	164,802		1,113,765	4,914,506
N/A	1865	Other Installations on Customer's Premises	-	-		-	-	-		-	-
N/A	1905	Land	-	-		-	-	-		-	-
CEC	1906	Land Rights	-	-		-	-	-		-	-
47	1908	Buildings and Fixtures	-	-		-	-	-		-	-
13	1910	Leasehold Improvements	-	-		-	-	-		-	-
8	1915	Office Furniture and Equipment	482,092	70,000		552,092	348,897	42,445		391,342	160,749
10	1920	Computer Equipment - Hardware	1,664,659	75,000		1,739,659	1,596,826	210,932		1,807,759	- 68,070
12	1925	Computer Software	2,441,150	2,800		2,443,950	2,406,779	670,479		3,077,258	- 633,278
10	1930	Transportation Equipment	3,542,261	145,000		3,687,261	2,110,127	173,580		2,283,707	1,403,553
8	1935	Stores Equipment	59,018	-		59,018	52,043	-		52,043	6,975
8	1940	Tools, Shop and Garage Equipment	750,869	32,000		782,869	531,034	39,902		570,937	211,932
8	1945	Measurement and Testing Equipment	5,000	-		5,000	-	-		-	5,000
8	1950	Power Operated Equipment	-	-		-	-	-		-	-
8	1955	Communication Equipment	642,513	100,000		742,513	69,708	15,065		84,773	657,740
8	1960	Miscellaneous Equipment	-	-		-	-	-		-	-
47	1970	Load Management Controls - Customer Premis	101,160	-		101,160	298,141	-		298,141	- 196,981
47	1975	Load Management Controls - Utility Premises	-	-		-	-	-		-	-
47	1980	System Supervisory Equipment	1,433,011	86,579		1,519,590	518,212	-		518,212	1,001,378
47	1985	Sentinel Lighting Rentals	-	-		-	-	-		-	-
47	1990	Other Tangible Property	-	-		-	-	-		-	-
47	1995	Contributions and Grants	- 8,449,133			- 8,449,133	- 1,753,072	-		- 1,753,072	- 6,696,061
	2005	Property under Capital Lease	-			-	-	-		-	-
47	2440	Deferred Revenue	- 1,448,137	- 1,132,703		- 2,580,840	- 262,091	- 298,960		- 561,051	- 2,019,789
		Total before Work in Process	**82,837,245**	**8,210,959**	**-**	**91,048,205**	**28,986,751**	**2,530,022**	**-**	**31,516,772**	**59,531,432**
	2070	Other utility plant	-			-					-
WIP	2055	Work in Process	3,583,245			3,583,245	-			-	3,583,245
		Total after Work in Process	**86,420,490**	**8,210,959**	**-**	**94,631,450**	**28,986,751**	**2,530,022**	**-**	**31,516,772**	**63,114,677**

Fixed Asset Continuity Schedules, Excluding Work in Progress

Tables 2-18 through 2-22 provide the Fixed Asset Continuity Schedules, excluding WIP for 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge, and 2016 Test Years. For the years 2012, 2013 and 2014, actuals are based on Revised CGAAP. The 2015 Bridge and 2016 Test Years are based on MIFRS. Tables 2-18 through 2-22 are as shown in Board Appendix 2-BA as required by the Filing Requirements.

The "CCA Class" for fixed assets shown in Appendix 2-BA is as provided by the Board and agrees with the CCA Class used for tax purposes in HHHI's tax returns.

Upon the date of IFRS adoption, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are recorded in Account 2440, Deferred Revenue and amortized to revenue over the service life of the related asset. In addition, historical amounts recorded in Account 1995 prior to the transition year are to be netted against the assets in PP&E that they relate to and no longer accounted for separately as an offset to PP&E. For purposes of cost allocation, and consistency within this application, HHHI has continued to utilize Account 1995 to track customer contributions, including contributed capital forecast for the 2015 Bridge Year and the 2016 Test Year.

A breakdown of account 1995, showing the reclassification, is provided in Table 2-23. Further detailed explanation of depreciation is provided in Exhibit 2, Tab 2, Schedule 3 and Exhibit 4, Tab 4, Schedule 1.

The calculation of rate base for the 2015 Bridge and 2016 Test Years does not include retirement of assets as no material asset retirements are planned for the Bridge and the Test Years.

Table 2-18: Appendix 2-BA - Fixed Asset Continuity Schedule as at December 31, 2012 - Revised CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,236,063	$ 190,042	$ -	$ 1,426,105	-$ 1,108,835	-$ 237,178	$ -	-$ 1,346,012	$ 80,093
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,738	$ -	$ -	$ 4,738	$ -	$ -	$ -	$ -	$ 4,738
N/A	1805	Land	$ 591,591	-$ 250	$ -	$ 591,341	$ -	$ -	$ -	$ -	$ 591,341
47	1808	Buildings								$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 5,145,637	$ 567,968	$ -	$ 5,713,606	-$ 1,117,451	-$ 88,877	$ -	-$ 1,206,328	$ 4,507,278
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 17,179,058	$ 1,896,201	$ -	$ 19,075,259	-$ 12,881,791	-$ 230,103	$ -	-$ 13,111,894	$ 5,963,365
47	1835	Overhead Conductors & Devices	$ 6,240,894	$ 688,861	$ -	$ 6,929,755	-$ 761,222	-$ 170,997	$ -	-$ 932,219	$ 5,997,536
47	1840	Underground Conduit	$ 970,548	$ 107,128	$ -	$ 1,077,676	-$ 98,676	-$ 20,488	$ -	-$ 119,163	$ 958,512
47	1845	Underground Conductors & Devices	$ 5,875,827	$ 648,566	$ -	$ 6,524,393	-$ 607,731	-$ 217,241	$ -	-$ 824,972	$ 5,699,420
47	1850	Line Transformers	$ 7,238,728	$ 799,001	$ -	$ 8,037,729	-$ 790,428	-$ 221,002	$ -	-$ 1,011,430	$ 7,026,298
47	1855	Services (Overhead & Underground)	$ 2,730,647	$ 301,405	$ -	$ 3,032,052	-$ 418,500	$ -	$ -	-$ 418,500	$ 2,613,552
47	1860	Meters	$ 1,179,057	$ 3,790,635	$ -	$ 4,969,692	-$ 76,329	-$ 391,136	$ -	-$ 467,465	$ 4,502,227
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 3,233,684	$ 356,930	$ -	$ 3,590,614	-$ 672,970	-$ 82,160	$ -	-$ 755,130	$ 2,835,484
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 384,354	$ 42,424	$ -	$ 426,778	-$ 255,489	-$ 10,290	$ -	-$ 265,779	$ 161,000
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,086,223	$ 266,567	$ -	$ 1,352,790	-$ 1,025,029	-$ 242,839	$ -	-$ 1,267,868	$ 84,922
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 2,485,912	$ 274,392	$ -	$ 2,760,304	-$ 1,481,219	-$ 184,231	$ -	-$ 1,665,450	$ 1,094,854
8	1935	Stores Equipment	$ 53,152	$ 5,867	$ -	$ 59,018	-$ 52,043	$ -	$ -	-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	$ 584,699	$ 64,538	$ -	$ 649,237	-$ 350,102	-$ 52,040	$ -	-$ 402,142	$ 247,096
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	-$ 6,507	-$ 51,625	$ -	-$ 58,132	-$ 58,132
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 570,108	$ 62,928	$ -	$ 633,035	-$ 298,141	$ -	$ -	-$ 298,141	$ 334,894
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,009,299	$ 111,405	$ -	$ 1,120,704	-$ 425,242	$ -	$ -	-$ 425,242	$ 695,462
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 6,385,598	$ 39,153	$ -	-$ 6,346,445	$ 1,268,002	$ 128,903	$ -	$ 1,396,905	-$ 4,949,540
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	$ 51,414,622	$ 10,213,760	$ -	$ 61,628,381	-$ 21,159,704	-$ 2,071,302	$ -	-$ 23,231,006	$ 38,397,376
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 51,414,622	$ 10,213,760	$ -	$ 61,628,381	-$ 21,159,704	-$ 2,071,302	$ -	-$ 23,231,006	$ 38,397,376
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[4]									
		Total						-$ 2,071,302			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment

Table 2-19: Appendix 2-BA - Fixed Asset Continuity Schedule as at December 31, 2013 - Revised CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2013

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,426,105	$ 156,819	$ -	$ 1,582,924	-$ 1,346,012	-$ 179,415	$ -	-$ 1,525,427	$ 57,497
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,738	$ -	$ -	$ 4,738	$ -	$ -	$ -	$ -	$ 4,738
N/A	1805	Land	$ 591,341	$ 250	$ -	$ 591,591	$ -	$ -	$ -	$ -	$ 591,591
47	1808	Buildings	$ -				$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 5,713,606	$ -	$ -	$ 5,713,606	-$ 1,206,328	-$ 91,165	$ -	-$ 1,297,492	$ 4,416,114
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 19,075,259	$ 3,191,693	$ -	$ 22,266,952	-$ 13,111,894	-$ 293,107	$ -	-$ 13,405,000	$ 8,861,951
47	1835	Overhead Conductors & Devices	$ 6,929,755	$ 1,079,885	$ -	$ 8,009,640	-$ 932,219	-$ 187,415	$ -	-$ 1,119,633	$ 6,890,007
47	1840	Underground Conduit	$ 1,077,676	$ 73,112	$ -	$ 1,150,788	-$ 119,163	-$ 21,655	$ -	-$ 140,818	$ 1,009,969
47	1845	Underground Conductors & Devices	$ 6,524,393	$ 619,154	$ -	$ 7,143,546	-$ 824,972	-$ 246,926	$ -	-$ 1,071,899	$ 6,071,648
47	1850	Line Transformers	$ 8,037,729	$ 694,253	$ -	$ 8,731,981	-$ 1,011,430	-$ 232,734	$ -	-$ 1,244,164	$ 7,487,817
47	1855	Services (Overhead & Underground)	$ 3,032,052	$ 22,489	$ -	$ 3,054,541	-$ 418,500	$ -	$ -	-$ 418,500	$ 2,636,041
47	1860	Meters	$ 4,969,692	$ 339,265	$ -	$ 5,308,957	-$ 467,465	-$ 159,421	$ -	-$ 626,886	$ 4,682,071
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 3,590,614	$ -	$ -	$ 3,590,614	-$ 755,130	-$ 82,317	$ -	-$ 837,447	$ 2,753,167
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 426,778	$ 3,137	$ -	$ 429,916	-$ 265,779	-$ 12,406	$ -	-$ 278,185	$ 151,731
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,352,790	$ 144,237	$ -	$ 1,497,027	-$ 1,267,868	-$ 115,155	$ -	-$ 1,383,024	$ 114,004
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,760,304	$ 67,746	$ -	$ 2,828,050	-$ 1,665,450	-$ 159,509	$ -	-$ 1,824,959	$ 1,003,091
8	1935	Stores Equipment	$ 59,018	$ -	$ -	$ 59,018	-$ 52,043	$ -	$ -	-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	$ 649,237	$ 48,101	$ -	$ 697,339	-$ 402,142	-$ 54,524	$ -	-$ 456,666	$ 240,673
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	-$ 58,132	-$ 4,634	$ -	-$ 62,767	-$ 62,767
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 633,035	$ 101,160	$ -	$ 734,195	-$ 298,141	$ -	$ -	-$ 298,141	$ 436,054
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,120,704	$ 16,538	$ -	$ 1,137,242	-$ 425,242	-$ 47,811	$ -	-$ 473,053	$ 664,189
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 6,346,445	-$ 907,623	$ -	-$ 7,254,067	$ 1,396,905	$ 165,680	$ -	$ 1,562,585	-$ 5,691,482
47	2440	Deferred Revenue[5]	$ -				$ -				$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	$ 61,628,381	$ 5,650,217	$ -	$ 67,278,598	-$ 23,231,005	-$ 1,722,514	$ -	-$ 24,953,519	$ 42,325,079
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less *Other Non Rate-Regulated Utility Assets (input as negative)*				$ -				$ -	$ -
		Total PP&E	$ 61,628,381	$ 5,650,217	$ -	$ 67,278,598	-$ 23,231,005	-$ 1,722,514	$ -	-$ 24,953,519	$ 42,325,079
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[4]									
		Total						-$ 1,722,514			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,722,514

Table 2-20: Appendix 2-BA - Fixed Asset Continuity Schedule as at December 31, 2014 - Revised CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2014

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,582,924	$ 772,756	$ -	$ 2,355,680	-$ 1,525,427	-$ 232,948	$ -	-$ 1,758,375	$ 597,306
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,738	$ -	$ -	$ 4,738	$ -	$ -	$ -	$ -	$ 4,738
N/A	1805	Land	$ 591,591	$ -	$ -	$ 591,591	$ -	$ -	$ -	$ -	$ 591,591
47	1808	Buildings	$ -				$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 5,713,606	$ 40,422	$ -	$ 5,754,028	-$ 1,297,492	-$ 78,714	$ -	-$ 1,376,207	$ 4,377,821
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,266,952	$ 4,605,229	$ -	$ 26,872,181	-$ 13,405,000	-$ 370,688	$ -	-$ 13,775,688	$ 13,096,493
47	1835	Overhead Conductors & Devices	$ 8,009,640	$ 688,955	$ -	$ 8,698,625	-$ 1,119,633	-$ 200,128	$ -	-$ 1,319,761	$ 7,378,864
47	1840	Underground Conduit	$ 1,150,788	$ 40,463	$ -	$ 1,191,251	-$ 140,818	-$ 22,918	$ -	-$ 163,736	$ 1,027,515
47	1845	Underground Conductors & Devices	$ 7,143,546	$ 1,048,667	$ -	$ 8,192,213	-$ 1,071,899	-$ 266,116	$ -	-$ 1,338,015	$ 6,854,198
47	1850	Line Transformers	$ 8,731,981	$ 1,703,294	$ -	$ 10,435,275	-$ 1,244,164	-$ 238,026	$ -	-$ 1,482,190	$ 8,953,085
47	1855	Services (Overhead & Underground)	$ 3,054,541	$ -	$ -	$ 3,054,541	-$ 418,500	$ -	$ -	-$ 418,500	$ 2,636,041
47	1860	Meters	$ 5,308,957	$ 81,419	$ -	$ 5,390,375	-$ 626,886	-$ 167,243	$ -	-$ 794,129	$ 4,596,247
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 3,590,614	$ 43,442	$ -	$ 3,634,056	-$ 837,447	-$ 80,998	$ -	-$ 918,444	$ 2,715,611
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 429,916	$ 1,040	$ -	$ 430,956	-$ 278,185	-$ 40,381	$ -	-$ 318,566	$ 112,390
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,497,027	$ 46,162	$ -	$ 1,543,189	-$ 1,383,024	-$ 35,621	$ -	-$ 1,418,645	$ 124,544
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,828,050	$ 385,211	$ -	$ 3,213,261	-$ 1,824,959	-$ 131,339	$ -	-$ 1,956,298	$ 1,256,963
8	1935	Stores Equipment	$ 59,018	$ -	$ -	$ 59,018	-$ 52,043	$ -	$ -	-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	$ 697,339	$ 23,530	$ -	$ 720,869	-$ 456,666	-$ 37,616	$ -	-$ 494,282	$ 226,586
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ 2,477	$ -	$ 2,477	-$ 62,767	-$ 2,576	$ -	-$ 65,343	-$ 62,865
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 734,195	$ -	$ -	$ 734,195	-$ 298,141	$ -	$ -	-$ 298,141	$ 436,054
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,137,242	$ 2,806	$ -	$ 1,140,049	-$ 473,053	-$ 45,158	$ -	-$ 518,212	$ 621,837
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 7,254,067	-$ 1,195,066	$ -	-$ 8,449,133	$ 1,562,585	$ 190,487	$ -	$ 1,753,072	-$ 6,696,061
47	2440	Deferred Revenue[5]	$ -				$ -			$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	$ 67,278,598	$ 8,290,836	$ -	$ 75,569,434	-$ 24,953,519	-$ 1,759,983	$ -	-$ 26,713,502	$ 48,855,932
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 67,278,598	$ 8,290,836	$ -	$ 75,569,434	-$ 24,953,519	-$ 1,759,983	$ -	-$ 26,713,502	$ 48,855,932
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						-$ 1,759,983			

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation
Transportation
Stores Equipment
Net Depreciation -$ 1,759,983

Table 2-21: Appendix 2-BA - Fixed Asset Continuity Schedule as at December 31, 2015 - MIFRS

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2015

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 2,355,680	$ 85,500	$ -	$ 2,441,180	-$ 1,758,375	-$ 648,404	$ -	-$ 2,406,779	$ 34,401
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,738	$ -	$ -	$ 4,738	$ -	$ -	$ -	$ -	$ 4,738
N/A	1805	Land	$ 591,591	$ 933,000	$ -	$ 1,524,591	$ -	$ -	$ -	$ -	$ 1,524,591
47	1808	Buildings	$ -				$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 5,754,028	$ 267,445	$ -	$ 6,021,473	-$ 1,376,207	-$ 61,228	$ -	-$ 1,437,434	$ 4,584,038
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 26,872,181	$ 2,877,676	$ -	$ 29,749,857	-$ 13,775,688	-$ 419,333	$ -	-$ 14,195,021	$ 15,554,836
47	1835	Overhead Conductors & Devices	$ 8,698,625	$ 1,223,235	$ -	$ 9,921,860	-$ 1,319,761	-$ 210,006	$ -	-$ 1,529,767	$ 8,392,093
47	1840	Underground Conduit	$ 1,191,251	$ 364,390	$ -	$ 1,555,641	-$ 163,736	-$ 24,714	$ -	-$ 188,450	$ 1,367,191
47	1845	Underground Conductors & Devices	$ 8,192,213	$ 498,591	$ -	$ 8,690,804	-$ 1,338,015	-$ 286,513	$ -	-$ 1,624,528	$ 7,066,276
47	1850	Line Transformers	$ 10,435,275	$ 794,064	$ -	$ 11,229,339	-$ 1,482,190	-$ 256,704	$ -	-$ 1,738,894	$ 9,490,445
47	1855	Services (Overhead & Underground)	$ 3,054,541	$ 342,263	$ -	$ 3,396,804	-$ 418,500	-$ 4,278	$ -	-$ 422,778	$ 2,974,026
47	1860	Meters	$ 5,390,375	$ 343,186	$ -	$ 5,733,561	-$ 794,129	-$ 154,835	$ -	-$ 948,963	$ 4,784,598
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 3,634,056	$ 150,000	$ -	$ 3,784,056	-$ 918,444	-$ 65,813	$ -	-$ 984,258	$ 2,799,798
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 430,966	$ 51,136	$ -	$ 482,092	-$ 318,566	-$ 30,332	$ -	-$ 348,898	$ 133,194
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,543,189	$ 121,500	$ -	$ 1,664,689	-$ 1,418,645	-$ 178,182	$ -	-$ 1,596,827	$ 67,862
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 3,213,261	$ 329,000	$ -	$ 3,542,261	-$ 1,956,298	-$ 153,830	$ -	-$ 2,110,128	$ 1,432,133
8	1935	Stores Equipment	$ 59,018	$ -	$ -	$ 59,018	-$ 52,043	$ -	$ -	-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	$ 720,869	$ 30,000	$ -	$ 750,869	-$ 494,282	-$ 36,802	$ -	-$ 531,085	$ 219,784
8	1945	Measurement & Testing Equipment	$ -	$ 5,000	$ -	$ 5,000	$ -	$ -	$ -	$ -	$ 5,000
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 2,477	$ 7,000	$ -	$ 9,477	-$ 65,343	-$ 4,365	$ -	-$ 69,708	-$ 60,230
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 734,195	$ -	$ -	$ 734,195	-$ 298,141	$ -	$ -	-$ 298,141	$ 436,054
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,140,049	$ 292,962	$ -	$ 1,433,011	-$ 518,212	$ -	$ -	-$ 518,212	$ 914,799
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 8,449,133		$ -	-$ 8,449,133	$ 1,753,072		$ -	$ 1,753,072	-$ 6,696,061
47	2440	Deferred Revenue[5]	$ -	-$ 1,448,137		-$ 1,448,137	$ -	$ 262,091		$ 262,091	-$ 1,186,046
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	$ 75,569,434	$ 7,267,811	$ -	$ 82,837,245	-$ 26,713,502	-$ 2,273,249	$ -	-$ 28,986,751	$ 53,850,494
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 75,569,434	$ 7,267,811	$ -	$ 82,837,245	-$ 26,713,502	-$ 2,273,249	$ -	-$ 28,986,751	$ 53,850,494
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						-$ 2,273,249			

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Net Depreciation	-$ 2,273,249

Table 2-22: Appendix 2-BA - Fixed Asset Continuity Schedule as at December 31, 2016 - MIFRS

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2016

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 2,441,180	$ 2,800	$ -	$ 2,443,980	-$ 2,406,779	-$ 670,479	$ -	-$ 3,077,259	-$ 633,278
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,738	$ -	$ -	$ 4,738	$ -	$ -	$ -	$ -	$ 4,738
N/A	1805	Land	$ 1,524,591	$ -	$ -	$ 1,524,591	$ -	$ -	$ -	$ -	$ 1,524,591
47	1808	Buildings	$ -				$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 6,021,473	$ 1,008,609	$ -	$ 7,030,082	-$ 1,437,434	-$ 93,129	$ -	-$ 1,530,563	$ 5,499,518
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 29,749,857	$ 3,706,539	$ -	$ 33,456,396	-$ 14,195,021	-$ 485,175	$ -	-$ 14,680,197	$ 18,776,199
47	1835	Overhead Conductors & Devices	$ 9,921,860	$ 1,501,254	$ -	$ 11,423,114	-$ 1,529,767	-$ 240,278	$ -	-$ 1,770,046	$ 9,653,069
47	1840	Underground Conduit	$ 1,555,641	$ 546,812	$ -	$ 2,102,453	-$ 188,450	-$ 33,826	$ -	-$ 222,276	$ 1,880,177
47	1845	Underground Conductors & Devices	$ 8,690,804	$ 208,164	$ -	$ 8,898,968	-$ 1,624,528	-$ 296,064	$ -	-$ 1,920,592	$ 6,978,376
47	1850	Line Transformers	$ 11,229,339	$ 893,285	$ -	$ 12,122,624	-$ 1,738,894	-$ 278,906	$ -	-$ 2,017,801	$ 10,104,823
47	1855	Services (Overhead & Underground)	$ 3,396,804	$ 387,911	$ -	$ 3,784,715	-$ 422,778	-$ 13,405	$ -	-$ 436,184	$ 3,348,531
47	1860	Meters	$ 5,733,561	$ 294,710	$ -	$ 6,028,271	-$ 948,963	-$ 164,802	$ -	-$ 1,113,765	$ 4,914,506
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 3,784,056	$ 285,000	$ -	$ 4,069,056	-$ 984,258	-$ 70,992	$ -	-$ 1,055,249	$ 3,013,806
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 482,092	$ 70,000	$ -	$ 552,092	-$ 348,898	-$ 42,445	$ -	-$ 391,343	$ 160,749
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,664,689	$ 75,000	$ -	$ 1,739,689	-$ 1,596,827	-$ 210,932	$ -	-$ 1,807,760	-$ 68,071
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 3,542,261	$ 145,000	$ -	$ 3,687,261	-$ 2,110,128	-$ 173,580	$ -	-$ 2,283,708	$ 1,403,553
8	1935	Stores Equipment	$ 59,018	$ -	$ -	$ 59,018	-$ 52,043	$ -	$ -	-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	$ 750,869	$ 32,000	$ -	$ 782,869	-$ 531,085	-$ 39,902	$ -	-$ 570,987	$ 211,882
8	1945	Measurement & Testing Equipment	$ 5,000	$ -	$ -	$ 5,000	$ -	$ -	$ -	$ -	$ 5,000
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 9,477	$ 100,000	$ -	$ 109,477	-$ 69,708	-$ 15,065	$ -	-$ 84,772	$ 24,705
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 734,195	$ -	$ -	$ 734,195	-$ 298,141	$ -	$ -	-$ 298,141	$ 436,054
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,433,011	$ 86,579	$ -	$ 1,519,590	-$ 518,212	$ -	$ -	-$ 518,212	$ 1,001,378
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 8,449,133	$ -	$ -	-$ 8,449,133	$ 1,753,072	$ -	$ -	$ 1,753,072	-$ 6,696,061
47	2440	Deferred Revenue[5]	-$ 1,448,137	-$ 1,132,703		-$ 2,580,840	$ 262,091	$ 298,960		$ 561,051	-$ 2,019,789
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	$ 82,837,245	$ 8,210,960	$ -	$ 91,048,205	-$ 28,986,751	-$ 2,530,022	$ -	-$ 31,516,773	$ 59,531,431
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less *Other Non Rate-Regulated Utility Assets (input as negative)*				$ -				$ -	$ -
		Total PP&E	$ 82,837,245	$ 8,210,960	$ -	$ 91,048,205	-$ 28,986,751	-$ 2,530,022	$ -	-$ 31,516,773	$ 59,531,431
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						-$ 2,530,022			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 2,530,022

As explained previously, upon the date of IFRS adoption, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are to be recorded in Account 2440, Deferred Revenue. Historical contributions are to be netted against the assets to which they are related. For the purposes of cost allocation and consistency within this application, HHHI has included all contributed capital including contributions forecast in Account 1995 for the 2015 Bridge and 2016 Test Years in Account 1995. Details of Account 1995 are provided in Table 2-23 below.

1 **Table 2-23: Details of USofA 1995**

2

Account 1995 Breakdown for Financial Reporting Purposes		Cost			Accumulated Depreciation			
		Opening Balance	Additions	Closing Balance	Opening Balance	Additions	Closing Balance	Net Book Value
December 31, 2014 MIFRS								
1830	Poles, Towers and Fixtures	(3,625,041)	-	(3,625,041)	(752,143)	(81,727)	(833,870)	(2,791,171)
1835	Overhead Conductors and Devices	(1,499,118)	-	(1,499,118)	(311,045)	(33,798)	(344,843)	(1,154,275)
1840	Underground Conduit	-	-	-	-	-	-	-
1845	Underground Conductors and Devices	(2,224,942)	-	(2,224,942)	(461,643)	(50,162)	(511,805)	(1,713,137)
1850	Line Transformers	-	-	-	-	-	-	-
1855	Services	-	-	-	-	-	-	-
1860	Meters	(1,100,033)	-	(1,100,033)	(228,241)	(24,800)	(253,041)	(846,992)
2440	Deferred Revenue	-	(1,448,137)	(1,448,137)	-	(71,604)	(71,604)	(1,376,533)
Total		**(8,449,133)**	**(1,448,137)**	**(9,897,270)**	**(1,753,072)**	**(262,091)**	**(2,015,163)**	**(7,882,107)**
December 31, 2015 MIFRS								
1830	Poles, Towers and Fixtures	(3,625,041)	-	(3,625,041)	(833,870)	(81,727)	(915,597)	(2,709,444)
1835	Overhead Conductors and Devices	(1,499,118)	-	(1,499,118)	(344,843)	(33,798)	(378,641)	(1,120,477)
1840	Underground Conduit	-	-	-	-	-	-	-
1845	Underground Conductors and Devices	(2,224,942)	-	(2,224,942)	(511,805)	(50,162)	(561,966)	(1,662,975)
1850	Line Transformers	-	-	-	-	-	-	-
1855	Services	-	-	-	-	-	-	-
1860	Meters	(1,100,033)	-	(1,100,033)	(253,041)	(24,800)	(277,842)	(822,192)
2440	Deferred Revenue	(1,448,137)	(1,132,703)	(2,580,840)	(71,604)	(108,473)	(180,077)	(2,400,763)
Total		**(9,897,270)**	**(1,132,703)**	**(11,029,973)**	**(2,015,163)**	**(298,960)**	**(2,314,123)**	**(8,715,850)**

3

Gross Assets – Property Plant and Equipment and Accumulated Depreciation (2.2.1.2)

Breakdown by Function

Table 2-24: Categorizes HHHI's assets into four categories:

- Distribution plant
- General plant
- Contributions and grants
- WIP

In accordance with the Uniform System of Accounts ("USoA"), HHHI has segregated gross assets as follows:

- Distribution plant asset accounts include USoA 1805 to 1860 - including assets such as substation equipment, poles, wires, transformers and meters;

- General plant asset accounts include USoA 1905 to 1990 and USoA 1611 - including assets such as buildings, computer software and hardware, transportation equipment, and tools;

- Contributions and grants includes USoA account 1995 – including all contributions in aid of capital that HHHI has received or forecasted to be received as per the Distribution System Code ("DSC"); and

- WIP –all costs related to assets that are not considered in-service as of December 31st of the applicable fiscal year. Costs are transferred out of WIP and into the appropriate category above once designated in-service in the field.

Table 2-25: Gross Assets by Category

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Reporting Basis	Revised CGAAP	Revised CGAAP	Revised CGAAP	Revised CGAAP	MIFRS	MIFRS
Distribution Plant	7,454,011	9,267,849	6,036,638	8,254,726	8,086,812	8,918,863
General Plant	879,083	906,758	521,201	1,231,176	629,136	424,800
Contributions and Grants	(1,433,093)	39,153	(907,623)	(1,195,066)	(1,448,137)	(1,132,703)
Total Excluding WIP	6,900,000	10,213,759	5,650,217	8,290,836	7,267,811	8,210,959
WIP	-	482,129	1,573,088	(10,822)	450,000	-
Total Including WIP	**6,900,000**	**10,695,889**	**7,223,305**	**8,280,014**	**7,717,811**	**8,210,959**

Detailed Breakdown by Major Plant Account

Table 2-26 below provides a detailed breakdown by major plant account for each functionalized plant item. Each plant item is accompanied by a description in accordance with the Board's USoA, including the 2016 Test Year. HHHI has also included a breakdown of accumulated amortization in the same format in Table 2-27.

Table 2-26: Gross Assets - Detailed Breakdown by Major Plant Function

	Description	2012 Board Approved	2012 Actual	Variance from 2012 Board Approved	2013 Actual	Variance from 2012 Actual	2014 Actual	Variance from 2013 Actual	2015 Bridge Year	Variance from 2014 Actual	2016 Test Year	Variance from 2015 Bridge
Reporting Basis		Revised CGAAP	Revised CGAAP		Revised CGAAP		Revised CGAAP		MIFRS		MIFRS	
Land and Buildings												
1805	Land	534,871	591,341	56,470	591,591	250	591,591	-	1,524,591	933,000	1,524,591	-
1806	Land Rights	4,738	4,738	0	4,738	-	4,738	-	4,738	-	4,738	-
1808	Buildings and Fixtures	3,080,205	3,590,614	510,409	3,590,614	-	3,634,056	43,442	3,784,056	150,000	4,069,056	285,000
	Sub-Total-Land and Buildings	3,619,814	4,186,693	566,879	4,186,943	250	4,230,385	43,442	5,313,385	1,083,000	5,598,385	285,000
Distribution Stations				-		-		-		-		-
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,380,992	5,713,606	1,332,614	5,713,606	-	5,754,028	40,422	6,021,473	267,445	7,030,082	1,008,609
	Sub-Total-Distribution Stations	4,380,992	5,713,606	1,332,614	5,713,606	-	5,754,028	40,422	6,021,473	267,445	7,030,082	1,008,609
Poles and Wires				-		-		-		-		-
1830	Poles, Towers and Fixtures	19,401,338	19,075,259	-326,079	22,266,952	3,191,693	26,872,181	4,605,229	29,749,857	2,877,676	33,456,395	3,706,539
1835	Overhead Conductors and Devices	9,129,398	6,929,755	-2,199,643	8,009,640	1,079,885	8,698,625	688,985	9,911,860	1,223,235	11,423,114	1,501,254
1840	Underground Conduit	1,885,425	1,077,676	-807,749	1,150,788	73,112	1,191,251	40,463	1,555,641	364,390	2,102,453	546,812
1845	Underground Conductors and Devices	5,452,468	6,524,393	1,071,925	7,143,546	619,154	8,192,213	1,048,667	8,690,804	498,591	8,898,968	208,164
	Sub-Total Poles & Wire	35,868,629	33,607,082	-2,261,547	38,570,925	4,963,843	44,954,269	6,383,344	49,918,161	4,963,892	55,880,930	5,962,769
Line Transformers				-		-		-		-		-
1850	Line Transformers	7,585,114	8,037,729	452,615	8,731,981	694,253	10,435,275	1,703,294	11,229,339	794,064	12,122,624	893,285
	Sub-Total Line Transformers	7,585,114	8,037,729	452,615	8,731,981	694,253	10,435,275	1,703,294	11,229,339	794,064	12,122,624	893,285
Services and Meters				-		-		-		-		-
1855	Services	2,556,444	3,032,052	475,608	3,054,541	22,489	3,054,541	-	3,396,804	342,263	3,784,715	387,911
1860	Meters	4,632,204	4,969,692	337,488	5,308,957	339,265	5,390,375	81,419	5,733,561	343,186	6,028,271	294,710
	Sub-Total Services and Meters	7,188,648	8,001,744	813,096	8,363,498	361,754	8,444,916	81,419	9,130,365	685,449	9,812,986	682,621
General Plant, Land and Buildings				-		-		-		-		-
1905	Land	-	-	-	-	-	-	-	-	-	-	-
1906	Land Rights	-	-	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	134,075	-	-134,075	-	-	-	-	-	-	-	-
	Sub-Total-General Plant, Land and Buildings	134,075	-	-134,075	-	-	-	-	-	-	-	-
IT Assets				-		-		-		-		-
1920	Computer Equipment - Hardware	1,379,041	1,352,790	-26,251	1,497,027	144,237	1,543,189	46,162	1,664,689	121,500	1,739,689	75,000
1611	Computer Software	1,562,279	1,426,105	-136,174	1,582,924	156,819	2,355,680	772,756	2,441,180	85,500	2,443,980	2,800
	Sub-Total-IT Assets	2,941,320	2,778,895	-162,425	3,079,952	301,057	3,898,870	818,918	4,105,870	207,000	4,183,670	77,800
Equipment				-		-		-		-		-
1915	Office Furniture and Equipment	399,406	426,778	27,372	429,916	3,137	430,956	1,040	482,092	51,136	552,092	70,000
1930	Transportation Equipment	2,749,028	2,760,304	11,276	2,828,050	67,746	3,213,261	385,211	3,542,261	329,000	3,687,261	145,000
1935	Stores Equipment	77,811	59,018	-18,793	59,018	-	59,018	-	59,018	-	59,018	-
1940	Tools, Shop and Garage Equipment	601,261	649,237	47,976	697,339	48,101	720,869	23,530	750,869	30,000	782,869	32,000
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	5,000	5,000	5,000	-
1955	Communication Equipment	33,023	-	-33,023	633,035	633,035	635,513	2,477	642,513	7,000	742,513	100,000
1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-Equipment	3,860,529	3,895,358	34,809	4,647,358	752,020	5,059,616	412,258	5,481,752	422,136	5,828,752	347,000
Other Distribution Assets				-		-		-		-		-
1970	Load Management Controls - Customer Premises	563,902	633,035	69,133	101,160	-531,876	101,160	-	101,160	-	101,160	-
1975	Load Management Controls - Utility Premises	-	-	-	-	-	-	-	-	-	-	-
1980	System Supervisory Equipment	942,255	1,120,704	178,449	1,137,242	16,538	1,140,049	2,806	1,433,011	292,962	1,519,590	86,579
1990	Other Tangible Property		-	-	-	-	-	-	-	-	-	-
1995	Contributions and Grants	-7,456,584	-6,346,445	1,110,139	-7,254,067	-907,623	-8,449,133	-1,195,066	-8,449,133	-	-8,449,133	-
2440	Deferred Revenue								-1,448,137	-1,448,137	-2,580,840	-1,132,703
2005	Property under Capital Lease		-	-	-	-	-	-	-	-	-	-
	Sub-Total-Other Distribution Assets	-5,950,427	-4,592,705	1,357,722	-6,015,665	-1,422,960	-7,207,925	-1,192,260	-8,363,100	-1,155,175	-9,409,224	-1,046,124
	Total before Work in Process	59,628,694	61,628,381	1,999,687	67,278,598	5,650,217	75,569,434	8,290,836	82,837,245	7,267,811	91,048,205	8,210,960
2070	Other utility plant		-	-		-		-		-		-
2055	Work in Process	2,596,729	1,570,979	-1,025,750	3,144,067	1,573,088	3,133,245	-10,822	3,583,245	450,000	3,583,245	-
	Sub-total-WIP	2,596,729	1,570,979	-1,025,750	3,144,067	1,573,088	3,133,245	-10,822	3,583,245	450,000	3,583,245	-
GROSS ASSET TOTAL		62,225,423	63,199,360	973,937	70,422,665	7,223,305	78,702,679	8,280,014	86,420,490	7,717,811	94,631,450	8,210,960

Table 2-27: Accumulated Amortization - Detailed Breakdown by Major Plant Function

	Description	2012 Board Approved	2012 Actual	Variance from 2012 OEB Approved	2013 Actual	Variance from 2012 Actual	2014 Actual	Variance from 2013 Actual	2015 Bridge Year	Variance from 2014 Actual	2016 Test Year	Variance from 2015 Bridge
	Reporting Basis	Revised CGAAP	Revised CGAAP		Revised CGAAP		Revised CGAAP		MIFRS		MIFRS	
	Land and Buildings											
1805	Land	-	-	-	-	-	-	-	-	-	-	-
1806	Land Rights	-	-	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	760,055	755,130	- 4,925	837,447	82,317	918,444	80,998	984,258	65,813	1,055,249	70,992
	Sub-Total-Land and Buildings	760,055	755,130	- 4,925	837,447	82,317	918,444	80,998	984,258	65,813	1,055,249	70,992
	Distribution Stations			-		-		-		-		-
1820	Distribution Station Equipment - Normally Primary below 50 kV	1,353,843	1,206,328	- 147,515	1,297,492	91,165	1,376,207	78,714	1,437,434	61,228	1,530,563	93,129
	Sub-Total-Distribution Stations	1,353,843	1,206,328	- 147,515	1,297,492	91,165	1,376,207	78,714	1,437,434	61,228	1,530,563	93,129
	Poles and Wires			-		-		-		-		-
1830	Poles, Towers and Fixtures	12,855,648	13,111,893	256,245	13,405,000	293,107	13,775,687	370,688	14,195,021	419,333	14,680,196	485,175
1835	Overhead Conductors and Devices	561,390	932,219	370,829	1,119,633	187,415	1,319,761	200,128	1,529,767	210,006	1,770,046	240,278
1840	Underground Conduit	126,788	119,165	- 7,623	140,820	21,655	163,737	22,918	188,451	24,714	222,277	33,826
1845	Underground Conductors and Devices	396,560	824,972	428,412	1,071,899	246,926	1,338,015	266,116	1,624,528	286,513	1,920,592	296,064
	Sub-Total Poles & Wire	13,940,386	14,988,249	1,047,863	15,737,352	749,102	16,597,201	859,850	17,537,767	940,566	18,593,111	1,055,345
	Line Transformers			-		-		-		-		-
1850	Line Transformers	575,418	1,011,430	436,012	1,244,164	232,734	1,482,190	238,026	1,738,894	256,704	2,017,801	278,906
	Sub-Total Line Transformers	575,418	1,011,430	436,012	1,244,164	232,734	1,482,190	238,026	1,738,894	256,704	2,017,801	278,906
	Services and Meters			-		-		-		-		-
1855	Services	540,068	418,500	- 121,568	418,500	-	418,500	-	422,778	4,278	436,184	13,405
1860	Meters	785,817	467,465	- 318,352	626,886	159,421	794,129	167,243	948,963	154,835	1,113,765	164,802
	Sub-Total Services and Meters	1,325,885	885,965	- 439,920	1,045,386	159,421	1,212,629	167,243	1,371,742	159,113	1,549,949	178,207
	General Plant, Land and Buildings			-		-		-		-		-
1905	Land	-	-	-	-	-	-	-	-	-	-	-
1906	Land Rights	-	-	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-General Plant, Land and Buildings	-	-	-	-	-	-	-	-	-	-	-
	IT Assets			-		-		-		-		-
1920	Computer Equipment - Hardware	1,250,214	1,267,867	17,653	1,383,023	115,155	1,418,644	35,621	1,596,826	178,182	1,807,759	210,932
1611	Computer Software	1,322,778	1,346,012	23,234	1,525,427	179,415	1,758,374	232,948	2,406,779	648,404	3,077,258	670,479
	Sub-Total-IT Assets	2,572,992	2,613,879	40,887	2,908,449	294,570	3,177,018	268,569	4,003,605	826,587	4,885,017	881,412
	Equipment			-		-		-		-		-
1915	Office Furniture and Equipment	278,899	265,779	- 13,120	278,184	12,406	318,566	40,381	348,897	30,332	391,342	42,445
1930	Transportation Equipment	1,691,638	1,665,450	- 26,188	1,824,959	159,509	1,956,298	131,339	2,110,127	153,830	2,283,707	173,580
1935	Stores Equipment	52,045	52,043	- 2	52,043	-	52,043	-	52,043	-	52,043	-
1940	Tools, Shop and Garage Equipment	424,049	402,141	- 21,908	456,666	54,524	494,282	37,616	531,084	36,802	570,987	39,902
1945	Measurement and Testing Equipment		-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment		58,133	58,133	62,767	4,634	65,343	2,576	69,708	4,365	84,773	15,065
1960	Miscellaneous Equipment		-	-	-	-	-	-	-	-	-	-
	Sub-Total-Equipment	2,446,631	2,443,545	- 3,086	2,674,619	231,073	2,886,531	211,913	3,111,860	225,329	3,382,852	270,992
	Other Distribution Assets			-		-		-		-		-
1970	Load Management Controls - Customer Premises	322,296	298,141	- 24,155	298,141	-	298,141	-	298,141	-	298,141	-
1975	Load Management Controls - Utility Premises	-	-	-	-	-	-	-	-	-	-	-
1980	System Supervisory Equipment	448,137	425,242	- 22,895	473,053	47,811	518,212	45,158	518,212	-	518,212	-
1990	Other Tangible Property		-	-	-	-	-	-	-	-	-	-
1995	Contributions and Grants	- 1,231,278	- 1,396,905	- 165,627	- 1,562,585	- 165,680	- 1,753,072	- 190,487	- 1,753,072	- 0	- 1,753,072	-
2440	Deferred Revenue								- 262,091	- 262,091	- 561,051	
2005	Property under Capital Lease		-	-	-	-	-	-	-	-	-	-
	Sub-Total-Other Distribution Assets	- 460,845	- 673,522	- 212,677	- 791,390	- 117,868	- 936,719	- 145,329	- 1,198,810	- 262,091	- 1,497,770	- 298,960
	Total before Work in Process	22,514,365	23,231,004	716,639	24,953,518	1,722,514	26,713,501	1,759,983	28,986,750	2,273,249	31,516,772	2,530,022
2070	Other utility plant	-	-	-		-		-		-		-
2055	Work in Process	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-WIP	-	-	-	-	-	-	-	-	-	-	-
	GROSS ASSET TOTAL	22,514,365	23,231,004	716,639	24,953,518	1,722,514	26,713,501	1,759,983	28,986,750	2,273,249	31,516,772	2,530,022

Variance Analysis on Gross Assets

Table 2-28 below provides the same level of detail as Table 2-26, however, for the purposes of the variance analysis, assets are categorized as Distribution Assets and General Plant. Only explanations of variances over HHHI's materiality threshold of $65,000 are further explained.

Table 2-28: Variance on Gross Assets

	Description	2012 Board Approved	2012 Actual	Variance from 2012 Board Approved	2013 Actual	Variance from 2012 Actual	2014 Actual	Variance from 2013 Actual	2015 Bridge Year	Variance from 2014 Actual	2016 Test Year	Variance from 2015 Bridge
Reporting Basis		Revised CGAAP	Revised CGAAP		Revised CGAAP		Revised CGAAP		MIFRS		MIFRS	
Distibution Assets:												
1805	Land	534,871	591,341	56,470	591,591	250	591,591	-	1,524,591	933,000	1,524,591	-
1806	Land Rights	4,738	4,738	0	4,738	-	4,738	-	4,738	-	4,738	-
1808	Buildings and Fixtures	3,080,205	3,590,614	510,409	3,590,614	-	3,634,056	43,442	3,784,056	150,000	4,069,056	285,000
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,380,992	5,713,606	1,332,614	5,713,606	-	5,754,028	40,422	6,021,473	267,445	7,030,082	1,008,609
1830	Poles, Towers and Fixtures	19,401,338	19,075,259	- 326,079	22,266,952	3,191,693	26,872,181	4,605,229	29,749,857	2,877,676	33,456,395	3,706,539
1835	Overhead Conductors and Devices	9,129,398	6,929,755	- 2,199,643	8,009,640	1,079,885	8,698,625	688,985	9,921,860	1,223,235	11,423,114	1,501,254
1840	Underground Conduit	1,885,425	1,077,676	- 807,749	1,150,788	73,112	1,191,251	40,463	1,555,641	364,390	2,102,453	546,812
1845	Underground Conductors and Devices	5,452,468	6,524,393	1,071,925	7,143,546	619,154	8,192,213	1,048,667	8,690,804	498,591	8,898,968	208,164
1850	Line Transformers	7,585,114	8,037,729	452,615	8,731,981	694,253	10,435,275	1,703,294	11,229,339	794,064	12,122,624	893,285
1855	Services	2,556,444	3,032,052	475,608	3,054,541	22,489	3,054,541	-	3,396,804	342,263	3,784,715	387,911
1860	Meters	4,632,204	4,969,692	337,488	5,308,957	339,265	5,390,375	81,419	5,733,561	343,186	6,028,271	294,710
1980	System Supervisory Equipment	942,255	1,120,704	178,449	1,137,242	16,538	1,140,049	2,806	1,433,011	292,962	1,519,590	86,579
1995	Contributions and Grants	- 7,456,584	- 6,346,445	1,110,139	- 7,254,067	- 907,623	- 8,449,133	- 1,195,066	- 8,449,133	-	- 8,449,133	-
2440	Deferred Revenue								- 1,448,137	- 1,448,137	- 2,580,840	- 1,132,703
		52,128,868	**54,321,113**	**2,192,245**	**59,450,129**	**5,129,016**	**66,509,789**	**7,059,660**	**73,148,464**	**6,638,675**	**80,934,623**	**7,786,160**
General Plant:												
1905	Land	-	-	-	-	-	-	-	-	-	-	-
1906	Land Rights	-	-	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	134,075	-	- 134,075	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	1,379,041	1,352,790	- 26,251	1,497,027	144,237	1,543,189	46,162	1,664,689	121,500	1,739,689	75,000
1611	Computer Software	1,562,279	1,426,105	- 136,174	1,582,924	156,819	2,355,680	772,756	2,441,180	85,500	2,443,980	2,800
1915	Office Furniture and Equipment	399,406	426,778	27,372	429,916	3,137	430,956	1,040	482,092	51,136	552,092	70,000
1930	Transportation Equipment	2,749,028	2,760,304	11,276	2,828,050	67,746	3,213,261	385,211	3,542,261	329,000	3,687,261	145,000
1935	Stores Equipment	77,811	59,018	- 18,793	59,018	-	59,018	-	59,018	-	59,018	-
1940	Tools, Shop and Garage Equipment	601,261	649,237	47,976	697,339	48,101	720,869	23,530	750,869	30,000	782,869	32,000
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	5,000	5,000	5,000	-
1955	Communication Equipment	33,023	-	- 33,023	633,035	633,035	635,513	2,477	642,513	7,000	742,513	100,000
1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	-	-
1970	Load Management Controls - Customer Premises	563,902	633,035	69,133	101,160	- 531,876	101,160	-	101,160	-	101,160	-
1975	Load Management Controls - Utility Premises	-	-	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property		-	-	-	-	-	-	-	-	-	-
2005	Property under Capital Lease		-	-	-	-	-	-	-	-	-	-
	Total before Work In Process	**7,499,826**	**7,307,269**	**- 192,557**	**7,828,470**	**521,201**	**9,059,645**	**1,231,176**	**9,688,781**	**629,136**	**10,113,581**	**424,800**
2070	Other utility plant		-	-		-		-		-		-
GROSS ASSET TOTAL		**59,628,694**	**61,628,381**	**1,999,687**	**67,278,598**	**5,650,217**	**75,569,434**	**8,290,836**	**82,837,245**	**7,267,811**	**91,048,205**	**8,210,960**

2012 Actual vs. 2012 Board Approved

- **Distribution Assets – $2,192,245**

2012 Actual Distribution Assets are higher than the 2012 Board Approved amount by $2,192,245. Items related to this variance include:

- Expenditures for HHHI's Pole-Trans transformer replacement projects were higher than the 2012 Board Approved amount. The level of investment in 2012 reflects the larger scope of work undertaken to replace aged and obsolete Pole-Trans transformers. In 2012, as part of HHHI's three (3) year aged and obsolete Pole-Trans phase out plan for Kingham Road in Acton, Pole-Trans expenditures totalled $1,040,177.

- 2012 Actual Contributed Capital was lower than 2012 Board Approved by $1,110,139. The main driver of this variance is the Steeles Avenue – Trafalgar Rd to 5th Line South (Phase 2 – Stage 2) capital project and Pole Relocations on Steeles Avenue between Winston Churchill Boulevard and Trafalgar Road capital project (collectively, the "Steeles Avenue Projects") initiated by the Region of Halton. The Steeles Avenue Projects were actually completed in 2013 and 2014, and thus, contributed capital for these projects was not received in 2012 as budgeted.

- **General Assets - ($192,557)**

The main driver of this ($192,557) variance is the 2013 implementation of the ERP system that was included in the 2012 budget. HHHI required additional time to research appropriate software vendors and ultimately released an RFP.

2013 Actual vs. 2012 Actual

- **Distribution Assets - $5,129,016**

2013 Actual Distribution assets are higher than 2012 Actual amounts by $5,129,016. Items contributing to this variance include:

- Municipal roadway relocation activity - $1,133,463
- Pole replacement activity due to age and condition - $1,183,227
- System extension and automation - $935,241
- Feeder upgrade - $620,746
- Pole-Trans conversion - $331,266
- Substations activity - $220,398
- Contributed Capital - $907,623

- **General Assets - $521,201**

2013 General Assets are higher than 2012 Actual amounts by $521,201 which is primarily related to:

- Computer hardware and software - $301,057
- Fleet addition - $67,746
- Tools and Equipment - $48,101

2014 Actual vs. 2013 Actual

- **Distribution Assets - $7,059,660**

2014 Actual Distribution assets are higher than 2013 Actual amounts by $7,059,660. Items related to this variance include:

- Municipal projects - $2,819,451
- Pole replacement activity due to age and condition - $2,144,150
- System upgrade and automation - $1,683,847
- Feeder upgrade - $114,148
- Contributed Capital - $1,195,066

- **General Assets - $1,231,176**

2014 General Assets are higher than 2013 Actual amounts by $1,123,176 which is primarily related to:

- ERP system in 2014 - $818,918
- Fleet addition - $385,211

2015 Bridge Year Forecast vs. 2014 Actual

- **Distribution Assets - $7,088,675**

2015 Bridge Year Distribution assets are forecasted to be higher than 2014 Actual amounts by $6,638, 675. Items expected to contribute to this variance include:

- Municipal and customer requested projects - $1,176,678
- Pole replacement activity due to age and condition - $1,099,697
- System conversion projects (27.6kV) - $1,549,738
- Pole-Trans conversion - $524,475
- Substation automation, system reinforcement and other substation activity - $527,407
- HHHI Transformer project and purchase - $933,000
- Contributed Capital - $1,448,137

- **General Assets - $629,136**

2015 Bridge Year General assets are forecasted to be higher than 2014 Actual amounts by $629,136. The main drivers of the increase are expected to be:

  - Single bucket truck (cab and chassis) - $325,000
  - Metering activity (including wholesale meter replacements) - $148,825
  - General plant - $150,000
    - New roof (43 Alice Street);
    - Furniture for engineering and customer care departments;
    - Replacement of two garage doors
  - Computer hardware and software - $167,000
  - 25 New Gate Keepers (Smart Metering) - $100,000

2016 Forecast vs. 2015 Forecast

- **Distribution Assets - $7,786,160**

2016 Distribution assets are forecasted to be higher than 2015 forecast amount by $7,786,160. Details of the forecasted projects for 2016 are in HHHI's DSP.

- **General Assets - $424,800**

2016 General assets are forecasted to be higher than 2015 forecast amount by $424,800. The main driver of the forecasted increase is discussed in HHHI's DSP.

Summary of Incremental Capital Module Adjustment

HHHI confirms that it has not applied for, nor received, any ICM adjustments as part of a previous IRM application.

Reconciliation of Continuity Statements to Calculated Depreciation Expenses

HHHI confirms that the depreciation expenses in the fixed asset continuity statements reconcile to the calculated depreciation expenses in Exhibit 4, Tab 4, Schedule 1 and are presented by account. As such, there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4.

Allowance for Working Capital (2.2.1.3)

Overview

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital; the 7.5% Allowance Approach or the filing of a lead/lag study. This Application has been prepared using the default Working Capital Allowance for the 2016 Rate Year of 7.5% in accordance with the Board policy for the calculation of the allowance for working capital for electricity rate applications published on June 3, 2015. Given the fact that this change in Board Policy is relatively recent, HHHI is still in the process of assessing the impact of the policy, and reserves the right to subsequently submit evident in support of an HHHI specific working capital allowance supported by a lead-lag study.

The working capital allowance for the 2016 Test Year is based upon 7.5% of the Cost of Power and controllable expenses. In calculating the working capital allowance for years 2012 to 2014 actuals and for the 2015 Bridge Year, HHHI used the Board's historical 15% Allowance Approach that was approved in its 2012 Cost of Service.

Table 2-29 provides a summary of HHHI's COP and controllable expenses used to the calculate working capital allowance for 2012 Board Approved, 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge Year and the 2016 Test Year.

Table 2-29: Summary of Working Capital Allowance

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Cost of Power	**46,736,102**	**45,746,999**	**50,494,619**	**55,410,232**	**66,099,360**	**66,075,638**
Controllable Expenses						
Operation	1,122,101	797,619	800,456	791,622	1,419,193	1,355,647
Maintenance	808,985	1,905,957	742,555	615,219	341,000	374,125
Billing and Collecting	1,548,690	1,072,259	1,210,087	1,203,346	1,584,893	1,890,937
Community Relations	-	-	-	-	-	-
Administrative and General Expenses	2,313,625	2,036,642	2,331,334	2,569,754	2,917,017	3,122,070
Donations - LEAP		4,875	2,975	24,054	12,000	12,027
Property Taxes	106,600	99,638	90,207	100,799	101,896	104,440
Allocated Depreciation	-	(184,231)	(159,509)	(131,339)	(153,830)	(173,580)
Total Controllable Expenses	**5,900,000**	**5,732,759**	**5,018,105**	**5,172,456**	**6,222,169**	**6,685,666**
Working Capital	52,636,102	51,479,758	55,512,724	60,582,688	72,309,529	72,761,304
Working Capital Allowance Rate	15%	15%	15%	15%	15%	7.5%
Total Working Capital Allowance	**7,895,415**	**7,721,964**	**8,326,909**	**9,087,403**	**10,848,229**	**5,457,098**

As shown in Table 2-30, the 2016 working capital allowance has decreased by $2,438,318 in comparison to the 2012 Board Approved amount. The change between the 2016 Test Year and 2012 Board Approved amount is a result of increased working capital requirements due to increased costs of power and controllable expenses, less the decrease in percentage rate applied in the computation of the working capital allowance from 15% to 7.5%. Table 2-30 provides a summary of the decrease between the 2016 Test Year and 2012 Board Approved allowance for working capital.

Table 2-30: Summary of Changes in Allowance for Working Capital

Description	2012 Board Approved	2016 Test Year	Change	Working Capital Allowance Percentage	Working Capital Allowance
Cost of Power	46,736,102	66,075,638	19,339,536	15%	2,900,930
Total Controllable Expenses	5,900,000	6,685,666	785,666	15%	117,850
Working Capital	**52,636,102**	**72,761,304**	**20,125,202**		**3,018,780**
COP and Controllable Expenses		72,761,304		7.5%	5,457,098
		72,761,304		15%	10,914,196
Decrease in Working Capital Allowance					(5,457,098)
Net Working Capital Allowance					(2,438,318)

Working capital increased by $20,125,202 between 2012 and 2016. The increase was due mainly to the increase in cost of power. However, this increase to cost of power was offset in 2016 by the calculated allowance for working capital as the percentage used for the calculation decrease from 15% in 2012 to 7.5% in 2016.

Cost of Power ("COP") Calculations

HHHI has calculated COP for the 2016 Test Year based on the 2016 load forecast, adjusted for the impact of Conservation and Demand Management activities and in accordance with the Board's filing requirements. A summary of the total COP expenses is provided in Table 2-31.

Table 2-31: Summary of Total Cost of Power Expenses

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Cost of Power Expenses						
Power Purchased	38,162,591	37,358,084	41,431,851	45,623,602	54,820,906	54,904,781
Wholesale Market Service Charges	3,272,631	2,646,854	2,729,242	2,886,065	3,064,223	3,068,988
Network Charges	2,942,577	2,885,393	3,196,989	3,601,142	3,885,570	3,654,054
Connection Charges	2,358,303	2,250,997	2,522,891	2,629,836	2,748,453	2,869,148
Low Voltage Charges		605,671	613,646	636,481	1,373,936	1,373,936
Smart Meter Entity Charges		-	-	33,107	206,273	204,731
Total Cost of Power Expenses	46,736,102	45,746,999	50,494,619	55,410,232	66,099,360	66,075,638

Commodity Prices

In accordance with the Filing Requirements, the commodity price estimate, used to calculate COP, was determined using actual 2014 data, split between Regulated Price Plan ("RPP") and non-RPP customers and the most current RPP pricing.

The RPP and non-RPP price was obtained from the Regulated Price Plan Price Report for the period of May 1, 2015 through April 30, 2016 published by the Board on April 20, 2015. For the purposes of calculating the 2016 Test Year, HHHI has used an estimate of $0.10210 per kWh for RPP customers. For non-RPP customers, HHHI has used $0.10186 per kWh which includes $0.01992 per kWh for the Wholesale Electricity Price and $0.08194 per kWh for Global Adjustment charges.

HHHI understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of this Application.

Regulatory Charges

For the purposes of determining the cost of Wholesale Market Service ("WMS") Charges for the 2016 Test Year, HHHI used the current 2015 WMS rate of $0.0044 per kWh and applied it to the 2016 load forecast.

For the purposes of determining the cost of Rural Rate Assistance Charges for the 2016 Test Year, HHHI used the current 2015 rate of $0.0013 per kWh and applied it to the 2016 load forecast.

Network and Connection Charges

HHHI incurs Network and Connection charges from both the IESO and Hydro One Networks Inc. ("HONI"). For the purposes of determining the Network and Connection costs for the 2016 Test Year, HHHI utilized the Board's 2016 Retail Transmission Service Rate ("RTSR") Model which incorporates the Uniform Transmission Rates ("UTR"s) as approved by the Board and HONI's approved 2015 Sub-transmission rates (EB-2014-0357). HHHI understands that the transmission costs will be updated to reflect any new rates that may become available prior to the approval of its application.

Low Voltage Charges

HHHI incurs low voltage charges through HONI sub-transmission invoicing. The 2016 Test Year costs are estimated to be $1,373,936. Details of the Low Voltage calculation are presented in Exhibit 8, Tab 7, Schedule 1.

Smart Meter Entity Charges

The Smart Meter Entity costs are calculated based on the IESO rate of $0.788 per month per Residential and General Service less than 50 kW customer approved by the Board on March 28, 2014. HHHI's 2016 load forecast customer count has been utilized for the 2016 Test Year calculation.

Table 2-32 provides a summary of the COP calculation for the 2016 Test Year.

Table 2-32: 2016 Cost of Power Calculation

HHHI 2016 Cost of Power Calculation					
2016 Load Forecast	kWh	kW	2014 %RPP		
Residential	195,182,110		96%		
General Service < 50 kW	48,031,437		82%		
General Service 50 to 999 kW	141,978,525	391,918	11%		
General Service 1000 to 4 999 kW	121,810,401	315,722	0%		
Street Lighting	1,466,975	4,090	0%		
Sentinel Lighting	464,833	633	0%		
Unmetered Scattered Load	932,138		0%		
TOTAL	609,866,419	712,364			
	-	-			
Electricity - Commodity RPP	2016	2016 Loss			
Class per Load Forecast RPP	Forecasted	Factor		2016	
Residential	187,374,825	1.0560	197,867,815	$0.10210	$20,202,304
General Service < 50 kW	39,385,778	1.0560	41,591,382	$0.10210	$4,246,480
General Service 50 to 999 kW	15,617,638	1.0560	16,492,225	$0.10210	$1,683,856
General Service 1000 to 4 999 kW	0	1.0560	0	$0.10210	$0
Street Lighting	0	1.0560	0	$0.10210	$0
Sentinel Lighting	0	1.0560	0	$0.10210	$0
Unmetered Scattered Load	0	1.0560	0	$0.10210	$0
TOTAL	242,378,241		255,951,423		26,132,640
Electricity - Commodity Non-RPP	2016	2016 Loss			
Class per Load Forecast	Forecasted	Factor		2016	
Residential	7,807,284	1.0560	8,244,492	$0.10186	$839,784
General Service < 50 kW	8,645,659	1.0560	9,129,816	$0.10186	$929,963
General Service 50 to 999 kW	126,360,887	1.0560	133,437,097	$0.10186	$13,591,903
General Service 1000 to 4 999 kW	121,810,401	1.0560	128,631,784	$0.10186	$13,102,435
Street Lighting	1,466,975	1.0560	1,549,126	$0.10186	$157,794
Sentinel Lighting	464,833	1.0560	490,864	$0.10186	$49,999
Unmetered Scattered Load	932,138	1.0560	984,338	$0.10186	$100,265
TOTAL	267,488,178		282,467,516		28,772,141
Transmission - Network		Volume			
Based on 2014 Actual		Metric		2016	
IESO					$623,779
Hydro One					$3,030,275
TOTAL					$3,654,054
Transmission - Connection					
Based on 2014 Actual		Metric		2016	
IESO					$510,910
Hydro One					$2,358,236
TOTAL					$2,869,148
Wholesale Market Service		Volume			
Class per Load Forecast		Metric		2016	
Residential		kWh	206,112,308	$0.0044	$906,894
General Service < 50 kW		kWh	50,721,198	$0.0044	$223,173
General Service 50 to 999 kW		kWh	149,929,322	$0.0044	$659,689
General Service 1000 to 4 999 kW		kWh	128,631,784	$0.0044	$565,980
Street Lighting		kWh	1,549,126	$0.0044	$6,816
Sentinel Lighting		kWh	490,864	$0.0044	$2,160
Unmetered Scattered Load		kWh	984,338	$0.0044	$4,331
TOTAL			538,418,938		$2,369,043
Rural Rate Assistance		Volume			
Class per Load Forecast		Metric		2016	
Residential		kWh	206,112,308	$0.0013	$267,946
General Service < 50 kW		kWh	50,721,198	$0.0013	$65,938
General Service 50 to 999 kW		kWh	149,929,322	$0.0013	$194,908
General Service 1000 to 4 999 kW		kWh	128,631,784	$0.0013	$167,221
Street Lighting		kWh	1,549,126	$0.0013	$2,014
Sentinel Lighting		kWh	490,864	$0.0013	$638
Unmetered Scattered Load		kWh	984,338	$0.0013	$1,280
TOTAL			538,418,938		$699,945
Low Voltage					
Based on 2014 Actual				2016	
Hydro One					$1,373,936
TOTAL			0		$1,373,936
Smart Meter Entity Fee		Volume			
Class per Load Forecast		Metric		2016	
Residential		Per Month	19,955	$0.7880	$188,690
General Service < 50 kW		Per Month	1,696	$0.7880	$16,041
TOTAL			21,651		$204,731

Description	2016
4705-Power Purchased	54,904,781
4708-Charges-WMS	2,369,043
4714-Charges-NW	3,654,054
4716-Charges-CN	2,869,148
4730-Rural Rate Assistance	699,945
4750-Low Voltage	1,373,936
4751-Smart Meter Entity Fee	204,731
TOTAL	66,075,638

Treatment of Stranded Assets Related To Smart Meter Deployment (2.2.1.4)

In HHHI's 2012 Cost of Service application (EB-2011-0271), HHHI requested disposition of all Smart Meter Costs included in Deferral and Variance Accounts 1555 – Smart Meter Capital Costs and 1556 – Smart Meter OM&A Costs. The Board approved the disposition and issued a Stranded Meter specific Rate Rider for the period May 1, 2012 to April 30, 2016 to recover the cost of stranded meters. The cost of only the stranded meters remained in account 1555 – Smart Meter Capital.

The revenue from the Board Approved Stranded Meter Rate Rider has been applied to account 1555 – Smart Meter Capital and Recovery Offset Variance Account, Sub-Account Stranded Meter Costs. HHHI will request final disposition of audited Stranded Meter Costs through a future rate application.

CAPITAL EXPENDITURES (2.2.2)

Planning (2.2.2.1)

Overview

In accordance with the Filing Requirements, HHHI has developed a Distribution System Plan ("DSP") and has included the DSP as a stand-alone document in Appendix 2-A of this Exhibit. The information presented in the DSP has been organized in accordance with Chapter 5 of the Board's *Filing Requirements for Electricity Distribution and Transmission Applications.* The DSP incorporates matters pertaining to asset management, regional planning, and renewable energy generation.

HHHI engaged Acumen Engineered Solutions International Inc. (AESI) to review the DSP in its entirety. Upon completion of the review, AESI provided an independent letter indicating their agreement that the DSP achieved the purposes of the Chapter 5 Filing Requirements. This letter is included in the DSP for convenience.

The categories of system investments, namely system renewal, system access, system service, and general plant, have been addressed and consolidated in HHHI's capital expenditure plan. HHHI has provided historical spending by capital project in the aforementioned categories for 2011, 2012, 2013, and 2014 Actuals, in addition to the 2015 Bridge and 2016 Test Years. HHHI has assigned all historical and forecasted construction projects to the system investment categories as required by the Board. The DSP provides the suggested spending level as determined through HHHI asset management planning, for the years 2016 through 2020.

Information related to the Regional Planning Process is found in Section 1.2.6 of the DSP.

Based on the evaluation of the distribution system, HHHI is not proposing any capital investments for capacity upgrades to accommodate applications for the connection of renewable energy generation plant for the 2016 Test Year. Information related to system capacity for the connection of renewable energy generation plant is found in Section 3.3 of the DSP.

HHHI assets fall into two broad categories:

- Distribution Plant - includes assets such as wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations
- General Plant - includes assets such as the office building, SCADA, equipment and tools.

For internal budgeting purposes, HHHI has categorized all spending to align with the new DSP categories of system renewal, system access, system service and general plant.

Budget

The following comments provide an overview of HHHI's capital budgeting process.

The budget is prepared annually by management and is reviewed by senior executives before being presented to HHHI's Board of Directors for approval. The budget is prepared before the start of each fiscal year. Once approved, the budget does not change, but provides a target against which actual results may be evaluated.

HHHI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital budget is a critical component of HHHI's business plan.

HHHI annual construction capital budget is developed in co-operation with the Engineering, Operations and Finance departments. Once developed, the budget is reviewed by senior management and then presented to HHHI Board of Directors for approval. Based on HHHI's asset management plan, a design of the projects is completed by the Engineering department. Labour hours and third party contracting costs are then estimated based on discussions with the Engineering and Operations departments and known third party contractor costs. Anticipated costs, including, but not limited to materials, trucking, and other costs are then broken down by job and applied accordingly within each project budget.

Non-construction capital projects are budgeted base on each departmental need, taking into account age and asset conditions, regulatory and statutory requirements. The 2015 Bridge Year non-construction capital projects are based on forecast.

Required Information (2.2.2.2)

Summary of Capital Expenditures

Table 2-33 provides a summary of historical capital expenditures for the past four (4) historical years, 2011 through 2014, projections for the 2015 Bridge and 2016 Test Years, as well as projections for the years 2017 through 2020. Table 2-33 is consistent with Board Appendix 2-AB. HHHI has made its best efforts to categorize historical projects into the DSP system investment categories. The annual capital expenditures include all new spending in the fiscal period. Costs for projects that are considered WIP at the end of a fiscal year are captured in the year spent, not the year the asset is transferred into service. The variance between the annual capital expenditure totals in the table and the total 'additions' in the continuity schedules are those applicable to WIP and contributed capital.

Cumulative gross capital expenditures incurred and forecasted by HHHI for the 2011 through 2015 period represents total net capital spending in the amount of $31,872,626. Chart 2-34 shows the percentage of cumulative gross capital expenditures incurred and forecasted by HHHI for the period 2011 through 2015 in each of the system investment categories. Cumulative gross capital expenditures forecasted by HHHI for the 2016 through 2020 period represents total net capital spending in the amount of $41,472,632. Chart 2-35 shows the percentage of the cumulative net capital expenditures forecasted by HHHI for the period 2016 through 2020 in each of the investment categories.

HHHI's main infrastructure focus is on renewal and this has been the driver of historical spending and is the driver of future spending.

Table 2-33: Board Appendix 2-AB - Capital Expenditure Summary – 2011 through 2020

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

First year of Forecast Period: 2016

CATEGORY	Historical Period (previous plan[1] & actual)								
	2011			2012			2013		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	N/A	1,182,087	--	N/A	5,251,191	--	N/A	1,867,987	--
System Renewal	N/A	2,316,136	--	N/A	2,560,260	--	N/A	1,584,398	--
System Service	N/A	757,210	--	N/A	1,192,256	--	N/A	1,777,792	--
General Plant	N/A	865,557	--	N/A	1,210,052	--	N/A	420,040	--
TOTAL EXPENDITURE	-	5,121,039	--	-	10,213,760	--	-	5,650,217	--
System O&M		$1,213,158	--		$ 2,706,376	--		$ 1,543,011	--

CATEGORY	Historical Period (previous plan[1] & actual)						Forecast Period (planned)				
	2014			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000				
System Access	N/A	2,680,732	--	1,578,189		-100.0%	1,339,885	290,760	1,589,978	256,040	256,410
System Renewal	N/A	2,362,906	--	1,870,124		-100.0%	3,790,671	4,226,861	2,818,292	4,220,233	5,464,607
System Service	N/A	1,975,057	--	3,485,366		-100.0%	2,302,791	1,854,882	3,535,241	4,567,366	1,856,986
General Plant	N/A	1,272,141	--	784,136		-100.0%	777,613	479,416	421,000	425,000	374,000
TOTAL EXPENDITURE	-	8,290,836	--	7,717,815	-	-100.0%	8,210,960	6,851,919	8,364,511	9,468,639	7,952,003
System O&M		$ 1,406,541	--	$ 1,850,667		-100.0%	$1,779,072				

Chart 2-34: Cumulative Gross Capital Expenditures 2011 - 2015

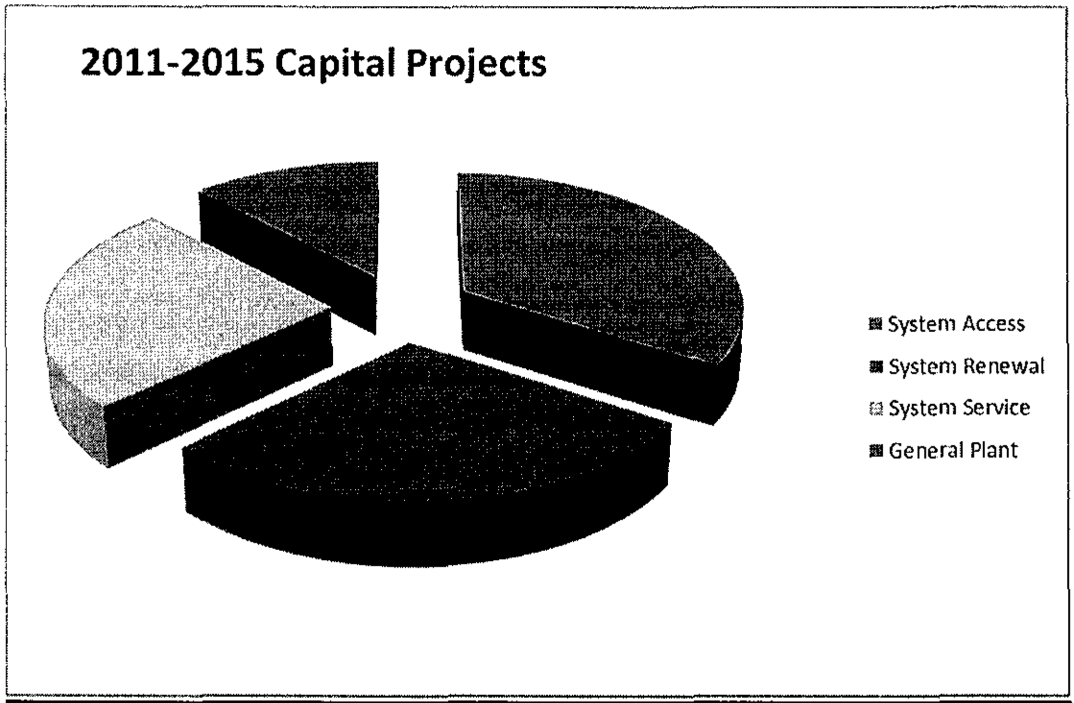
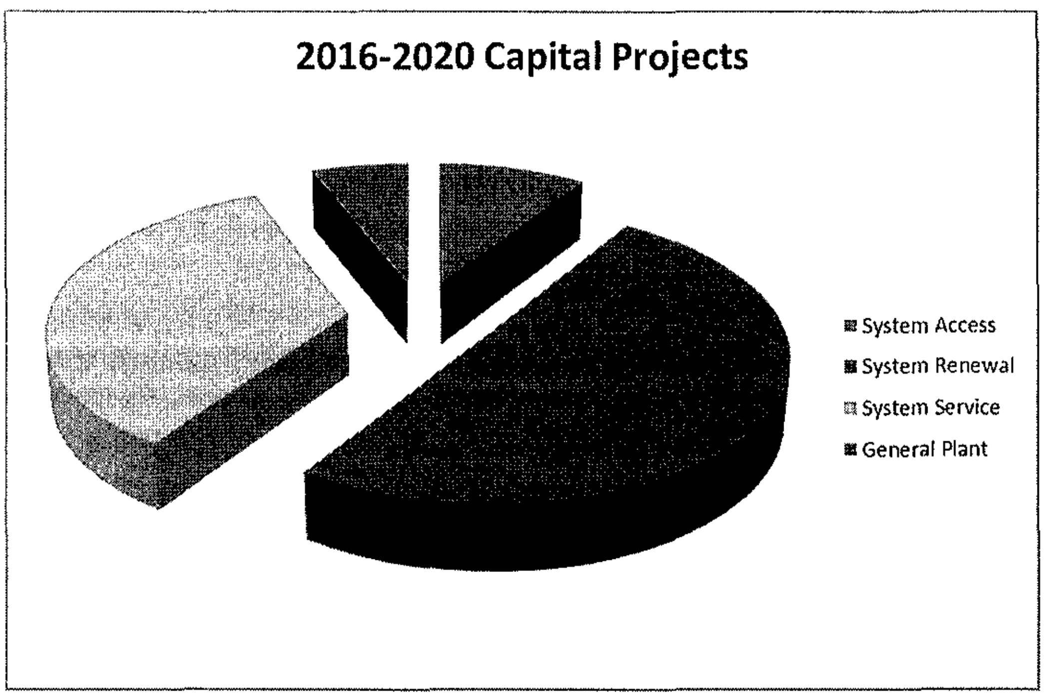


Chart 2-35: Cumulative Gross Capital Expenditures 2016 - 2020



Variance of Year-Over-Year Category Spending

An analysis of year over year trending for historical costs within the DSP categories follows.

2012 Actual vs. 2011 Actual

System Access (SA):

Included in the 2012 additions is $3,660,492 of smart meter capital costs that were transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012.

In 2012, planned system access work began on pole line construction along Steeles Avenue. The pole line was relocated to accommodate regional road improvement plans between Trafalgar Road and Winston Churchill Blvd. HHHI also continued pole line relocations on Steeles Avenue, carried over from 2011 into 2012, between James Snow Parkway and 5th Line South. The level of expenditures in 2012 as compared to 2011 reflects the increased amount of system access work undertaken in 2012.

System Renewal (SR):

System renewal expenditures in 2011 and 2012 are consistent over the 2 year period and reflect HHHI's commitment to ensuring aged assets are rehabilitated or replaced prior to failure, thus decreasing outages to customers as a result of failed equipment. Significant expenditures in this category relate to replacement of aged poles and underground infrastructure replacements (Pole-Trans transformers and primary cable).

System Service (SS):

In 2012, system service expenditures reflected HHHI ongoing focus to ensure its distribution system is robust and flexible. System access projects in 2012 reflected HHHI's commitment to providing distribution excellence by procuring and beginning to install automated switches at key locations in the 44kV sub-transmission system. Expenditures in the category also included upgrading key feeder lines on the distribution system to ensure a continued support of current load and accommodate new load from in-fill development.

General Plant (GP):

Included in the 2012 General Plant total is $200,278 of computer hardware and software capital cost that was transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012. Addition items in 2012 include additions to Building, Furniture and Fixtures for $356,930, GIS system implementation for $57,583 and Fleet for $274,392.

Table 2-36: 2012 Actual vs. 2011 Actual

Description	2011 Actual	2012 Actual	Variance from 2011 Actual
System Access	1,182,087	1,590,699	408,613
System Access -Smart Meter Cost transfer to Capital from DVA 1555	-	3,660,492	3,660,492
System Renewal	2,316,186	2,560,260	244,075
System Service	757,210	1,192,256	435,046
General Plant	865,557	1,009,774	144,218
General Plant - Smart Meter Cost transfer to Capital from DVA 1555		200,278	200,278
Total Capital Expenditure	**5,121,039**	**10,213,760**	**5,092,721**

2013 Actual vs. 2012 Actual

System Access (SA):

The levels of expenditure in 2013 as compared to 2012 reflect an increased need to address municipally driven work along Steeles Avenue as the Region of Halton continued its road widening projects.

System Renewal (SR):

Expenditures for system renewal projects in 2012 were greater in 2013 as the level of investment in 2012 reflects the larger scope of work undertaken to replace aged and obsolete Pole-Trans transformers. In 2012, HHHI Pole-Trans expenditures in Acton totalled $1,040,177 replacing aged and obsolete poletrans transformers on Kingham Road and surrounding streets in Acton as part of HHHI's three (3) year Pole-Trans phase out plan for Kingham Road. In 2013, HHHI completed the Kingham Road project and moved forward on a smaller scoped Pole-Trans replacement project on Bower and John Streets in Acton to remedy potential safety issues involving Pole-Trans transformers. In 2013, the smaller scope of work for Pole-Trans replacements totalled $345,071.

System Service (SS):

The increased level of expenditures relating to system service projects in 2013 reflect HHHI's commitment to ensuring the distribution system is robust and accommodating for growth. In 2013, HHHI undertook two significant pole line projects addressing capacity on the distribution system. The projects addressed potential constraints at HHHI's municipal substation MS19 by bringing a third feeder, 19-F3, out of the substation as well as increase reliability by extending the 27.6kV distribution system along Trafalgar Road from 15 Side Road to 10 Side Road, working towards creating a distribution loop.

General Plant (GP):

The change in spending over the 2 years is attributed primarily to the $200,278 of computer hardware and soft capital cost that was transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012. Addition items contributing to the reduction in spending include Building, Furniture and Fixtures for $356,930, GIS system implementation for $57,583 and Fleet for $206,646.

Table 2-37: 2013 Actual vs. 2012 Actual

Description	2012 Actual	2013 Actual	Variance from 2012 Actual
System Access	1,590,699	1,867,987	277,287
System Access -Smart Meter Cost transfer to Capital from DVA 1555	3,660,492	-	(3,660,492)
System Renewal	2,560,260	1,584,398	(975,862)
System Service	1,192,256	1,777,792	585,536
General Plant	1,009,774	420,040	(589,734)
General Plant - Smart Meter Cost transfer to Capital from DVA 1555	200,278	-	(200,278)
Total Capital Expenditure	**10,213,760**	**5,650,217**	**- 4,563,543**

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2014 Actual vs. 2013 Actual

System Access (SA):

In 2014, the level of expenditures relating to system access projects varied largely from expenditures in 2013 mainly due to municipally driven projects along Steeles Avenue and at the intersection of 10 Side Road and 10th Line. In 2014, HHHI continued relocating plant along Steeles Avenue as part of Region of Halton road widening projects.

System Renewal (SR):

The increased level of expenditure in 2014 reflects HHHI's commitment to ensuring the prudent replacement of aged assets. In 2014, HHHI continued normal levels of individual pole replacements in addition to renewing plant along Delrex Blvd and Sargent Road in Georgetown. In 2014, there was also an increase in Operations driven pole replacements (poles identified by line staff as needing replacement). A significantly larger scope of Pole-Trans replacements in 2014 (Lakeview Subdivision in Acton) was performed as compared to similar work on Bower Street in 2013.

System Service (SS):

The increased level of expenditures in 2014 relating to system service projects reflects HHHI's continued conversion of the 8.32kV distribution system to 27.6kV in a continued effort to increase reliability in the southern regions of HHHI's service territory. Additional expenditures include the purchase and installation of six (6) 46kV automated switches.

General Plant (GP):

The main cause of the variance in General Plant between 2013 and 2014 is the addition of the financial system (Great Plains) in 2014 for $772,756.

Table 2-38: 2014 Actual vs. 2013 Actual

Description	2013 Actual	2014 Actual	Variance from 2013 Actual
System Access	1,867,987	2,680,732	812,746
System Renewal	1,584,398	2,362,906	778,508
System Service	1,777,792	1,975,057	197,265
General Plant	420,040	1,272,141	852,101
Total Capital Expenditure	5,650,217	8,290,836	2,640,620

2015 Forecast vs. 2014 Actual

System Access (SA):

In 2015, the estimated level of expenditures as compared to the actual expenditures for system access projects in 2014 are less and reflect the nature of work HHHI plans to undertake relating to this category.

System Renewal (SR):

In 2015, the overall estimated level of expenditures relating to system renewal projects as compared to actual expenditures for this same category in 2014 are less and reflect the significantly larger amount of system renewal work relating to the replacement of old poles and removing aged PoleTrans transformers from service between 2014 and 2015.

System Service (SS):

In 2015, the estimated level of expenditures for system service projects is greater than the actual 2014 expenditures. HHHI's level of expenditures in 2015 reflects HHHI's continued commitment to ensuring the distribution system is reliable and flexible to better serve customers.

General Plant (GP):

The 2015 General Plant amount is $488,005 less when compare to 2014. The main driver of this variance is a reduction in computer software of $687,256, and increased costs in building of $150,000 and computer hardware of $121,000.

Table 2-39: 2015 Forecast vs. 2014 Actual

Description	2014 Actual	2015 Forecast	Variance from 2014 Actual
System Access	2,680,732	1,578,189	(1,102,543)
System Renewal	2,362,906	1,870,124	(492,782)
System Service	1,975,057	3,485,366	1,510,309
General Plant	1,272,141	784,136	(488,005)
Total Capital Expenditure	**8,290,836**	**7,717,815**	**(573,021)**

2016 Forecast vs. 2015 Forecast

System Access (SA):

System Access spending is relatively consistent over the two years

System Renewal (SR):

2016 spending is increased due increased vintage replacement projects and pole replacement strategies.

System Service (SS):

System Service spending in 2015 is significantly higher than previous years due to the land purchase for the new Transformer Station.

General Plant (GP):

Spending in this category is relatively consistent over the two years.

Table 2-40: 2016 Forecast vs. 2015 Forecast

Description	2015 Forecast	2016 Forecast	Variance from 2015 Forecast
System Access	1,578,189	1,339,885	(238,304)
System Renewal	1,870,124	3,790,671	1,920,547
System Service	3,485,366	2,302,791	(1,182,575)
General Plant	784,136	777,613	(6,523)
Total Capital Expenditure	7,717,815	8,210,960	493,145

2016 Forecast vs. 2017 Forecast

System Access (SA):

The main driver in System Access spending in 2016 is municipally directed road widening projects. Specifically, two significant projects: the intersection widening project at Trafalgar Road and 10 Side Road and the road widening project along 9th Line between Steeles Ave and 10 Side Road. The combined budget for these two projects is $1,668,844. These projects involve relocating utility poles, wires, anchors, and related equipment. There is currently no significant road widening projects planned for 2017 however, there is a large project planned for 2018. The primary risk to completion to these projects is that work may be delayed until the Region of Halton can acquire the necessary land and easements. HHHI generally will not commence construction until confirmation that land and easements are acquired or permission to enter and construct our work is received. As a result of these potential delays, budgeting and timing for these projects can be difficult to predict.

System Renewal (SR):

The main driver in System Renewal spending in 2017 is an increase in vintage system replacement projects and substation improvements. Switchgear replacement projects are scheduled every two years, beginning in 2017. 2017 also includes a significant Pole-Trans transformer replacement project in Acton. The design work for the project is scheduled for 2016 with construction in 2017. The Silver Creek MS transformer is scheduled for replacement in 2017. The next major substation projects are scheduled for 2019.

System Service (SS):

The main difference in System Service spending between the two years is the installation of automated switches on the 46kV system. Two (2) switches are planned for installation in each of 2016, 2018 and 2019, and none in 2017 or 2020.

General Plant (GP):

Three (3) projects are the key drivers for the increased spending in General Plant in 2016. The roof over the garage at the HHHI office needs to be resurfaced in 2016. As well, the parking lot requires complete resurfacing and repaving that year. The other main project in 2016 is the implementation of an Interactive Voice Response (IVR) system. This system addresses customer preferences for improved communication and self-service options as identified in our customer surveys and focus groups.

Table 2-41: 2016 Forecast vs. 2017 Forecast

Description	2016 Forecast	2017 Forecast	Variance from 2016 Forecast
System Access	1,339,885	290,760	(1,049,125)
System Renewal	3,790,671	4,226,861	436,190
System Service	2,302,791	1,854,882	(447,909)
General Plant	777,613	479,416	(298,197)
Total Capital Expenditure	**8,210,960**	**6,851,919**	**(1,359,041)**

Trending from 2017 to 2020

System Access (SA):

System Access projects are expected to remain fairly consistent with the exception of 2018 when a large Region of Halton driven road widening project on Winston Churchill Blvd. is expected to proceed.

System Renewal (SR):

System Renewal projects are planned fairly evenly throughout the duration of this plan. There is a decrease in System Renewal spending planned in 2018 to accommodate the increase in System Access spending. Two larger feeder renewal projects are scheduled for 2020 to upgrade and harden parts of the distribution system in Acton and Georgetown. The intent of these projects is to renew portions of the distribution system that are reaching the end of useful life and no longer meet current standards for construction.

System Service (SS):

2018 and 2019 will see the completion of a number of voltage conversion projects and the construction of a new municipal substation. Voltage Conversion projects planned over the next several years is intended continue to expand the 27.6kV distribution system.

General Plant (GP):

General Plant expenditures are fairly consistent for the duration of this plan and are largely driven by fleet replacements.

Table 2-42: Trending from 2017 to 2020

Description	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
System Access	290,760	1,589,978	256,040	256,410
System Renewal	4,226,861	2,818,292	4,220,233	5,464,607
System Service	1,854,882	3,535,241	4,567,366	1,856,986
General Plant	479,416	421,000	425,000	374,000
Total Capital Expenditure	**6,851,919**	**8,364,511**	**9,468,639**	**7,952,003**

Capital Project Summary

Table 2-43 provides a summary of all capital projects for the years 2011 through 2014, the 2015 Bridge Year and the 2016 Test Year. All projects above HHHI's materiality threshold of $65,000 have been listed individually within the DSP categories and all individual projects below the threshold have been grouped together as miscellaneous within the applicable category. HHHI's DSP, found in Appendix 2-A, provides capital project summaries along with full descriptions and justifications of all individual material projects listed in the table for the 2016 Test Year. These summaries are found in the DSP. Table 2-43 is consistent with the Board's Appendix 2-AA, Capital Projects Table.

Table 2-43: Capital Projects Table – 2011 to 2016

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
Reporting Basis	CGAAP	Revised GAAP	Revised GAAP	Revised GAAP	MIFRS	MIFRS
System Access						
Jobs for Asymetrical Account - 2012 COS						
Steeles Avenue -5th Line South to Trafalgar Road		1,507.35	4,400.91	435,954.84		
Steeles Avenue Pole Relocations between Trafalgar & WCB		765,414.33	935,310.72			
10 sdrd west of WCB	11,616.76					
10 Side Road/ 10th Line Round-About			2,593.61	539,619.11	9,315.28	
10112 4th Line	150.14					
10296 8th Line	1,248.63					
103 King st	2,178.95					
10545 Townline	807.53					
10583 3rd Line	9,108.16					
106 Joseph St	211.87					
10617 Trafalgar	2,115.03					
10676 Trafalgar Rd	807.53					
10766 Trafalgar Rd	7,181.95					
109 Moore Park Cres, Georgetown	300.28					
10th Line & 10 Sdrd	4,360.08					
11051 Trafalgar Rd	300.37					
11445 Hwy 25- Old Speyside School	1,428.31					
11674 Line	329.21					
11694 Winston Churchill Blvd- Disconnect & Removal	150.14					
12 Morgan Dr	329.21					
12156 17th sdrd- Pole and anchor install to accommodate sentinel light	2,490.76					
12266 10th line, georgetown- sheridian nurseries	4,691.11					
12496 6th line	3,750.20					
12562 9th Line	164.60					
12799 9th line	3,097.02					
13010 8th Line	5,520.83					
13260 Fallbrook Trail	3,624.92					
13261 10th Line-Upgrade 100-200	850.69					
13441 4th Line- Panel Change	164.60					
13536 15th sdrd	300.28					
13536 4th Line	7,718.42					
13564 7th Line	458.77					
13709 22nd sdrd	427.42					
13819 Trafalgar Rd	316.14					
139 Kingham rd, Acton	300.28					
13980 9th line	1,445.17					
14 Southwinds dr	8,185.08					
14243 9th Line	329.21					
14303 Trafalgar Rd	4,042.12					
15350 Argyll Rd	150.14					
16 Mountainview Rd S	9,142.95					
17 River St- Acton Public Library	20,464.40					
177 Mountainview Rd	514.38					
18 Heather Court, Georgetown	300.28					
18 Weber Dr, Georgetown	6,169.59					
19 Valleyview rd, georgetown	300.28					
19 Willow st N- U/G installation between 15 & 9 Willow	17,089.90					
197 Mill St W	238.58					
20 John St- Georgetown	446.27					
21 Cedar rd, acton	1,247.06					
211 Armstrong ave- change o/h to u/g	1,645.91					
24 Browns Cres, Acton	329.21					
24 Churchill cres	238.56					
264 Main st s- georgetown	1,464.04					
283 Queen St- Acton	211.87					
29 & 31 Birchway place, Acton	5,044.55					
29 Todd Rd- Water Tower	8,872.76					
3 Churchill cres- upgrade 60-200	655.83					
3 Crombie Pl, Georgetown	300.28					
30 Armstrong Ave, Georgetown	13,414.20					
307 Armstrong ave- upgrade 200-400 amps	117.59					
32 Albert St	329.21					
35 Sinclair Ave, Georgetown	1,444.62					
362 Delrex Blvd, Georgetown	336.32					

Table 2-43: Capital Projects Table – 2011 to 2016 (Cont'd)

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
Reporting Basis	CGAAP	Revised GAAP	Revised GAAP	Revised GAAP	MIFRS	MIFRS
383 Delrex Blvd. Georgetown	300.28					
383 Delrex- Temp- Vacant lot between 383 & 385	2,433.22					
40 Charles st	1,513.14					
400 GUELPH ST. GEORGETOWN		29,012.67				
42 Munro Circle	329.21					
44 Eastern Ave- Acton	10,283.80					
48 Armstrong Ave	309.11					
5 Hepburn Cres. Georgetown	329.21					
5 Oakridge Dr. Georgetown	6,407.45					
510 Main st. Glen Williams	300.25					
53 Samuel Cres. Georgetown	6,075.92					
54 Arcourian Dr	329.21					
54 Armstrong- New service	2,877.52					
55 River Dr- Upgrade 60-100	579.54					
59 Sotton Cres. Georgetown	300.23					
5th line & 5 sdrd	2,767.75					
5th Line and Steeles Ave. Hornby	158.54					
6153 22 sdrd	3,325.75					
65 Jocelyn Cres. Georgetown	4,577.04					
73 Main St N. Georgetown	1,645.12					
7451 5th sdrd	7,565.69					
7558 5th line- Milton- Union gas station	4,259.20					
8 Ann st. georgetown	300.39					
8070 Hornby Rd. Hornby	9,539.42					
8150 10th line	3,254.96					
83 Moore Park cres. Georgetown	452.42					
8551 5th Line	2,935.35					
8th line (main st) Pole line relocation	3,485.98					
9 Airdale Crt. Georgetown	329.21					
9 Church St- Georgetown Library & Cultural Center	4,902.20					
90 Weber Dr. Georgetown	300.22					
9015 4th line	1,375.75					
9111 3rd Line	2,902.33					
9249 Hwy 25	4,412.23					
9419 Hwy 25	6,224.95					
9454 3rd line	9,000.06					
97 Irwin Cres. Georgetown	300.26					
5th Line (Steeles Avenue to 10 Side Road)						531,245.00
ACTON REAR YARD POLE REPLACEMENT PROGRAM	5,522.40					
Armstrong Ave. Georgetown	1,158.72					
Campbellville Road: Dublin Line Round-About Relocations					65,532.53	
Campbellville Road: JSP / Tremaine Road - Round-about (WO: 195551)			31.23			
Connect 9.98kw Microfit solar cogeneration project	4,399.17					
Eden Oak townhouse- Subdivision	3,033.91					
Gellert Center Solar Panel Project	4,900.00					
General Meter Service & Installs	1,395.57					
Generation - FIT		7,513.78				
Hall Rd (Glen) Apartment Building (58 Units)					150,000.40	
HHVH PH 4, Eagleview	2,900.67					
HHVH phase 5	5,119.78					
Interval Metering Installation/ Exchange	5,302.05					
KINGHAM RD. POLETRANS CONVERSION	323.05					
L11 Conc 4 Hume crt- Temp Service	2,378.64					
Lot 1 Conc 1 32nd Sdrd	3,735.76					
Make Ready Install Anchors at Pole 7149	1,541.70					
Make Ready Upgrades					22,686.00	15,424.00
Make Ready Work - 15 sdrd	541.51					
Meadows in the Glen	11,580.42					
Metering	130,647.00	3,790,635.00	339,265.00	61,419.00	149,526.00	
Metering General Service > 50KW upgrade						44,729.00
Metering Residential Interval Materials						114,824.00
Microfit		9,535.74				
Misc Capital Jobs	214,901.03	3,357.33	457,513.00	13,679.00		
MTO 401 Bridge Widening (5th Line South) Relocations****					18,415.60	
New 100 amp service for water control valve-corner or steels and wcb	6,691.55					
New 200 Amp Service- 104 Guelph St- Cogeco hub	13,676.27					
New 600 volt service- Cross Railroad at traffic lights- 22nd sdrd	20,793.67					
New Streetlight- 5th Line & 15th sdrd- N.E Corner	252.76					
New Streetlighting at Intersection of Hwy 7 & 4th line	318.65					
Pole Relocations on Highway #25 at 5 Side Road	15,704.44					
Pole Relocations on Steeles Avenue between WCB and Trafalgar Road	4,005.23					
Pole Replacements	80,318.94					
Pole, Conductor, Tx., and Switch Replacements on Church Street East, Acton.	254.38					
Reconductoring WCB from Guelph Street on Old Pine Crest Road to CNR Tracks on WCB	989.55					
Residential Meter Installations/ Exchange	3,547.49					
Service Relocations - Winston Churchill Blvd (2-Lane Reconstruction 5 sdrd to Norval EMU), PR-2144			794.11			
Silver Creek Estates Phase 2	38,575.36					
Smart Meters	38,459.25	86,447.97			100,000.00	
Steeles Avenue - James Snow Parkway to 5th Line South (Phase 2 - Stage 1)	170,619.59	577,756.93	- 75,448.22			
Steeles Avenue -5th Line South to Trafalgar Road - 2015 Phase					1,064,152.74	
Steeles Avenue Pole Relocations between Trafalgar & WCB - 2015 Phase				1,610,060.58		
Technical Service Layouts						20,000.00
Trafalgar rd & Lindsay Crt Lot 7 Conc 21	15,016.83					
Trafalgar Road: 10 Side Road Intersection Relocations	2,084.02		200,727.99		6,756.40	253,665.00
Upgrade 60-200, 11 Kaiser cr	2,503.36					
Wallace Street and McDonald Blvd Relocate Poles and Anchors	41,130.83					
West Meadows Townhouse Complex- Dr Moore and Wallace	27,969.83					
Wildwood Road Relocations (Highway 7 to Oakridge Drive)					9,483.93	
Winston Churchill Blvd: 10th Side Road Re-Alignment & WCB 2- Lane Reconstruction Guelph St. to 17 Sdrd) (WO: 194158)			794.00			
Grand Total	**1,182,057**	**5,251,191**	**1,867,997**	**2,690,732**	**1,575,159**	**1,339,885**

Table 2-43: Capital Projects Table – 2011 to 2016 (Cont'd)

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
Reporting Basis	CGAAP	Revised GAAP	Revised GAAP	Revised GAAP	MIFRS	MIFRS
System Renewal						
10365 Hwy 7 L28 C7- Upgrade to 3phase- Caldron Gas Bars Ltd	2,125.79					
10826 5th line- Change blown tx	2,693.77					
15 Sdrd East of 4th line	4,272.30					
16469 10th Sdrd	2,398.50					
22 Sdrd West of Hwy 7	9,048.40					
5 Charles St- Change blown TX	4,231.27					
5th Line South of Steeles Ave	24,217.93					
64 Miller dr- leaking Transformer	4,628.24					
6th line north of 22 sdrd	7,531.05					
Airbrake Maintenance in Various Locations	10,572.32					
Ashgrove Substation Outfit New Control House		24,602.02				
Asset Management	21,612.03					
Ballinafad Substation Transformer Refurbishment				112,414.85		
Byron St- Pole Line Rebuild	6,367.74					
Cap. WTR HTRS- Material	77,630.98					
Change Broken 45' pole- 2nd "s" bend of hwy 25 on 15th sdrd	6,381.35					
Contractor dug into u/g primary	1,952.47					
Copper Theft Repair- MS 5 Silvercreek Substation	1,081.09					
Cross MS switchgear replacement						714,205.00
Cross Sub13 Municipal Substation 4.16 kV Upgrades				1,529.01		
Cutout Replacement program (AB Chance Porcelain Cutout in particular)		25,543.85	13,805.55			
Green Energy Initiative - Solar Panel Pilot Project		264,373.74				
Live Front Transformer Replacements						98,639.44
Metering Retail/Interval PMU replacements						91,425.00
Misc Capital Jobs	17,455.69					
Oil Recloser Refurbishment			4,437.41			
Pole Change Outs- Hume Court	415.78					
Pole Line Re-Build. Supply to C10Z147 from Maple Avenue (Georgetown)				197,714.53		
Pole Replacement- 2 Chipper Crt	2,496.25					
Pole Replacements	1,238,266.02	1,180,177.12	1,183,227.13	1,908,706.37	1,099,696.90	2,000,000.00
Pole Trans Conversion - Kingham	821,950.32	1,040,177.26	4,924.46			
Pole Trans conversion (Bower Street Acton)			331,265.66	83,431.50		
Pole Trans -Conversion (Elizabeth & Elmore Dr. Acton)				37,728.80	524,475.40	
Poletrans Transformer Replacements (Acton) - Design 2016. Build 2017 - Norman/ Rosemary						38,100.00
Poletrans Transformer Replacements (Georgetown) -Design/ Build - Hillside Dr						500,000.00
Porcelain Switch Replacements			45,487.24	3,861.48		21,886.11
Power Transformer Life Extension					56,229.36	21,979.00
Princess Anee Dr. Georgetown	2,702.88					
Purchase of Land- Transformer Station			250.00			
Replace Broken Pole between 51 & 55 Charles	275.52					
Replace Pole- 209 Mill St W	6,165.29					
Replace Pole- 24 main st S	3,762.81					
Replace Pole- 6065 6th line	1,961.60					
Replace Pole- 9 Park Ave	2,519.51					
Substation Painting Program	6,643.72	13,888.55		17,519.18	21,024.32	
Switchgear Replacement, John Street, Georgetown	24,825.04	11,499.85				
Vintage Underground Replacement Program					168,698.00	304,526.00
Grand Total	**2,316,186**	**2,560,260**	**1,584,398**	**2,362,906**	**1,870,124**	**3,790,671**

Table 2-43: Capital Projects Table – 2011 to 2016 (Cont'd)

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
Reporting Basis	CGAAP	Revised GAAP	Revised GAAP	Revised GAAP	MIFRS	MIFRS
System Service						
27.6kV Extension up Trafalgar Road	14,235.15	162.64	758,753.91	2,493.42		
27.6kV Extension/loop on 5 Sdrd	13,888.89			460,730.06		
44kV and Extend 8.32kV - 27 Side Road	138,526.50	202,978.49				
44kV Dist Automation (Procurement & inst 6 Load-break SWs in 2012)		273,298.34				
44kV Distribution Automation (Procurement & installation 12 Load-break SWs)	242.83		162,661.21	413,499.41		
5 Side Road 27.6kV Conversion (8th Line to Trafalgar Road incl. 8th Line North of 5 Sdrd)					751,630.34	
5 Side Road 27.6kV Conversion (Trafalgar Road to 8th Line) - Design only.					10,493.20	
5F3 on 32 Sdrd						234,992.00
5th Line South Phase Reconfiguration for Scada-Mate Switch (2)	41,059.69					
8 kV Reliability improvements - Silver Creek MS		124,234.97	84,572.65			
8th Line 5-10 Sdrd 27.6kV Conversion					787,654.30	
Armstrong F3 Feeder Clean-up Work				27,513.43		
Armstrong MS F1/ F2 Riser Pole Re-Build				86,634.76		
Armstrong MS Feeder Building (19-F3)			620,745.78	27,513.43		
Ashgrove Station Service			25,646.92	4,880.14		
Ashgrove Substation Outfit New Control House	7,703.04					
Automated Switches, 27.6kV System						143,244.00
Automated Switches, 46kV System (2 Switches)						156,607.30
Ballinafad MS Reclosers						155,629.00
Ballinafad Substn. - Feeder Re-configuration		77,051.67	31,034.75			
Convert 8.32kv Line to 27.6 kv (8th Line - 5th Sdrd to 10th Sdrd)	4,682.97	271.71		3,374.63		
Convert 8.32kV Line to 27.6kV (8th Line: 5th SdRd to Steeles)		2,684.00	2,119.11	606,795.25		
Development SEL protection relay and comm processor - Material	4,907.70					
Extend 27.6kV Distribution System North on Trafalgar Road to Halton Hills Drive.				16,593.45		
Feeder Reinforcement, Delrex Blvd. (Jessop Crt. To Sargent Road) - Design Only						28,427.00
Feeder Reinforcement, Delrex Blvd. (Rexway Dr. to Maple Ave.)						346,812.00
Georgetown 4kV System Reinforcement					175,191.40	
Glen Williams Bus VT upgrade			6,464.30	41,431.88		
Glen Williams Station Service			24,402.68	893.49		
Glen Williams Substaion - Outfit New Control House	7,990.51	12,246.65				
Ground Grid Study - (design only)				17,456.87		
HHH Solar Project	36,643.90					
Install Two (2) Scada-Mate Switches			993.73	30,878.40		
Lot 25 Conc 9- Fallbrook Trail- Addition of Solid Blade Inline Switches	2,656.57					
New Feeder from Armstrong MS	405.24					
New Hydro One ICCP Router & Firewall (in accordance to Hydro One Specification) -					4,000.00	
New SCADA servers and historical server hardware refresh -					15,000.00	
New station batteries (Lead acid or NiCd).					10,000.00	
Norval VT Replacement			264.13			
POLE RELOCATIONS, WCB FROM OLD PINECREST RD. NORTH ON WCB.		90,762.99				
Purchase of Land- Trafalgar Substation	236,720.00					
Purchase/ Install Scada-Mate Switch					70,536.26	
Reconducting Main St (from River Dr to first pole North of CN track)	11,210.47	136,565.36				
REGULATOR RELOCATION FROM 3RD LINE TO 22ND SDRD	22,870.96					
River Substation Transformer Fans	2,486.86					
SCADA	13,630.63		16,536.00	2,306.00		
SCADA operating PC refesh (Windows XP end of support).					2,000.00	
SCADA Radio Expansion	58,308.20	6,316.47	5,007.72	31,646.53	153,569.00	
SCADA Switch Integration						86,579.00
SCADA Systems		111,405.00				
SCADA Wireless Faulted Circuit Indicators						48,983.00
Scada-Mate Switches (QTY: 2)	105,859.89					
Silver Creek Substn. - Feeder Reconfiguration (re-budget)	3,762.82	47,364.74	38,367.00			
Smart Grid Infastructure for 2012 - Scada-Mate Switches (QTY: 2)		105,020.71				
Substation Automation/Modernization					116,393.00	
Trafalgar Road 27.6kV Extension (15 Sdrd to Maple Avenue)					3,938.48	671,181.00
Transformer Station and Substation					1,383,000.00	
Upgrade and Relocate 34.5kV Switch.	7,113.45					
Voltage Conversion, 5 Side Road (8th Line to 9th Line) - Design						19,643.04
Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line) - Construction						406,693.66
WIRELESS FAULT INDICATORS - VARIOUS LOCATIONS	20,103.94					
Grand Total	**757,210**	**1,192,256**	**1,777,792**	**1,975,057**	**3,485,366**	**2,302,791**

Table 2-43: Capital Projects Table – 2011 to 2016 (Cont'd)

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
Reporting Basis	**CGAAP**	**Revised GAAP**	**Revised GAAP**	**Revised GAAP**	**MIFRS**	**MIFRS**
General Plant						
Buildings, Furniture & Fixtures	153,479.00	356,930.00		43,442.00	150,000.00	50,000.00
Computer Hardware	52,859.00	266,567.00	144,237.00	46,162.00	121,500.00	
Computer Software	173,442.00	190,042.00	156,819.00	772,756.00	85,500.00	
Continuation of Cyber Security Project from 2010	5,052.16					
Ergonomic Fumiture Upgrades						35,000.00
GIS - ESRI Implementation	35,810.32	57,583.45				
IBM System i POWER8 Install						75,000.00
Interactive Voice Response (IVR) for Customer Care						100,000.00
Mobile Truck Radio Repeater	7,866.41					
New Ashgrove Voice radio repeater - Kontact Plus					5,000.00	
New base station radios at Alice St. (qty. 2) - Kontact plus					2,000.00	
New battery resistance tester					5,000.00	
New substation waming signs –					5,000.00	
Office Equipment	39,498.00		3,137.00	1,040.00	51,136.00	35,000.00
Parking Lot Paving						150,000.00
Quadra License						2,800.00
Roof Resurfacing - Garage Section						85,000.00
SCADA	176,058.00					
SCADA Outage Management System Interfaces						67,813.00
Small Tools	26,608.00	64,538.00	48,101.00	23,530.00	30,000.00	32,000.00
Vehicles (rolling stock)	194,884.00	274,392.00	67,746.00	385,211.00	329,000.00	145,000.00
Grand Total	**865,557**	**1,210,052**	**420,040**	**1,272,141**	**784,136**	**777,613**

Capital Project Variance – 2012 Board Approved vs. 2012 Actual

Table 2-44 provides a summary of capital project for 2012 actual project costs compared to 2012 Board-Approved projects. An explanation of the material variances follows.

Table 2-44: 2012 Capital Projects vs. 2012 Board Approved Projects

Projects	OEB Category	2012 Board Approved	2012 Actual	Variance
Reporting Basis				
System Access				
10 Sd Rd (2-Lane Reconst from 9th Ln to WCB), PR-1437C	System Access	-	-	-
Generation - FIT	System Access	6,708.00	7,511.78	(803.78)
Microfit	System Access	20,124.00	9,535.74	10,588.26
Pole Relocations on Steeles Av between WCB & Trafalgar Rd (PR-2044B)	System Access	1,047,700.00	765,414.33	282,285.67
Steeles Avenue - Trafalgar Rd to 5th Line South (Phase 2 - Stage 2)	System Access	496,638.00	1,507.35	495,130.65
Steeles Avenue - James Snow Parkway to 5th Line South (Phase 2 - Stage 1)	System Access	274,021.00	577,758.98	(303,737.98)
Subdivision	System Access	-		-
W.C.B. -5 Sd Rd to Norval (Design 2012)	System Access	24,950.00	-	24,950.00
Services	System Access	-	-	-
400 GUELPH ST. GEORGETOWN	System Access	-	29,012.67	(29,012.67)
Smart Meters	System Access	-	66,447.97	(66,447.97)
Misc Job	System Access		3,367.38	(3,367.38)
Metering	System Access	-	3,790,635.00	(3,790,635.00)
Total		1,870,141.00	5,251,191.20	(3,381,050.20)

Projects	OEB Category	2012 Board Approved	2012 Actual	Variance
Reporting Basis				
System Renewal				
Ashgrove Substation Outfit New Control House	System Renewal	21,394.00	24,602.02	(3,208.02)
Cutout Replacement program (AB Chance Porcelain Cutout in particular)	System Renewal	35,173.00	25,543.85	9,629.15
Pole Replacements - 2012	System Renewal	722,941.00	1,180,177.12	(457,236.12)
Pole Trans Conversion - Phase 3 at Kingham Rd, Acton -Final	System Renewal	653,459.00	981,267.94	(327,808.94)
River Substation Transformer Fans	System Renewal	17,832.00		17,832.00
Substation Painting Program	System Renewal	8,121.00	13,886.55	(5,765.55)
Switchgear Replacement, John Street, Georgetown	System Renewal	47,286.00	11,499.85	35,786.15
Green Energy Initiative - Solar Panel Pilot Project	System Renewal	200,000.00	264,373.64	(64,373.64)
Pole Trans Conversion - Kingham	System Renewal	-	58,909.32	(58,909.32)
Total		1,706,206.00	2,560,260.29	(854,054.29)

Projects	OEB Category	2012 Board Approved	2012 Actual	Variance
Reporting Basis				
System Service				
27.6kV Extension up Trafalgar Road - (10 Sd Rd to 15 Sd Rd) Phase 2 (2012)	System Service	327,972.00	152.64	327,819.36
44kV and Extend 8.32kV - 27 Side Road	System Service	176,660.00	202,978.49	(26,318.49)
44kV Dist Automation (Procurement & Inst 6 Load-break SWs in 2012)	System Service	437,324.00	273,298.34	164,025.66
44kV Distribution Automation (Procurement & installation 12 Load-break SWs)	System Service	437,081.00		437,081.00
8 kV Rel improv - Silver Creek MS	System Service	107,978.00	124,234.97	(16,256.97)
Ballinafad Subsln. - Feeder Re-configuration	System Service	109,417.00	77,051.67	32,365.33
Convert 8.32kV Line to 27.6kV (8th Line: 5th SdRd to 10th SdRd) - Build/Construct	System Service	(639.00)	271.71	(910.71)
Convert 8.32kV Line to 27.6kV (8th Line: 5th SdRd to Steeles) - Build/Construct	System Service	470,876.00	2,584.00	468,292.00
Glen Williams Substaion - Outfit New Control House	System Service	21,106.00	12,246.85	8,859.15
Reconducting Main St (from River Dr to first pole North of CN track)	System Service	99,027.00	136,565.38	(37,538.38)
SCADA Radio Expansion (Year 2 of 3)	System Service	52,613.00	8,318.47	44,294.53
SCADA Systems	System Service	26,500.00	111,405.00	(84,905.00)
Silver Creek Subsln. - Feeder Reconfiguration (re-budget)	System Service	105,654.00	47,364.74	58,289.26
Smart Grid Infrastructure for 2012 - Scada-Mate Switches (QTY: 2)	System Service	125,614.00	105,020.71	20,593.29
POLE RELOCATIONS, WCB FROM OLD PINECREST RD. NORTH ON WCB.	System Service	-	90,762.99	(90,762.99)
Total		2,497,183.00	1,192,255.96	1,304,927.04

Projects	OEB Category	2012 Board Approved	2012 Actual	Variance
Reporting Basis				
General Plant (Other Capital Items)				
Buildings, Furniture & Fixtures	General Plant	10,000.00	356,930.00	(346,930.00)
Computer Hardware	General Plant	80,000.00	266,567.00	(186,567.00)
Computer Software	General Plant	68,000.00	190,042.00	(122,042.00)
Small Tools	General Plant	43,470.00	64,538.00	(21,068.00)
Vehicles (Rolling Stock)	General Plant	230,000.00	274,392.00	(44,392.00)
ERP System	General Plant	350,000.00	-	350,000.00
IT Capital Budget	General Plant	-	-	-
GIS - ESRI Implementation	General Plant	-	57,583.45	(57,583.45)
Convert inView Lite to inView Premium) Meter Reading	General Plant	45,000.00		45,000.00
Total		826,470.00	1,210,052.45	(383,582.45)

2012 Board Approved vs 2012 Actual

System Access:

The main drivers of the variance in this category are the Steeles Avenue – Trafalgar Rd to 5th Line South (Phase 2 – Stage 2) Pole Relocation and the pole relocations on Steeles Avenue between Winston Churchill Boulevard and Trafalgar Road for a total budgeted costs of $1,544,338 with actual costs of $766,921.

Included in the 2012 amount is $3,660,492 of smart meter capital cost that was transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012.

System Renewal:

The main drivers of the variance in this category is pole replacements due to age and conditions with an actual cost of $1,180,177 compared to the 2012 Board Approved amount of $7,22941.

Pole-Trans Conversion with an actual cost of $981,267 compared to the 2012 Board Approved amount of $653,459 also contributed to the variance.

System Service:

The drivers for the variance in this category are two (2) distribution automation projects with an approved budget of $874, 405 and actual cost of $273,298.

A 27.6kV Extension project with a budget of $327,972 and actual cost of $152, in addition to a project to convert a 8.32 kV pole line to 27.6kV with an approved budget of $470,876 and actual costs of $2,584 have contributed to the variance.

General Plant:

The main driver of this variance is the EPR system that was budgeted for 2012 but implementation started in 2013.

Included in the 2012 amount is $200,278 of computer hardware and software capital cost that was transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012.

Table 2-45: 2012 Board Approved vs 2012 Actual

Description	2012 Board Approved	2012 Actual	Variance from 2012 Board Approved
System Access	1,870,141	1,590,699	279,442
System Access -Smart Meter Cost transfer to Capital from DVA 1555	3,660,492	3,660,492	-
System Renewal	1,706,206	2,560,260	- 854,054
System Service	2,470,683	1,192,256	1,278,427
General Plant	852,970	1,009,774	- 156,804
General Plant - Smart Meter Cost transfer to Capital from DVA 1555	200,278	200,278	-
Total Capital Expenditure	**10,760,770**	**10,213,760**	**547,010**

Treatment of Projects

Life Cycle Greater than One Year: HHHI's accounting policy is to include projects in fixed assets when complete. Capital projects which are not yet completed are included in WIP. Capital projects with a life cycle greater than one year will be carried over from one year to the next in WIP. Once completed, expenditures are removed from WIP and capitalized to fixed assets at which point they begin depreciating.

Treatment of Cost of Funds: HHHI's accounting policy is to capitalize borrowing costs that are directly related to its capital expenditures. HHHI will continue to capitalize borrowing costs under IFRS if they meet the criteria of a qualifying asset which is defined in the Board's Report of the Board EB-2008-0408 Transition to International Financial Reporting Standards, June 28, 2009 as "an assets that necessarily takes a substantial period of time to get ready for its intended use or sale".

Components of Other Capital Expenditures

HHHI does not have other capital expenditures, such as non-distribution activities, for which it needs to provide components.

Capitalization Policy (2.2.2.3)

Capitalization Policy Overview

HHHI capitalization policies were presented and approved by the Board in HHHI's 2012 Cost of Service rate application. There are no changes to the capitalization policies that were approved in 2012.

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 assets and are defined as assets that lack physical substance. They include goodwill, patents, copyrights and computer software.

- **Betterment** - a "betterment" is a cost which enhances the service potential of a capital asset and/or increases its value, and is therefore capitalized. 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. Betterment does not include general maintenance-related actions that seek to sustain an asset's 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.

Depreciation

Depreciation is recognized 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 assets are not depreciated until the project is complete and in service.

Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended. For rate setting purposes, in the first year of service, depreciation is calculated using the ½ year rule. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated.

The useful life of the assets HHHI uses for depreciation purposes was derived from the HHHI Specific Kinectrics Report as filed in the 2012 Cost of Service. The componentization of HHH assets for IFRS along with the useful lives was approved by the Board in HHHI 2012 Cost of Service.

Overhead Policy

HHHI's overhead policy has been reviewed by its external auditors and has been deemed IFRS compliant.

HHHI has reviewed and changed its overhead policy, including the capitalization component, to follow a more direct allocation of costs. The review was for the transition to IFRS and HHHI has been using this policy since 2012. The policy was approved by the Board in HHHI's 2012 Cost of Services. The policy is discussed in Exhibit 4 for convenience. There were no changes to HHHI's overhead policies that were approved in the 2012 Cost of Service.

Customer Contributions Changes

Under CGAAP, HHHI recorded customer contributions as an offset to the cost of capital assets and amortized accordingly. Under MIFRS, HHHI cannot capitalize these customer contributions as part of its net capital assets, but instead will classify the contributions as a deferred revenue liability and amortize the costs to revenue over the life of the asset the contribution relates to. For financial reporting purposes, HHHI has classified forecasted customer contributions for the 2015 Bridge Year and 2016 Test Year as deferred revenue and amortized the contribution to revenue over the life of the related asset. For rate setting purposes, these costs are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense. For financial statement purposes, historical contributed capital has been reallocated and netted against the specific PP&E asset they relate to, however, for continuity and rate setting purposes, these costs are included in Account 1995. Please see Table 2-23 - Account 1995 Breakdown for the reconciliation between financial statement reporting and rate setting classification.

Capitalization of Overhead (2.2.2.4)

Overview

The capitalization of overhead costs was dealt with and approved in HHHI 2012 Cost of Service. As discussed above HHHI overhead policy is IFRS compliant and there were no changes to the policy that was approved in 2012.

Burden Rates

Table 2-47 summarizes the historical and forecasted overhead rates related to the capitalization of costs on self-constructed assets. The rates are changed and updated periodically to reflect actual costs or changed circumstances.

HHHI has three types of overhead costs that are capitalized: (a) Fleet; (b) Stores; and (c) Payroll Benefits. HHHI also capitalizes payroll benefits. These costs are directly allocated to capital through the use of a burden rate in the payroll system. HHHI budgets payroll benefits for each employee and the resulting overhead percentage is attached to the employee through the payroll system. Capital, OM&A and recoverable burden costs are calculated in the payroll system and flow directly to each project. The benefits attached to each employee's hours are directly charged to Capital, OM&A or recoverable, as applicable.

Table 2-46: Board Appendix 2-D - Summary of Capitalized Overhead Expense

OM&A Before Capitalization	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Bridge Year	2016 Test Year
Salaries and Benefits	$ 4,759,645	$ 5,307,544	$ 5,267,310	$ 4,502,418	$ 4,856,870
Material Costs	$ 2,747,932	$ 2,663,788	$ 2,232,236	$ 2,481,862	$ 3,178,960
Contract Services	$ 3,137,463	$ 3,107,635	$ 3,904,777	$ 3,582,314	$ 3,430,852
Property Costs	$ 1,473,618	$ 701,458	$ 632,355	$ 1,451,935	$ 1,443,483
Other Costs	$ 894,224	$ 744,461	$ 588,618	$ 1,399,836	$ 1,438,041
Communication Costs	$ 313,648	$ 450,064	$ 590,096	$ 509,620	$ 722,050
Total OM&A Before Capitalization (B)	$ 13,326,530	$ 12,974,950	$ 13,215,392	$ 13,927,985	$ 15,070,255

Capitalized OM&A	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Bridge Year	2016 Test Year	Directly Attributable ? (Y/N)	Explanation for Change in Overhead Capitalized
Salaries and Benefits	$ 1,774,884	$ 2,630,660	$ 2,470,908	$ 1,002,728	$ 1,089,616	Y	
Material Costs	$ 2,242,902	$ 2,583,930	$ 1,361,167	$ 2,374,998	$ 3,129,333	Y	
Contract Services	$ 2,968,635	$ 2,482,747	$ 3,863,544	$ 2,652,024	$ 2,462,509	Y	
Property Costs	$ 414,527	$ 100,000	$ 231,490	$ 755,065	$ 598,442	Y	
Other Costs		$ -	$ -	$ 933,000	$ 931,060	Y	
Communication Costs		$ -	$ -	$ -			
Total Capitalized OM&A (A)	$ 7,400,948	$ 7,797,337	$ 7,927,109	$ 7,717,815	$ 8,210,959		
% of Capitalized OM&A (=A/B)	56%	60%	60%	55%	54%		

Table 2-47: Overhead Rates

Description	Unit	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Burden Rates:							
Payroll Benefits	Direct Labour	67%	67%	67%	67%	67%	67%
Overhead Rates:							
Stores Costs	Material $	24%	24%	24%	24%	24%	24%
Small Truck	Direct Labour	$ 26.00	$ 26.00	$ 27.00	$ 27.72	$ 27.72	$ 27.72
Large Truck	Direct Labour	$ 47.50	$ 47.50	$ 49.00	$ 50.30	$ 50.30	$ 50.30

Costs of Eligible Investments for the Connection of Qualifying Generation Facilities (2.2.2.5)

HHHI has not incurred any capital costs related to the connection of qualifying generation facilities.

<u>New Policy Options for the Funding of Capital (2.2.2.6)</u>

On September 18, 2014, the Board released the *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.* In the report, the Board established the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

> *"The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module (or "ACM").*
>
> *Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP."*

HHHI is not applying for Advanced Capital Module review for any incremental capital projects.

Addition of Previously Approved ACM and ICM Project Assets to Rate Base (2.2.2.7)

HHHI has not applied for approval of ICM Assets and therefore has no such assets added to its rate base.

Service Quality and Reliability Performance (2.2.2.8)

HHHI follows the Board's Reporting and Record Keeping Requirements Guideline to report its service quality indicators annually. In accordance with the Filing Requirements, Table 2-48 is provided below and is consistent with Board Appendix 2-S, Service Quality Indicators. The table provides the performance measurements for the last five (5) historical years – 2010 through 2014.

Customer Focus

Service Quality

HHHI places a strong focus on providing customers with distribution excellence. This focus includes maintaining exceptional levels of customer service. HHHI has continuously exceeded the OEB's minimum standards.

The connection of New Services – High Voltage target is not applicable for HHHI as HHHI has no high voltage connections.

In all areas measured, HHHI has met or exceeded its targets in 2014 and historically, HHHI has always exceeded the Board targets. In particular, it should be noted that for the past three years, all appointments have been met and all connections for new services completed, one hundred percent (100%) of the time.

HHHI notes that telephone accessibility is a high priority for their customers. The telephone is still, by far, the preferred method of contact for the vast majority of HHHI's customers. In HHHI's 2014 customer service survey, it was noted that eighty-eight percent (88%) of customers prefer to use the telephone to contact HHHI. HHHI continues to strive for improvement and with reference to the general capital plan, the utility will be implementing an Interactive Voice Response (IVR) system to provide customers with added features and flexibility to better respond to their needs.

Table 2-48: Customer Focus – Service Quality - Historical Measures

Service Quality	Board Target	2014	2013	2012	2011	2010
Connection of New Services - Low Voltage (LV)	90%	100.00%	100.00%	100.00%	100.00%	100.00%
Connection of New Services - High Voltage (HV)	90%	0.00%	0.00%	0.00%	0.00%	0.00%
Appointment Scheduling	90%	100.00%	100.00%	100.00%	100.00%	100.00%
Appointments Met	90%	100.00%	100.00%	100.00%	96.00%	99.20%
Rescheduling a missed appointment	100%	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65%	89.70%	83.20%	87.70%	85.50%	86.20%
Telephone Call Abandon Rate	10%	1.00%	1.70%	1.40%	3.10%	2.00%
Written Responses to Enquiries	80%	100.00%	99.90%	100.00%	100.00%	100.00%
Emergency Response Urban	80%	100.00%	100.00%	98.81%	100.00%	100.00%
Emergency Response Rural	80%	100.00%	100.00%	89.60%	100.00%	100.00%
Reconnection Performance Standard	85%	100.00%	100.00%	100.00%		

Customer Satisfaction

Table 2-49 shows HHHI's Target Customer Satisfaction measures with recent historical years.

In January 2015, HHHI reviewed its methodology to monitor and report on First Contact Resolution.

HHHI understands that billing accuracy is imperative for all customers. HHHI will be moving to monthly billing in 2016 and as such, continued billing accuracy is paramount. HHHI has achieved 99.9% billing accuracy. The transition to monthly billing will result in customers receiving twice as many bills from the utility so ensuring that those bills are accurate is an important part of maintaining customer satisfaction and trust.

Customer satisfaction is an important measure of customer loyalty and trust. In an environment where the electricity sector receives a high amount of attention in the media, maintaining customer satisfaction is a priority.

In the 2014 Customer Satisfaction Survey HHHI's customer's satisfaction level was 90%. This survey was conducted in March 2014, with very recent memories of the December 2013 Ice-Storm.

Table 2-49: Customer Focus – Customer Satisfaction – Historical Measures

Customer Satisfaction Measures	Board Target	2014	2013	2012	2011	2010
First Contact Resolution	Not Available	100.00%				
Billing Accuracy	98%	99.95%	99.91%			
Customer Satisfaction Survey Results	Not Available	90.00%	93.00%			

Operational Effectiveness

Table 2-50 shows HHHI's system reliability measures for the five (5) most recent historical years. HHHI has removed any major events from the measures (i.e. 2013 Ice Storm). HHHI's five (5) year historical average is within the Board's target range. HHHI is an embedded distributor to Hydro One and as such, will experience loss of supply. Loss of Supply is not a variable that HHHI can alter in an effort to improve reliability.

Outage Frequency (SAIFI)

In 2014, HHHI's greatest frequency of outages came as a result of foreign interference. Foreign interference may include but is not limited to vehicles, animals and dig-ins. Overhead lines are more likely to experience foreign interference and as the HHHI distribution system consists of fifty-nine percent (59%) overhead lines, the lines are susceptible to foreign interference outside the control of HHHI. As overhead lines are more likely to experience foreign interference, In an attempt to limit animal contacts, HHHI has reviewed the use of "pole/transformer spikes" as a deterrent. However, as many of the animal contacts involve raccoons, subjective study has shown that the raccoons are quite adept at maneuvering around the obstacle. HHHI continues to review any new products that may aid in decreasing the frequency of foreign interference outages.

Defective equipment was responsible for the next greatest frequency of outages. Field Interruption Reports indicate that in 2013 HHHI replaced ten (10) porcelain switches that were reported as broken or faulty and had been the cause of a power interruption or were replaced as part of a downstream replacement of defective equipment. In 2014, HHHI replaced nine (9) porcelain switches and two (2) porcelain insulators as the devices were identified as broken or faulty. The average time spent on replacing defective switches and insulators ranged between 1 to 2 hours. The time spent replacing these defective porcelain devices impacts O&M costs as well as being an inconvenience to customers.

Distribution insulators and switches are not normally replaced based on their performance. They are typically replaced when the pole or equipment they are associated with is replaced as part of a larger infrastructure project. HHHI has implemented a regular replacement program for porcelain insulators and switches. The current program and investments are both reactive and proactive to ensure that the distribution system is reliable and safe to operate. Reactive investments are made in conjunction with other projects, while proactive replacement removes aged assets that are more susceptible to failure. HHHI has directed its workforce to replace any porcelain switch with a polymer type switch when they are working on them in the field. HHHI field staff will also regularly identify areas where suspect porcelain insulators are located for inspection and replacement purposes.

As part of its 2012 Cost of Service application, HHHI requested additional OM&A for tree trimming in an effort to aggressively reduce the frequency of tree contacts. While HHHI did not receive the total funds requested, HHHI increased the tree trimming schedule, beginning in 2011 and continuing over the next three (3) years. As a result of the aggressive schedule, tree contact frequency has decreased and as evident by the SAIFI numbers, the average number of outages per customer has decreased. There was a slight increase again in 2013 and 2014 due to several ice and wind storms between April 2013 and March 2014. HHHI expects to continue the aggressive schedule on a three (3) year rotating cycle. HHHI would like to make note that as a result of the emergency tree trimming that was conducted in most of the HHHI service area during the 2013 Ice Storm, HHHI's contracted arborist has indicated that the vegetation growth in the area could actually increase, thus making the continuation of an aggressive schedule a reliability requirement in HHHI's opinion.

Outage Duration (SAIDI)

In 2013, HHHI experienced two (2) ice storms and a wind storm. Each of the storms resulted in significant outages. The ice storm in December 2013 was considered a Major Event and as such, is not included in the 2013 reliability numbers. However, the April 2013 ice storm and July 2013 wind storm are included in the measures thus explaining the significant increase in the SAIDI number.

By far, the longest outages in HHHI's service territory are a result of adverse weather. In an effort to improve the duration of outages, HHHI is working towards a more automated and integrated distribution system. Substation reclosers, SCADA remote operated switches, SCADA wireless faulted circuit indicators and automated switches will enable to Control Room to locate faulted portions of the system quicker, dispatch crews more efficiently and effectively and remotely sectionalize faulted sections allowing crews to focus their time on repairing the fault, instead of manually sectionalizing before beginning repairs.

In addition to the automation, HHHI will optimize its Control Room partnership with Oakville Hydro Distribution Inc. by using the expertise of the in-house GIS Technician to increase the usability of distribution system maps. Additionally, HHHI has provided each line truck with a tablet that will enable crews in the field to access the up to date GIS mapping and to ensure the information provided to the Control Room and field crews are consistent.

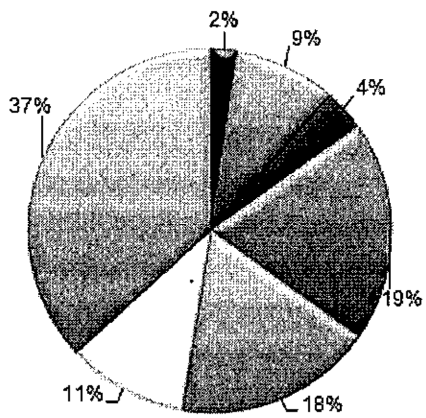
Table 2-50: Historical Service Quality Indicators

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
SAIDI	1.780	1.550	1.530	2.510	1.250	1.780	1.380	1.230	2.080	1.210
SAIFI	2.750	1.670	1.900	1.990	1.610	2.750	1.490	1.340	1.480	1.470
5 Year Historical Average										
SAIDI					1.724					1.536
SAIFI					1.984					1.706

Table 2-51: 2014 OEB Yearbook Statistics

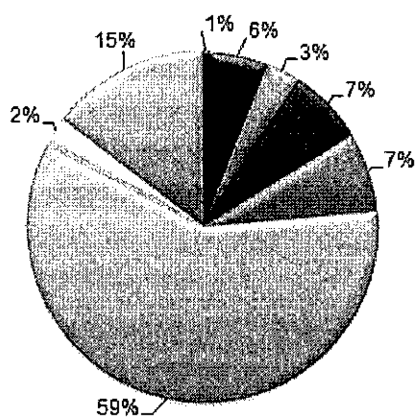
Halton Hills Hydro Inc.

Outage Frequency by Type



Customer Interruptions	
0 - Unknown/Other	102
1 - Scheduled Outage	751
2 - Loss of Supply	3,213
3 - Tree Contacts	1,324
4 - Lightning	10
5 - Defective Equipment	6,904
6 - Adverse Weather	6,230
7 - Adverse Environment	37
8 - Human Element	3,747
9 - Foreign Interference	12,956
Total	35,274

Outage Duration by Type



Customer-hours of Interruptions	
0 - Unknown/Other	186
1 - Scheduled Outage	1,470
2 - Loss of Supply	867
3 - Tree Contacts	1,916
4 - Lightning	10
5 - Defective Equipment	1,985
6 - Adverse Weather	16,110
7 - Adverse Environment	74
8 - Human Element	650
9 - Foreign Interference	3,973
Total	27,241

APPENDIX 2-A

DISTRIBUTION SYSTEM PLAN

2015

Halton Hills Hydro Distribution System Plan

Distribution System Plan

2016 - 2020

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About this Document

Halton Hills Hydro has prepared this Distribution System Plan in accordance with the Ontario Energy Board's Chapter 5 *Consolidated Distribution System Plan Filing Requirements*. Chapter 5 section references are provided in parenthesis next to each section for clarification and ease of use.

This Distribution System Plan has had an independent review from a third party engineering firm, AESI. AESI confirms that it addresses the goals and achieves the purpose of the OEB Chapter 5 consolidated Distribution System Plan Filing Requirements dated March 28, 2013. The review letter is included as Appendix K of this document.

Executive Summary

This Distribution System Plan has been created as part of Halton Hills Hydro's 2016-2020 Cost of Service rate application. This plan provides a comprehensive strategy for asset maintenance and capital expenditure over the next five years. Halton Hills Hydro's mission statement, "To Provide Halton Hills with Electricity Distribution Excellence in a Safe and Reliable Manner" has provided the overall vision for creating this plan. Safety and reliability are top priorities for the utility and are two key ways the utility strives to provide distribution excellence to customers. This Distribution System Plan is built on the principles of excellence, safety and reliability. The plan takes a prudent, cost effective approach to infrastructure investment and renewal to serve current and future customer preferences and requirements.

This plan provides a comprehensive strategy for asset management as well as a prudent, cost effective guidance for capital project expenditure over the next five years. The utility has developed a detailed Asset Management Strategy which informed the Asset Management Process section of this plan and is attached as Appendix A. The utility has also provided a detailed capital expenditure plan which supports asset management, accommodates third party requirements and plans for growth and technological improvements.

The Asset Management section of this plan provides historical data on the number and types of assets found in Halton Hills Hydro's distribution system as well as asset condition and inspection and maintenance strategies and prioritization.

The Capital Expenditure portion of the plan provides an analysis of the historical 5 year period leading up to the time frame of this plan as well as forecasted costs for the life of the plan. This plan categorizes projects by the four major categories of System Access, System Renewal, System Service and General Plant. Within each category and across categories, projects are assigned a risk ranking and a priority to help the utility with resource planning and budgeting.

This comprehensive plan will provide the utility with a prudent strategy for investment for the years to come.

1. Distribution System Plan (5.2)

This document provides the comprehensive asset management and capital expenditure information to support the Cost of Service rate application.

Halton Hills Hydro distributes electricity within the municipal boundaries of the Town of Halton Hills. The service territory covers 280 sq. km including 25 sq. km of urban and 255 sq. km of rural territory. The urban areas encompass the towns of Acton and Georgetown as well as several smaller hamlets. Halton Hills Hydro's distribution network consists of 12 municipal substations and 1527 km of underground and overhead distribution lines. Halton Hills Hydro is owned by Halton Hills Community Energy Corporation who is wholly owned by the Town of Halton Hills. The utility services approximately 22,000 customers. Approximately 19,625 of those customers are residential, 1,700 small commercial, 112 renewable generation connections and the remaining customers spread across the remaining customer classes.

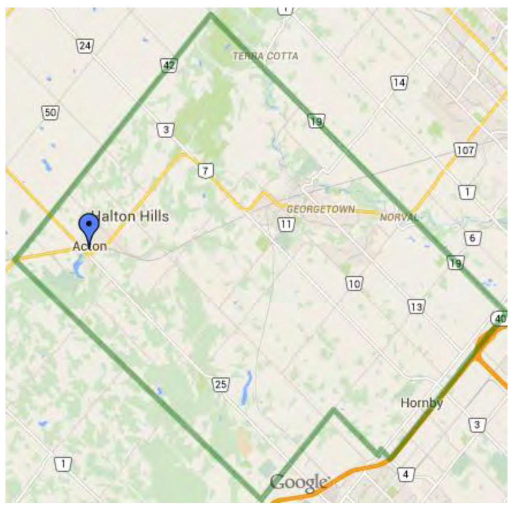


Figure 1 Halton Hills Hydro Service Territory

Halton Hills Hydro maintains 1,527 kilometers of medium- and low-voltage distribution circuits that transport electricity from the provincial transmission grid. The utility receives primary supply from Hydro One at three locations as follows:

- Three-phase three-wire 44 kV sub-transmission – Halton Hills Hydro has three (3) feeder positions (designated 42M23, 42M25 and 42M28) from Pleasant transformer station.
- Three-phase three-wire 44 kV sub-transmission –Halton Hills Hydro shares a feeder position with Milton Hydro, and Guelph Hydro (73M04) that emanates from Fergus TS.
- Three-phase four-wire 16/27.6Y kV distribution – Halton Hills Hydro has three (3) feeder positions (designated 41M21, 41M29 and 41M30) from Halton transformer station

Halton Hills Hydro distributes electricity at the sub-transmission and primary distribution voltage levels listed below:

- Three-phase three-wire 44 kV sub-transmission
- Three-phase four-wire 16/27.6Y kV distribution
- Three-phase four-wire 4.8/8.32Y kV distribution
- Three-phase four-wire 2.4/4.16Y kV distribution

There are twelve (12) municipal substations strategically located throughout our service territory that provide 2.4/4.16Y kV primary distribution voltages in the urban areas (i.e. Action and Georgetown) and 4.8/8.32Y kV primary distribution voltages in the rural parts of the service territory.

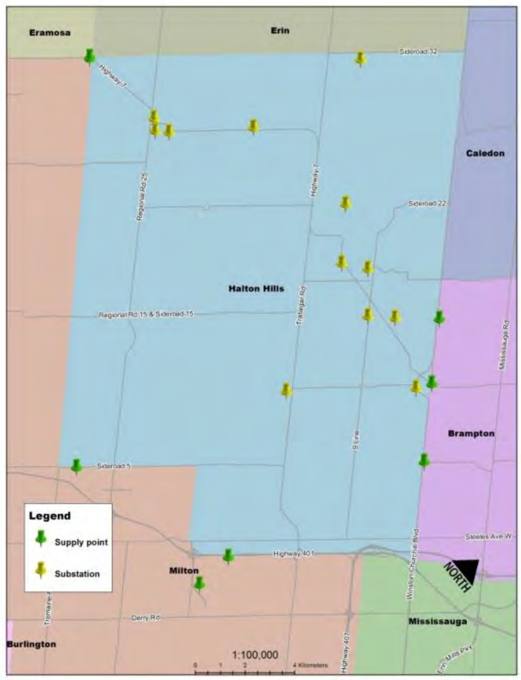


Figure 2 Halton Hills Hydro Substations and Supply Points

Halton Hills Hydro's mission statement is "Providing Halton Hills with electricity distribution excellence in a safe and reliable manner". This mission statement is supported by the following key objectives:

- Safety
- Reliability
- Competitive Rates
- Financial Metrics
- Conservation
- Environmental
- Community Focused
- Smart Grid Implementation

Safety and reliability are top priorities for the utility and are two key ways the utility strives to provide distribution excellence to customers. This Distribution System Plan is built on the principles of excellence, safety and reliability. The plan takes a prudent, cost effective approach to infrastructure investment and renewal to serve current and future customer preferences and requirements.

1.1 Distribution System Plan Overview (5.2.1)

This section provides a high level overview of the information filed in this plan.

1.1.1 Key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

There are a number of key inputs that affect this plan as depicted in Figure 3 below:

a) System Expansion plans – This category of inputs includes our ongoing voltage conversion projects as well as defined feeder circuit reinforcements.
b) Reliability reports – System reliability reports including our SAIDI, SAIFI and CAIDI statistics as well as reports identifying underperforming feeder circuits are used to strategically plan system upgrades.
c) Municipal road projects – Where the Region of Halton or the Town of Halton Hills undertakes road widening, installation of roundabouts, infrastructure replacements and other similar projects, there is a requirement for the utility to relocate pole lines to accommodate. These projects are highly dependent on the municipality for timing and can be difficult for the utility to schedule.
d) Asset Management Plan – Where the utility's asset management plan identifies components requiring replacement or refurbishment, these inputs are considered as part of the overall capital investment plan.
e) Developer Initiated Projects – new developments or subdivisions require our design efforts, line extensions and other associated work.
f) Other Drivers – Any other inputs or factors that affect planning including but not limited to Renewable Energy Generation, customer projects, third parties and regional planning.

Figure 3 Inputs to Distribution System Plan

Capital investments are broken into the four categories of: System Access, System Renewal, System Service and General Plant. The scope and timing of these investments is based on a holistic strategy evaluating all projects in terms of risk and priority as well as factoring in requirements from third parties and risks identified through the utility's asset management framework.

While this plan sets out Halton Hills Hydro's investment strategy for the next five years, it should be noted that System Access projects can have a significant impact on the timing of other projects. System Access projects are those the utility has obligations to act on and in doing so some system renewal or system service projects may be rescheduled to accommodate regulatory obligations. The utility is obligated by the Public Service Works on Highways Act, R.S.O. 1990, Chapter 49 to take up, remove or change our infrastructure however when the municipality cannot provide specific details or timeframes, utility driven projects can be put at risk. Halton Hills Hydro will mitigate such risk by reassessing priority and evaluating financial impacts of such changes to determine if all planned projects can commence or if some may need to be deferred.

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

In 2014, Halton Hills Hydro implemented a new Enterprise Reporting Platform (ERP) financial software package. There are some key elements of this new system which will help the utility realize cost savings and efficiencies. The new Quadra estimating software system allows the Engineering Department to prepare more accurate estimates in a significantly streamlined manner. These accurate estimates including detailed work packages and improved bill of materials for the crews will allow for more accurate budgeting and planning of capital projects. The financial reporting capabilities of the new financial system will allow the Finance Department to more accurately track, analyze and report on costs throughout the utility.

Halton Hills Hydro is committed to maintaining a three year vegetation management cycle to proactively manage tree trimming within mandated clearance guidelines. At the same time, this tree trimming cycle reduces nuisance outages, potential damage to conductors and public safety.

Halton Hills Hydro expects that with good planning over the forecasted period, cost savings will be achieved through:

- An increased focus on asset renewal, specifically deteriorated assets and those assets that have reached or surpassed their end of useful life. This not only ensures the distribution system continues to be reliable but also reduces operating and maintenance (O&M) costs relating to trouble calls due to aged assets. Over time, life cycle costs will be reduced by ensuring distribution equipment is of sufficient quality to deliver power to customers.
- A continued approach to converting rural 4.8/8.32kV to 16.0/ 27.6kV to accommodate planned load growth in Georgetown south (Vision Georgetown – 20,000 people and 1,700 jobs between 2021 and 2031) is anticipated to improve line losses.

- Proactive planning with respect to material ordering will also be a source of savings. Through competitive bid processes Halton Hills Hydro can achieve cost savings for equipment such as transformers.

Halton Hills Hydro has established a transformer cost evaluation system based on the EDA Electricity Distributors Association (EDA) formula for total cost of ownership to assess the total cost of ownership including an evaluation of the upfront cost and the cost of losses. This methodology assists the utility in selecting transformers that are efficient and reasonably priced. In the following example five (5) transformers are evaluated and the least expensive transformer over time wins the bid provided that the lead times are acceptable.

Transformer Stock Code:	OH015						Analysis Date:		
Transformer Type:	Pole								
Transformer Rating Info:	1-Phase, 100 kVA, 4160GrdY/2400 - 347/600 V								
Manufacturer, Bid Price & Guaranteed Performance				Analysis of Transformer Ownership Costs				Other Considerations	
Manufacturer	Unit Price (P)	No-load (core) losses, watts (N)	Load (winding) losses, watts (L)	Present Value of No-load Losses	Present Value of Load Losses	Total Cost of Losses	Total Transformer Ownership Costs [(Col 2) + (Col 7)]	Delivery, weeks A.R.O.	F.O.B. Location
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5_	(Col 6)	(Col 7)	(Col 8)	(Col 9)	(Col 10)
Manufacturer	$3,650.00	190	610	$1,577.00	$2,501.00	$4,078.00	$7,728.00	12	Halton Hills Hydro
Manufacturer	$4,090.00	145	756	$1,203.50	$3,099.60	$4,303.10	$8,393.10	12	Halton Hills Hydro
Manufacturer	$3,895.00	192	840	$1,593.60	$3,444.00	$5,037.60	$8,932.60	8	Halton Hills Hydro
Manufacturer	$3,465.00	217	1272	$1,801.10	$5,215.20	$7,016.30	$10,481.30	14	Halton Hills Hydro
Manufacturer	$5,399.21	255	912	$2,116.50	$3,739.20	$5,855.70	$11,254.91	16	Halton Hills Hydro
Manufacturer	$0.00	0	0					0	Halton Hills Hydro
Recommended Manufacturer:									
Selected on basis of:	Lowest evaluated ownership cost						Click To Sort From Lowest to Highest		
Notes:									

Figure 4 Transformer Cost Evaluation System

The Total Ownership Cost is expressed by the following formula:

T.O.C. = (unit sale price) + X*NL + Y*FL

where X = the cost of No Load Losses in dollars per Watt
NL = No-Load losses in Watts
Y = the cost of Full-Load losses in dollars per Watt
FL = Full-Load losses in Watts

The present cost of No-Load losses used in this evaluation is $8.30/ Watt, while the present cost of Full-Load losses is $4.10/ Watt.

1.1.3 Period covered by the Distribution System Plan

This distribution system plan covers the historical period of 2011-2015, and forecast period of 2016-2020. This five year forecast period allows for a reasonable assessment of capital investment and strategic planning.

1.1.4 Vintage of information used to prepare this Distribution System Plan

The asset information utilized in preparation of this plan was accumulated between 2007 and 2014. The information and technical characteristics for all assets, including their location, history and performance is stored in our Asset.

The capital investment plans for the forecast period were prepared in 2015.

1.1.5 Where applicable, an indication of important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing

This is Halton Hills Hydro's first Distribution System Plan filing under the new Chapter 5 requirements.

1.1.6 Aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

As mentioned previously, the System Access projects have the highest reliance on external parties. The utility is required to accommodate these items; however, the timing can be highly unpredictable pending input from the various third parties involved. The timing of these projects can have a significant impact on the timing of other projects. With System Access Projects, the amount of notice the utility receives regarding whether or not the project is proceeding can vary significantly by project.

The IESO has identified as part of the Regional Planning Process the need for Halton Hills Hydro to construct and operate a 230 - 27.6 kV, 125 MVA LTR Municipal Transformer Station to meet near term load requirements. The Northwest Greater Toronto Area Integrated Regional Resource Plan (NWGTA Region IRRP Report) published April 28, 2015 states in section 7.2.2 that: Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.

The NWGTA Region IRRP report is attached as Appendix B. of this document.

As the capital requirement for this project is significant, HHH intends to file a separate Incremental Capital Module (ICM) for associated expenditures rather than including in this Distribution System Plan. Many of the projects outlined in this Distribution System Plan are required to enable the supply from this new Transformer Station. Where possible, projects will include the addition of circuits to existing poles that have already been replaced or installed as part of voltage conversion projects or regional road activities. Some voltage conversion projects may be accelerated or placed in a high priority to ensure that new circuits are available to make use of the MTS capacity as it becomes available.

1.2 Coordinated Planning with Third Parties (5.2.2)

As part of Halton Hills Hydro's ongoing planning process, the utility regularly consults with third parties including customers, the transmitter, other distributors, the region, the IESO and other third parties as required.

Description of Consultations (5.2.2 a)

1.2.1 Municipal Government Consultations

Halton Hills Hydro interacts with the Town of Halton Hills and Region of Halton staff in many ways to ensure coordinated infrastructure planning, construction of customer and utility driven projects in a timely manner, and review of development applications. The majority of Town driven projects fall under the System Access category whereby the utility is regulated to accommodate. These projects can impact other Halton Hills Hydro initiated projects if they have to be deferred or changed to accommodate the Town.

The Town of Halton Hills has established a Vision Georgetown Plan which, once implemented, will add about 20,000 people by 2031 to an area of 1,000 acres in southern Georgetown. Vision Georgetown is the product of provincial growth targets for the Greater Golden Horseshoe area which started in 2006 with "Places to Grow in 2006". The provincial plan allocated an additional 130,000 people and 50,000 jobs between 2021 and 2031 to the Halton Region. The utility's long term plans to expand its 16/27.6Y kV distribution system as well as its plans to build a new Transformer Station to deliver power to this area will be integral to accommodating this future development in Halton Hills.

1.2.1.1 Town of Halton Hills Public Utilities Coordinating Committee (PUCC) Meeting

Halton Hills Hydro meets quarterly with the Town of Halton Hills Engineering and Infrastructure Services Departments, Region of Halton, Union Gas, Bell Canada, Cogeco Cable, and Rogers Communications to discuss ongoing and upcoming project. These meetings allow all parties to discuss planned work and coordinate individual efforts. The PUCC meetings also allow all members to discuss specific concerns that one member may be experiencing and have open conversation about ways to resolve the issue.

Halton Hills Hydro provides PUCC members with quarterly project updates by providing a list of ongoing and upcoming work at each meeting, discussing plans, and answering questions from PUCC members. The utility also uses this opportunity as one of numerous ways to inform third parties whom are attached to utility infrastructure that work will be required of them. PUCC meetings are also an opportunity for Halton Hills Hydro to receive lists and maps from the municipality pertaining to their forecasted work and development. Such information is vital to Halton Hills Hydro's planning and budgeting.

1.2.1.2 Development Review Committee

Halton Hills Hydro participates in the Town of Halton Hills Development Review Committee (DRC) meetings which occur bi-weekly. These meetings are an opportunity for Town, Region, and utility staff to review perspective development, servicing, zoning by-law, and site plan applications. At the DRC meeting Town, Region, and utility staff meet with perspective persons or companies proposing development within the Town of Halton Hills. These meetings are an opportunity for Halton Hills Hydro to review potential development applications before the site plan stage. At this stage, comment can be provided to the Town of Halton Hills and the perspective person or company about what impacts the development may have on the utilities distribution system (if any) and what requirements the applicant will need to consider when they submit an application for service. Comments are provided verbally and in writing. This process is helpful to those developing in the Town of Halton Hills as it provides them with feedback that will enable them to prepare a complete application to the Town. A complete application is circulated to agencies such as Halton Hills Hydro. The utility reviews the application and provides formal comments to the Town of Halton Hills. The DRC meetings do not affect Distribution System Plan investment levels but rather contributes to successfully engaging with current and potential customers.

1.2.1.3 Environmental Assessments

Halton Hills Hydro participates in a number of municipally driven Environmental Assessments (EA). Participation is typically at a reviewer level however comment and feedback is provided to the municipal governments where necessary. Presently Halton Hills Hydro is participating in the following EA consultations and Technical Agency Committee (TAC) meetings:

- Trafalgar Road (Steeles Avenue to Highway 7) – Regionally of Halton.
- 9th Line (Steeles Avenue to 10 Side Road) – Region of Halton.
- Mayfield Road – Region of Peel and Halton.
- GTA West Transportation Study – Ministry of Transportation.

Participating in EA and TAC meetings is important to understand long term forecasting of municipal infrastructure planning which may and often does have impacts on capital plans.

1.2.1.4 Other Town of Halton Hills Initiatives

Halton Hills Hydro works closely with its shareholder, the Town of Halton Hills in supporting a number of town initiatives. Halton Hills Hydro staff sits on the Town Sustainability Committee and the utility is a strong supporter of the Mayor’s Community Energy Plan and the Town Green Plan.

1.2.2 Transmitter Consultations (Hydro One)

Halton Hills Hydro actively consults with its upstream transmitter, Hydro One, with respect to available capacity for renewable generation. In the early days of the IESO Feed-In-Tariff (FIT) program Hydro One introduced a bulk capacity allocation termed Threshold Connection Impact Assessment which has been more recently termed Threshold Allocation Assessment. This allows utilities to apply for bulk capacity from Hydro One for connecting multiple renewable generation projects. Halton Hills Hydro has continuously worked with Hydro One to attain and maintain bulk capacity from Pleasant TS DESN1 for renewable projects. The utility also coordinates the connection with Hydro One’s Ontario Grid Control Center to ensure they are aware of all FIT generators.

1.2.3 Embedded Distributor Consultations (Hydro One – Erin)

Halton Hills Hydro has one embedded distributor, Hydro One, who is supplied 4.8/ 8.32kV from its municipal substation MS #1. Halton Hills Hydro communicates with that distributor to see if they have any upcoming projects or are aware of any developments that may require significant capacity from Halton Hills Hydro. Hydro One has confirmed that they are not aware of any significant load growth or reduction and have no planned projects that would impact Halton Hills Hydro.

1.2.4 Third Party Telecommunication and Street Lighting Company Consultations

Halton Hills Hydro's Engineering staff corresponds regularly with telecommunications companies such as Bell Canada, Cogeco Cable, and Rogers Communications regarding ongoing work.

When Halton Hills Hydro is preparing an infrastructure build, or renewal project, staff circulates the plans to telecommunication and municipal street light companies enabling them to determine if the project will impact them. If an impact is identified, the utility works closely with the affected parties to ensure impacts can be resolved. As an example, where a telecommunication company is attached to poles that are going to be replaced, the HHH advises the company to prepare a transfer design compliant with Ontario Regulation 22/04 "Electrical Distribution Safety". The utility then receives their transfer design, reviews it, and issues a permit for their work. Following issuance of a permit, Halton Hills Hydro monitors their progress and requests a Record of Inspection when their work is complete. Such coordination is helpful as it allows all parties to prepare their work and ensures Halton Hills Hydro meets its regulatory requirements.

In addition, the utility receives and reviews telecommunication and municipal street light company applications for their own projects (ex: new pole attachments, overlashing) and issues a permit for their work. If the third party attacher requires the utility to perform work to enable their project to proceed, Halton Hills Hydro assesses the request and if feasible performs the requested work. Following issuance of a permit, the utility also monitors their progress and requests a Record of Inspection when their work is complete. Such coordination is helpful as it allows all parties to prepare their work and ensure Halton Hills Hydro meets its regulatory requirements.

1.2.5 Customer Engagement

Halton Hills Hydro regularly and proactively engages with customers throughout the year. The utility has 20% of their customers actively following them on Facebook and Twitter. On these platforms, customers receive regular updates regarding the utility, the industry and initiatives to benefit them as well as information on planned and unplanned outages. Customers engage in an ongoing dialogue with the utility about its quality of service on these sites.

Halton Hills Hydro looks for opportunities throughout the year to engage with customers at events in the community. In attending these events, the utility is able to reach customers who otherwise wouldn't regularly interact with the utility. Halton Hills Hydro is at an average of 20 community events throughout the year. Some of these events are: Earth Day Eco Fair, Georgetown Big Daddy Festival, Acton Leathertown Festival, Acton and Georgetown Fall Fairs, Acton and Georgetown Santa Claus Parades, Acton and Georgetown Farmers Markets, Canada Day in Glen Williams and other events throughout the year. Staff throughout the organization participates in these events providing customers a chance to interact directly with their utility.

In preparing this Distribution System Plan, Halton Hills Hydro engaged directly with customers through telephone and online surveys and through customer focus groups. Customers were asked questions related to power outages and restoration as well as questions related to operating and capital expenses. Customer preferences regarding equipment replacement strategies and spending priorities were sought. 426 customers participated in the telephone survey and 930 customers participated in the online survey. The combined results produce a margin of error of +/- 2.6%, 19 times out of 20. Seven commercial customers participated in a focus group session, while 20 residential customers participated in a focus group session. The primary purpose of the focus groups was to gain a better understanding of the issues around Operational and Capital expenses. Details of the survey and focus group results are outlined in Appendix I.

1.2.6 Regional Planning Process (5.2.2.b)

Halton Hills Hydro’s service territory spans two regional planning zones; the Northwestern Sub region of the GTA West Region and also to the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Planning activity for the GTA West Region is in the Integrated Regional Resource Planning phase of the process. Two transmission projects have been identified to address the near- and medium-term needs in this Region: the Halton Hills Hydro MTS project, and reinforcement of 230kV circuits H29 and H30 that supply Pleasant TS. Work on the first project is already underway, led by Halton Hills Hydro. As the earliest need for the second project is not until 2023, the study team will monitor the load growth and reassess this issue during the next regional planning cycle. The IESO IRRP report recommends the construction of the Halton Hills Hydro Transformer Station as the least-cost option for serving growth within Halton Hills.

Planning activity for the KWCG region is also in the Integrated Regional Resource Planning Phase. Two transmission projects have been identified to address the near- and medium-term needs in this Region: the first being the Guelph Area Transmission Reinforcement (“GATR”) project, and the second being the installation of switches on circuits M20D and M21D. Execution of the first project is already underway while the second in the project development phase. Halton Hills Hydro is an embedded LDC in this Region and is also served by Fergus TS. Halton Hills Hydro has recently expressed concerns regarding load growth and single supply reliability to Acton from Fergus TS feeder M4. This is primarily a distribution planning activity and Halton Hills Hydro and Hydro One Distribution have agreed to assess and develop a plan to address these reliability concerns. Ultimately, this may result in some distribution investments for Halton Hills Hydro.

Halton Hills Hydro was active in the NW Sub Region of the GTA West Region as a direct group participant and attended group meetings to provide input to the plan. The Northwest Greater Toronto Area Integrated Regional Resource Plan (NWGTA Region IRRP Report) published April 28, 2015 states in section 7.2.2 that: Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.

Presently, Halton Hills Hydro is proceeding with the detailed design of a new Transformer Station in 2015 in accordance to the recommendation of the IRRP report.

Halton Hills Hydro also falls within the KWCG region group, Since Halton Hills Hydro is embedded to Hydro One Distribution in this group's area, HHH did not participate as a core member. Rather Halton Hills Hydro is working with Hydro One Distribution directly to ensure distribution needs are met in Halton Hills.

The Final IESO IRRP Report for the NW Sub Region of the GTA West Region is attached as Appendix B of this document. The Regional Planning Status letter from Hydro One is attached as Appendix C of this document.

1.2.7 Commitment letter from IESO in relation to REG investments included (5.2.2 c)

Halton Hills Hydro received a Letter of Comment from the IESO with respect to our Renewable Energy Generation Investments for 2016-2020. The letter, dated March 6, 2015, is included as Appendix D.

The letter states that "The renewable energy generation connections information in Halton Hills Hydro's Plan is therefore reasonably consistent with that of the IESO."

1.3 Performance Measurement for Continuous Improvement (5.2.3)

Halton Hills Hydro strives for continuous improvement in all aspects of the organization. As such, the utility has a number of processes and metrics in place to monitor performance. These metrics review planning from a number of perspectives: Customer oriented performance, cost efficiency and effectiveness and system performance.

1.3.1 Identify and define metrics used to monitor system planning process performance (5.2.3 a)

Halton Hills Hydro has established an Enterprise Risk Management Framework. This framework was developed in 2012 and provides a risk-based approach to strategic planning and decision making. Effective risk management is supported by consistent monitoring, communication and reporting of those risks that might have a material impact on operations, financial performance, regulatory compliance and the reputation of Halton Hills Hydro. Risk management has been incorporated into the corporation's strategic and business planning processes and support major decisions made by senior management and the Board of Directors.

The diagram below provides an overview of risk based planning and decision making at Halton Hills Hydro:

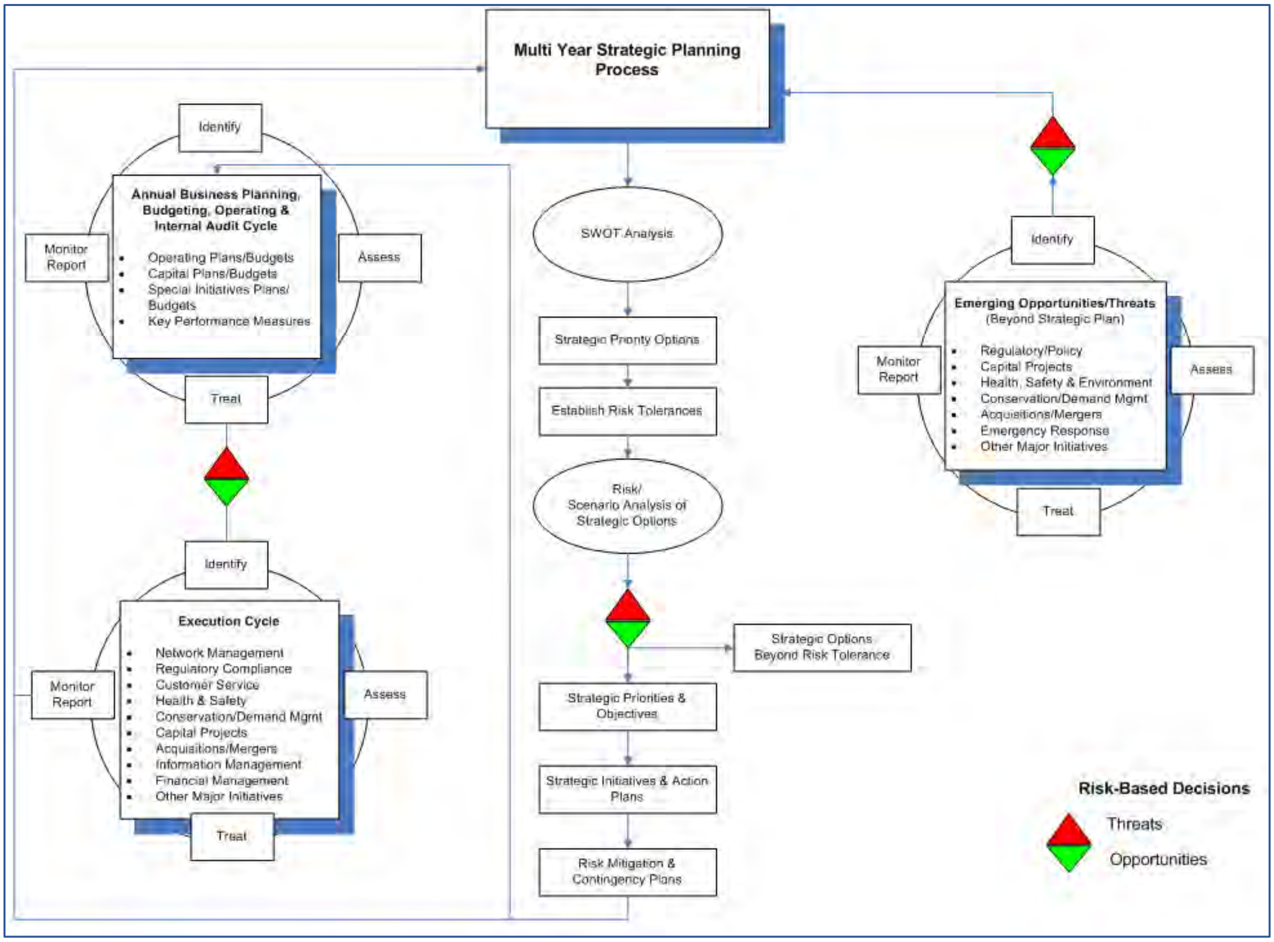


Figure 5 Multi-Year Strategic Planning Process

This risk process is built into the utility's strategic planning process. Business plans at the corporate level and at the department level identify key risks and mitigations strategies.

The corporate risk register is reviewed and updated on a quarterly basis by the management team with changes reported to the Halton Hills Hydro Board of Directors.

Another way Halton Hills Hydro monitors performance is through the OEB Scorecard. Using this tool, Halton Hills Hydro is able to monitor performance in each of the key areas identified by the Ontario Energy Board. Fig. 6 below is the most recent scorecard available at the time of filing this Distribution System Plan.

									Target	
Performance Outcomes	**Performance Categories**	**Measures**	**2009**	**2010**	**2011**	**2012**	**2013**	**Trend**	**Industry**	**Distributor**
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time	99.70%	99.20%	96.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time	85.60%	86.20%	85.50%	87.70%	83.20%		65.00%	
	Customer Satisfaction	First Contact Resolution								
		Billing Accuracy					99.91%			
		Customer Satisfaction Survey Results					93%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]								
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	1.75	1.78	1.38	1.23	2.08			at least within 1.23 - 1.78
		Average Number of Times that Power to a Customer is Interrupted	1.22	2.75	1.49	1.34	1.48			at least within 1.22 - 2.75
	Asset Management	Distribution System Plan Implementation Progress					On-track			
	Cost Control	Efficiency Assessment				1	1			
		Total Cost per Customer [See Note below]	$611	$622	$647	$684	$642			
		Total Cost per Km of Line [See Note below]	$9,441	$9,208	$9,382	$9,542	$9,034			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved)			17.00%	15.00%	22.90%			6.15MW
		Net Cumulative Energy Savings (Percent of target achieved)			33.00%	61.00%	72.20%			22.48GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.31	1.15	1.69	1.25	1.06			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.83	0.91	0.87	0.90	1.04			
		Profitability: Regulatory Return on Equity — Deemed (included in rates)			8.57%	9.12%	9.12%			
		Profitability: Regulatory Return on Equity — Achieved			9.14%	13.30%	14.97%			

Scorecard - Halton Hills Hydro Inc. 9/2/2014

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

Note
These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.

Figure 6 OEB Scorecard 2014

Halton Hills Hydro has an innovative health and safety program through a partnership with Springboard Management that provides policy and procedure awareness for all staff, ongoing training and also management of contractor safety.

As a part of this safety program, Halton Hills Hydro has implemented an online system to track employee compliance. Areas tracked include ensuring employees have read all policies, taken any required tests, maintained appropriate certification and are competent in the training received. Figure 7 below shows the compliance dashboard used to monitor safety performance.

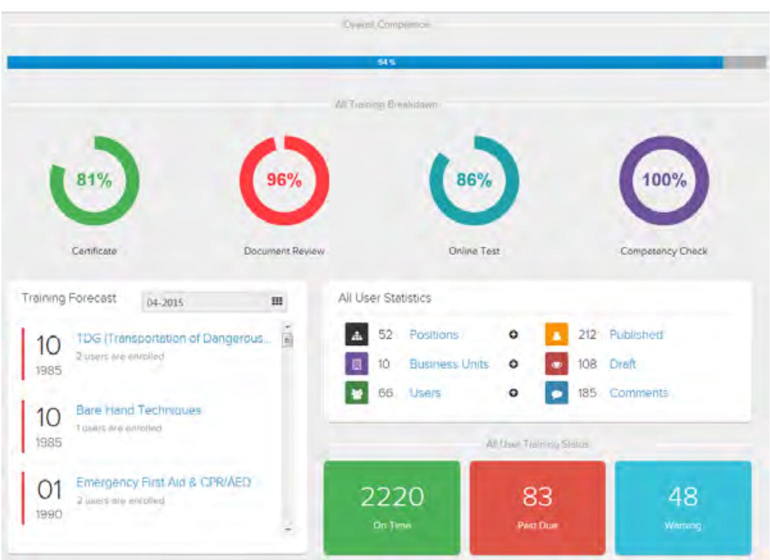


Figure 7 Safety Compliance Dashboard

1.3.1.1 Supply Voltage Metrics

Halton Hills Hydro strives to provide its customers with a consistently reliable supply of power. This is done by supplying voltage at our customers' service entrance within the tolerances of CAN/CSA C235-83 "Preferred Voltage Levels, 0 – 50,000V", Table 3 provided below.

Nominal System Voltages	Voltage Variation Limits Acceptable at Service Entrances			
	Extreme Operating Conditions			
Single Phase		Normal Operating Conditions		
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three-Phase				
4-Conductor				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/388	250/432	254/440
227/480Y	245/424	254/440	288/500	293/508
347/600Y	306/530	318/550	360/625	367/635
Three-Phase				
3-Conductor				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

Table 1 CAN/CSA C235-85

The above table is replicated from CAN/CSA C235-83 and prescribes the acceptable voltage variations and operating conditions a utility must supply at the customers service entrance. When a customer contacts Halton Hills Hydro with concerns about the quality of their supply voltage, the utility installs a voltage monitoring device at the customer's service entrance to assess the quality of supply voltage. Where the voltage deviates outside the band of normal operating conditions but remains within the band of extreme operating conditions Halton Hills Hydro makes improvements or takes corrective action on a planned and programmed basis. Where the supply voltage deviates outside of the band of extreme operating conditions Halton Hills Hydro takes corrective action as soon as possible.

Halton Hills Hydro works to maintain the quality of supply voltage. Where Halton Hills Hydro can safely install a voltage monitoring device to assess the quality of supply, the utility continues to do so in an effort to help customers and ensure the quality of supply is consistent with CAN/CSA C235-83. While Halton Hills Hydro makes every effort to deliver power within normal operating conditions, variation in voltage resulting from external forces such as operating practices of an upstream distributor or transmitter, exceptionally high loads, and severe weather conditions can impact power quality. Halton

Hills Hydro strives to maintain zero (0) instances of voltage variations outside of the band of extreme operating conditions and five (5) or less instances per year of voltage variations outside of the band of normal operating conditions but within the extreme band. A customer contacting Halton Hills Hydro with a voltage complaint does not constitute a voltage issue until Halton Hills Hydro has installed a voltage monitoring device and verified the complaint.

1.3.1.2 Power Quality Metrics

Halton Hills Hydro strives to provide its customers with a reliable and safe supply of power that is free of power quality problems. When a customer contacts Halton Hills Hydro to report a power quality problem, the utility installs a power quality monitoring device at the customers service entrance, or as close as possible to the service entrance, if safe to do so. Depending on the type of service and location of installation Halton Hills Hydro can monitor voltage, current, harmonics, voltage sag/ swell, transients, demand, and other power quality factors. A report is provided to the affected customer that summarizes the reported problem, the findings of the power quality survey, corrective actions and recommendations. Halton Hills Hydro strives to have less than five (5) power quality related issues annually.

1.3.2 Summary of performance and trends over the historical period (5.2.3 b)

The graphs below reflect Halton Hills Hydro's SAIDI, CAIDI and SAIFI statistics over the past 6 years. Statistics including loss of supply and excluding loss of supply are displayed together for ease of comparison.

1.3.2.1 System Average Incident Duration Index

The first figure and table below show the utility's system average incident duration index statistics.

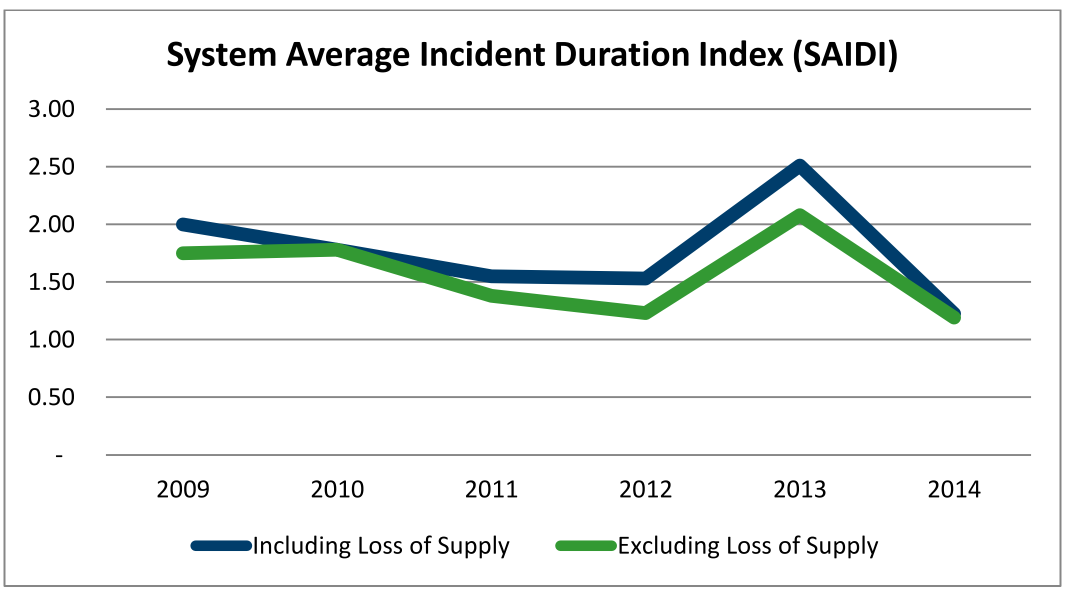


Figure 8 System Average Incident Duration Index

In 2013, Halton Hills Hydro experienced three major weather events. There was an ice storm in April of that year, a severe thunder storm in July and then the significant Ice Storm in December of 2013. These three events each caused significant storm damage and resulted in the high SAIDI numbers for that year.

As can be seen from the table below, aside from the unusual weather events in 2013, these statistics have been steadily improving over the past 6 years.

SAIDI – System Average Incident Duration Index (Hours)		
	Including Loss of Supply	Excluding Loss of Supply
2009	2.00	1.75
2010	1.78	1.78
2011	1.55	1.38
2012	1.53	1.23
2013	2.51	2.08
2014	1.25	1.21

Table 2 SAIDI statistics

1.3.2.2 Customer Average Incident Duration Index

The figure and table below show the customer average incident frequency index.

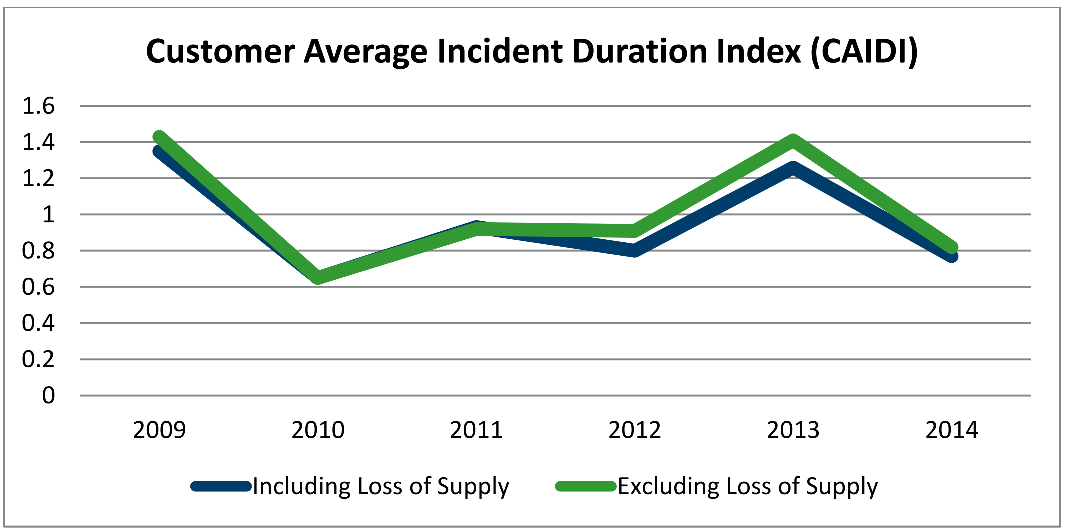


Figure 9 Customer Average Incident Duration Index

As can be seen by Figure 8 and table 3, the customer average incident frequency index was affected by three severe weather events in 2013 as identified in the system average incident duration index section. Even with these events, the utility has maintained a 99.989% reliability average over the past five years, representing slightly less than an hour per customer per year.

CAIDI – Customer Average Incident Duration Index (Hours)		
	Including Loss of Supply	Excluding Loss of Supply
2009	1.35	1.43
2010	0.65	0.65
2011	0.93	0.92
2012	0.8	0.91
2013	1.26	1.41
2014	0.77	0.82

Table 3 CAIDI statistics

1.3.2.3 System Average Incident Frequency Index

In 2010, the utility experienced an abnormally high number of feeder trips in February of that year. While these incidents were brief in duration, they affected our system average incident frequency index. Aside from the incidents in February of 2010, our SAIFI statistics have remained fairly consistent over the past few years.

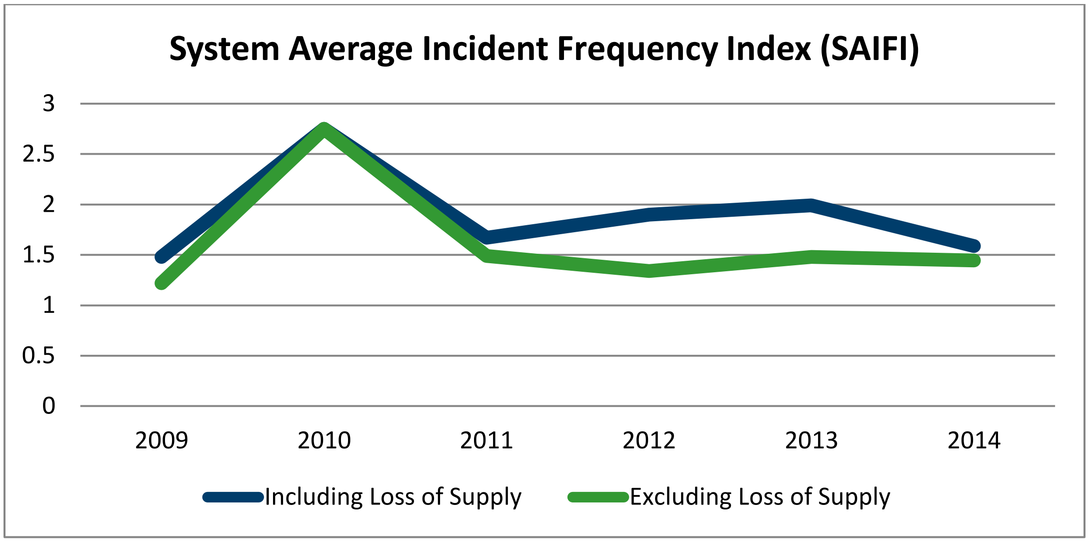


Figure 10 System Average Incident Frequency Index

SAIFI – System Average Incident Frequency Index (Incidents)		
	Including Loss of Supply	Excluding Loss of Supply
2009	1.48	1.22
2010	2.75	2.75
2011	1.67	1.49
2012	1.9	1.34
2013	1.99	1.48
2014	1.61	1.47

Table 4 SAIFI statistics

1.3.2.4 Power Quality Complaints 2010 - 2014

Halton Hills Hydro has established and maintains a database that tracks customer complaints of poor power quality factors. This database is used to log the customer information, service information, the problem being reported and devices being affected. When a customer contacts Halton Hills Hydro to report a power quality disturbance and prior to a power quality monitoring device being installed a log is entered into our database and is used as an administrative tool to track the issue. The following pie charts represent the percentages of reported problems from 2010 to 2014 (most recent displayed first).

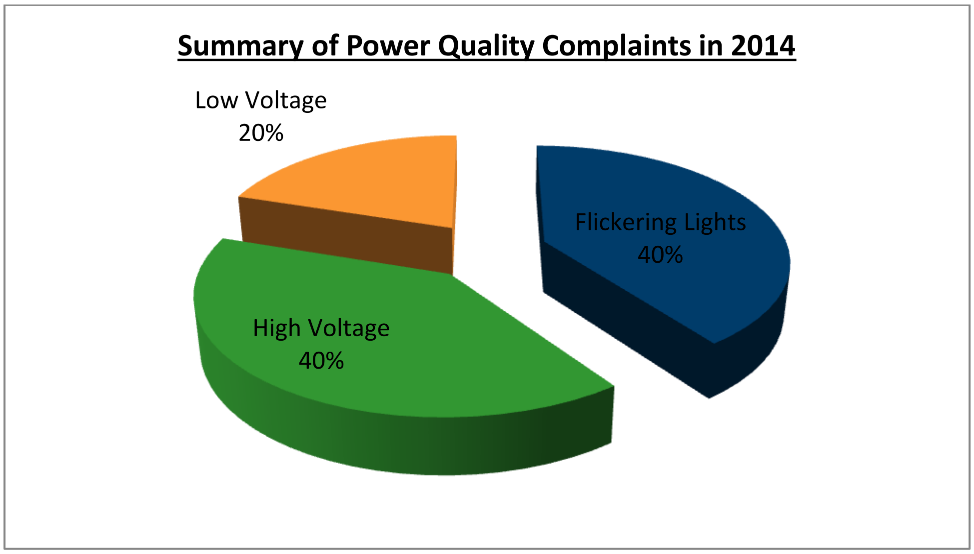


Figure 11 Power Quality Complaints 2014

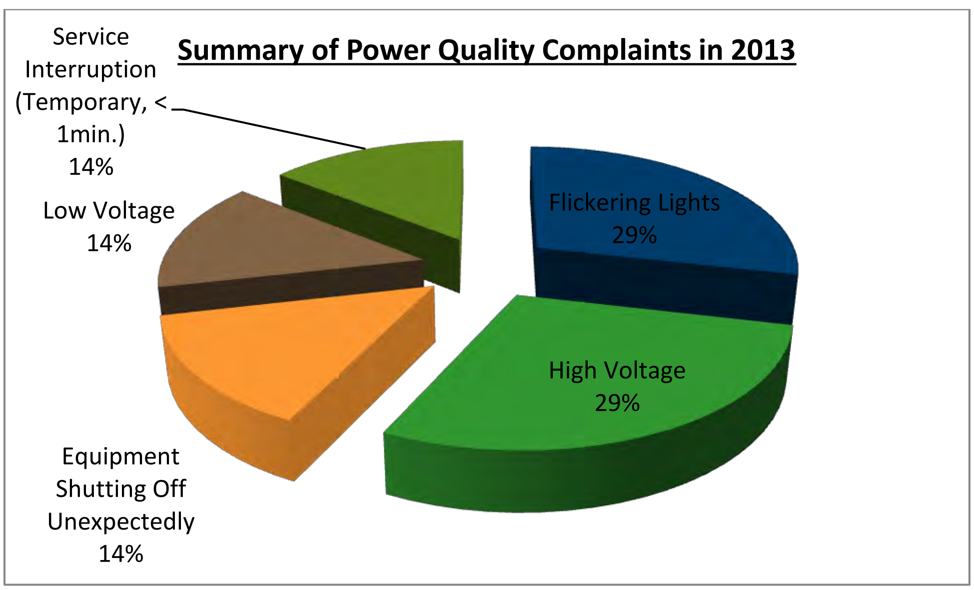


Figure 12 Power Quality Complaints 2013

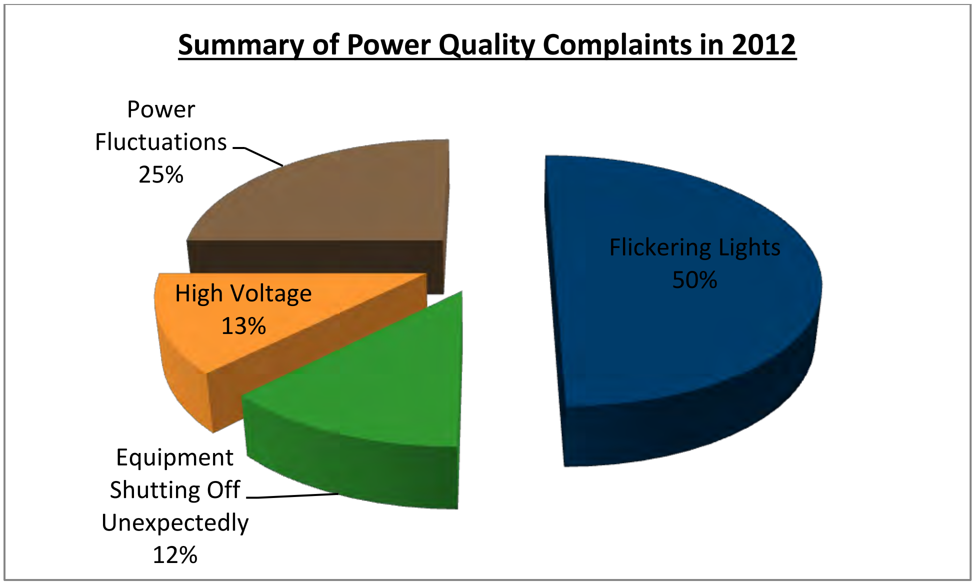


Figure 13 Power Quality Complaints 2012

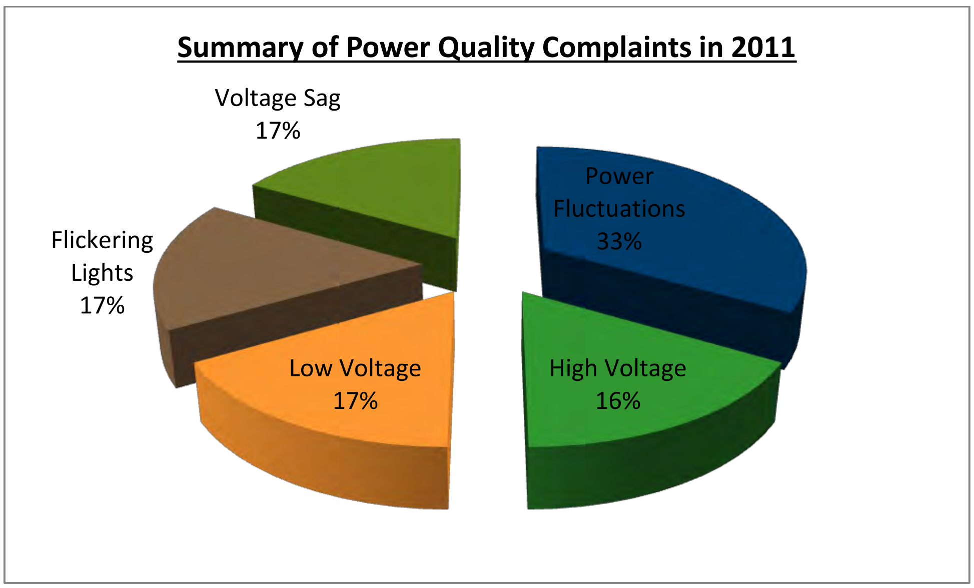


Figure 14 Power Quality Complaints 2011

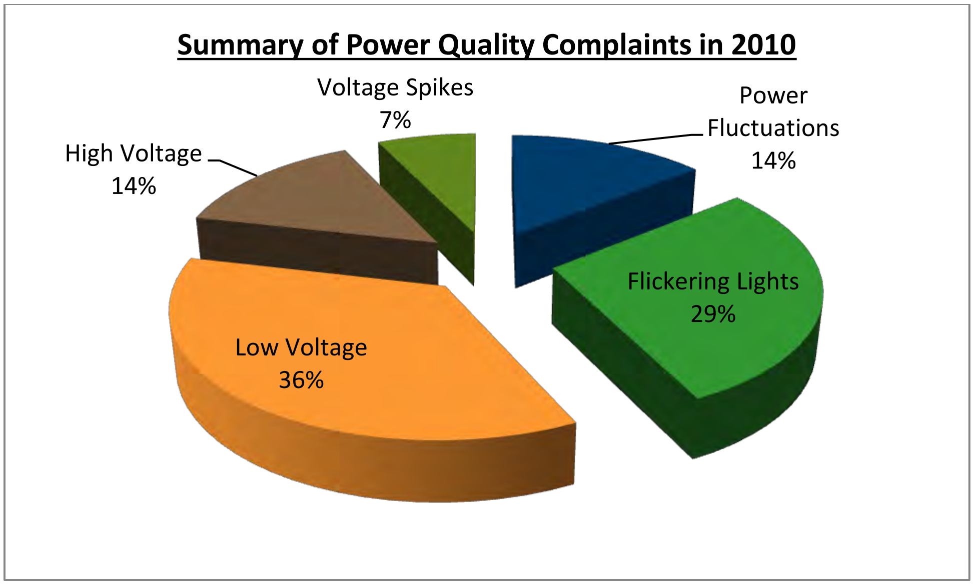


Figure 15 Power Quality Complaints 2010

Power Quality Issue Reported	2010	2011	2012	2013	2014	Totals by Issue
Flickering Lights	4	1	4	2	2	13
High Voltage	2	1	1	2	2	8
Low Voltage	5	1		1		7
Service Interruption (Temporary, <1 min.)				1		1
Equipment Shutting Off Unexpectedly			1	1		2
Voltage Sag		1				1
Power Fluctuations	2	2	2			6
Voltage Spikes	1					1
Totals by Year	14	6	8	7	4	

Table 5 Power Quality Issues by Year

Since 2011 Halton Hills Hydro has received an average of 5 calls per year from customers to report power quality problems where a power quality monitoring devices was installed. The category chosen by hydro staff when logging a complaint (ex: Voltage Spikes, Low Voltage, etc.) are determined based on what information the customer reports. As can be seen from the charts above, reported power quality issues have for the most part decreased over the past 5 years however it should be noted that in many cases, a reported power quality problem does not necessarily mean there is a problem with respect to the distribution system but may rather indicate contributing factors downstream of the service entrance. In all cases Halton Hills Hydro works closely with our customers to identify a reported problem and remedy the issue as part of our commitment to providing our customers with electricity distribution excellence.

1.3.3 Continuous Improvement

Explain how this information has affected the Distribution System Plan and has been used to continuously improve the asset management and capital expenditure planning process. (5.3.2 c)

1.3.3.1 Power Quality

Power quality issues reported in this DS Plan are customer reported issues for which Halton Hills Hydro can provide a power quality monitoring device to monitor the quality of power at the customer's service entrance. Halton Hills Hydro has not identified any specific areas where asset renewals or capital expenditures would reduce the number of reported problems and therefore has not attributed any asset renewal or system service projects contained in this DS Plan to power quality related issues. Some system service projects contained in this DS Plan address system constraints and operational challenges which will increase system reliability during peak demand periods and enable increased flexibility to operate the distribution system and not affect the deliverance of electricity.

2 Asset Management Process (5.3)

This section details Halton Hills Hydro's strategy for optimizing ongoing capital and operating and maintenance expenditures on its distribution system and general plant.

2.1 Asset Management Process Overview (5.3.1)

2.1.1 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 (5.3.1 a)

Halton Hills Hydro's mission statement is: "To provide Halton Hills with electricity distribution excellence in a safe and reliable manner." It is supported by the following corporate objectives: Safety, Reliability, Competitive Rates, Financial Metrics, Conservation, Environmental, Community Focused, Smart Grid Implementation.

These objectives form the basis for the asset management process and influence the entire Distribution System Planning process.

Halton Hills Hydro's first priority in asset management is safety for staff, customers and the general public. Safety comes ahead of all other priorities in the planning process. Reliability, competitive rates, financial metrics, conservation, environment, and community focus all play into the planning processes. The utility's Asset Maintenance Process is built on a foundation of ensuring a reliable and sustainable distribution system in a cost efficient manner.

This Distribution System plan strikes a balance between maintenance and replacement costs. Certain assets are only replaced when it becomes more expensive to keep them in service while others may be upgraded to accommodate growth or enable smart grid. The system asset review looks at condition based assessments of assets rather than strictly an age based replacement program.

2.1.2 Information regarding the components (inputs/outputs) of the asset management process used to prepare the capital expenditure plan. (5.3.1 b)

2.1.2.1 Asset Register

Halton Hills Hydro's Asset Register is their ESRI Geographical Information System (GIS) and associated databases. This register stores the information and technical characteristics for all assets, including their location, history and performance.

2.1.2.2 Asset Condition Assessment

Halton Hills Hydro's annual program for pole testing records a variety of factors relating to the condition of the pole including a determination of each poles overall condition. The condition ratings are good, fair, fair-to-poor, and poor.

Pole Condition	Comments
Good	Cracks, slight rot or feathering.
Fair	Cracks, mechanical damage, surface rot at/ below ground line, moderate rot, pole top feathering/ split.
Fair-Poor	Cracks to ground line, mechanical damage moderate to extensive rot/ decay, pole top feathering/ split.
Poor	Cracks, mechanical damage, extensive damage, rot, and decay at ground line, internal and external decay pockets.

Table 6 Condition Categories for Wood Poles.

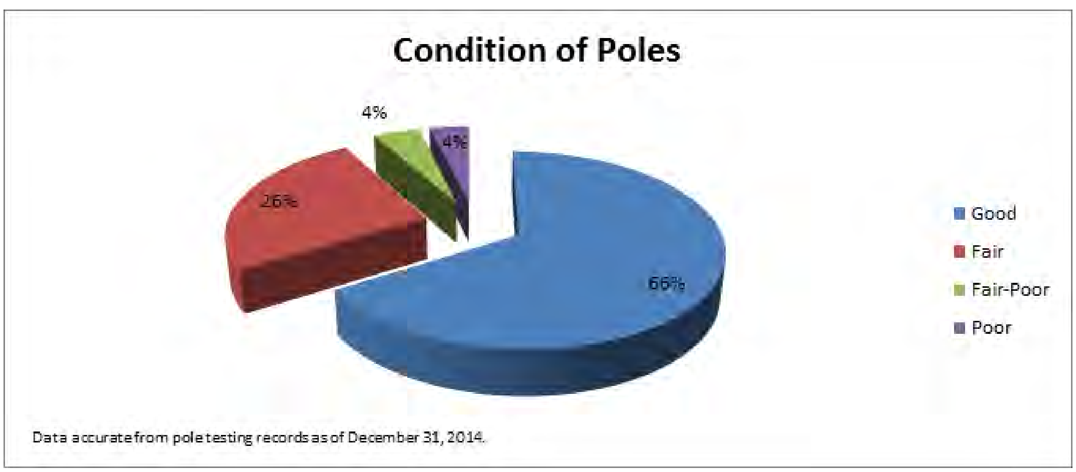


Figure 16 Condition Assessment of Wood Poles owned by Halton Hills Hydro.

The condition assessment is reflective of the state of the utility poles and the worst performing poles, usually identified as requiring replacement during annual testing, are marked, work orders are prepared, and the poles are replaced in the same year as the testing. Pole testing drives a portion of Halton Hills Hydro's annual capital expenditures relating to removing vintage and defective assets from service before they fail.

Further details with respect to Halton Hills asset assessments are detailed in the Asset Management Plan SP14-03 contained in appendix A.

Municipal Substations are inspected on a monthly basis. Checklist items include feeder loading, physical equipment condition noting deterioration or damage, vegetation creep, security status, any tank leakage. Power transformers are evaluated on the basis of age, loading and oil data. This asset is normally proactively replaced taking careful attention to each of the evaluation factors. Switchgear are evaluated on the basis of age, breaker types and future requirements. Evaluation of these factors also enables proactive replacement

Substation Feeder loading is periodically reviewed to ensure adequate reliability, efficiency and capacity to enable proper maintenance outages and ensure capacity for new customer connections

2.1.2.3 Asset capacity utilization/constraint assessment

Feeder peak demand loading at each of the twelve HHH owned municipal substations is recorded on a monthly basis and is periodically reviewed to determine capacity of existing feeders and the ability to connect future load and maintain suitable loading levels for reliability. For this planning cycle the peak demand loading for the last five years was averaged to complete an overall assessment on the feeder capacity in order to identify possible constraints.

2.1.2.4 Historical data on customer interruptions caused by equipment failure

Halton Hills Hydro maintains an historical record of power outages by cause. The graph in Figure 17 below represents the percentage of power outages caused by equipment failure over the five year period from 2010 to 2014.

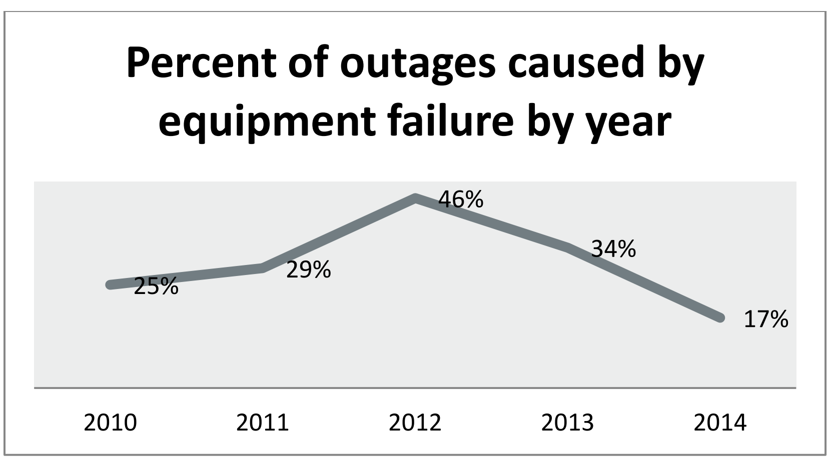


Figure 17 Power Outages by Equipment Failure

As can be seen from this graph, outages caused by equipment failure spiked in 2012. This was due to a single incident caused by porcelain insulator failure.

On February 21, 2012 at 3:01pm Halton Hills Hydro experienced a significant porcelain insulator failure. Forty-Four (44) Customers along Hwy 7, Dublin Line and Turtle Lake Drive experienced a voltage surge when an insulator on our 44kV circuit (73M04) sheared off and dropped onto our 4.8kV single phase (5F1 – red phase) under-build. The momentary contact between these two conductors allowed a higher than normal voltage "spike" to travel along our 4.8kV system adversely affecting all customers connected to it. This equipment failure is expected to have happened due to the age of the equipment and visible, hairline cracks that can be seen along the edge of the broken porcelain. No other outside forces acted on this equipment such as weather or impact on the pole or equipment. We received calls from affected customers describing sparks coming from the electrical receptacles in their homes, a burnt electrical smell as well as popping and cracking noises coming from connected appliances and equipment. All customers that contacted Halton Hills Hydro describing issues related to the voltage surge were given the recommendation to contact an electrician to determine if there were any issues within their homes that needed to be addressed and to contact Halton Hills Hydro to determine what the next steps will be to replace or repair equipment damaged during this event. Halton Hills Hydro filed an insurance claim in the amount of $57,000 with The Mearie Group.

As a direct result of this incident, Halton Hills Hydro has implemented an active porcelain insulator and switch replacement program. As a result, outages caused by equipment failure have dropped significantly.

Halton Hills Hydro does not currently apply a specific reliability based "worst performing feeder" analysis as part of their asset management process. However, the utility does investigate suspected worst performing feeders on a case by case basis. These suspect cases are found by recorded feeder trips logged on our SCADA system (not all feeders are presently monitored by SCADA) and by customer inquiries. The utility is presently considering the implementation of a system wide process.

2.1.2.5 Reliability risk/consequence of failure analysis

Each of the Municipal Substations is comprised of a single power transformer and associated switchgear. In the event of a single component failure, the remaining substations would be expected to service the load of the failed substation. For planning purposes a high level single equipment failure (eg. Power transformer) assessment is necessary.

2.2 Overview of Assets Managed (5.3.2)

This section provides detailed characteristics of Halton Hills Hydro's service territory, system configuration and assets managed. These details provide an important foundation for understanding Halton Hills Hydro's asset management and investment strategy.

2.2.1 Description of distribution service area (5.3.2 a)

Halton Hills Hydro's service territory covers 280 square kilometers. 255 sq. km of the territory is rural and the remaining 25 sq. km is urban.

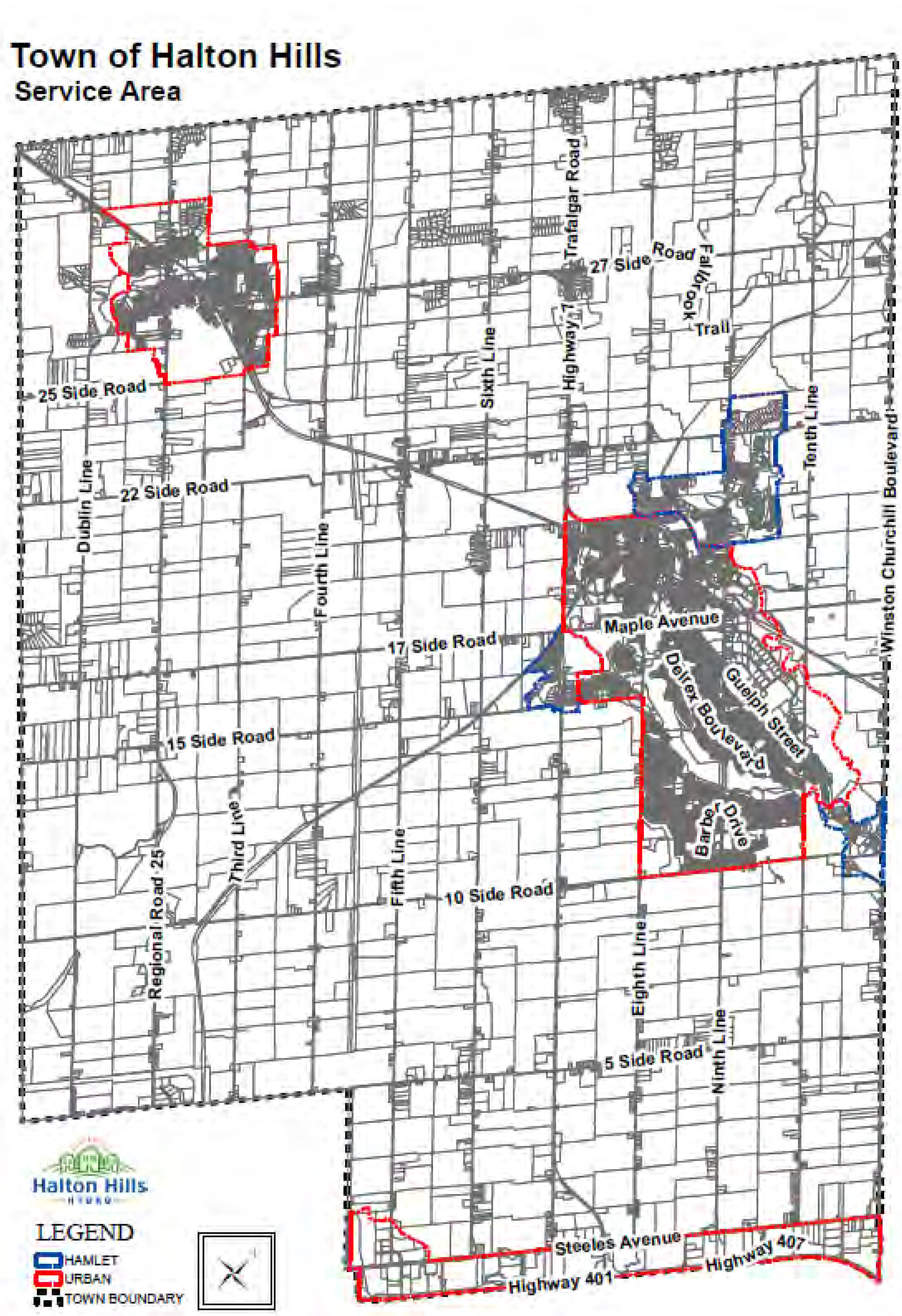


Figure 18 map of urban and rural service territory

The climate in the Town of Halton Hills is defined as Dfb or “Warm Summer Continental Climate” in the Köppen climate classification system. There are two distinct climate zones separated by the Niagara Escarpment which runs through our territory. A significant portion of the rural area is located within the provincial Greenbelt. The territory also forms part of three watersheds: to the west of Acton, a small area flows toward the Grand River, the northern half flows into the Credit River, including the Black Creek and Silver Creek tributaries and the southern half flows into the Sixteen Mile Creek. Above the Escarpment, a large portion of the rural area is classified as environmentally sensitive wetlands. Extreme minimum temperature recorded at -30°C and extreme maximum of 38°C with average temperatures between 4.9°C and 20.7°C. Precipitation ranges from 44.2mm to 78.5mm seasonally. The geology of the area can pose challenges in certain areas due to the presence of the Niagara Escarpment. In particular, the west and north east portions of Halton Hills Hydro’s service territory require specialized equipment to excavate due to an overburden as deep as two feet with rock or shale below. This specialized equipment can increase project costs in those areas.

2.2.2 Summary description of system configuration (5.3.2 b)

Halton Hills Hydro’s electricity distribution network serves 22,000 households and businesses with 1,527 kilometers of medium- and low-voltage distribution circuits that transport electricity from the provincial transmission grid. The distribution system delivered 520,068,501 kilowatt-hours of energy in 2013 and serviced a summer peak demand of 111,279 kW.

The HHH service area is supplied by seven feeders from three Hydro One Transformer Stations at 44kV which is subsequently stepped down to 27.6 kV and 4.16 kV(other system voltages) through a network of municipal substations to feed the 22,000 customers in the service area.

Halton Hills Hydro’s distribution system is made up the following major components:

- Total kilometers of line: 1527
  - Overhead circuits: 890
  - Underground circuits: 637
- Halton Hills Hydro has 12 Municipal substations with nameplate capacities as indicated in Table 7 below. Stations with dual ratings have cooling fans on the radiators to boost capacity:

Halton Hills Hydro Municipal Substations

Municipal Substation	Nameplate Capacity
Ballinafad MS1	5 MVA
Willow MS3	5 MVA
Silver Creek MS5	5 MVA
Beardmore MS 7	5 MVA
Queen MS 9	5 MVA
Glen Williams MS11	10/13.3 MVA
Cross MS13	10 MVA
River MS15	10/13.3 MVA
Mountainview MS17	10/13.3 MVA
Armstrong MS19	10/13.3 MVA

Norval MS21	5 MVA
Ashgrove MS23	5 MVA

Table 7 Halton Hills Hydro Municipal Substations

2.2.3 Asset Information (5.3.2 c)

Information on the quantity, age and capability of existing assets is essential to understand and effectively manage the asset base. The asset register, Halton Hills Hydro's ESRI geographical information system (GIS) and associated databases store information and technical characteristics for all assets, including their location, history and performance.

Information regarding Halton Hills Hydro's major assets, including useful lives and quantities is summarized below. This information is detailed in Appendix A and was compiled between 2007 and 2014. All assets are inspected in compliance with the minimum requirements outlined in Appendix C of the Ontario Energy Board's Distribution System Code. Further detail of our inspection practices are outlined below.

Details of Halton Hills Hydro's assets can be found in the Engineering Report SP14-03, Multi-Year Electricity Distribution System Asset Management Plan: 2016-2020, which can be found in Appendix A. This document was prepared in 2014 and 2015.

2.2.3.1 Overhead Distribution System

Halton Hills Hydro owns and maintains 890 km of overhead distribution system. The major components of the overhead distribution system and their useful lives are provided below.

Useful lives of overhead distribution system equipment in Years	
Wood distribution pole	**50**
Transformers	**40**
Reclosers	**40**
Switches	**40**
Voltage Regulators	**40**
Conductors	**50**

Table 8 Useful lives of overhead distribution system equipment.

2.2.3.1.1 Wood Distribution Poles

Wood Distribution Poles	
Useful Life:	50 Years
Quantity in Service:	8780
Asset Management Strategy:	Conditional Testing

Conditional testing methodology complements visual observation and includes sounding the pole at various heights, sonic stress wave evaluation and Resistograph™ testing. As specified in Halton Hills

Hydro's Pole Testing & Inspection Procedure (appendix E), the utility tests 1200 poles annually. The data from the pole testing is maintained in the utility's asset database.

Examples of Carpenter Ant Damage

Example of Severe Ground-Line Decay

Figure 19 Examples of Pole Damage

Within CSA Standard C22.3 No 1, Overhead Systems, clause 8.3.1.3 stipulates that "When the strength of a structure has deteriorated to 60% of the required capacity, the structure shall be reinforced or replaced." The results of the in-situ non-destructive evaluation methods described above are used as the criteria for "field marking" wood distribution poles for subsequent replacement.

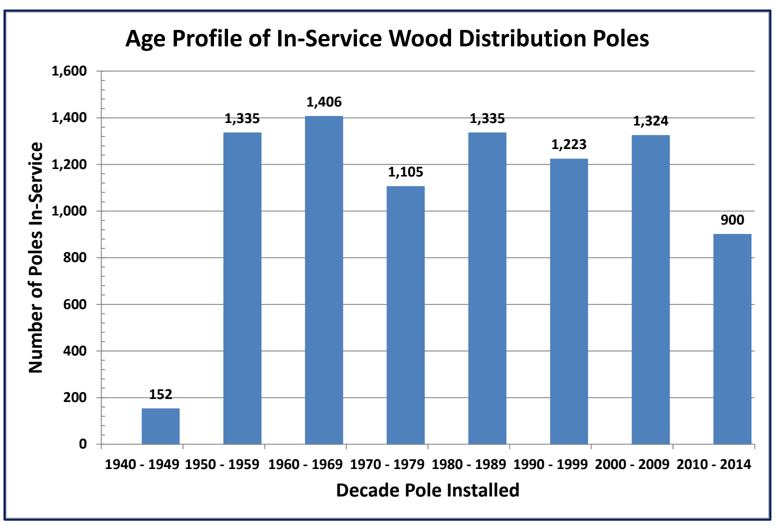


Figure 20 Age Distribution of In-Service Wood Distribution Poles

As can be seen in the graph above, Halton Hills Hydro has 1400 poles exceeding their 50 year expected lifespan and an additional 1400 poles approaching end of life. Given this age profile, Halton Hills Hydro has implemented an accelerated pole replacement program targeting 275-280 distribution poles each year for the next ten years.

In addition to assessing the age of the poles, Halton Hills Hydro also tracks pole condition and has evaluated all poles based on the following condition rating:

Pole Condition	Comments
Good	Cracks, slight rot or feathering.
Fair	Cracks, mechanical damage, surface rot at/ below ground line, moderate rot, pole top feathering/ split.
Fair-Poor	Cracks to ground line, mechanical damage moderate to extensive rot/ decay, pole top feathering/ split.
Poor	Cracks, mechanical damage, extensive damage, rot, and decay at ground line, internal and external decay pockets.

Table 9 Pole Condition Rating

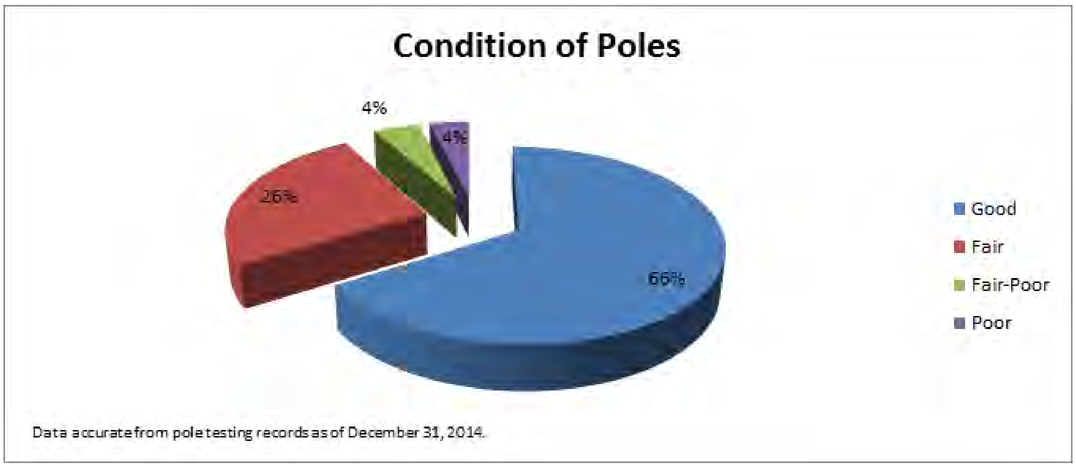


Figure 21 Pole Condition

As can be seen from the chart below, 34% of Halton Hills Hydro poles have some level of damage or wear.

In certain circumstances, where feasible, the utility undertakes a cluster approach to pole replacements whereby all the poles on a street are replaced rather than spot replacing individual poles. This impacts capital spending but allows for upgrading and modernizing of equipment at the same time as the pole is replaced.

Prioritization for planned pole replacements follows the following methodology:

- Age and Condition of the Pole: Known age compared to useful life and condition of the pole based on pole testing results is the first criteria considered to identify poles eligible for replacement.
- Proximity to public spaces: The proximity of the pole to gathering places such as a pole located adjacent to a school or recreation facility has a higher priority than a pole in a rural area.

- Highest Voltage on pole: Poles carrying a 44 kV sub-transmission feeder has a higher priority than a pole that supports only a low-voltage overhead bus.
- Impact on System Reliability: A pole carrying backbone distribution circuits has a higher priority than a pole that supports fused lateral circuits.
- Other Factors and Opportunities: If there is an opportunity to carry out a voltage conversion project or other modernization effort in conjunction with the pole replacements, these poles will be assigned a higher priority than otherwise would have been the case.

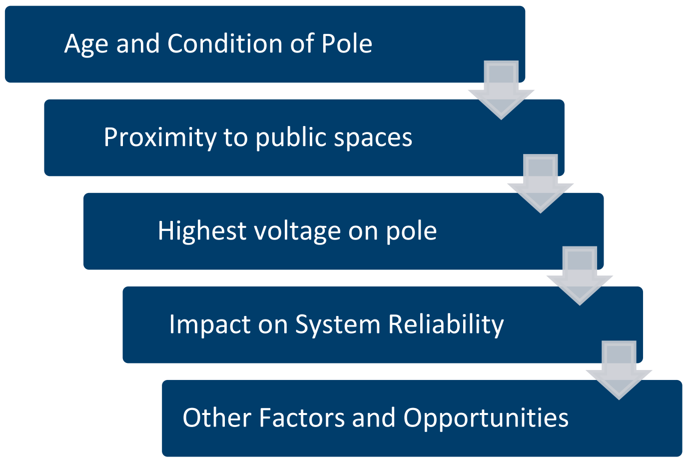


Figure 22 Pole Replacement Prioritization Process Flow

2.2.3.1.2 Pole Mounted Distribution Transformers

Pole Mounted Distribution Transformers	
Useful Life:	40 Years
Quantity in Service:	2420
Asset Management Strategy:	Run to Failure

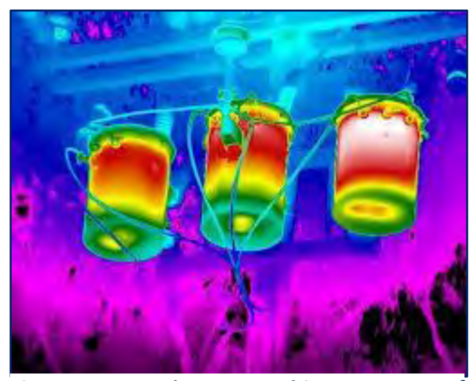


Figure 23 Thermo-graphic Image of Distribution Equipment

Halton Hills Hydro has 948 pole mounted transformers in service exceeding their expected 40 year lifespan. Pole mounted transformers are visually inspected on a three year cycle in urban areas and a 6 year cycle in rural areas for signs of signs of insulating oil on external tank surfaces which might be indicative of overloading or a leaking gasket on the secondary terminals or off-circuit tap changer. Halton Hills Hydro also employs a qualified contractor to perform thermal scanning of our substations plus 5 poles egressing the substation in each direction. The utility has determined through historical thermal scanning that this has been the area where most issues have been. The entire distribution system is thermal scanned every 2 years and all privately owned substations in the service territory every 3 years. Pole mounted distribution transformers are normally run to failure.

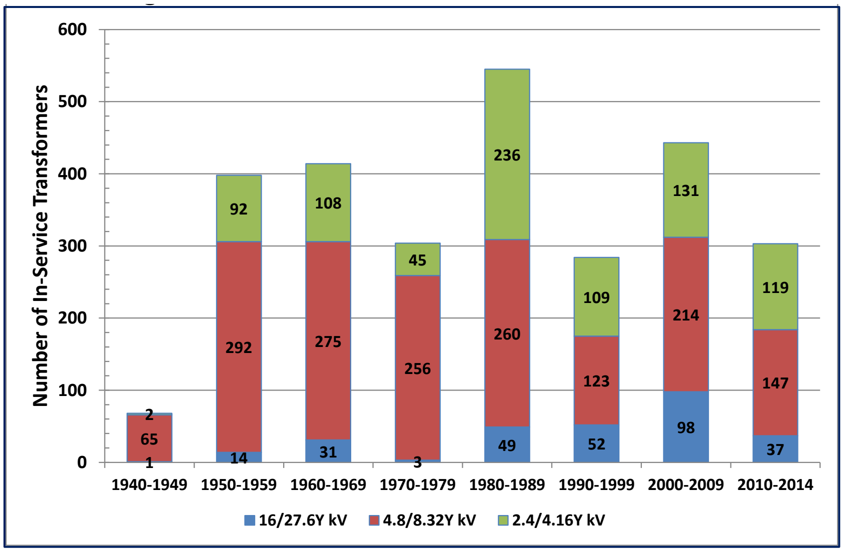


Figure 24 Age Profile of 1-Phase Pole-Mounted Distribution Transformers

Two exceptions to the utility's pole-mounted transformer replacement policy exist:

1. Overloaded transformers - Overloading of a transformer can be problematic in that continued excessive loading generates sustained heat from which the thermal impacts can damage the cellulose insulation and reduce the overall life expectancy of the transformer. Halton Hills Hydro makes a concerted effort when these situations are identified to remedy the problem by replacing the transformer with a larger one or by installing a second transformer and dividing the customers among the now two transformers.
2. Modernization of transformers connected to Halton Hills Hydro's 2.4/4.16Y kV distribution system that provide a three-wire 600 V supply (also sometimes referred to as a "*600V delta supply*") to certain business customers. This initiative encompasses modernization of transformers, overhead secondary bus conductors, and revenue metering systems.

2.2.3.1.3 Sectionalizing Switches

Sectionalizing Switches	
Useful Life:	40 Years
Quantity in Service:	34 Group Operated, 22 Mechanically operated
Asset Management Strategy:	Strategic Replacement

Of the 34 Group Operated Switches in service, 6 are classified as distribution automation and another 6 are scheduled for upgrade in the near future. These switches are a component of the utilities smart grid strategy to provide improved reliability and value to customers.

Halton Hills Hydro completes a visual inspection seeking visual signs of misalignment of the switch blades and visual signs of damage to the interrupter module. The utility also augments this inspection program with physical testing of the switch to ensure it can be activated when needed.

Halton Hills Hydro is developing a program to be in place by the end of 2016 which will have all airbreak and loadbreak switches within our service territory on a rotating schedule for routine maintenance. We have found the switches that are operated frequently do not have the maintenance requirements compared to switches that are operated less frequently which tend to seize and/or corrode due to lack of use. These switches are important to maintain in good working condition as they may be required for sectionalizing and system reconfiguration during construction, maintenance, and/or emergency work throughout the year.

Figure 25 46kV Loadbreak Switch

Halton Hills Hydro does not have an active replacement program for load interrupter switches. Rather the organization has made strategic investments in distribution automation switches for its 44 k sub-transmission system to improve the overall reliability performance and smart grid enablement of its system.

2.2.3.1.4 Regulators and Reclosers

Regulators and Reclosers	
Useful Life:	40 Years
Quantity in Service:	Regulators – 9 Reclosers - 9
Asset Management Strategy:	Maintenance and refurbishment

Halton Hill Hydro has:

- Nine (9) single-phase voltage regulators in active service (on the 4.8/8.32Y kV distribution system) at three locations as defined in Table 10 below; and

Feeder Designation	Location Description	Regulator Manufacturer & Type	Controls	Year of Manufacture
23F1	15 Sdrd/3rd Line	Siemens-Allis JFR	Cooper CL6	~ 1981
"	"	"	Accustat IJ2	~ 1981
"	"	"	Accustat IJ2	~ 1981
5F2	22 Sdrd/3rd Line	Cooper VR32	Cooper CL6	2006
"	"	+	Cooper CL6	2006
"	"	_	Cooper CL6	2006
11F3	10th Ln/Clayhill	Cooper VR32	Cooper CL6	2009
"	"	"	Cooper CL6	2009
"	"	"	Cooper CL6	2009

Table 10 Inventory of Single-Phase Step Voltage Regulator Installations

- Nine (9) single-phase automatic circuit relosers in active service (on the 2.4/4.16Y kV distribution system). The age of these devices is unknown.

A voltage regulator is essentially an auto transformer with multiple taps used to change the winding ratio under load. This effectively boosts or reduces the line voltage usually by 10 percent based on a feedback signal from local control circuitry. Such devices are used on long rural feeders where the voltage drop under normal loading conditions would otherwise lie outside the acceptable range (as set forth in CSA Standard CAN3-C235, *Preferred Voltage Levels for AC Systems, 0 to 50 000 V*) for customers connected near the end of the feeder.

Reclosers are generally self-contained fault interrupting devices used on over-head circuits to clear temporary faults and restore service automatically. This greatly improves overall reliability on a feeder by rapidly restoring service following a temporary fault. There is an added benefit to reliability in that a recloser can sectionalize a downstream section of line following a permanent fault and prevent additional customers upstream on the feeder from being without power.

Our voltage regulators are inspected semi-annually and we have a reclosure maintenance program which is working towards a 6 year cycle for all reclosures in our system to be inspected and maintained.

Voltage regulators can generally be overhauled several times through to the end of their useful life. End of life replacement occurs when control technology advances or parts are no longer available from a given manufacturer making the unit unserviceable or too costly to maintain.

Similarly, reclosers are also maintainable and able to be overhauled for many years. End of life is also dependent on parts availability. In some cases where greater reliability or automation is required, oil circuit reclosers may be replaced with newer vacuum reclosers equipped with electronic controls.

2.2.3.1.5 Primary and Secondary Conductors

Primary and Secondary Conductors	
Useful Life:	50 Years
Quantity in Service:	890 km of overhead circuits
Asset Management Strategy:	Run to Failure

Visual inspection and infrared thermography are the maintenance techniques utilized for conductors. Visual inspections are conducted on a three year cycle. Infrared thermography is performed every two years.

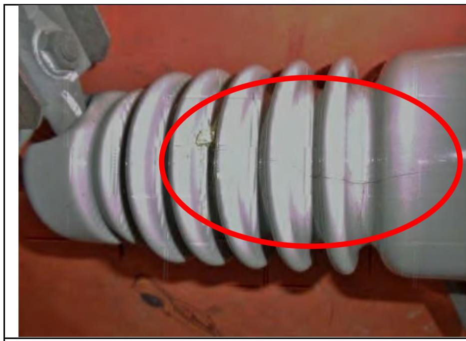
There is no active replacement program for primary or secondary conductors. Rather modernization of the primary conductors, line-post insulators and secondary bus distribution systems is carried out inherently in conjunction with the pole replacement program.

In addition to visual inspection, the utility maintains a three year cycle for vegetation management thereby reducing nuisance outages and damage to conductors caused by vegetation contact and enhancing public safety.

2.2.3.1.6 Porcelain Line Post Insulators and Switches

Porcelain Line Post Insulators and Switches	
Asset Management Strategy:	Active Replacement Program

Halton Hills Hydro has developed an ongoing program to rectify an area of concern where premature failure of porcelain line post insulators and switches is occurring. This issue is due to cracking within the porcelain body, water penetration and freezing that weakens the porcelain body causing untimely failure. The utility has directed its workforce to replace any porcelain switch with a polymer type switch when they are working on them in the field. They are also identifying areas where suspect porcelain insulators are located for inspection and replacement purposes.



Porcelain switch identifying crack in body

Failed Porcelain switch

Failed 46kV Post type porcelain Insulator

Figure 26 Examples of Failed Porcelain Equipment

2.2.3.2 Underground Distribution System

Halton Hills Hydro owns and operates 636 km of underground primary cables energized at 2.4/ 4.16Y kV, 4.8/ 8.32Y kV, 16/ 27.6Y kV, and 44kV. The table below lists Halton Hills Hydro's useful life schedule for underground distribution equipment.

Useful lives of underground distribution system equipment in Years	
Underground primary cable including utility chambers	40
Underground secondary cable	40
Underground transformers including fault indicators	40
Underground switchgear and junction cubicle	20

Figure 27 Useful Lives of Underground Equipment

2.2.3.2.1 Pad-Mounted Transformers

Pad-Mounted Transformers	
Useful Life:	40 Years
Quantity in Service:	Single Phase: 1270 Three Phase: 152
Asset Management Strategy:	Run to Failure

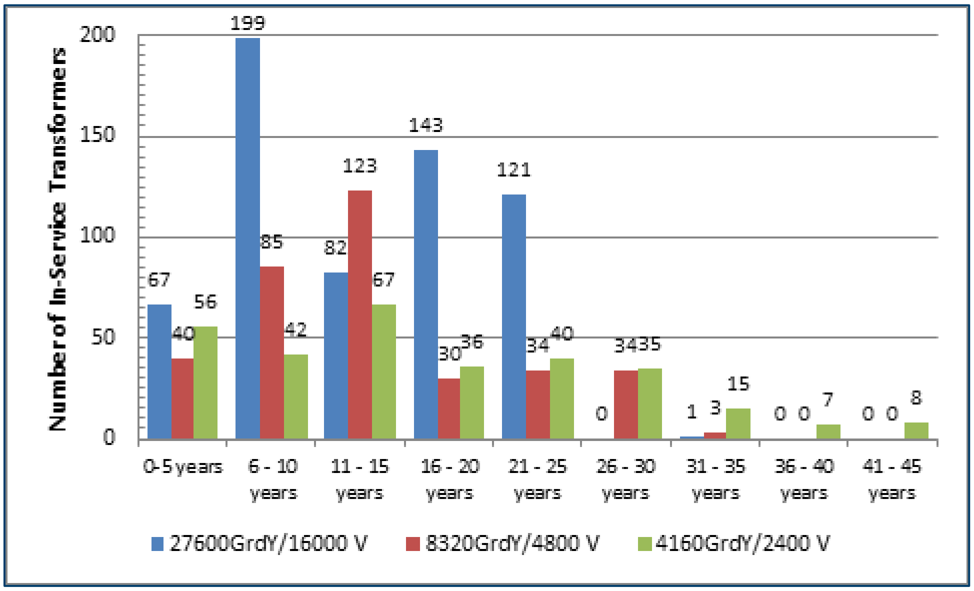


Figure 28 Profile of 1-Phase Pad-mounted Distribution Transformers by supply voltage level

There are 8 single-phase transformers that have been in service more than 40 years and an additional 7 which are approaching the end of their expected useful life.

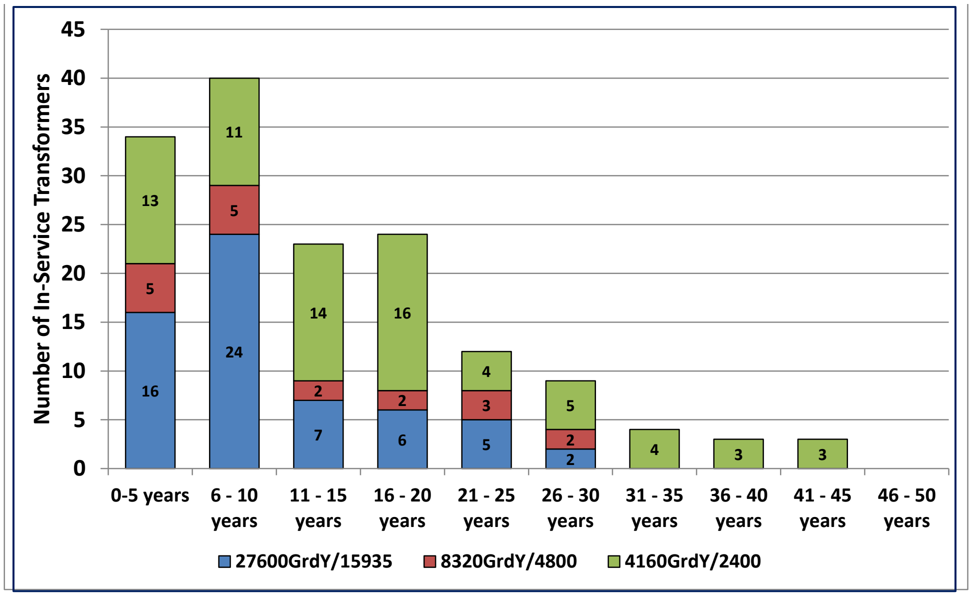


Figure 29 Profile of 3-Phase Pad-mounted Distribution Transformers by supply voltage level

There are 3 three-phase transformers that have been in service more than 40 years and an additional 3 which are approaching the end of their expected useful life.

Single-phase and three-phase pad-mounted dead-front distribution transformers are subject to visual inspection every three years for signs of excessive corrosion, insulating oil on external tank surfaces which might be indicative of overloading or a leaking gasket on the secondary terminals or off-circuit tap changer, signs of attempted forced entry (and other indication of vandalism). Other than such visual inspections, pad-mounted distribution transformers are normally run-to-failure.

Halton Hills Hydro owns and operates Live Front Pad-mount Transformers which are significantly aged assets. This type of transformer depicted in figure 30 below contains exposed primary and secondary connections. According to records, Halton Hills Hydro has seven (7) live front transformers in service. These transformers were manufactured in the early 1970’s and have been in service for approximately 40 or more years. Live front transformers are no longer installed by Halton Hills Hydro as CSA standard C227.4 permits only dead-front padmounted transformers.

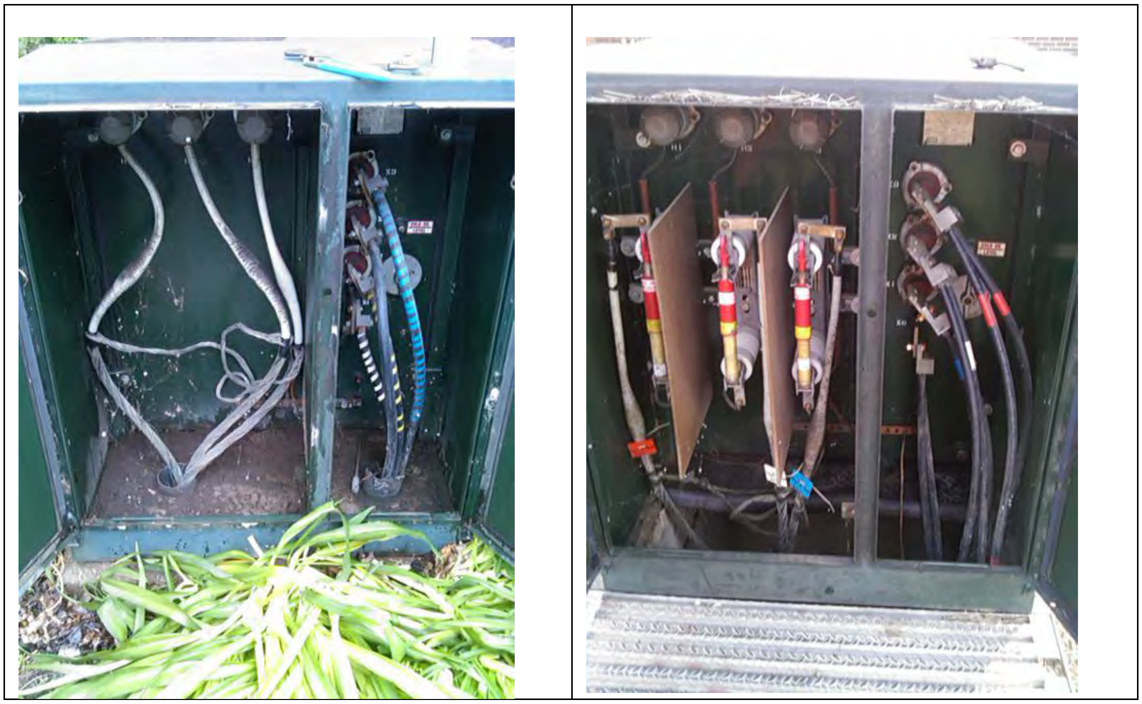


Figure 30 Live Front Padmount Transformer

Such transformers having exposes connections make them inherently more hazardous should an arc flash occur resulting from failed equipment. Replacement of live front transformers addresses issues with operating aged assets and safety and will need to be assessed on a location by location basis and associated costs determined in a similar manner. In some instances however where a larger portion of the distribution system is being renewed/ rebuilt, efficiencies may present themselves to include replacement of a live front padmounted transformer as part of a larger scoped project.

Pad-mounted distribution transformers are not proactively replaced based solely on their age. Other factors such as degree of corrosion, evidence of leaking gaskets, and technical obsolescence are also considered. Additionally, the age of the underground primary cables supplying these transformers are also considered and these replacements can be considered candidates for infrastructure renewal or voltage conversion projects.

2.2.3.2.2 Indoor Transformer Vaults

Indoor Transformer Vaults	
Useful Life:	40 Years
Quantity in Service:	7
Asset Management Strategy:	Long term replacement strategy

There are seven buildings within Halton Hills Hydro’s service territory where the supply arrangement is oil-filled distribution transformers installed in an electrical vault within the building. Transformer vaults owned and operated by Halton Hills Hydro supply three-phase power to our customers whereby each vault is comprised of three (3) individual transformers totaling twenty-one (21) transformers in use.

	
Typical Vault Access Door and Ventilation Vent	**Typical Transformer Arrangement within Vault**

Figure 31 Indoor Vault Transformers

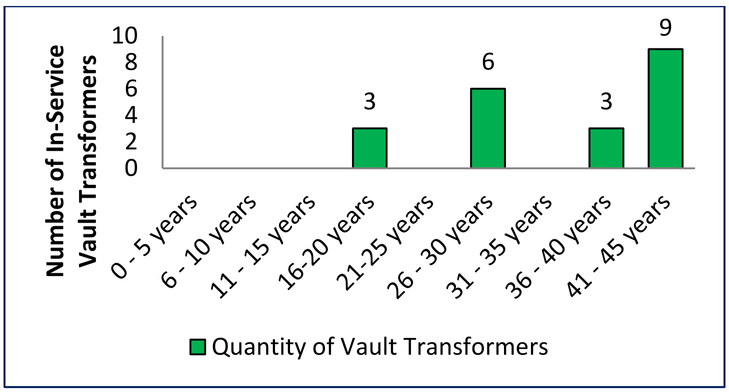


Figure 32 Age Profile of In-Service Vault Transformers

Indoor transformer vaults are subject to visual inspection on a 3-year basis for signs of insulating oil on external tank surfaces which might be indicative of overloading or a leaking gasket on the secondary terminals or off-circuit tap changer.

Modernizing the existing indoor transformer vaults within Halton Hills Hydro's service territory will be a multi-year endeavor that will require significant coordination effort. Halton Hills Hydro will be assessing the overall condition of its transformer vaults and will develop a priority ranking strategy to be utilized in the determination of modernizing the vaults. Investment in indoor transform vault modernization is scheduled to begin in 2017 and continuing in 2019 and 2020 forecasting two vaults per year in the latter two years.

2.2.3.2.3 Pole-Trans Transformer Units

Pole-Trans Transformer Units	
Useful Life:	40 Years
Quantity in Service:	77
Asset Management Strategy:	Active replacement strategy

In certain subdivisions in the past, Pole-Trans Transformer units were installed. These are metallic street light poles with a liquid filled distribution transformer integrated into the base of the pole. These types of poles have not been manufactured for several years.

Figure 33 Typical Pole-Trans Roadway Lighting Pole

Due to tight clearances, these units could only accommodate 2.4/4.16Y kV distribution systems. The design is inconsistent with modern worker safety needs due to the lack of insulation on the connectors.

The age profile for these Pole-Trans units is indicated in the table below.

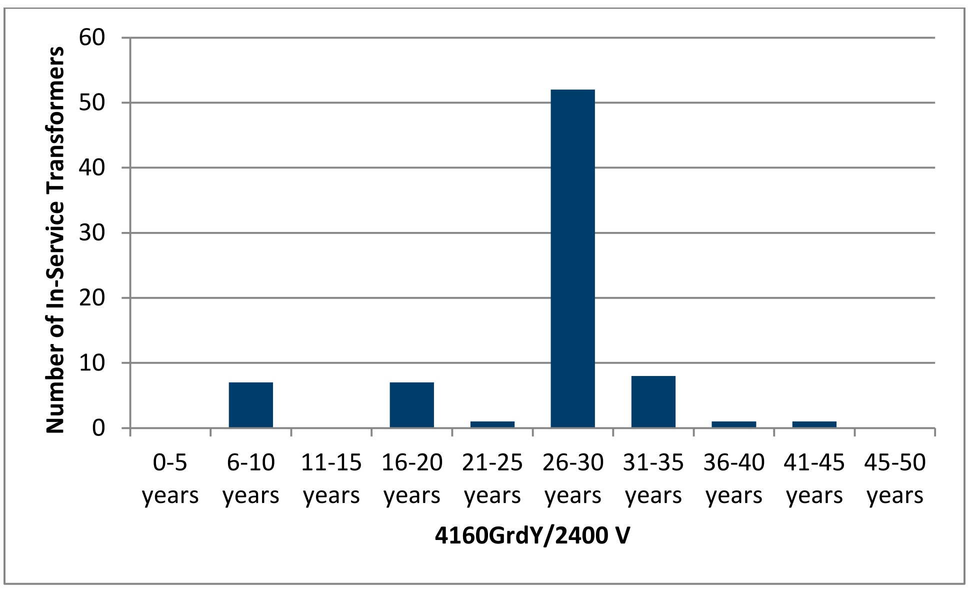


Figure 34 In service Pole Trans Transformers

The majority of these transformers will reach the end of their useful life in the next five to 10 years. At the same time much of the underground infrastructure supplying PoleTrans will reach its end of useful life. Rather than replacing PoleTrans with similar units Halton Hills Hydro will be replacing PoleTrans transformers with padmounted transformers and installing new primary distribution cable to supply the padmount transformers. This will minimize disruptive impacts to customers and provide the most cost effective and efficient means to upgrade these systems.

Replacement of these transformers is expected to be completed by 2022. The priority of expenditure on these replacements recognizes the following risk factors:

1. Addressing areas with known safety risks to those operating the distribution system or known areas where our distribution system is at risk.
2. Addressing a larger population of devices in the urban centers of Acton and Georgetown on an annualized basis.
3. Number of customers affected by a potential outage and potential length of outages.
4. Age and condition of the PoleTrans and cable in specific areas.

This proactive approach addresses the utilities desire to ensure its equipment is safe to operate, risks to the distribution system are minimized by replacing aged and obsolete devices, and the assets operated provide value to the utility.

2.2.3.2.4 Sectionalizing Switchgear

Sectionalizing Switchgear	
Useful Life:	20 Years
Quantity in Service:	33
Asset Management Strategy:	Run to Failure

Figure 35 Typical Padmounted Sectionalizing Switchgear

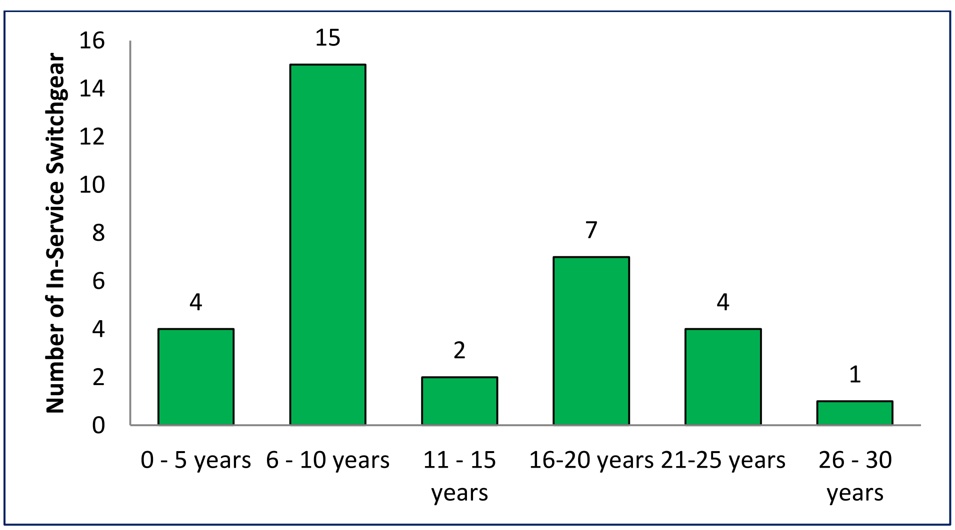


Figure 36 Age Profile of In-Service Padmount Switchgear

Padmounted sectionalizing switchgear or padmounted junction enclosures are subjected to visual inspections and when necessary dry ice cleaning. If during inspection problems or defects are identified, proactive measures can be taken to assess and remedy the situation often replacing the defective component without replacing the entire device (air insulated devices).

These devices are run to Failure.

2.2.3.2.5 Underground Power Cables

Underground Power Cables	
Useful Life:	40 Years
Quantity in Service:	222,486.1m
Asset Management Strategy:	Run to Failure

Halton Hills Hydro owns and operates primary distribution cables that are installed underground, either direct buried or in duct, that are used to distribute electricity to our residential and business customers throughout our service territory. Cable type and size may vary as the cables were installed over many years however in the past 13 years Halton Hills Hydro has standardized on using 28kV rated cable that is either copper or aluminum, has tree-retardant cross-linked polyethylene insulation, full or 1/3 concentric neutral depending on size of cable, and whose outer jacket is poly-vinyl chloride (PVC) or linear low density polyethylene encapsulated (LLDPE). Current requirements also require the cable to be strand-filled to fill the small voids between the compressed or compact conductor. The below figure depicts the typical construction of a primary cable.

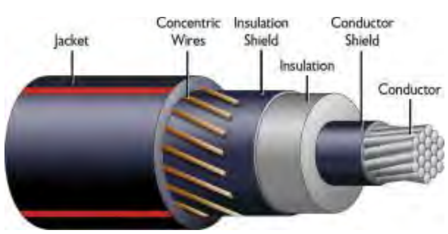


Figure 37 Typical Primary Cable Construction

There is no practical method for inspecting the integrity of underground power cables. However, padmount transformers are inspected on a three year cycle in urban areas and a six year cycle in rural areas. If the visual inspection shows signs of wear or damage, a more thorough investigation is performed. In 2015, Halton Hills Hydro will be utilizing a contractor to open and photograph every padmount transformer to provide a more detailed assessment. This assessment will become part of the utility's asset register and will be repeated periodically.

Halton Hills Hydro has piloted with cable rejuvenation technologies in an attempt to renew aged cable assets in an effort to reduce the overall capital expenditure. Further rejuvenation treatments may be forthcoming as Halton Hills Hydro identifies locations in the distribution system where cable life extension makes more sense than cable replacement. Figure 38 below outlines considerations with respect to prioritizing expenditures for cables.

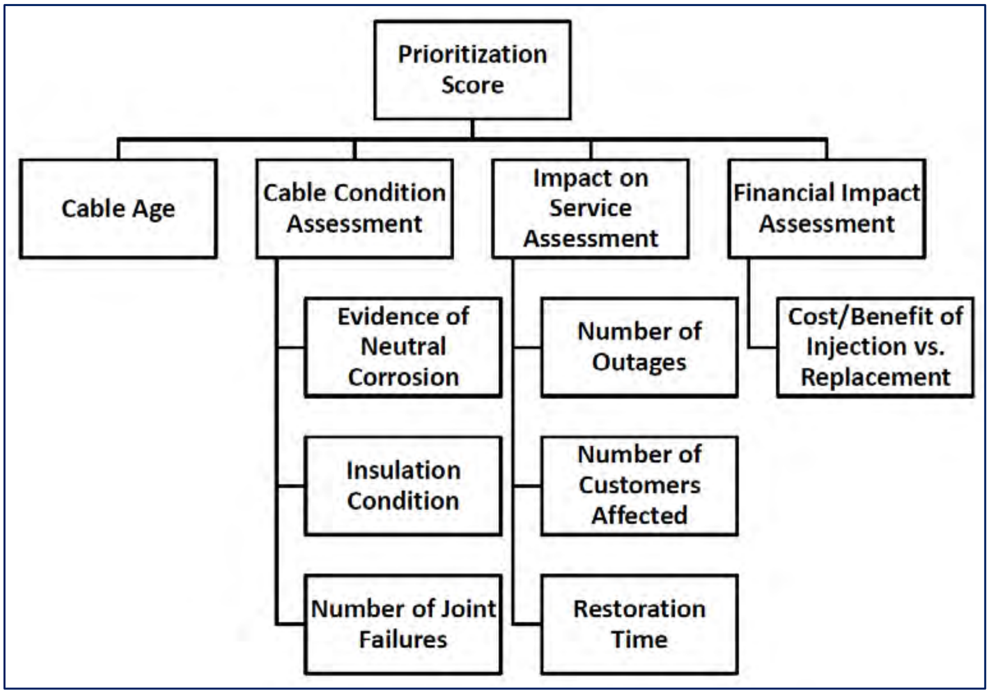


Figure 38 Ranking Scheme for Prioritizing Cable Replacement / Rejuvenation Projects

Halton Hills Hydro does not actively replace only primary distribution cables as a stand-alone project. Rather, these types of cables are replaced in conjunction with a larger project such as other asset replacement projects (ex. Poletrans transformers replacements) thereby renewing all of the major assets used in underground distribution.

2.2.3.2.6 Underground Low Voltage Service Cables

Underground Secondary Cables	
Useful Life:	40 Years
Quantity in Service:	416,763.8m
Asset Management Strategy:	Run to Failure

Age of service has not been recorded for low voltage service connections. Installation method has only been captured for 50% of installations.

There is no practical method to inspect these cables, however, it is unlikely that these cables will ever need replacement. There is no active replacement program.

2.2.3.3 Customer Owned Substations

Halton Hills Hydro provides supply to fifty-eight (58) customer-owned substations as identified in the table below.

Customer-Owned Substation Designation	Transformer Apparent Power Rating	Transformer High-Voltage Rating	Transformer Low-Voltage Rating	Installation Year	Supply Feeder Designation
AE	2,000	44,000			73M04
AM	2,667	44,000	600Y/347		42M25
BA	750	44,000			42M23
BE	1,000	44,000	600Y/347	2004	42M28
BP	2,000	44,000			73M04
CA	1,667	44,000			42M28
CK	1,667	44,000	600Y/347		42M25
CT	750	44,000			42M28
D	1,500	44,000			42M25
DA	1,000	44,000			42M28
DF	750	44,000	600Y/347	2010	42M28
EF	1,000	44,000	600Y/347	2008	42M28
F	1,000	44,000			42M25
FA	1,000	44,000			42M23
FB	3,000	27,600	600Y/347	2006	41M21
G	1,000	44,000			42M28
GA	1,000	44,000			42M25
HC	1,000	44,000			42M25
I	1,500	44,000			42M28
IA	1,000	44,000			42M25
J	2,000	44,000		1987	42M25
JA	3,000	44,000			73M04
K	1,500	44,000			42M23
KA	1,500	44,000			73M04
L	667	44,000	600Y/347		42M28
LA	1,000	44,000			73M04
LA	500	27,600			41M29
M	5,000	44,000			42M28
MA	1,000	44,000			73M04
MM	1,500	44,000	600Y/347		42M28
N	1,000	44,000			42M28
NA	1,500	44,000			73M04
OC	1,000	27,600	600Y/347		41M29

P	1,500	44,000			42M28
PA	3,000	44,000		2009	73M04
PC	1,000	44,000	600Y/347	2005	42M28
PL	1,500	44,000	600Y/347		42M28
PT	750	44,000			42M28
R	750	44,000			42M25
RA	1,000	44,000			42M23
RC	1,000	44,000			42M28
S	1,500	44,000			42M28
SA	1,000	44,000	600Y/347	2006	42M28
SD	1,500	44,000			42M28
SF	4,000	27,600	600Y/347	2007	41M29
SM	750	44,000	600Y/347	2004	73M04
SU	2,000	44,000	600Y/347	2005	42M28
T	1,000	44,000	600Y/347		42M28
TA	1,000	44,000	600Y/347		42M28
TO	2,000	44,000	600Y/347	2007	42M28
U	1,500	44,000			42M25
UN	1,500	44,000	600Y/347	2007	42M28
V	1,000	44,000	600Y/347		42M28
W	1,500	44,000	600Y/347	2013	42M28
WA	1,500	44,000			42M23
WP	1,000	44,000		2010	42M25
X	1,500	44,000			42M25
Z	1,000	44,000			42M28

Table 11 Customer Owned Substations listing

With a customer-owned substation, Halton Hills Hydro’s obligations are simply to ensure that the customer is made aware from time to time that it has an ongoing obligation to maintain the customer-owned substation in good working order (so as not to negatively impact Halton Hills Hydro’s reliability performance).

To encourage our customers who own 44kV substations, Halton Hills Hydro offers one (1) free disconnection and reconnection of their 44kV supply to enable customers to perform annual maintenance on their substation. Halton Hills Hydro also performs thermal scanning on all privately owned substations in their service territory once every three years.

2.2.3.4 Municipal Substations

Halton Hills Hydro has 12 municipal substations within its service territory that step the voltage down from a 44 kV sub-transmission level to a three-phase four-wire distribution levels (either 2.4/4.16Y kV in urban areas or 4.8/8.32Y in rural areas). The substation operating designations, supply sub-transmission circuits, and nameplate rating of the substation power transformer are indicated in Table 12 below.

Municipal Substation Designation	Municipal Substation Identifier	Nameplate Rating of Power Transformer	Voltage Rating of Power Transformer	Designation of Supply Feeder Circuit
MS-1	Ballinafad	5,000	44000-8320GrdY/4800	42M23
MS-3	Willow	5,000	44000-4160GrdY/2400	73M4
MS-5	Silvercreek	5,000	44000-8320GrdY/4800	42M23
MS-7	Beardmore	5,000	44000-4160GrdY/2400	73M4
MS-9	Queen	5,000	44000-4160GrdY/2400	73M4
MS-11	Glen Williams	5,000	44000-8320GrdY/4800	42M23
MS-13	Cross	10,000	44000-4160GrdY/2400	42M25
MS-15	River	10,000	44000-4160GrdY/2400	42M25
MS-17	Mountainview	10,000	44000-4160GrdY/2400	42M28
MS-19	Armstrong	10,000	44000-4160GrdY/2400	42M28
MS-21	Norval	5,000	44000-8320GrdY/4800	42M23
MS-23	Ashgrove	5,000	44000-8320GrdY/4800	42M23

Table 12 List of Municipal Substations

Halton Hills Hydro conducts monthly inspections of each of the 12 owned substations while maintaining a substation maintenance program. This program includes annual transformer oil testing at all sites and a routine rotating 3 year shutdown at each substation. Shutdown activities include Load interrupter switch maintenance, general cleaning & inspections and electrical diagnostic testing such as transformer insulation resistance and ratio. Also scheduled in the maintenance program is routine protection relay re-verification and circuit breaker maintenance. The utility employs a qualified contractor to perform thermal scanning of our substations plus 5 poles that egress the substation in each direction. This thermal scanning is performed on an annual basis.

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

Within each substation, there are three major components. The useful lives of these components are as follows:

Asset Category	Typical Useful Life (years)
Power transformers	35
Switchgear	40
DC Station Service	20

Table 13 Useful Lives of Substation Components

2.2.3.4.1 Substation Power Transformers

Substation Power Transformers	
Useful Life:	35 Years
Quantity in Service:	12
Asset Management Strategy:	Active Refurbishment

The age profile of the in-service substation power transformers is indicated in the figure below:

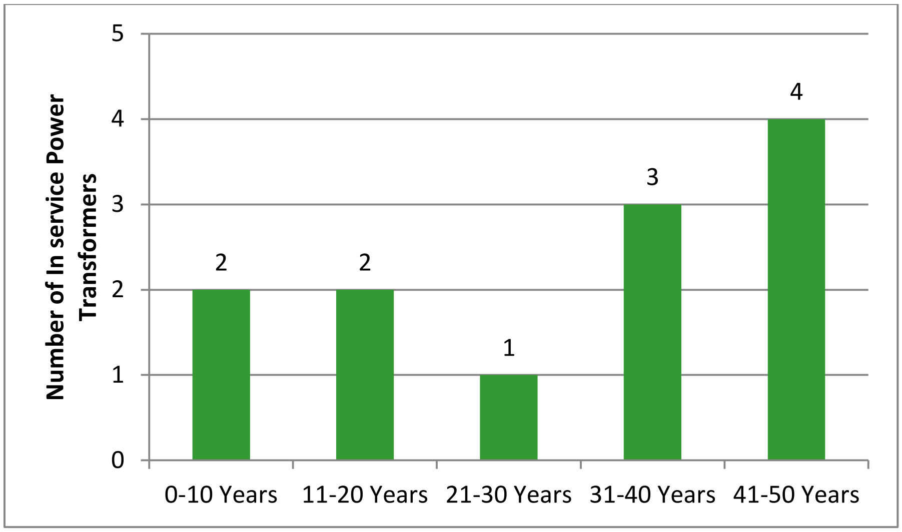


Figure 39 Age Profile of In-Service Substation Power Transformers

Substation power transformers aren't 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, Halton Hills Hydro maintains two operating spares, one for the 4.16kV systems and one for the 8.32kV system.

The table below provides the overall power transformer assessment recommendations taking into account transformer age, oil condition and loading.

Municipal Substation Designation	Municipal Substation Name	Age	Oil Conditio n	Loading	Recommendation
MS 1	Ballinafad	43	Good	70%	Defer to next 5 year cycle
MS 3	Willow	46	Good	71%	Replace due to age
MS 5	Silver Creek	42	Good	115%	Replace
MS 7	Beardmore	36	Fair	45%	Process oil and defer
MS 9	Queen	36	Good	87%	Defer to next 5 year cycle

MS 11	Glen Williams	8	Fair	56%	Process oil
MS 13	Cross	16	Good	95%	Monitor loading
MS 15	River	6	Fair	66%	Process oil
MS 17	Mountainview	26	Good	76%	Maintain per schedule
MS 19	Armstrong	19	Fair	55%	Process oil
MS 21	Norval	42	Fair	56%	Assess station end of life
MS 23	Ashgrove	33	Fair	95%	Assess station end of life

Table 14 Power Transformer Refurbishment Program

2.2.3.4.2 Substation Switchgear

Substation Switchgear	
Useful Life:	40 Years
Quantity in Service:	12
Asset Management Strategy:	Active Refurbishment

Of the twelve Municipal substations, four (4) have outdoor open bus switchgear structure types, six (6) have walk in metalclad types, one (1) is indoor bungalow type and one (1) is outdoor metalclad type.

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 each 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.

The table below summarizes the recommended switchgear refurbishments for the planning period.

Municipal Substation Designation	Municipal Substation Name	Age	Breaker Type	Type	Future Require ments	Recommendation
MS 1	Ballinafad	40	Oil Recloser	Open low profile structure	automate	Upgrade to vacuum recloser
MS 3	Willow	29	Air Magnetic	Walk in Metal Clad	None	Maintain
MS 5	Silver Creek	27	SF6	Walk in Metal Clad	None	Maintain
MS 7	Beardmore	36	Vacuum recloser	Metal Clad	None	Maintain

MS 9	Queen	36	Air Magnetic	Walk in Metal Clad	None	Replace in 2020
MS 11	Glen Williams	65	Vacuum Recloser	Open Structure	None	Maintain, assess structure
MS 13	Cross	44	Air magnetic	Walk in metal clad	Upgrade bus, add new feeder	Replace in 2016
MS 15	River	9	Vacuum	EEMAC Type C	Add new feeder	Maintain & expand
MS 17	Mountainview	29	SF6	Indoor Metal Clad	Add new feeder	Maintain & expand
MS 19	Armstrong	19	SF6	EEMAC Type A	Add new feeder	Maintain & expand
MS 21	Norval	49	Oil recloser	Open Structure	None	Assess station end of life
MS 23	Ashgrove	40	Oil recloser	Open low profile structure	None	Assess station end of life

Table 15 Substation Switchgear refurbishment Summary

2.2.3.4.3 Substation DC Station Service

Substation DC Station Service	
Useful Life:	20 Years
Quantity in Service:	12
Asset Management Strategy:	Active Refurbishment

HHHI has an active station battery maintenance program. 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 on the manufacturer's guidance.

The typical useful life of substation DC subsystem is 20 years. None of the battery systems will be due for replacement during the planning horizon for this asset management plan. The VRLA batteries themselves have a shorter 10 year design life typically. These will be replaced as required. Opportunities to invest in longer life batteries may be explored.

2.2.3.5 Revenue Metering Systems

Revenue Metering Systems	
Asset Category	Useful Life
Industrial/Commercial, Wholesale Meters	20 Years
PTs and CTs	45 Years
Smart Meters & Related Equipment	15 Years
Asset Management Strategy:	Reverification Process, Run to Failure

There are three categories of revenue metering systems: wholesale revenue metering used to measure Halton Hills Hydro's purchase of electricity from the provincial transmission grid or from transformer stations, instrument transformers used to convert voltage and current to lower safe levels that the meters will accept and retail revenue metering systems used to measure the utility's sale of electricity to customers or receipt of electricity from embedded renewable energy generators.

2.2.3.5.1 Industrial/Wholesale Meters

Meters are generally tracked by the date that they were sealed in accordance with Measurement Canada guidelines. Different classes of meters have different seal periods ranging generally from six to ten years. When the seal expires, the meter must be removed from service and sent to a certified meter shop for re-verification testing. If the meter still meets the regulated requirements, it is re-sealed and a new expiry date is applied. Typically meters are resealed and used again for as long as they pass re-verification. Halton Hills Hydro has 7 wholesale metering points each with a main and alternate meter for a total of 14 meters. A service contract is maintained with a Meter Service Provider (MSP). This contract includes provisions for managing spare meters and emergency stock.

Meters are generally run to failure for as long as they pass the re-verification process at the time of seal expiry. Meters may be phased out as new technology or features become available or if customers request advanced features.

Presently, HHHI communicates with Industrial and Wholesale meters via phone lines and cellular modems where traditional phone lines are difficult to install & maintain. Initiatives have begun to start investigating alternative communication methods.

Regulatory requirements in the future may also require the conversion to new communication methods such as LAN/WAN based TCP/IP. In this case meters would be phased out and replaced as the seals expire or as dictated by regulation

2.2.3.5.2 Current Transformers (CTs) and Potential Transformers (PTs)

Secondary retail metering systems for larger customer services generally require CTs and PTs to convert current and voltage to acceptable levels for the meters to use. Primary metering units exist in cases where customers have more than one substation supplied. Older units contain Instrument transformers within an oil filled tank while modern units use separate solid dielectric Instrument transformers.

Instrument transformers and primary metering units are generally not maintained once installed. Periodic tests, however, are performed to ensure the Instrument transformers maintain their accuracy throughout their useful life. Routine inspections may also be carried from time to time, generally during meter exchanges to ensure that the billing ratios/multipliers are correct.

This asset type includes oil filled retail primary metering units (PMU). Modern solid dielectric instrument transformers are generally preferred for new installations. Past practice has been run these units to failure rather than proactively replace. With new PMUs having long lead times and the challenge of collecting consumption data for billing purposes, a refurbished unit is kept as a spare. PMUs are proactively replaced as they reach end of life with solid dielectric PMUs.

The Wholesale metering points are maintained through a Meter Service Provider. The service agreement includes provisions to provide spare instrument transformers in the event of a failure. The units may therefore be run to failure with new instrument transformers purchased as needed.

Instrument transformers located in customer switchgear or metering cabinet are typically not actively replaced but rather maintained or exchanged as a customer's main electrical service needs change.

2.2.3.5.3 Smart Meters

Residential and small commercial smart meters were installed in 2009 & 2010 as part of the Ontario government mandate. All of Halton Hills Hydro's residential and small commercial meters were changed at that time. HHHI intends to enable group sampling on the residential smart meter population in order to more effectively manage the meter seals rather than exchanging all meters on a 10 year basis.

Residential smart meters are run until seal expiry. They are categorized into sample groups based on meter type and expiry. A sample of meters from each group must be removed and sent to a Measurement Canada approved facility for re-verification. If the sample group passes verification, the entire group seal date is extended and meters not removed may remain in service. If the sample meters fail, the entire sample group would have to be removed and replaced. Routine inspections are generally not carried out until the meter is exchanged at which point they are verified for accuracy and resealed.

2.2.4 System Capacity Assessment

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 (5.3.2 d)

Halton Hills Hydro is supplied via seven Sub-transmission feeders from three Hydro One owned Transformer Stations with feeder capacities as follows:

Transformer Station	Owner	Supply Feeders	Supply Voltage	Capacity
Pleasant TS	Hydro One	42M23	44 kV	25 MVA
		42M25	44 kV	25 MVA
		42M28	44 kV	25 MVA
Fergus TS	Hydro One	73M4	44 kV	~ 14 MVA
Halton TS	Hydro One	41M21	27.6 kV	16 MVA
		41M29	27.6 kV	16 MVA
		41M30	27.6 kV	16 MVA

Table 16 Feeder Capacities

Georgetown South and the southern Steeles Ave./Hwy 401 corridor is a high growth area supplied by Halton TS at 27.6 kV. For planning purposes, the average peak demand for 27.6 kV feeders in Halton Hills is 16 MVA. This has proven to be the optimum loading level for 27.6 kV feeders for a number of reasons:

it enables connection of new developments, provides for rural voltage conversions in high growth areas, maintains optimal power quality, ensures system reliability for maintenance and keeps line losses to a minimum. Capacity at the Halton TS station is expected to be used by 2018. Halton Hills Hydro has been active in the NW GTA IRRP group led by the IESO (formerly OPA). Recommendations are for Halton Hills Hydro to construct and operate a new 230 kV – 27.6 kV 125 MVA LTR Municipal Transformer Station. This will ensure that new load in the south will have adequate supply. Halton Hills Hydro is proceeding with this initiative.

Central Georgetown, including the commercial/industrial and north rural area is supplied by the three feeders from Pleasant TS at 44 kV. For planning purposes, the average peak demand for 44kV feeders in Halton Hills is 25 MVA. This has been the optimum loading level to enable connection of predominantly new infill and green-field developments. There is still capacity to service load for near term infill developments. Future load growth will be examined during the next IESO IRRP cycle.

Acton is supplied via a single 44 kV feeder from Fergus TS. This supply has reached capacity for HHH purposes. There exists difficulty with transferring load between Pleasant TS and Fergus TS which has posed reliability and future supply concerns. HHH is presently working with Hydro One for future options. High load growth is not a concern in this area.

Load transfers are not practical among the three transformer stations due to differences in supply voltage and long feeder lengths that pose power quality concerns.

27.6 kV System Assessment

The average Peak Demand MVA summary for the 27.6 kV system from Halton TS is illustrated in the table below:

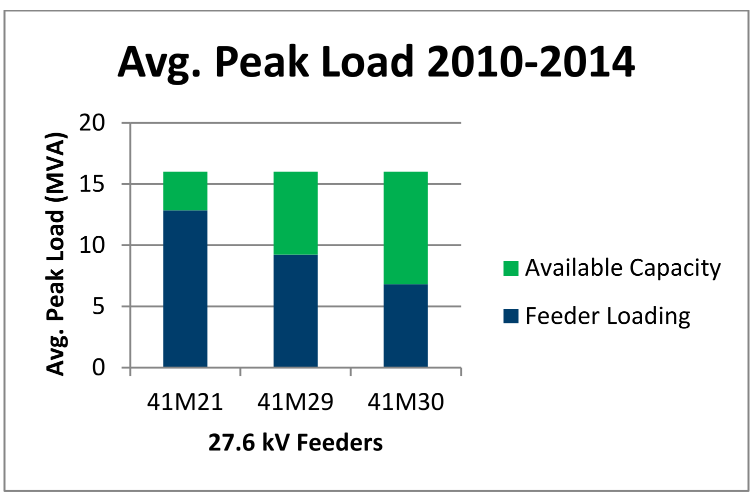


Figure 40 - 27.6 kV Feeders

Total capacity = Qty. 3 feeders x 16 MVA = 48 MVA
Existing loading = 29 MVA
Average load per feeder = 9.5 MVA

There is sufficient capacity in the feeders to support average peak loading and would support some additional customer load. As was mentioned previously, the southern area served by the 27.6 kV systems is designated as high growth and existing capacity is forecast to be used up by 2018.

Contingency Analysis – Assume loss of one feeder
New feeder count = 2
Load per remaining feeder = 29 MVA / 2 = 14.5 MVA
Surplus = (16 MVA – 14.5 A) x 2 feeders = 3 MVA
Existing feeder surplus = 3 MVA / 16 MVA = 0.2 MVA

This high level view would maintain optimal feeder loading and power quality for a sustained period of time and would allow a feeder failure during extreme peak periods. This also assumes ideal feeder load transfer capability which is generally possible on this system.

As mentioned previously, the 27.6 kV system is forecasted to experience the highest load growth with predictions that the 27.6 kV feeders will reach capacity by 2018 with no additional feeders available to HHH from the existing Halton TS. To plan for new load growth, HHH is commencing the design and build of a new Municipal Transformer Station as identified by the IESO (formerly OPA) IRRP planning group.

44 kV System Assessment

The average Peak Demand MVA summary for the 44 kV system from Pleasant TS and Fergus TS is illustrated in the table below:

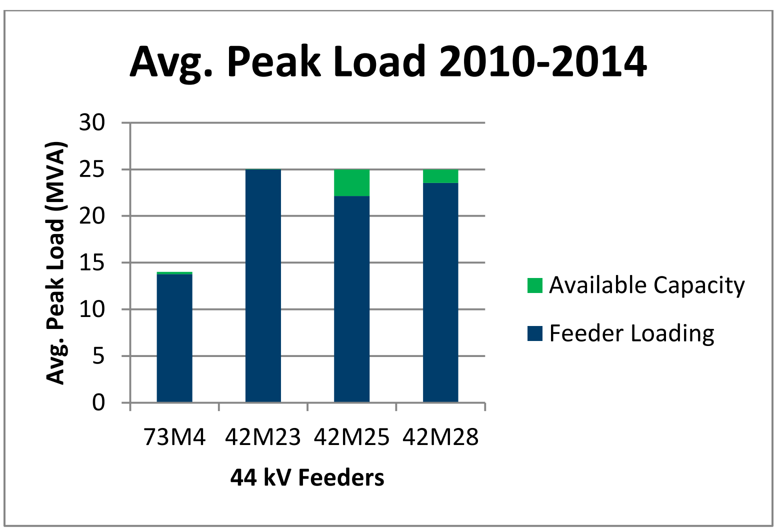


Figure 41 - 44 kV Feeders

Total capacity = Qty. 3 feeders x 25 MVA + Qty. 1 feeder x 14 MVA = 89 MVA
Existing loading = 84 MVA
Average load per feeder = 21 MVA

Contingency Analysis – Assume loss of one feeder
New feeder count = 3
Load per remaining feeder = 84 MVA / 3 = 28 MVA
Shortfall = (28 MVA – 25 MVA) x 3 feeders = 9 MVA
Required Additional Feeders = 9 MVA / 25 MVA = 0.36

Consider that the Fergus M4 is a shared feeder and capacity is limited to existing load only. For reliability purposes, the Fergus M4 Load (HHH component) has historically been fully transferred for short durations to the Pleasant TS M23. Transfer capability in reverse (ie. Pleasant M23 to Fergus M4 is limited/prohibited during peak periods. Therefore, assuming that HHH`s Fergus M4 load is fully transferable to Pleasant M23, re-run analysis for Pleasant TS only.

Total capacity = Qty. 3 feeders x 25 MVA = 75 MVA
Existing loading = 70 MVA
Average load per feeder = 23.3 MVA

Contingency Analysis – Assume loss of one feeder
New feeder count = 2
Load per remaining feeder = 70 MVA / 2 = 35 MVA
Shortfall = (35 MVA – 25 MVA) x 2 feeders = 20 MVA
Required Additional Feeders = 20 MVA / 25 MVA = 0.8

This high level view indicates that the Pleasant TS feeders are at/exceeding capacity. Future load growth is minimal based on limited projected infill developments. Power quality issues may develop in a single feeder loss contingency during peak loading periods.

With these considerations in mind HHH will engage stakeholders during the next IESO IRRP planning cycle to explore reliability based solutions to the Pleasant TS 44 kV system and determine solutions to incremental load growth.

Georgetown 4.16 kV Assessment

Halton Hills Hydro operates twelve municipal substations supplied from the 44 kV system. There are two 4.16 kV distribution systems in Georgetown and Acton respectively as well as a surrounding rural 8.32 kV system. For planning purposes, the average Peak Demand Amps for 4.16 kV feeders in Georgetown is 300A. This has historically been an optimum loading level to enable connection of new customers for infill developments, to maintain optimal power quality, to ensure system reliability for maintenance and to keep line losses to a minimum. The power transformers generally have sufficient capacity to maintain these levels. For the Acton 4.16 kV system the planning average Peak Demand Amps level is 230A. The power transformers at the Acton stations are smaller by comparison and so support lower load levels. For the rural 8.32 kV stations, the planning average peak demand is 120 A.

The Georgetown 4.16 kV system is constrained and does not provide sufficient redundancy at peak periods largely due to the ability of existing feeders to accept load transfers. Feeder capacity has been identified as an investment driver. Initiatives are under way to reinforce and relieve these constraints. Existing feeders are being split to reduce loading on existing circuits and enable capacity for new infill developments. The existing 4.16 kV substations have additional feeder breaker bays for expansion of new circuits. Enabling these new circuits will allow for better use of existing capacity on the 4.16kV power transformers as well as provide increased reliability and reduced load levels resulting in improved line losses.

The average Peak Demand Amps summary for the Georgetown feeders is illustrated in the table below:

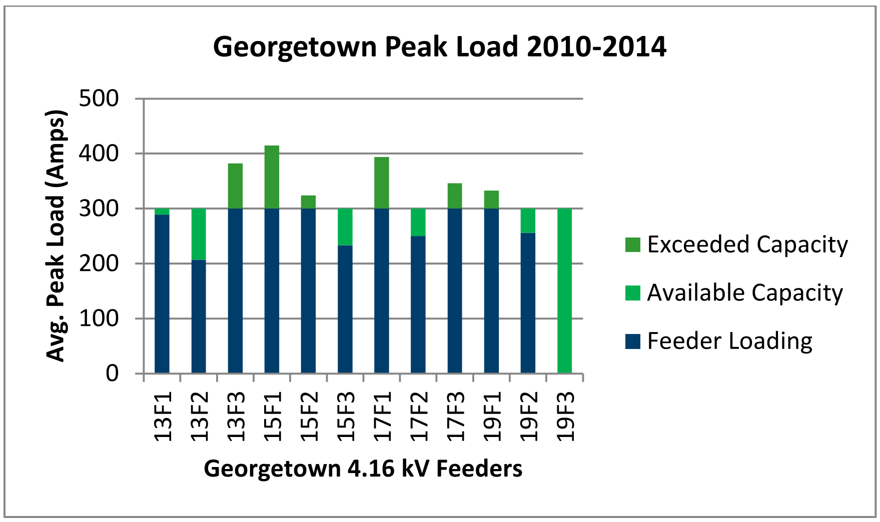


Figure 42 Georgetown Peak Load

Total capacity	Qty. 12 feeders x 300 A = 3600 A
Existing loading	3429 A
Average load per feeder	286 A

The numbers listed above suggest that there is sufficient capacity in the feeders to support average peak loading and would support some additional customer load but is nearing capacity. Due to present system conditions, the feeder loading is not equally balanced.

Contingency Analysis	**Assume loss of one power transformer**
New feeder count	9
Load per remaining feeder	3429 A / 9 = 381 A
Shortfall	(381 A – 300 A) x 9 feeders = 729 A
Required additional feeders	729 A / 300 A = 2.43

This high level view would maintain optimal feeder loading and power quality for a sustained period of time and would allow a failure during extreme peak periods. This also assumes ideal feeder load transfer capability. This is not the case in all areas of Georgetown. Further. Conductor sizes on main feeders are not ideal. Many areas of Georgetown utilize 1/0 Cooper overhead conductor which simply will not support these load levels during extreme loading periods. Additional feeder breaker positions are planned to further aid in load transfer capability. Further, anticipated infill load growth will require additional capacity.

Acton 4.16 kV Assesment

The average Peak Demand Amps summary for the Acton feeders is illustrated in the table below:

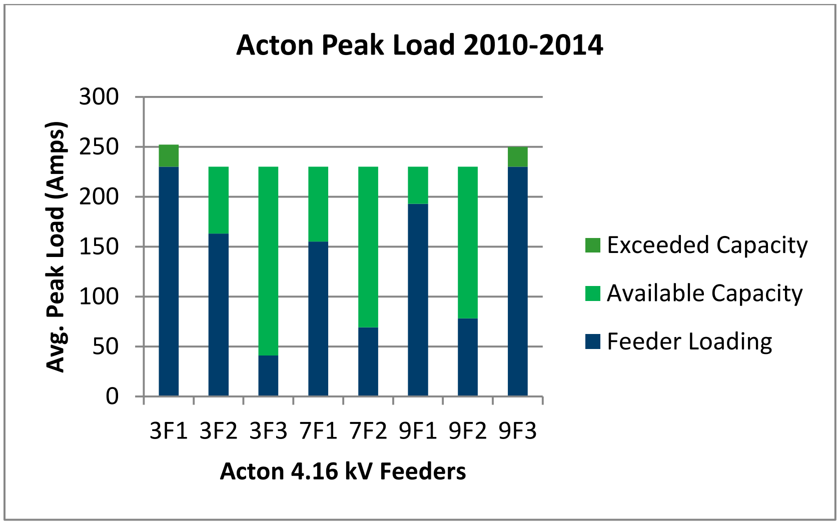


Figure 43 Acton Peak Load

Total capacity	Qty. 8 feeders x 230 A = 1840 A
Existing loading	1201 A
Average load per feeder	150 A

The numbers listed above suggest that there is sufficient capacity in the feeders to support average peak loading and would support additional customer load. Due to present system conditions, the feeder loading is not equally balanced.

Contingency Analysis	**Assume loss of one power transformer**
New feeder count	5
Load per remaining feeder	1201 A / 5 = 240 A
Shortfall	(240 A – 230 A) x 5 feeders = 50 A
Required additional feeders	50 A / 230 A = 0.22

This very high level view would maintain optimal feeder loading and power quality for a sustained period of time and would allow a failure during extreme peak periods. This also assumes ideal feeder load transfer capability. This is not the case in all areas of Acton. Further. Conductor sizes on main feeders are not ideal. Many areas of Acton utilize 1/0 Cooper overhead conductor which will have difficulty supporting these load levels during extreme loading periods.

Rural 8.32 kV Assessment

The 8.32 kV system is constrained in the North Rural area surrounding Acton. This system is used to supply new growth in the Acton East area and northwest Georgetown. Projects are aimed at reducing loading on the existing circuits and reviewing capacity on the existing substations. Higher density Load growth in the south east rural area has prompted the need for 27.6 kV expansion and voltage conversions. As the 8.32 kV system recedes northwards, two existing substations have been identified for future decommissioning. A new municipal substation has been identified to move the remaining 8.32 kV load supplied by these two stations. New load growth west of Georgetown would also be accommodated and reinforcement of existing load northbound to Acton, relieving existing constrained assets to the north.

The average Peak Demand Amps summary for the Rural feeders is illustrated in the table below:

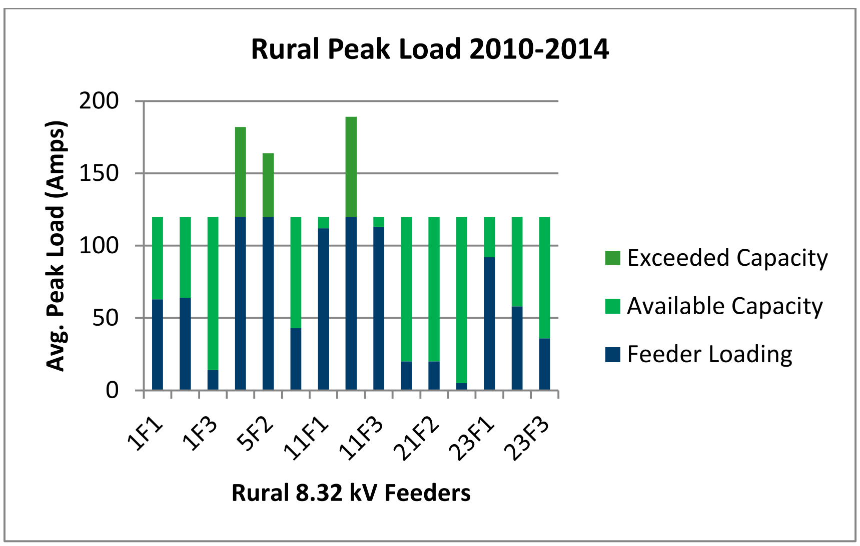


Figure 44 Rural Peak Load

Total capacity	Qty. 15 feeders x 120 A = 1800 A
Existing loading	1175 A
Average load per feeder	78 A

The numbers listed above suggest that there is sufficient capacity in the feeders to support average peak loading and would support additional customer load. Due to present system conditions, the feeder loading is not equally balanced.

Contingency Analysis	Assume loss of one power transformer
New feeder count	12
Load per remaining feeder	1175 A / 12 = 98 A
Surplus	(120 A – 98 A) x 12 feeders = 264 A
Existing feeder surplus	264 A / 120 A = 2.2

This very high level view would maintain optimal feeder loading and power quality for a sustained period of time and would allow a failure during extreme peak periods. This also assumes ideal feeder load transfer capability. This is not the case in all rural areas of Halton Hills. Long feeder lengths have provided challenges in serving loads during routine station maintenance outages.

Considering that the Ashgrove MS 23 and Norval MS 21 distribution systems are presently undergoing 27.6 kV voltage conversions since the areas serviced have been identified as high load growth areas. A new analysis would need to be completed considering the future absence of both of these substations.

New Total capacity	Qty. 9 feeders x 120 A = 1080 A
Projected loading	1094 A
Average load per feeder	122 A

Contingency Analysis	Assume loss of one power transformer
New feeder count	6
Load per remaining feeder	1080 A / 6 = 180 A
Shortfall	(180 A – 120 A) x 6 feeders = 360 A
Required additional feeders	360 A / 120 A = 3

Analysis

- Norval MS and Ashgrove MS back each other up.
- Ashgrove MS provides limited, non-peak period back up to both Glen Williams MS and Silver Creek MS
- New load growth is planned on the 8.32 kV system in North West Georgetown and East Acton.
- The power transformer at Silver Creek MS is presently at capacity and has limited ability to accept load transfers.
- The long normal feeder lengths impact the ability to accept load transfers while maintaining optimal power quality

Summary: New capacity will be required for the 8.32 kV system. This requirement is addressed in the Capital Expenditure Plan.

2.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

The asset life cycle practices and policies employed by Halton Hills Hydro are specific to the asset and can include simple measures such as visual inspections or can include more in depth examinations such asset testing and results analysis. The information gathered from asset assessments is used to determine a course of action with respect to the asset and can be a contributor to the asset renewal portion of the annual capital expenditures.

2.3.1 Asset replacement and refurbishment policies and maintenance planning criteria and assumptions (5.3.3 a)

Halton Hills Hydro's practices and policies surrounding asset management and sustainment are described in the following but as well in more specific detail in the Asset Management Plan SP14-03. The management of assets is specific to the asset with respect to the approach, preventative or reactive, and what type of oversight is employed. In general, asset management practices and policies address the following factors to determine and mitigate the risk of operating aged assets.

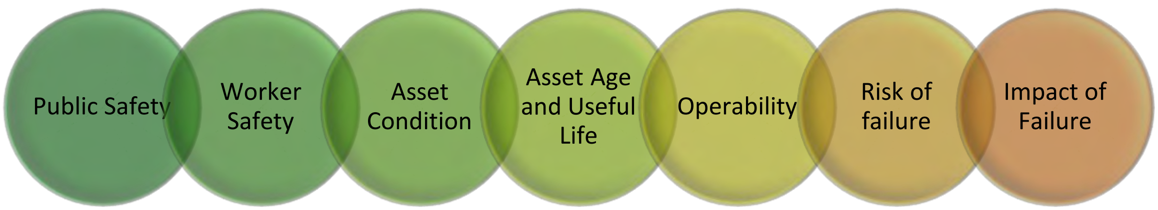


Figure 45 Asset Management Factors

- Public Safety
- Worker Safety
- Assets condition
- Assets age and Useful Life
- Operability (i.e.: does it functions as intended?)
- Risk/likelihood of failure
- Impact of failure: What is the impact of failure? System outages, public safety concerns?

The above factors are considered when assessing an asset's condition. Where the assessment of the asset does not warrant further action, aside from future inspection, the asset can be left in service. Where the assessment of the asset identifies further attention Halton Hills Hydro employ's its policies and procedures to address the asset and take corrective actions. The output of asset condition assessments forms part of the annual capital budget and prioritizing capital renewal expenditures for rehabilitation or replacement.

The timing of the renewal investments with respect to assets is often considered from a condition based assessment but is also viewed with respect to the asset reaching or surpassing the end of its economic useful life. The utility must strike a balance between leaving an asset in service beyond the end of its useful life and the point at which the asset is no longer safe to operate/ will cause significant problems if it fails (ie: outages).

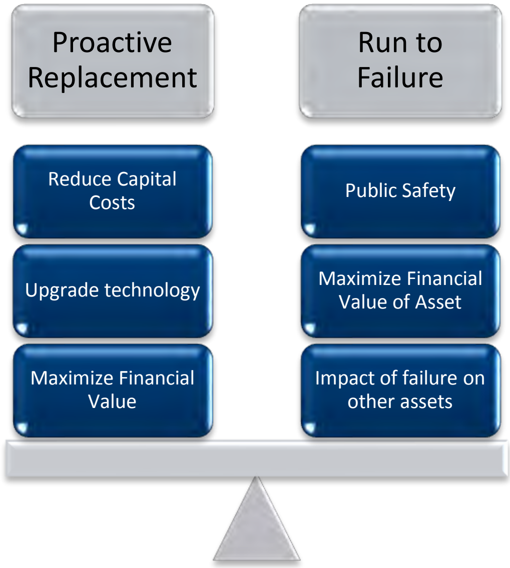


Figure 46 Balanced Asset Assessment

Certain assets can remain in service until they fail provided safety is not compromised. This Distribution System Plan along with the Asset Management Plan SP14-03 addresses the major devices operated by Halton Hills Hydro and the methods by which they are operated. There are two approaches to replacing assets.

Each asset can be run to failure. This is less expensive for short term planning and maximizes the financial value of the asset, however, it becomes inefficient to manage returning to the location to replace each asset as it fails. This method also tends to be a 'like for like' replacement rather than upgrading technology.

Another approach is to proactively replace a cluster of like assets at the time that the first asset begins to fail. This can be more expensive in the short term but pays off over the asset life cycle as it allows for technological upgrades and minimizes customer disruptions to replace the assets.

This Distribution System Plan considers the age and condition of assets vs their financial value and strikes a balance between both to ensure our distribution system operates safely and reliably for our customers.

As can be seen in this Distribution System Plan and the Asset Management Plan SP14-03, management of assets is specific to the asset or asset class. Such an approach to asset management ensures that expenditures for asset condition assessment are made wisely and for the equipment that has the greatest impact on the distribution system as well as in compliance with regulatory requirements. As such, Halton Hills Hydro employs both a proactive and reactive approach to asset management.

Proactive asset management involves continual condition assessments and includes:

- Poles
- Substation Transformers
- Substation Breakers
- Substation/ On-Load Tap Changers
- Oil Circuit Relcosers.
- Load Break Switches/ Switchgear

Reactive asset management relates more to equipment that does not get more than a visual inspection and includes:

- Conductor and Cable

- Distribution Transformers
- Pole Line Hardware
- Metering Equipment

Halton Hills Hydro employs preventative maintenance practices and policies relating to specific assets to ensure the assets are operating properly and the risk of failure kept low or otherwise identified. A proper maintenance program is essential to the safe and reliable delivery of electricity to customers. The preventative maintenance programs employed by Halton Hills Hydro are performed to regulated requirements, include staff and/ or qualified contractors, and may include specific industry standards and manufacturer specifications. Halton Hills Hydro's Pole Testing Policy/Procedure is included as Appendix E.

2.3.3 Routine Inspection & Preventative Maintenance

Halton Hills Hydro currently abides by the OEB requirements of performing system inspections every 3 years for our Urban area, and exceeds the requirements by inspecting our Rural area every 3 years (6 years is the OEB minimum requirement). When deficiencies are identified by inspection patrols, a more detailed inspection of the asset with the deficiency is conducted and an action plan developed for corrective action in accordance with OEB requirements.

Deficiencies identified during routine system inspections are identified and recorded on a Patrol Deficiency Record report, an example of which can be found in Figure 45. This report identifies the location and description of equipment. Each item is then given a priority of 1 for immediate repair or 2 for scheduled repair. The record is completed once repairs have taken place.

Page ____ of ____

Halton Hills HYDRO

Patrol Deficiency Record

Zone ______________ Date ______________

Circuit ______________ Patrolled by ______________

Address	Pole or Device ID #	Equipment classification (pole, tx, switch, etc.)	Repair Required/ Problem (Yes/No)	Priority 1 or 2 1 = immediate 2 = schedule	Assigned to or Work Order #	Date Repair Scheduled	Date repair Completed
Number of deficiencies for the Zone							

Figure 47 System Inspection Record

Halton Hills Hydro's service territory is divided into three zones for maintenance and inspection purposes. As identified in Figure 46 Below, one zone is inspected each year. Each zone is inspected in the year following the tree trimming for that zone. This way, any additional vegetation issues can be identified as well.

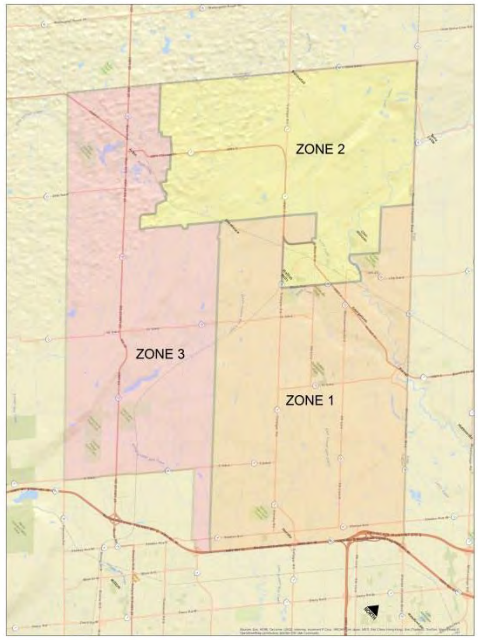
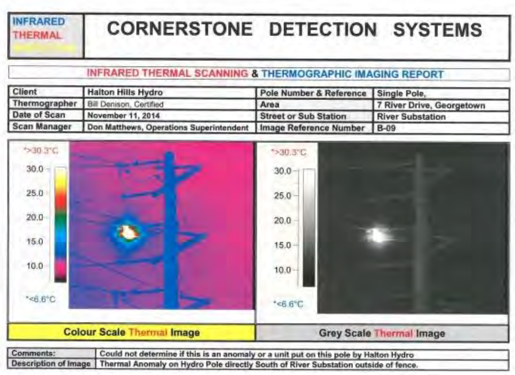


Figure 48 System Inspection Zones

2.3.3.1 Overhead Distribution System Inspection & Maintenance

In addition to our inspection patrols, Halton Hills Hydro employs a qualified contractor to perform thermal scanning of all substations plus 5 poles egressing the substation in each direction. The utility has determined through historical thermal scanning that this has been the area where most issues have been identified. The entire distribution system is thermal scanned every 2 years and all privately owned substations in the service territory are scanned every 3 years. Figure 47 below is an example of a thermal imaging report.



INFRARED
THERMAL

CORNERSTONE DETECTION SYSTEMS

INFRARED THERMAL SCANNING & THERMOGRAPHIC IMAGING REPORT

Client	Halton Hills Hydro	Pole Number & Reference	Single Pole,
Thermographer	Bill Denison, Certified	Area	7 River Drive, Georgetown
Date of Scan	November 11, 2014	Street or Sub Station	River Substation
Scan Manager	Don Matthews, Operations Superintendent	Image Reference Number	B-09

*>30.3°C
30.0
25.0
20.0
15.0
10.0
*<6.6°C

Colour Scale Thermal Image | Grey Scale Thermal Image

Comments:	Could not determine if this is an anomaly or a unit put on this pole by Halton Hydro
Description of Image	Thermal Anomaly on Hydro Pole directly South of River Substation outside of fence.

Figure 49 Sample Thermal Scan Inspection Report

2.3.3.2 Substation System Inspection & Maintenance

Halton Hills Hydro conducts monthly inspections of each of the 12 owned substations while maintaining a substation maintenance program. This program includes annual transformer oil testing at all sites and a routine rotating 3 year shutdown at each substation. Shutdown activities include Load interrupter switch maintenance, general cleaning & inspections and electrical diagnostic testing such as transformer insulation resistance and ratio. Also scheduled in the maintenance program is routine protection relay re-verification and circuit breaker maintenance. The utility employs a qualified contractor to perform thermal scanning of our substations plus 5 poles that egress the substation in each direction. This thermal scanning is performed on an annual basis.

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

	
4.8/8.32kV rural substation - external reclosers	**4.8/8.32kV rural substation- internal circuit breakers**

Table 17 4.8/8.32 kV Rural Substations

2.3.3.3 Voltage Regulators Inspection & Maintenance

Voltage regulators are inspected semi-annually and the utility has a recloser maintenance program which is working towards a 6 year cycle for all reclosers in the system to be inspected and maintained. 1200 wood poles are tested annually which represents approx. 15% of the poles in the utility's system. This information is used as part of the asset management system to determine if poles will meet end of life criteria, or will fail prematurely and require early replacement.

2.3.3.4 Vegetation Management

Halton Hills Hydro maintains a three year vegetation management schedule to trim trees throughout their service territory. The utility trims trees for safety reasons, to maintain line clearances, and to improve system reliability. Tree trimming is performed by skilled arborists who ensure the well-being of the tree while maintaining the safety of staff and the community

Figure 50 Vegetation Management Zones

2.3.3.4 Porcelain insulators and switches Inspection & Maintenance

Halton Hills Hydro has developed an ongoing program to rectify an area of concern where premature failure of porcelain line post insulators and switches is occurring. This issue is due to cracking within the porcelain body, water penetration and freezing that weakens the porcelain body causing untimely failure. The utility has directed its workforce to replace any porcelain switch with a polymer type switch when they are working on them in the field. They are also identifying areas where suspect porcelain insulators are located for inspection and replacement purposes.

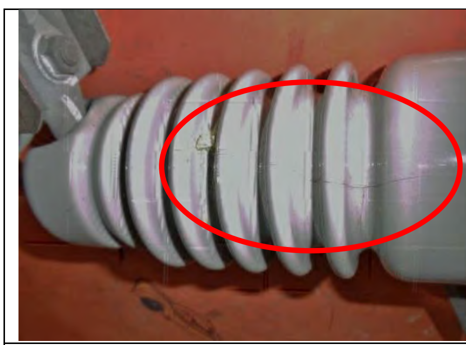
		
Porcelain switch identifying crack in body	**Failed Porcelain switch**	**Failed 46kV Post type porcelain Insulator**

Figure 51 Examples of Failed Porcelain equipment

2.3.3.5 Airbreak and Loadbreak Switches Inspection & Maintenance

Halton Hills Hydro is developing a program to be in place by the end of 2016 which will have all airbreak and loadbreak switches within their service territory operated on a rotating schedule for routine maintenance. The utility has found the switches that are operated frequently do not have the same maintenance requirements compared to switches that are operated less frequently which tend to seize and/or corrode due to lack of use. These switches are important to maintain in good working condition as they may be required for sectionalizing and system reconfiguration during construction, maintenance, and/or emergency work throughout the year.

Figure 52 46kV Loadbreak Switch

3 Capital Expenditure Plan (5.4)

This section provides a detailed expenditure plan for Halton Hills Hydro over the next five years. This plan is detailed by investment category and includes information in investments over the past five year period as well as the forecast period.

3.1 Summary (5.4.1)

Halton Hills Hydro's five year plan for capital expenditure details projects in each of the 4 categories as outlined in Fig. 51 below.

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

Figure 53 Capital Investment Categories from Chapter 5 Filing Requirements

These categories are defined as follows:

- System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the 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 the distributor's distribution system to provide customers with electricity services.
- System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements
- 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

Where a project has multiple drivers, the project has been categorized under the key or trigger driver with other drivers noted as appropriate.

3.1.1 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' (5.4.1 a)

3.1.1.1 Load Growth

Halton Hills Hydro is experiencing significant growth in the southern regions of their service territory, primarily in south Georgetown. The utility is also seeing a number of in-fill developments in Georgetown and Acton. As shown in the following table and development maps, developments in Georgetown noted as "In Progress" will contribute to an additional 1,242 new residential lots anticipated by the end of 2017. These developments coupled with Vision Georgetown, other future developments, and in-fill development will see significant residential growth over the next 10 to 15 years.

There is steady growth in Halton Hills related to new service requests and service upgrades. There is a new 56 unit apartment building in development in Georgetown as well as ongoing commercial development in the Steeles Avenue/401 Premier Gateway corridor.

Presently Halton Hills Hydro has capacity to manage known developments presently under construction. HHHI is able to assess demand for new services and developments using in-house software to determine impacts on the distribution system and what changes may be needed to accommodate the development. Such information is used to determine scope of work related to supplying the development and may translate into capital work where distribution expansions are required. HHHI has internal resources to address and prepare for load growth through the use of system planning tools that are used assess system capacity and potential shortfalls/ constraints and how such limiting factors can be mitigated. These tools allow Halton Hills Hydro to determine and prepare for the additional capacity needs that will be required by proposed developments not yet under construction that are identified in the following table and development maps. Such capacity will need to be supplied from our 16.0/27.6kV distribution system for which additional circuits/ feeders will be necessary to support the load growth.

MAP ID	FILE NAME	# of HOUSES/BUILDINGS	TYPE
F1	TOWN SURPLUS LAND (Halton Hills Drive)	Option 1: 3 apartments bldg's - 198 units. Option 2: 1 apartment bldg's -66 units & 48 Townhomes. Option 3: 70 Townhomes.	Future Development
R8	LINDSAY COURT 2301132 ONTARIO INC.	141	Future Development
IR4	OTEL, MOUNTAINVIEW RESIDENCES	Multiple Units	Future Development
R13	HAMMOND MANUFACTURING	63	Future Development
F2	TOWN SURPLUS LANDS (Georgetown Memorial Arena Site)	Option 1: 2 apartment bldg's - 135 units. Option 2: 2 apartment bldg's - 126 units. Option 3: 1 apartment bldg's - 118 units.	Future Development
R30	FERNBROOK HOMES PHASE 3/ Sierra Cres. Townhomes	273	In Progress
R36	H.H.V.H.I. 16 (PHASE 4& 5)	747	In Progress
R9	127 MOUNTINVIEW ROAD N	38	In Progress
R24	UPPER CANADA COLLEGE - MENKES	184	In Progress
F3	VISION GEORGETOWN (Study Area)	20,000 people, 1,700 jobs Residential density projected as 62% low density, 21% medium density, 17% high density. Estimating 7,000 residential lots. 6 elementary schools, 1 secondary school Mixed commerical/ retail uses.	Future Development
F4	Norval Area Development	300-400	Future Development
F5	TOWNHOMES & MULTI-UNIT RESIDENTIAL BUILDING	102 Townhouses, 72 unit apartment building	Future Development
F6	TOWNHOMES	11	Future Development
R3	DAWKINS - ACTON EAST HOUSING	16	Existing Development
R7	FINORO CUSTOM HOMES INC.	6	Future Development
R2	MCDONALD BLVD	118	Future Development
R31	DOCTOR MOORE CRT and WALLACE ST	23	Existing Development
R4	MOLINARO - 9647 HIGHWAY 7	33	Future Development
R17	SUMMERTREE PHASE II (CHARLESTON HOMES, BISHOP COURT)	31	Future Development
R26	EDEN OAK CREDITVIEW HEIGHTS (formerly Devins)	32	Future Development
R5	BOSNJAK	8	Future Development

R12	ESQUESING DEVELOPMENTS LIMITED	20	Future Development
I8	FIRST GULF	1	Future Development
I1	GREAT LANDS CORPORATION	1	Future Development
R11	EDEN OAK CREDIT HEIGHTS (formerly DESOL)	33	Future Development
R10	CHURCHILL VALLEY ESTATES	23	Future Development
I4	GIAGRANDE	1	Future Development
I9	HIGGINS - CARTTERA PHASE III	1	In Progress
I2	775,000 sq.ft. WAREHOUSE AND DISTRIBUTION CENTRE	3	Future Development

Table 18 Development in Halton Hills

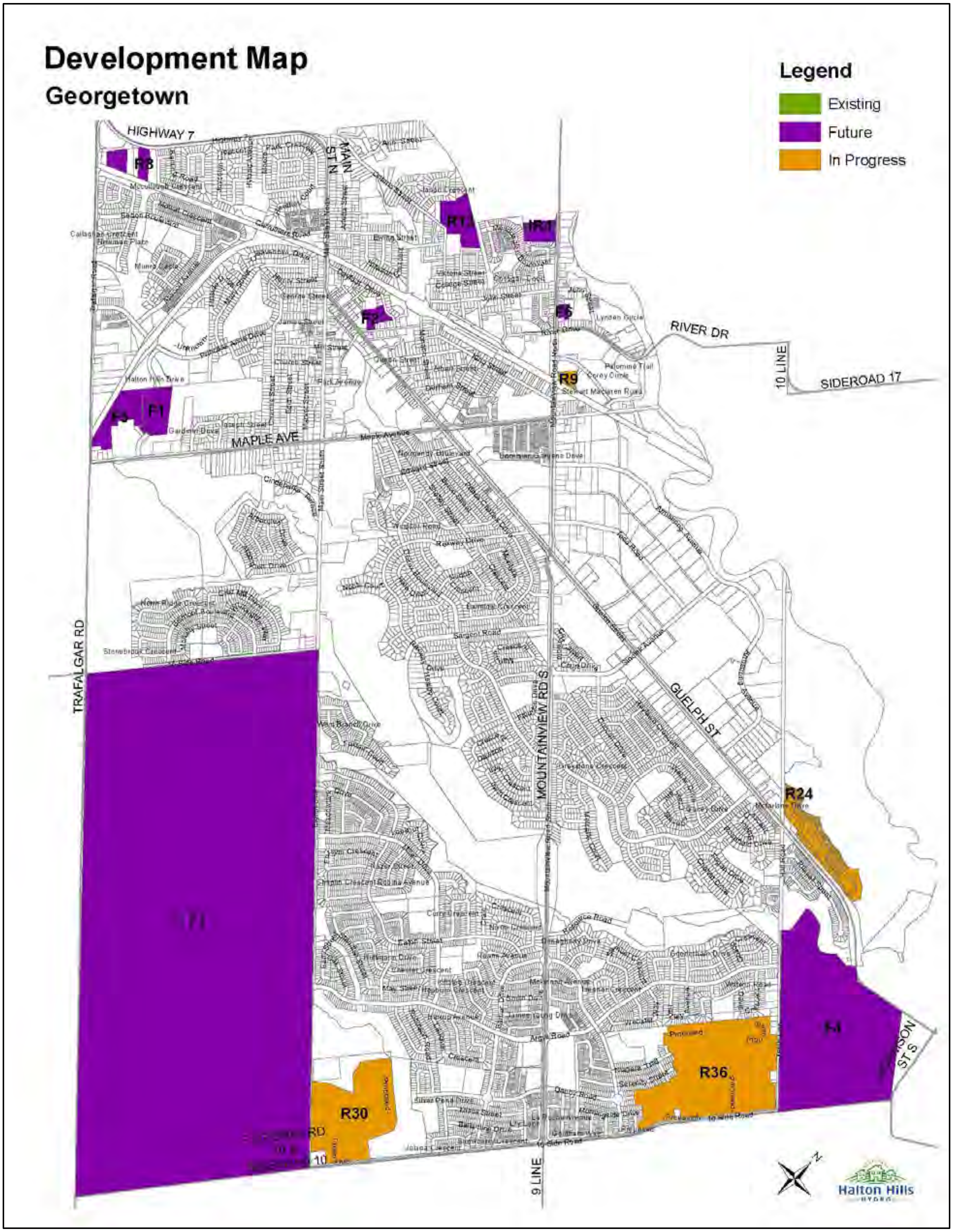


Figure 54 Development in Georgetown

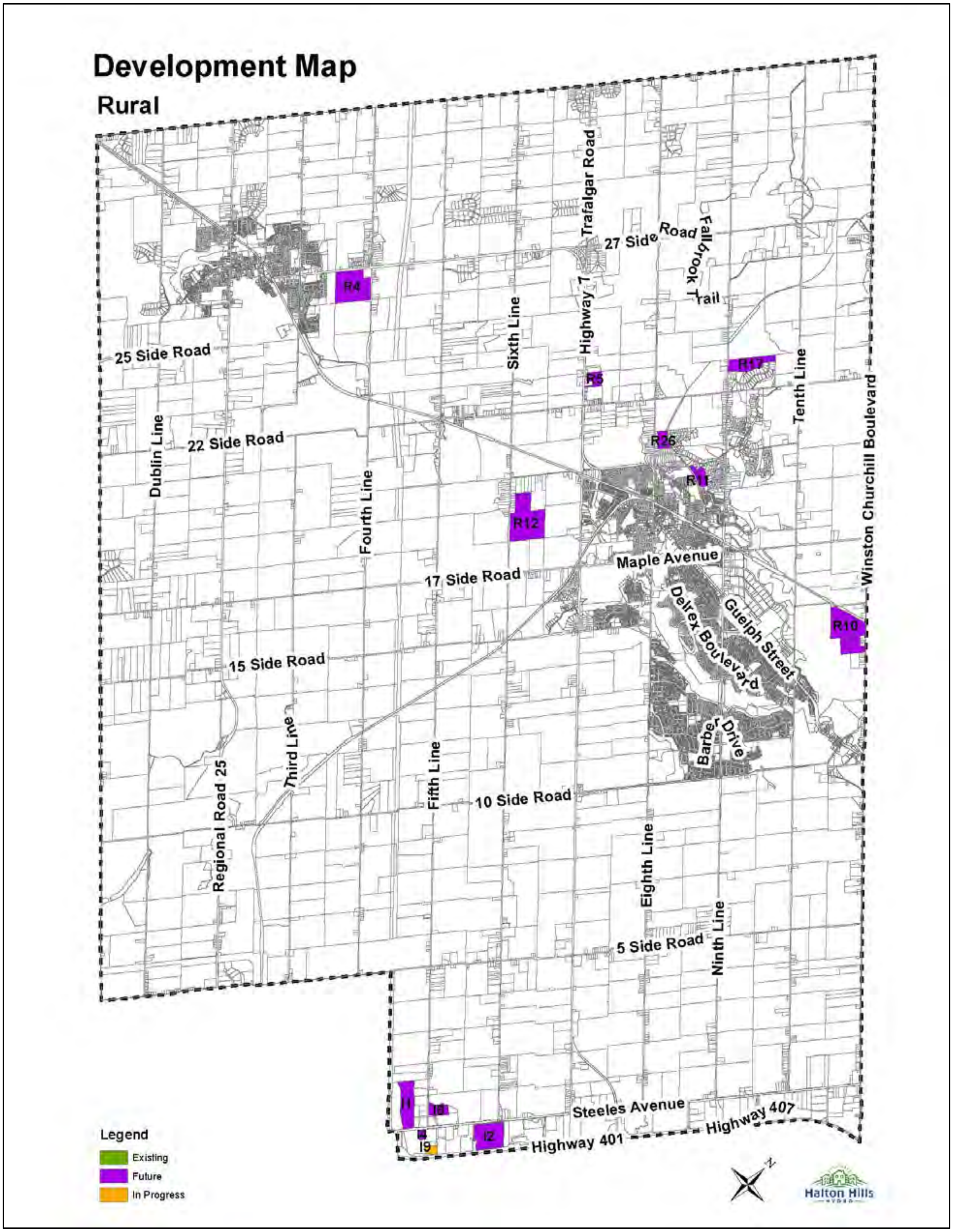


Figure 55 Development in Halton Hills Rural Service Area

Figure 56 Development in Acton

While the 27.6kV and 8.32kV distribution systems can accommodate load growth, Halton Hills Hydro is more vigilant in assessing capacity required for in-fill development on our 4.16kV system to ensure system will not be constrained. Because of the anticipated growth in Georgetown south the 5 year forecast period includes reasonable system service investments relating to our 27.6kVdistribution system that will see the system developed to accommodate the growth of Vision Georgetown as well as in-fill development around the Town of Halton Hills municipal building. Such proactive projects will ensure that HHHI can meet its system access requirements as these developments begin construction and distribution services to the developments occur.

System renewal projects include replacing defective and aged poles, feeder reinforcements to ensure urban 4.16kV distribution systems can support current load and future in-fill development, and the removal of obsolete equipment (Poletrans transformers) that present difficulties for operation.

3.1.1.2 Generation Customers

Halton Hills Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects anticipated from 2016 to 2020. There are no large projects anticipated in the service territory. Should a large connection or a concentrated number of connections in a specific area occur, Halton Hills Hydro will assess any potential system limitations and work with the applicants to enable renewable energy connections provided such connections would not adversely affect the distribution system.

Based on a calculated remaining maximum capacity and the projected generation projects Halton Hills Hydro has the capacity in place to accept future renewable generation projects. As such, there are no specific investments planned to accommodate renewable energy connections.

3.1.2 Total annual capital expenditures over the forecast period, by investment category (5.4.1 b)

The table below provides a summary of our capital expenditures by investment category over the forecast period. Note, this table is gross dollar amounts and does not reflect capital contributions for System Access projects.

	Year					
OEB Category	2016	2017	2018	2019	2020	Total
System Access	$2,472,588	$886,314	$3,330,938	$967,143	$1,038,920	$8,695,904
System Renewal	$3,790,671	$4,226,861	$2,818,292	$4,220,233	$5,464,607	$20,520,664
System Service	$2,302,791	$1,854,882	$3,535,241	$4,567,366	$1,856,986	$14,761,866
General Plant	$777,613	$479,416	$421,000	$425,000	$374,000	$2,477,029
Annual Totals:	**$9,343,663**	**$7,447,472**	**$10,105,472**	**$10,179,742**	**$8,734,513**	**$45,810,862**

Table 19 Gross Capital Expenditures

3.1.2.1 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 (5.4.1 c)

The following is a brief description of the outputs of the asset management plan SP14-03 and capital expenditure plans and processes for each of the categories, system access, system renewal, system service, and general plant.

The overall plan strikes a balance between managing system assets based on outputs from HHHI's Asset Management Plan SP14-03 and ensuring our distribution system is ready to accommodate anticipated growth through prudent planning and making responsible financial investments that will benefit customers. The asset renewal component will address mostly aged assets that have been determined to be defective, obsolete, or have surpassed their useful life.

Individual projects are ranked based on the impact the project has and the probability of the impact occurring. The risk level is calculated based on these factors following which a priority level is assigned based on the level of risk. Essentially, a high risk level translates to a high priority level. The following table listed the priority levels used by Halton Hills Hydro and the description of the priority.

3.1.2.2 System Access

System access projects are those the utility is obligated to perform and can include connecting new customers, connection renewable generation, and accommodating municipally driven projects such as road widening. System access projects are customer driven and therefore timelines are often determined by the customer and Halton Hills Hydro is expected to meet those timelines.

This distribution system plan identifies system access projects as:

1. General and Residential service layouts;
2. Subdivisions;
3. Renewable Generation (microFIT and FIT);
4. Municipally driven projects.

Capital contributions to the above noted types of projects are representative of what the utility has forecasted based on experience and known information used for decision making. These projects are mostly reactive and as such, investment for system access projects will be determined based on the needs of individual projects. Factors such as asset conditions will have minimal impact on system service projects unless efficiencies can be found for which investments are deemed prudent and service to better our system.

To determine a starting point from which to budget, Halton Hills Hydro has reviewed historical budgeting for general and residential service layouts, subdivisions and renewable generation connections on which to base the 5-year forecast for the same expenditures. With respect to municipally driven projects, Halton Hills Hydro has included anticipated expenditures based on known factors relating to each project however some refinement will occur once the scope of work for each project has been finalized through consultations with the municipality. Over the course of the 5-year forecast period the following projects have been planned to ensure our regulatory obligations are met.

3.1.2.3 General and Residential Technical Service Layouts

This category represents capital work that is necessary to accommodate customer service requests. Such work activities include installing transformers, service wire, guying and anchors, and making connections to the distribution system.

3.1.2.4 Subdivisions

This category represents capital work required to accommodate developer driven subdivisions and demand. The expenditure represents the cost involved with HHHI performing aspects of work to connect the development to the distribution system. Where necessary, capital contributions are collected from developers in accordance with the Ontario Energy Board's DSC and HHHI's Conditions of Service. Generally the developer constructs the civil and electrical infrastructure as part of their development and Halton Hills Hydro performs the connections to the distribution system. At the onset of a new subdivision, Halton Hills Hydro requests a letter of credit allocating a financial sum of funds that would be available to HHHI if HHHI were to have to complete the developers work. This practice demonstrates financial responsibility and mitigates risks to our customers with respect to unplanned expenditures should HHHI have to complete the developers work.

3.1.2.5 Renewable Generation

The anticipated expenditures for this category are reflective of the level of investment needed to enable renewable generation connections. At present Halton Hills Hydro believes its distribution system has sufficient capacity for additional generation, above what is noted in the Renewable Energy Generation Investment Plan (Appendix F). This translates into a low level of expenditures for microFIT and FIT projects, mostly labour and equipment, and in some cases the metering related materials (FIT). The level and frequency of investment is largely dependent on customer request and timing.

3.1.2.6 Road Widening/ Improvements

The expenditures represented in this category represent the investment levels HHHI has determined, at a high level, will be needed to satisfy regulatory obligations (Public Service Works on Highways Act RSO 1990 Chapter P.49) and accommodate municipal road improvement projects. Because these projects are heavily dependent on municipal readiness HHHI must plan for the work but cannot guarantee that the expenditures will take place in the planned years. Cost recovery is based on cost sharing arrangements specified in the Public Service Works on Highways Act which dictates that both parties will equally share the costs of labour, equipment, and labour saving devices. In cases where HHHI is requested to perform work outside the scope of the work that is required to meet our regulatory obligations, HHHI requests that the third party fund this work.

3.1.2.7 Meters

There are two categories of revenue metering systems: wholesale revenue metering used to measure Halton Hills Hydro’s purchase of electricity from the provincial transmission grid or from transformer stations and retail revenue metering systems used to measure the utility’s sale of electricity to customers or receipt of electricity from embedded renewable energy generators.

Projects in this category include upgrades to existing metering infrastructure; testing and replacement based on Measurement Canada seal expiry and technology improvements. All existing residential and small commercial meters at Halton Hills Hydro were installed in 2009 and 2010 as part of Ontario’s smart metering program. Residential smart meters are essentially run to failure or until re-verification deems them unsuitable for continued use. As 2019/2020 approaches, a planned approach will be undertaken to re-establish group sampling for the smart meter population in order that meter exchanges may be smoothed out year over year rather than on a 10 year cycle.

3.1.3 System Renewal

System renewal projects are those the distributor has determined are necessary to replace or refurbish assets used in its distribution system to maintain the ability of the distribution system to provide customers with electrical services. Halton Hills Hydro’s Asset Management Plan SP14-03 identifies the major assets used to distribute power to customers and the maintenance practices related to each asset category. System renewal projects included in this DS Plan are those directly linked to the Asset Management Plan and the related capital expenditures and planning processes are derived from the output of the Asset Management Plan.

Halton Hills Hydro categorizes its system renewal projects by asset type. These projects will be described below and supported in greater detail with justification further on in this DS Plan (Capital Project Sheets).

3.1.3.1 Wood Poles

Halton Hills Hydro’s Asset Management Plan SP14-03 has identified 1,487 poles that were installed before 1960 and are well past their useful life of 50 years but are still in service. The following figure taken from the Asset Management Plan demonstrates the age profile of these assets and provides justification for the level of expenditures HHHI deems necessary to address the portion of aged assets as well as address poles deemed defective through pole testing.

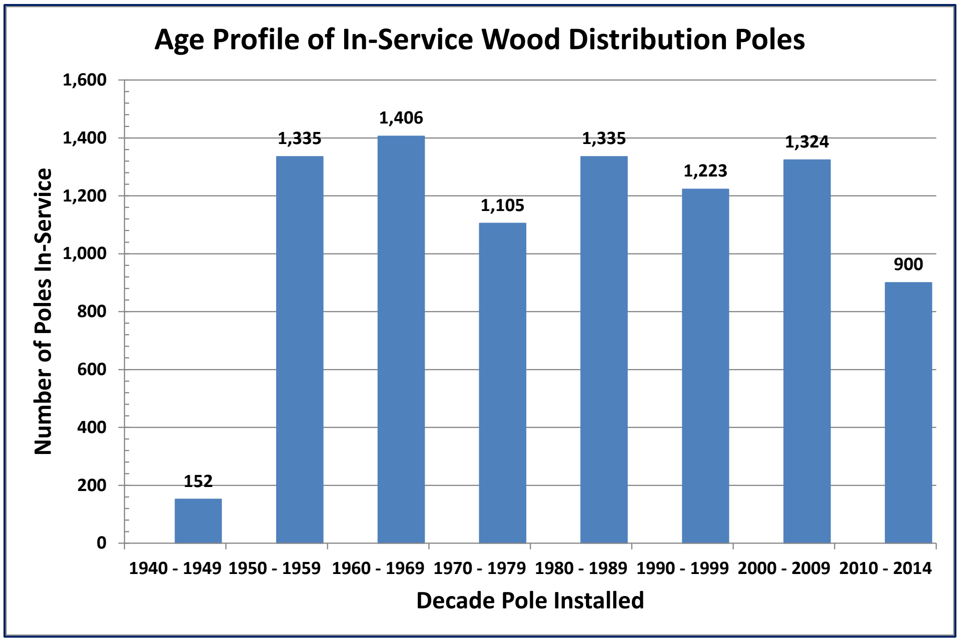


Figure 57 Age profile of Wood Poles

The number of poles identified in the Asset Management Plan as being well past their useful life is reflective of the age of portions of HHHI's distribution system. Over the 5-Year forecast period, HHHI will make the necessary investments to reduce the amount of these aged assets in use. HHHI will continue to pace its expenditures related to pole replacements on an annual basis as well as over the forecast period to mitigate the risk of continuing to have a large number of poles that could fail and result in large expenditures in a short period of time. Such risks could include altering the overall programs of the forecast period whereby projects are deferred to later years to accommodate large expenditures for unplanned system renewal work. A balanced and paced approach will mitigate such risks.

3.1.3.2 Padmounted Switchgear Replacement

Halton Hills Hydro's Asset Management Plan SP14-03 identified five (5) padmounted switchgear's that have been is service in excess of their useful life. This DS Plan includes a reasonable level of expenditure to address this aged infrastructure and mitigate the potential failure and inconveniences to customers that are attributed to failure of electrical equipment. In the forecasted 5-year period Halton Hills Hydro will replace two of its oldest switchgears as part of its proactive approach to address aged infrastructure.

3.1.3.3 Live-Front Padmounted Transformers

Halton Hills Hydro's Asset Management Plan SP14-03 identified seven (7) live front padmounted transformers that have been in service since the late 1960's and early 1970's. These units have been in use well past their useful life and are obsolete. Current standards, CSA C227.3 and C227.4 for single phase and three phase padmounted transformers specify dead-front transformers. Utilities only purchase dead-front padmounted transformers which are physically larger and incompatible with live-front terminations. Were a live-front transformer to fail it would be difficult to simply replace it with a dead-front unit. This DS Plan includes a reasonable level of expenditures aimed at replace all seven (7) units and the supplying cable with dead-front padmounted transformers within the 5-year forecast period.

3.1.3.4 PoleTrans Transformers

Halton Hills Hydro's Asset Management Plan SP14-03 identifies that there are seventy-seven (77) PoleTrans Transformers in service. PoleTrans transformers represent an age of construction where a minimalistic approach to underground distribution system had been adopted by some utilities. The units essentially look like a street light pole complete with light, but with a distribution transformer installed at the base of the pole. These units are obsolete and present safety concerns for staff having to work on the as discussed in SP14-03 section 4.5. If a PoleTrans transformer were to fail Halton Hills Hydro would have to replace it with a padmounted transformer. This DS Plan includes a reasonable level of expenditure to proactively replace PoleTrans transformers and the supplying primary cable to mitigate the risks identified in the Asset Management Plan SP14-03 and this DS Plan.

3.1.3.5 Feeder Renewal, Acton & Georgetown

This DS Plan includes a reasonable level of expenditure to ensure a significant portion of our urban Acton feeder network is renewed to maintain reliability and improve system operation. Halton Hills Hydro's three substations that supply electricity to most of Acton can be interconnected using feeders along Church Street and Willow Street.

This DS Plan also includes a reasonable level of expenditures to renew a 2.4/ 4.16kV distribution feeder in Georgetown. The age of infrastructure in some of the established areas of Georgetown have reach and exceed the useful life of that equipment (ex. poles). To mitigate the risk of aged assets failing, Halton Hills Hydro will proactively renew its aged infrastructure.

The infrastructure supporting the distribution network in established areas of Acton and Georgetown has aged and is of an older construction style that is not compatible with current design and construction standards.

3.1.3.6 Vault Transformers

Halton Hills Hydro's Asset Management Plan SP14-03 identifies that there are seven (7) vault transformers in service. The Asset Management Plan identifies that vault transformers and related construction are generally old and significantly out dated. They are also problematic from an operational and maintenance perspective. The vault rooms lack ventilation which impacts the transformers ability to cool as is evidenced in SP14-03 by pictures showing leaking oil. This DS Plan includes a reasonable level of expenditure to decommission transformer vaults over the 5-year forecasted period and replace the transformation with a traditional padmounted transformer. This program is a proactive approach and is intended to address the risk of operating old transformers many of which are exceeding their useful life and which located inside buildings.

3.1.4 System Service

The system service category are generally projects the distributor has identified as necessary to address system capacity constraints and/ or system operational challenges. These projects can includes capital investments that are intended to improve system reliability, operations, and increase efficiencies through voltage upgrades, distribution automation, and intelligent devices all of which are intended to enhance customer value and increase operational effectiveness. The projects identified in this DS Plan are those Halton Hills Hydro believes will strike a balance between increasing system reliability and addressing system constraints while maintaining a reasonable level of investment to enable future system access projects related to the growth Halton Hills is experiencing under Provincial growth targets in the Greater Toronto Area (GTA).

3.1.4.1 Automated Load Break Switches

This DS Plan includes a modest level of expenditures relating to enhancing Halton Hills Hydro's system automation by investing in automated load break switches on our 44kV and 16.0/27.6kV distribution systems. Halton Hills Hydro maintains a program for installing automated switches intended to increase system reliability as well as reduce O&M costs by allowing automated switches to be operated from the office/ control room rather than sending line staff to the switch to operate it. Automated switches are installed at key points in the distribution system to have the greatest impact for the investment.

3.1.4.2 Feeder Conversions

This DS Plan includes a number of projects aimed at developing Halton Hills Hydro's 16.0/27.6kV distribution system to accommodate future load growth targets in the southern regions of Georgetown which include Georgetown South development, Vision Georgetown (Provincially directed growth of 20,000 residents and 1,700 jobs between 2021 and 2031), and in-fill development near the Town of Halton Hills municipal office. The intent with feeder conversion (voltage conversion) projects is to replace and upgrade aged assets that currently distribute and support rural 4.8/ 8.32kV and to increase capacity for future higher density load growth utilizing the 27.6 kV system. These projects are also forward compatible as the new pole line infrastructure will support future load growth by being able to accommodate additional circuits

3.1.4.3 Feeder Reinforcement and Upgrades

Included in this DS Plan are reasonable levels of expenditures to address system constraints on Halton Hills Hydro's urban 4.16kV system, supplied from the 44kV sub-transmission system. These investments are necessary to address increasing infill development load in the urban centres of Acton and Georgetown. With increasing load comes the challenge of transferring load during peak periods and during maintenance activities. Certain areas were constructed when demand for electricity was not as great as it is now. Construction standards and materials (ie. 1/0 Copper conductor) used at the time are no longer suitable to support the new load levels. While presently impractical to convert to higher voltage levels, the opportunity exists to increase load transfer capability in conjunction with the replacement of end of life assets. There exists capacity at the existing municipal substations that may be better utilized by the addition of new feeder circuit breakers and transferring load to the new feeder supply points. A side benefit to splitting the feeder load along with larger conductor sizes is a reduction is feeder loading and a reduction in line losses. Increasing conductor size and reducing the load by splitting it into two feeders can have an overall line loss reduction of approximately 25%. The reinforcement of feeders will include the replacement of aged poles and transformers and increasing conductor size to ensure that main feeders are sufficient to support load growth from in-fill developments, increased demand from service upgrades and new retail development.

Halton Hills Hydro also includes in this DS Plan the intent to establish a 44kV feeder loop in the north area of Georgetown to increasing reliability for industrial customers and GO Transit. The project will see a 44kV distribution loop established that will enable Halton Hills Hydro to supply customers from multiple points on the 44kV distribution system thereby increasing reliability. This project also affords the utility to performing circuit switch that will maintain supply to customers connected to the 44kV.

3.1.5 General Plant

General Plant projects are expenditures the utility needs to make to run its day-to-day business and are not necessarily derived from any project categorized as system access, system renewal, or system service. General Plant investments include:

- Fleet vehicles;
- Office building, furniture;
- Tools;
- Information Technology/ Computers

3.1.5.1 Fleet Vehicles

The fleet project sheet and annualized outlook for the 5-year forecasted period provided in Appendix G demonstrates Halton Hills Hydro's investments that are necessary to maintain and replace its fleet vehicles. Halton Hills Hydro generally replaces small vehicles on a 10 year cycle and large trucks on a 12 year cycle with other vehicles assessed every five years.

3.1.5.2 Office Building and Furniture

Projects in this category include maintenance and upgrades to Halton Hills Hydro's physical environment including building, furniture, parking lot and grounds. Included in this plan are projects to resurface the garage roof and the employee parking lot.

3.1.5.3 Tools

Halton Hills Hydro includes in this DS Plan a modest level of expenditures related to tools such as live line tools, chain saws, drills, measuring wheels, and other operational equipment. The tools entry under General Plant is typically informed by in field staff that identifies the need for equipment or the necessary repair of defective equipment. The types of equipment purchased can vary year to year and are influenced primarily based on staff needs.

3.1.5.4 Information Technology/ Computers

Information technology is a critical part of the infrastructure of the utility. This category includes hardware such as servers, computers and backup solutions as well as the software systems used to run the business and bill customers as well as ensure the security of customer and utility data.

This Distribution Plan includes a strategy to replace the IBR iSeries server which runs the Customer Information and Billing System. The current server is 8 years old and upgrading to a new Power8 Server will provide increased system performance, dynamic resource sharing, reduced footprint and improved energy efficiency.

3.1.6 A list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category (5.4.1 d)

The table below provides a listing of material capital projects planned for the forecast period. Projects are listed by category and priority ranking.

OEB Category (Primary)	Project (Detailed Location)	Priority	2016	2017	2018	2019	2020
System Access	Make Ready Upgrades	4	$17,424	$17,772	$18,128	$18,490	$18,860
System Access	microFIT/FIT	4	$43,735	$44,609	$45,501	$46,411	$47,340
System Access	Subdivisions	4	$207,000	$244,260	$288,227	$340,108	$401,327
System Access	Technical Service Layouts	4	$376,036	$384,685	$393,532	$402,584	$411,843
System Access	Trafalgar Road/10 Side Rd	4	$357,295	$0	$0	$0	$0
System Access	Winston Churchill Blvd. (5 Side Rd to Mayfield Rd).	4	$0	$0	$2,426,000	$0	$0
System Access	9th Line (Steeles to 10 Side Rd).	4	$1,311,549	$0	$0	$0	$0
System Access	Metering Residential/Interval	4	$114,824	$114,824	$114,824	$114,824	$114,824
System Access	Metering General Service >50kW	4	$44,726	$44,726	$44,726	$44,726	$44,726
System Access	Metering Wholesale	4	$0	$35,438	$0	$0	$0
System Renewal	Annual Pole Testing & Replacements	5	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
System Renewal	Switchgear Replacement, PMH-9	3	$0	$66,204	$0	$72,825	$0
System Renewal	Acton Feeder Tie Reinforcement, Church St. (Queen/ Beardmore)	5	$0	$22,728	$0	$443,724	$0
System Renewal	Acton Feeder Tie Reinforcement, Willow St. (Beardmore/ Willow)	5	$0	$0	$0	$22,728	$449,951
System Renewal	Porcelain Switch & Insulator Replacements	4	$21,686	$22,120	$22,562	$23,013	$23,474
System Renewal	Poletrans Transformer Replacements (Georgetown)	4	$500,000	$43,100	$512,400	$0	$0
System Renewal	Poletrans Transformer Replacements (Acton)	4	$38,100	$560,000	$43,100	$547,125	$294,419
System Renewal	Live Front Transformer Replacements	4	$98,689	$103,624	$108,805	$57,123	$0
System Renewal	Vintage Underground Replacements	3	$304,586	$380,733	$40,000	$40,000	$418,806
System Renewal	Vault Transformer Replacements	4	$0	$75,000	$0	$160,000	$164,000
System Renewal	Feeder Renewal, Georgetown (MS #13/ MS #17)	3	$0	$0	$0	$20,000	$450,000
System Renewal	Feeder Renewal, Acton Area	3	$0	$0	$0	$20,000	$450,000
System Renewal	Power transformer life extension	4	$21,979	$21,979	$0	$0	$0
System Renewal	Cross MS switchgear replacement	5	$714,205	$0	$0	$0	$0
System Renewal	Cross MS egress rebuild incl new feeder 4	5	$0	$337,107	$0	$0	$0
System Renewal	Silver Creek MS transformer replacement	5	$0	$594,266	$0	$0	$0
System Renewal	Willow MS transformer replacement	4	$0	$0	$0	$407,429	$0
System Renewal	Willow MS Egress rebuild	5	$0	$0	$0	$328,887	$0
System Renewal	Glen Williams MS ground grid & fence replacement	5	$0	$0	$0	$77,379	$0
System Renewal	Queen MS Switchgear Replacement	4	$0	$0	$0	$0	$716,266
System Renewal	Queen MS Egress rebuild	4	$0	$0	$0	$0	$328,887
System Renewal	Queen MS Ground grid and fence replacement	4	$0	$0	$0	$0	$77,379
System Renewal	Metering Retail/Interval PMU replacements	4	$91,425	$0	$91,425	$0	$91,425

System Service	SCADA Switch Integration	4	$86,579	$86,579	$0	$0	$0
System Service	SCADA Wireless Faulted Circuit Indicators	4	$48,983	$0	$0	$0	$0
System Service	Automated Switches, 27.6kV System	3	$143,244	$150,406	$157,568	$164,730	$171,892
System Service	Automated Switches, 46kV System (2 Switches)	3	$158,607	$0	$174,468	$198,259	$0
System Service	Feeder Reinforcement, Delrex Blvd. (Rexway Dr. to Maple Ave.)	3	$346,812	$0	$0	$0	$0
System Service	Feeder Reinforcement, Delrex Blvd. (Jessop Crt. To Sargent Rd)	3	$28,427	$497,853	$497,853	$0	$0
System Service	Trafalgar Rd, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).	3	$671,181	$0	$0	$0	$0
System Service	Voltage Conversion, 5 Side Road (Trafalgar Rd to 8th Line)	4	$408,694	$0	$0	$0	$0
System Service	Voltage Conversion, 5 Side Rd (8th to 9th Line)	4	$19,643	$412,235	$0	$0	$0
System Service	Voltage Conversion, 5 SdRd (9th to 10th Line)	4	$0	$22,728	$453,395	$0	$0
System Service	Voltage Conversion, 6th Line (5 SdRd to 10 SdRd & 6th Line to Trafalgar)	4	$0	$0	$41,218	$798,356	$0
System Service	Voltage Conversion, 6th Line (10 SdRd to 15 SdRd & 6th Line to Trafalgar)	3	$0	$0	$0	$778,218	$730,718
System Service	27.6kV Extension & Loop, Maple Ave (Trafalgar to Main St S)	4	$0	$0	$0	$37,718	$577,083
System Service	44kV Feeder Loop, John St to Ewing St, Georgetown	4	$0	$0	$0	$28,428	$377,293
System Service	Extend 19-F3 Feeder on Armstrong Ave (SE to Guelph St.)	4	$0	$0	$20,000	$450,000	$0
System Service	5F3 on 32 Sdrd	3	$234,992	$0	$0	$0	$0
System Service	8th Line 27600V 2nd Cct	3	$0	$412,555	$0	$0	$0
System Service	17 Sdrd and 4th Ln 3Ph Extension	3	$0	$0	$523,334	$0	$0
System Service	22 Sdrd Limehouse 3Ph between 4th & 5th	3	$0	$0	$0	$340,805	$0
System Service	Steeles Ave 2 Cct underbuild 27600V	3	$0	$0	$556,405	$0	$0
System Service	Trafalgar Rd 8320V Conversion Steeles to 10 Sdrd	3	$0	$0	$0	$834,628	$0
System Service	Ballinafad MS Reclosers	5	$155,629	$0	$0	$0	$0
System Service	River MS - Add Feeder 4 breaker & egress	5	$0	$178,899	$0	$0	$0
System Service	Detailed design for Trafalgar MS	4	$0	$93,626	$0	$0	$0
System Service	Trafalgar MS Build excl. Power Transformers	4	$0	$0	$1,111,000	$0	$0
System Service	Trafalgar MS Build 2 x power transformers	4	$0	$0	$0	$744,000	$0
System Service	Armstrong MS new feeder 4	5	$0	$0	$0	$192,224	$0
General Plant	Remote Debit Machine	3	$0	$10,000	$0	$0	$0
General Plant	Interactive Voice Response (IVR)	3	$100,000	$0	$0	$0	$0
General Plant	Locate Ticket mgmt & new locate set	3	$0	$26,040	$0	$0	$0
General Plant	Electronic Document Mgmt	3	$0	$0	$100,000	$0	$0
General Plant	Quadra License	3	$2,800	$2,800	$0	$0	$0
General Plant	SCADA Outage Mgmt System Interfaces	4	$67,813	$0	$0	$0	$0
General Plant	IBM System i POWER8 Install	3	$75,000	$0	$0	$0	$0
General Plant	Mountainview Brick restoration	5	$0	$56,576	$0	$0	$0
General Plant	Building Upgrades	3	$50,000	$50,000	$50,000	$50,000	$50,000
General Plant	Mail Insertion Machine	3	$0	$0	$0	$65,000	$0
General Plant	Ergonomic Furniture Upgrades	3	$35,000	$12,000	$12,000	$12,000	$12,000
General Plant	Office Furniture (Accounting)	3	$35,000	$0	$0	$0	$0
General Plant	Parking Lot Paving	4	$150,000	$0	$0	$0	$0
General Plant	Tools (Operations/ Engineering)	4	$32,000	$32,000	$32,000	$32,000	$32,000
General Plant	Vehicles	4	$145,000	$290,000	$227,000	$266,000	$280,000

General Plant	Roof Resurfacing - Garage	4	$85,000	$0	$0	$0	$0
Subtotals			$9,343,663	$7,447,472	$10,105,472	$10,179,743	$8,734,513
Contributed Capital			$1,132,703	$595,554	$1,740,960	$711,103	$782,510
Totals			$8,210,960	$6,851,919	$8,364,511	$9,468,640	$7,952,003

Table 20 Capital Expenditure Summary

3.1.7 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 (5.4.1 e)

Halton Hills Hydro has been active on the North West GTA IRRP sub planning group led by the IESO (formerly the OPA). The IRRP recommendation is that Halton Hills Hydro to construct and operate a 230 - 27.6 kV, 125 MVA LTR Municipal Transformer Station to meet near term load requirements. As the capital requirement for this project is significant, HHH intends to file a separate Incremental Capital Module (ICM) for associated expenditures rather than including in this Distribution System Plan.

Halton Region has undertaken class environmental assessments on Trafalgar Road and on 9th Line in Halton Hills. It is anticipating that the output of these regional planning processes will result in the road authority requiring utility relocation. This DS Plan includes estimated expenditures for relocation our infrastructure in 2016 along 9th Line as well as at the intersection of Trafalgar Road and 10 Side Road. Timing for these projects is dependent on the Region of Halton acquiring land for relocations, these are system access projects for which Halton Hills Hydro is obligated to undertake per the Public Service Works on Highway Act, R.S.O. 1990.

Furthermore, Halton Hills Hydro has been working with the Region of Peel, Region of Halton, and Hydro One Brampton Networks Inc. with respect to road improvements on Winston Churchill Blvd. The road improvements will require relocation of both utilities infrastructure for which Halton Hills Hydro and Hydro One Brampton Networks Inc. are jointly designing a pole line which both utilities will cohabitate and in doing so achieve cost savings. At present, Halton Regions plans with respect to road improvements will include significant changes in the area of Winston Churchill Blvd and 10 Side Road where Halton Hills Hydro presently is anticipating relocation all of its infrastructure to accommodate the road improvements. The utility has been corresponding with the Region of Peel's design firm who advises they expect utility relocations to begin in 2018. As such Halton Hills Hydro has included this system access project in that year.

3.1.8 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 (5.4.1 f)

Halton Hills Hydro actively engages with customers throughout the year for input and feedback. The utility participates in approximately 20 community events each year to provide information to customers on programs and solicit feedback. The utility undertakes a telephone customer satisfaction survey every two years using an independent third party. This survey of residential and commercial customers seeks feedback on a number of areas including reliability, operational effectiveness, outage management, value for money, cost effectiveness and affordability. Over the past two survey periods, Halton Hills Hydro has consistently received an A rating from its customers exceeding the provincial averages in all major areas of performance.

Halton Hills Hydro regularly engages with their customers on social media and through their website as well as in person at community events. 20% of the utility's customers follow them on social media, placing them top three in the province for customer engagement.

Town Hall meetings are held for specific projects. In January 2015, the utility held a public meeting prior to launching their 2015 tree trimming program. Feedback from this session was positive; customers want tree trimming to take place to improve reliability.

In preparation of this plan, a 2015 Electric Utility Customer Engagement Survey (Appendix I) was completed to obtain customer preferences related to spending.

62% of customer surveyed felt that utility spending should focus on both reducing the number of unplanned outages and the duration of unplanned outages. Outage management is addressed in this plan through a number of feeder renewal and reinforcement projects as well as through SCADA upgrades including OMS integrations. The top communication method customers prefer for finding out power outage information is through accessing recorded telephone messages. In 2016, we will be implementing an Interactive Voice Response (IVR) system to address this preference.

62% of Halton Hills Hydro customers prefer a pro-active replacement strategy over run-to-failure options. When asked about increased rates to pay for capital expenditures, 71% of customers were willing to pay more for replacing aging equipment to improve safety and reliability. This plan addresses a number of system renewal projects focused on replacing aging equipment including an accelerated pole replacement program to remove aging poles from our distribution system.

Looking at operational expenditures, 53% of respondents said they would pay more for tree-trimming. They were less willing to pay for other operational items. Tree trimming remains a focus of the utility for the next five years.

Overall, customers show reluctance to pay for growth and are more willing to pay for items that they feel directly impact or improve service for them. While we are obligated to service growth, we will keep this information in mind as we work on our customer communication strategies moving forward.

3.1.9 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 (5.4.1 g)

The capital project map in Figure 56 focuses on major system renewal and system service projects included in this distribution system plan. It shows the correlation between these projects, planned developments and system voltages. Also shown are major system access projects.

As can be seen by this map, system renewal projects are focused in the two urban areas of Acton and Georgetown. These projects include feeder reinforcements to ensure urban 4.16kV distribution systems can support current load and future in-fill development, and the removal of obsolete equipment (Poletrans transformers) that present difficulties for operation.

System service projects address system capacity constraints and/ or system operational challenges. The projects identified here will strike a balance between increasing system reliability and addressing system constraints while maintaining a reasonable level of investment to enable future system access projects related to the growth Halton Hills is experiencing. As can be seen from the map, these projects focus on extending the 27.6 kV systems to address future development, including the significant Vision Georgetown project labeled as F3 on this map. These projects also ensure additional feeder loops are created on both the 27.6 kV and 44kV systems to increase system reliability. A number of the 27.6 kV expansion projects are designed to enable supply from the new Halton Hills Transformer Station when completed.

The system access projects indicated on this map are driven by Halton Region road works projects. Through the Public Service Works on Highway's Act RSO 1990 Chapter P49, Halton Hills Hydro is required attend these projects when required and permitted by the road authority. Project timelines are dependent upon approval to proceed from Halton Region. Cost effective benefits are derived from these projects as they allow for new infrastructure to be built and provides an opportunity to plan for future needs such as extending system voltages (ex. 16.0/ 27.6kV) and building feeder loops increasing system reliability and flexibility.

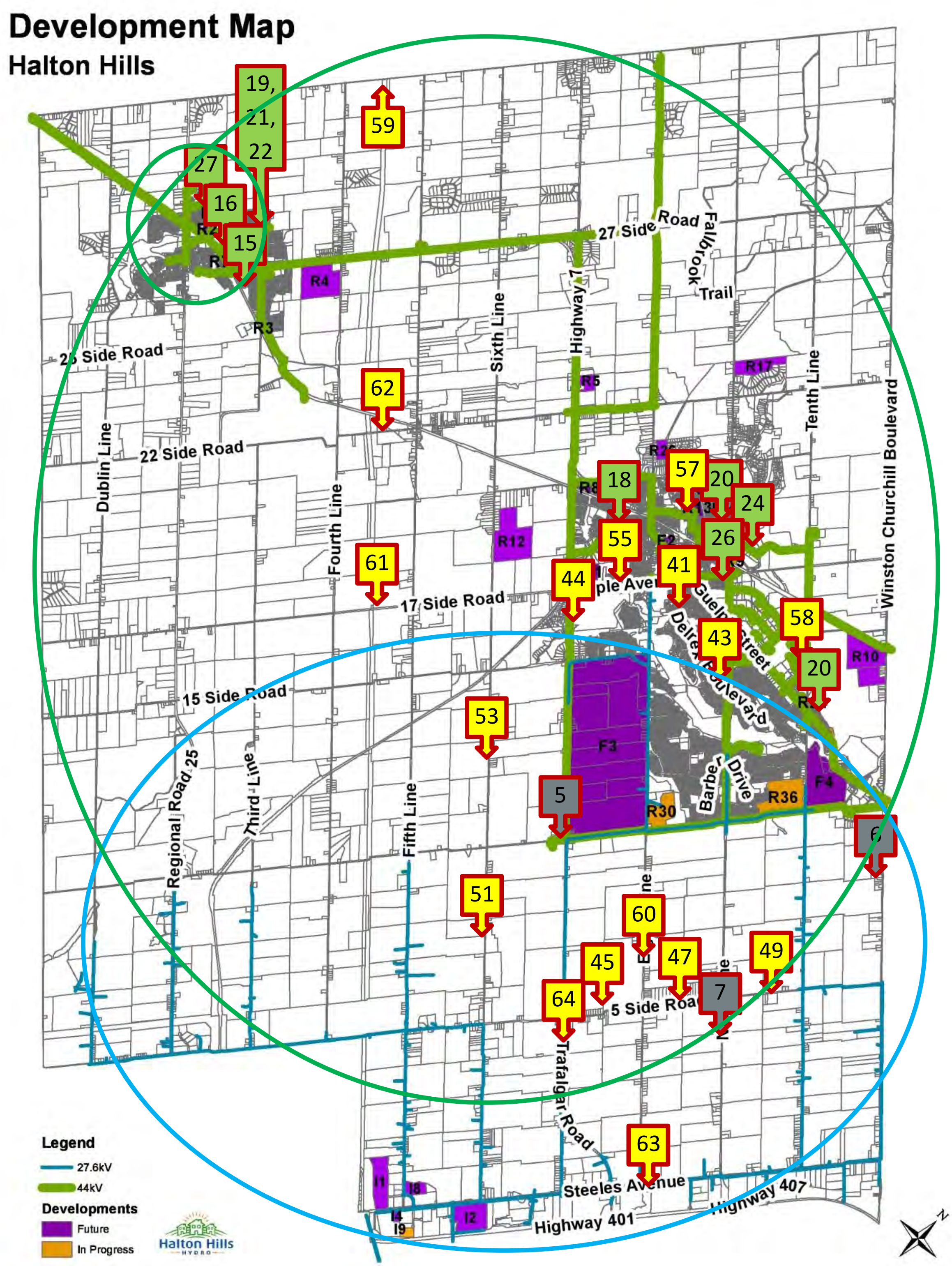


Figure 58 Mapped Capital Projects

Mapped capital projects identified in Figure 56:

System Access – Significant Municipally Driven projects

5 Trafalgar Road/ 10 Side Road (CAP14-005)

6 Winston Churchill Blvd. (5 Side Road to Mayfield Road)

7 9th Line (Steeles Avenue to 10 Side Road)

System Renewal – Significant Vintage Replacement Projects

15 Acton Feeder Tie Reinforcement, Church St. (Queen/ Beardmore)

16 Acton Feeder Tie Reinforcement, Willow St. (Beardmore/ Willow)

18 Poletrans Transformer Replacements (Georgetown) -Design/ Build - Hillside Dr

19 Poletrans Transformer Replacements (Acton) - Design 2016, Build 2017 - Norman/ Rosemary

20 Poletrans Transformer Replacements (Georgetown) - Design 2017, Build 2018 - Glen Williams/ Guelph St @ Hall Road

21 Poletrans Transformer Replacements (Acton) - Design 2018, Build 2019 - Division/Clare/ Norman

22 Poletrans Transformer Replacements (Acton) - Design 2019, Build 2020 - McDonald Blvd, Acton

24 Vintage Underground Replacement Program

26 Feeder Renewal, Georgetown (MS #13/ MS #17)

27 Feeder Renewal, Acton Area

System Service - Significant Feeder Reinforcement and Voltage Conversion Projects

41 Feeder Reinforcement, Delrex Blvd. (Rexway Dr. to Maple Ave.)

43 Feeder Reinforcement, Delrex Blvd. (Jessop Crt. To Sargent Road) - Construction

44 Trafalgar Road, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).

45 Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line) - Construction

47 Voltage Conversion, 5 Side Road (8th Line to 9th Line) - Construction

49 Voltage Conversion, 5 Side Road (9th Line to 10th Line) - Construction

51 Voltage Conversion, 6th Line (5 Side Road to 10 Side Road & 6th Line to Trafalgar Road) - Construction

53 Voltage Conversion, 6th Line (10 Side Road to 15 Side Road & 6th Line to Trafalgar Road) – Construction

55 27.6kV Extension & Loop, Maple Avenue (Trafalgar Road to Main Street South) - Construction.

57 44kV Feeder Loop, John Street to Ewing Street, Georgetown - Construction

58 Extend Feeder 19-F3 on Armstrong Avenue (South-East to Guelph St.)

59 Feeder 5F3 8320V Extension/ System Operational Enhancements

60 8th Line, 2nd circuit 27600V Steeles Avenue to 10 Side Road

61 17 Side Road and 4th Line, 3-Phase 8320 Extension/ Loop

62 22 Side Road 4th to 5th Line, 3-Phase 8320 Extension/ Loop

63 Steeles Avenue, 2 circuit 27600V underbuild, 6th Line to 10th Line

64 Trafalgar Road, 8320V Conversion to 27600V, Steeles Avenue to 10 Side Road

Halton Hills Hydro has a number of System Automation projects identified over the next five years. The goal of these projects is to leverage technology to maximize the benefit of Halton Hills Hydro's 24/7 control room. These projects include installation of automated switches and SCADA system upgrades to enhance the utilities Smart Grid and create a system where the control room can utilize automation to reduce crew time, reduce outage durations and improve system reliability. Integrating SCADA into an Outage Management System will provide the Control Room with a level of insight into the distribution system where they can identify and isolate outages with quicker response times than is currently possible with a manually operated system.

Halton Hills Hydro expects a steady amount of growth over the next five (5) years. This DS Plan includes an aggressive approach to ensuring we have supply capacity in the southern regions of Georgetown to accommodate current developments and Vision Georgetown (20,000 people and 1,700 businesses) between 2021 and 2031 as mandated by provincial regulation. Halton Hills Hydro includes in this DS Plan system service projects that will expand our 16.0/27.6kV distribution system to bring capacity from the Steeles Avenue corridor and our planned transformer station to the southern region of Georgetown to accommodate this growth.

Furthermore, this DS Plan includes expenditures further developing Halton Hills Hydro's smart grid deployment by increasing the number of automated switches employed on our 16.0/27.6kV. Over the course of the next five (5) years Halton Hills Hydro will install ten (10) additional automated switches on our 16.0/27.6kV distribution system at strategic locations to improve system reliability, enhanced system performance and data we collect from the field, and reduce O&M costs related to field crews performing switching operations. This work will coincide with expanding our 16.0/27.6kV distribution system to accommodate the provincially regulated growth Georgetown is and will be experiencing.

With respect to renewable generation and as discussed in the Renewable Energy Generation Investment Plan (Appendix G) Halton Hills Hydro has sufficient capacity at this point in time to accommodate the known renewable generation FIT projects as well as accommodate many more microFIT projects. This DS Plan does not include and capital expenditures to accommodate renewable generation. Currently, Halton Hills Hydro has over 100 microFIT renewable generators connected, and over the next 5 years the utility estimates that between 10 to 15 connections per year will take place assuming no significant changes are made to the program rules and/ or reduction of contract prices.

3.1.10 A list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned (5.4.1 h):

Key Driver	OEB Category (Primary)	Project (Detailed Location)	2016	2017	2018	2019	2020
Customer Preference	System Access	Make Ready Upgrades	$17,424	$17,772	$18,128	$18,490	$18,860
Customer Preference	System Access	microFIT/FIT	$43,735	$44,609	$45,501	$46,411	$47,340
Customer Preference	System Access	Subdivisions	$207,000	$244,260	$288,227	$340,108	$401,327
Customer Preference	System Access	Technical Service Layouts	$376,036	$384,685	$393,532	$402,584	$411,843
Customer Preference	System Access	Trafalgar Road/10 Side Rd	$357,295	$0	$0	$0	$0
Customer Preference	System Access	Winston Churchill Blvd. (5 Side Rd to Mayfield Rd).	$0	$0	$2,426,000	$0	$0
Customer Preference	System Access	9th Line (Steeles to 10 Side Rd).	$1,311,549	$0	$0	$0	$0
Customer Preference	General Plant	Remote Debit Machine	$0	$10,000	$0	$0	$0
Customer Preference, Innovation	General Plant	Interactive Voice Response (IVR)	$100,000	$0	$0	$0	$0
Innovation	General Plant	Locate Ticket mgmt & new locate set	$0	$26,040	$0	$0	$0
Innovation	General Plant	Electronic Document Mgmt	$0	$0	$100,000	$0	$0
Innovation	General Plant	Quadra License	$2,800	$2,800	$0	$0	$0
Innovation, Technology	System Service	SCADA Switch Integration	$86,579	$86,579	$0	$0	$0
Innovation, Technology	System Service	SCADA Wireless Faulted Circuit Indicators	$48,983	$0	$0	$0	$0
Innovation, Technology	General Plant	SCADA Outage Mgmt System Interfaces	$67,813	$0	$0	$0	$0
Innovation, Technology	General Plant	IBM System i POWER8 Install	$75,000	$0	$0	$0	$0
Technology	System Access	Metering Residential/Interval	$114,824	$114,824	$114,824	$114,824	$114,824
Technology	System Access	Metering General Service >50kW	$44,726	$44,726	$44,726	$44,726	$44,726
Technology	System Access	Metering Wholesale	$0	$35,438	$0	$0	$0
Technology	System Renewal	Annual Pole Testing & Replacements	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Technology	System Renewal	Switchgear Replacement, PMH-9	$0	$66,204	$0	$72,825	$0
Technology	System Renewal	Acton Feeder Tie Reinforcement, Church St. (Queen/ Beardmore)	$0	$22,728	$0	$443,724	$0
Technology	System	Acton Feeder Tie	$0	$0	$0	$22,728	$449,951

	Renewal	Reinforcement, Willow St. (Beardmore/ Willow)					
Technology	System Renewal	Porcelain Switch & Insulator Replacements	$21,686	$22,120	$22,562	$23,013	$23,474
Technology	System Renewal	Poletrans Transformer Replacements (Georgetown)	$500,000	$43,100	$512,400	$0	$0
Technology	System Renewal	Poletrans Transformer Replacements (Acton)	$38,100	$560,000	$43,100	$547,125	$294,419
Technology	System Renewal	Live Front Transformer Replacements	$98,689	$103,624	$108,805	$57,123	$0
Technology	System Renewal	Vintage Underground Replacements	$304,586	$380,733	$40,000	$40,000	$418,806
Technology	System Renewal	Vault Transformer Replacements	$0	$75,000	$0	$160,000	$164,000
Technology	System Renewal	Feeder Renewal, Georgetown (MS #13/ MS #17)	$0	$0	$0	$20,000	$450,000
Technology	System Renewal	Feeder Renewal, Acton Area	$0	$0	$0	$20,000	$450,000
Technology	System Renewal	Power transformer life extension	$21,979	$21,979	$0	$0	$0
Technology	System Renewal	Cross MS switchgear replacement	$714,205	$0	$0	$0	$0
Technology	System Renewal	Cross MS egress rebuild incl new feeder 4	$0	$337,107	$0	$0	$0
Technology	System Renewal	Silver Creek MS transformer replacement	$0	$594,266	$0	$0	$0
Technology	System Renewal	Willow MS transformer replacement	$0	$0	$0	$407,429	$0
Technology	System Renewal	Willow MS Egress rebuild	$0	$0	$0	$328,887	$0
Technology	System Renewal	Glen Williams MS ground grid & fence replacement	$0	$0	$0	$77,379	$0
Technology	System Renewal	Queen MS Switchgear Replacement	$0	$0	$0	$0	$716,266
Technology	System Renewal	Queen MS Egress rebuild	$0	$0	$0	$0	$328,887
Technology	System Renewal	Queen MS Ground grid and fence replacement	$0	$0	$0	$0	$77,379
Technology	System Renewal	Metering Retail/Interval	$91,425	$0	$91,425	$0	$91,425

		PMU replacements					
Technology	System Service	Automated Switches, 27.6kV System	$143,244	$300,812	$315,137	$329,461	$343,786
Technology	System Service	Automated Switches, 46kV System (2 Switches)	$158,607	$0	$174,468	$198,259	$0
Technology	System Service	Feeder Reinforcement, Delrex Blvd. (Rexway Dr. to Maple Ave.)	$346,812	$0	$0	$0	$0
Technology	System Service	Feeder Reinforcement, Delrex Blvd. (Jessop Crt. To Sargent Rd)	$28,427	$497,853	$497,853	$0	$0
Technology	System Service	Trafalgar Rd, 27.6kV Extension (15 Sdrd to 17 Sdrd/ Maple Ave.).	$671,181	$0	$0	$0	$0
Technology	System Service	Voltage Conversion, 5 Side Road (Trafalgar Rd to 8th Line)	$408,694	$0	$0	$0	$0
Technology	System Service	Voltage Conversion, 5 Side Rd (8th to 9th Line)	$19,643	$412,235	$0	$0	$0
Technology	System Service	Voltage Conversion, 5 SdRd (9th to 10th Line)	$0	$22,728	$453,395	$0	$0
Technology	System Service	Voltage Conversion, 6th Line (5 SdRd to 10 SdRd & 6th Line to Trafalgar)	$0	$0	$41,218	$798,356	$0
Technology	System Service	Voltage Conversion, 6th Line (10 SdRd to 15 SdRd & 6th Line to Trafalgar)	$0	$0	$0	$778,218	$730,718
Technology	System Service	27.6kV Extension & Loop, Maple Ave (Trafalgar to Main St S)	$0	$0	$0	$37,718	$577,083
Technology	System Service	44kV Feeder Loop, John St to Ewing St, Georgetown	$0	$0	$0	$28,428	$377,293
Technology	System Service	Extend 19-F3 Feeder on Armstrong Ave (SE to Guelph St.)	$0	$0	$20,000	$450,000	$0
Technology	System Service	5F3 on 32 Sdrd	$234,992	$0	$0	$0	$0
Technology	System Service	8th Line 27600V 2nd Cct	$0	$412,555	$0	$0	$0
Technology	System Service	17 Sdrd and 4th Ln	$0	$0	$523,334	$0	$0

		3Ph Extension					
Technology	System Service	22 Sdrd Limehouse 3Ph between 4th & 5th	$0	$0	$0	$340,805	$0
Technology	System Service	Steeles Ave 2 Cct underbuild 27600V	$0	$0	$556,405	$0	$0
Technology	System Service	Trafalgar Rd 8320V Conversion Steeles to 10 Sdrd	$0	$0	$0	$834,628	$0
Technology	System Service	Ballinafad MS Reclosers	$155,629	$0	$0	$0	$0
Technology	System Service	River MS - Add Feeder 4 breaker & egress	$0	$178,899	$0	$0	$0
Technology	System Service	Detailed design for Trafalgar MS	$0	$93,626	$0	$0	$0
Technology	System Service	Trafalgar MS Build excl. Power Transformers	$0	$0	$1,111,000	$0	$0
Technology	System Service	Trafalgar MS Build 2 x power transformers	$0	$0	$0	$744,000	$0
Technology	System Service	Armstrong MS new feeder 4	$0	$0	$0	$192,224	$0
Technology	General Plant	Mountainview Brick restoration	$0	$56,576	$0	$0	$0
Technology	General Plant	Building Upgrades	$50,000	$50,000	$50,000	$50,000	$50,000
Technology	General Plant	Mail Insertion Machine	$0	$0	$0	$65,000	$0
Technology	General Plant	Ergonomic Furniture Upgrades	$35,000	$12,000	$12,000	$12,000	$12,000
Technology	General Plant	Office Furniture (Accounting)	$35,000	$0	$0	$0	$0
Technology	General Plant	Parking Lot Paving	$150,000	$0	$0	$0	$0
Technology	General Plant	Tools (Operations/ Engineering)	$32,000	$32,000	$32,000	$32,000	$32,000
Technology	General Plant	Vehicles	$145,000	$290,000	$227,000	$266,000	$280,000
Technology	General Plant	Roof Resurfacing - Garage	$85,000	$0	$0	$0	$0
Subtotals			$9,343,663	$7,447,472	$10,105,472	$10,179,743	$8,734,513
Contributed Capital			$1,132,703	$595,554	$1,740,960	$711,103	$782,510
Totals			$8,210,960	$6,851,919	$8,364,511	$9,468,640	$7,952,003

Table 21 Projects by Key Driver

As explained in the sections that follow, the table above identifies projects by key driver.

3.1.10.1 Projects undertaken in response to customer preference

While Halton Hills Hydro engaged customers as a part of the planning process for this Distribution System Plan, no specific project was initiated solely as a result of customer preference. Rather, customer preferences with respect to capital expenditures were considered as part of the evaluation and prioritizing of projects with in the plan.

Halton Hills Hydro considers customer preference in prioritizing certain projects. In particular, system access projects are typically customer driven and the utility is required to complete these projects which can include connecting new customers, connecting renewable generation, and accommodating municipally driven projects such as road widening. System access projects are customer driven and therefore timelines are often determined by the customer and Halton Hills Hydro is expected to meet those timelines.

In addition to customer directed projects, the utility considers customer preference in projects undertaken to provide additional access to data or flexibility of services offered to enhance customer service. Implementation of a new Interactive Voice Response (IVR) phone system will allow greater flexibility for customers to access the utility. A remote debit machine will improve accessibility for those customers paying in the office.

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

In taking advantage of technology based opportunities to improve operational efficiency, Halton Hills Hydro includes in this DS Plan the deployment of additional automated switches that will be installed at key points on the distribution system, bring information back to the office and control room about the state of the system, and serve to reduce O&M costs by lessening the amount of man hours spent by field staff travelling to switching points to perform switching operations. The continued inclusion of automated switches will compliment Halton Hills Hydro's smart grid programs that began in 2011 with the first installation of automated switches on the 16.0/27.6kV distribution system.

3.1.10.3 Projects undertaken to study or demonstrate innovative processes, services, business models, or technologies.

Halton Hills Hydro prides itself on being ahead of the curve and being best in class. This is demonstrated through a recently implemented estimating software tool, Quadra, which is used by the Engineering Department to produce estimates for projects. Quadra contains Halton Hills Hydro's construction standards that were approved by a Professional Engineer per O.Reg. 22/04. Each standard (called an assembly in Quadra) contains a bill of material, labour and vehicle hours, and cost components for these factors. The software also contains assemblies related to specific labour based functions such as conductor stringing and pole removal. The utility implemented this innovative software in November 2014 to improve the accuracy and efficiency by which estimates are created. Quadra also interacts with the utility's financial and inventory systems whereby materials can be requisitioned electronically rather than paper based as was done prior to implementation.

Halton Hills Hydro's Engineering Department will also begin using SpidaCalc, engineering software to perform non-linear pole line design. This software was purchased in late 2013 and over the course of 2014 Halton Hills Hydro worked with the software developer to ensure all of their standards were input into the software so that engineering analysis can take place with a high level of accuracy. SpidaCalc software was implemented at Halton Hills Hydro as a proactive measure to be ready for an anticipated revision to CSA standard C22.3 No.1 “Overhead Systems” which will require the sole use of non-linear analysis. Up to this point Halton Hills Hydro had been using linear analysis which will not be permitted once CSA publishes a revised standard. We will also be enhancing our use of our GIS system and adding to the data captured by the system. In 2015, electronic mapping was introduced to move away from reliance on paper maps. Use of this system will continue to be enhanced over the next few years.

Halton Hills Hydro is also considering the further use of cable injection/ rejuvenation technologies to address aging cable assets. In 2014 Halton Hills Hydro conducted a pilot project and injected primary cables in a small area of Georgetown’s southern region supplied by 16.0/27.6kV. Halton Hills Hydro is considering further cable injection in areas where it makes sense to extend the life of cables rather than incurring significant costs associated with trenching and duct and cable installations in built up urban areas. The utility may realize significant cost savings if additional cable injection is possible to extend the life of cables.

3.2 Capital Expenditure Planning Process Review (5.4.2)

3.2.1 Capital planning objectives, criteria & assumptions (5.4.2 a)

Halton Hills Hydro takes a prudent, cost effective approach to asset management and capital planning. The overarching goal mandated by the utility’s mission statement is “to provide electricity distribution excellence in a safe and reliable manner”. Safety and reliability are the first considerations in capital planning. Customer satisfaction is a key to providing distribution excellence. As a result, customer driven projects are always given a high priority in the planning process. As part of the planning process, the engineering and operations departments prepare detailed project sheets and budgets for each project. These expenditures receive both executive and Board of Directors review prior to approval for inclusion in the final budget.

Halton Hills Hydro has seen significant growth over the past number of years. This growth comes in the form of new development in vacant lands (farm fields) as well as in-fill development in established urban neighbourhoods. The capital planning process strikes a balance between system renewal and system service projects to ensure that the distribution system will support the growth in the Halton Hills community. The utility includes customer driven (system access) projects to ensure regulatory requirements are met. Some factors that affect decision making and drive projects include:

- Regulatory obligations (ex. municipal road widening);
- Asset condition – What are the conditions of the asset or asset group? Is there a public safety risk in allowing deteriorated assets to remain in service?
- Load growth – Where is load growth planned? What does municipal planning have scheduled?

- System optimization – What can we do to optimize the expenditures and have the greatest impact? Convert 4.8/ 8.32kV system to 16.0/ 27.6kV and incorporate into overall growth plans? Determine key locations for Automated switches?
- System constraints – Do we have constrained areas of the distribution system that would make it difficult to perform switching operations?

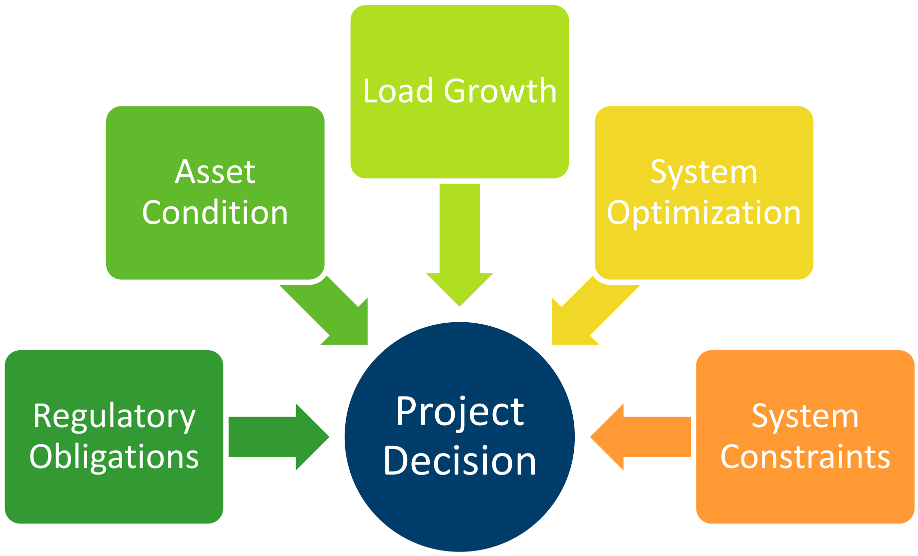


Figure 59 Project Decision Inputs

These factors are used to plan what capital projects are of necessity each year. Halton Hills Hydro determines the scope of the projects and prioritizes each project to ensure that planned work is completed in the planned year. In general regulatory obligations take precedent however such projects are often driven by customers and therefore timelines are largely dependent on the customer's schedule. Halton Hills Hydro strives to strike a balance in their annual capital plans to ensure that if customer work does not proceed as planned, there are other projects that can be moved up and be completed ahead of schedule.

HHHI proactively schedules its annual projects to incorporate design, material ordering and construction timeframes. Expenditures are planned throughout the year to ensure a consistent level of spending that does not over burden the utilities finances and ensures material and crew availability.

3.2.2 Policy and procedures for considering non distribution system alternatives to relieving system capacity or constraints such as regional planning processes (5.4.2 b)

Halton Hills Hydro's capital planning process focuses on delivering value to customers by moving forward with projects that will provide access to the distribution system, ensure its reliability, and maintains Halton Hills Hydro's reputation in the community. The capital planning processes ensures that expenditures relate directly to asset management objectives, are in line with customer response and corporate objectives, and serve to the betterment of the distribution system. These objectives lead to the primary factors that drive capital planning:

- Regulator objectives;
- Asset condition;
- Load growth;
- System optimization;
- System constraints;

When planning annual capital expenditures, Halton Hills Hydro evaluates these factors when planning and budgeting expenditures to ensure that capital planning is in line with corporate objectives and relate to the growing demand for reliable power. Halton Hills Hydro's annual capital plan is reviewed by senior management and approved by the utility's board of directors.

If a need arises to attend to unplanned projects (unplanned municipal/ customer driven work) that would impact Halton Hills Hydro's annual capital budget, Halton Hills Hydro reviews the necessity of the additional projects, determine the priority of such project compared to planned work, the cost of such work, and if taking on the additional project would impact the annual budget. If necessity dictates that unplanned work proceed, Halton Hills Hydro evaluates alternatives for planned work to determine if a form of the planned work could proceed or if the project needs to be deferred for a year. Alternatives can include:

- Perform system analysis using distribution engineering simulation software and determine if system efficiencies can be gained to address constraint issues through system re-configuration.
- Determining impacts on system reliability and efficiency gains by implementing a design alternative and evaluating the costs involved.
- Evaluation of safety factors relating to the alternative:
    - Is the alternative safe and does it promote public and worker safety?
    - How long can the alternative remain in use before additional attention is required?
    - Can approved standards be implemented to improve system reliability and safety as part of an alternative solution (ie: increase clearances, reduce potential electrical exposure hazards)?
- Resources such as materials and labour are factored into alternative decisions.
- Attend to community focused initiatives and programs such as CDM and renewable generation where such programs can positively impact the distribution system and become part of a non-distribution alternative that provides value to our customers.

Once a preferred design alternative is selected, the utility will prepare a business case that supports reallocation of capital funds for the betterment of the distribution system that will allow unplanned work, usually system access or emergency system renewal, to proceed and that respects the overall capital planning process of the utility. The business case is then reviewed by senior management for final approval. In instances where distribution expansions are required to meet the needs of customer driven system access projects, Halton Hills Hydro will perform an economic evaluation consistent with the OEB Distribution System Code. Where an economic evaluation identifies a shortfall in revenues, Halton Hills Hydro will require a capital contribution from the customer to lessen the impact on Halton Hills Hydro's capital budget and financial burden on rate payers.

3.2.3 Description of process used to identify, select, prioritize and pace projects by investment category (5.4.2 c)

Projects at Halton Hills Hydro are analyzed using a two pronged approach. They are given a risk rating based on the utilities Enterprise Risk Management Framework and given a priority ranking. These rankings are reviewed relative to each other and relative to the overall capital budget for the year. To ease the burden on rate payers, the utility strives to maintain a stable capital expenditure plan with an annual variance within 3 percent of the overall capital budget.

All projects are given a priority ranking as follows:

5 – Project must be completed in the budgeted year and cannot be delayed. All projects with a risk rating of 15 or higher fall into this category.
4 – These projects should be completed within the budgeted year if at all possible. Deferring the project can have implications for customers. Delays of a few months are typically acceptable. All Customer Directed projects fall in this category. All projects with a risk of 10-14 fall within this category.
3 – These projects could be delayed by up to one year without significant impact. Risk is below 10.
2 – These projects could be deferred if necessary
1 – These projects are not mandatory. They can be deferred without impact.

Figure 60 Project Priority matrix.

Projects are evaluated for risk based on an impact and probability assessment to determine an overall risk value. The risk values assigned to a project are based on the risk should the project not be completed.

Risk Impact: The impact value represents the significance of the risk to the utility. The impact can range from insignificant to catastrophic. A rating of 5 is the highest risk impact, while 1 is the lowest impact.

Risk Probability: This is the likelihood or probability that a particular risk will occur. These probabilities range from rare to almost certain and are evaluated within a set time period, typically one year. A probability of 5 represents a risk that is highly likely to occur while a probability of 1 represents a rare or unlikely event.

Risk and impact are multiplied to determine an overall risk rating for each project. Each project could have a possible risk ranging from 1 (extremely low risk) to 25 (extremely high risk).

Within Halton Hills Hydro's capital expenditure plan, each project within each of the four investment categories is identified with a risk rating and a priority ranking. In taking a prudent approach to capital expenditure while minimizing potential customer bill impacts, a project must rate a minimum priority of three to be included in the capital expenditure plan.

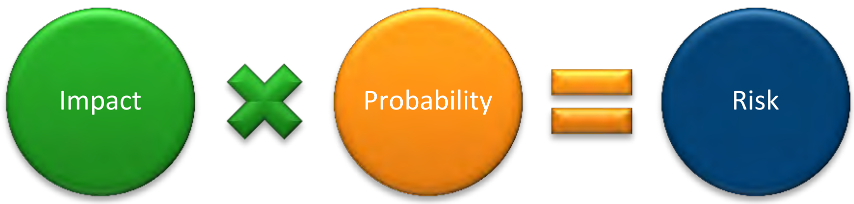


Figure 61 Risk Rating System

Project pacing is driven by an analysis of project risk and priority along with overall capital expenditure budget. The utility strives to keep its capital expenditure stable throughout the forecast period of this plan. Annual capital budgets are kept within 3% to maintain a stable pacing of expenditure.

3.2.4 Any other mechanisms used to engage customers for the purpose of identifying their needs, priorities and preferences(5.4.2 d)

Halton Hills Hydro customers have participated in two random telephone surveys over the past 5 years. These surveys were conducted by an independent third party with results compared across the province and country. The survey was conducted with both residential and small commercial customers as these two classes represent 99% of the utilities' customer base. Customers have responded positively indicating that the utility receives high ratings for providing excellent quality services and for providing consistent, reliable energy.

Customer Service Quality			
Top 2 boxes, 'strongly + somewhat agree'	**Halton Hills Hydro**	**National**	**Ontario**
Deals professionally with customers' problems	85%	82%	78%
Pro-active in communicating changes and issues affecting Customers	80%	74%	73%
Quickly deals with issues that affect customers	82%	79%	74%
Customer-focused and treats customers as if they're valued	82%	74%	72%
Is a company that is 'easy to do business with'	85%	79%	75%
Cost of electricity is reasonable when compared to other utilities	60%	60%	55%
Provides good value for money	70%	67%	63%
Delivers on its service commitments to customers	85%	84%	82%

Base: total respondents with an opinion

Table 22 Customer Service Quality
Source: Simul Corporation 2014 UtilityPulse survey. Attached as Appendix H

Survey results show that 74% of Ontario customers believe that the utility should be investing more in the electricity grid to reduce the number of outages and 83% feel utilities should be investing in maintaining and upgrading equipment.

Priority Investments	
Top 2 Boxes: 'Very high priority + High priority'	**Ontario LDCs**
Investing more in the electricity grid to reduce the number of outages	74%
Burying overhead wires	60%
Developing a smart phone application	31%
Maintaining and upgrading equipment	83%
Providing sponsorships to local community causes	43%
Making better use of social media	30%
Providing more self-serve services on the website	38%
Educating customers about energy conservation	74%
Reducing the time needed to restore power	79%
Investing more in tree trimming	58%

Base: An aggregate of respondents from 2014 participating LDCs

Table 23 Priority Investments
Source: Simul Corporation 2014 UtilityPulse survey.

Halton Hills Hydro held a public information session on January 20, 2015 prior to implementing its 2015 tree trimming program. In attendance at the public meeting was Halton Hills Hydro staff as well as the contracted arborist and tree trimmers. The purpose of this session was to provide information about the tree trimming program as well as answer customer questions and concerns, including review of specific trees and likely tree trimming outcomes. The session was held in the Village of Glen Williams in the area where the 2015 tree trimming would be occurring. 12 residents attended. They supported the utility's tree trimming initiative and were pleased to see it commence.

In 2015, Halton Hills Hydro engaged SimulCorp to conduct customer surveys and focus groups to provide information supporting the Distribution System Plan. Customer engagement is a key driver for the successful development of Halton Hills Hydro's capital and operational expenditures plan. The key to effective engagement lies in understanding customers' attitudes, wants, needs, motivations, and in recognizing that customer opinions matter. Customer engagement is crucial for the longer term success of the LDC.

62% of customer surveyed felt that utility spending should focus on both reducing the number of unplanned outages and the duration of unplanned outages. Outage management is addressed in this plan through a number of feeder renewal and reinforcement projects as well as through SCADA upgrades including OMS integrations. The top communication method customers prefer for finding out power outage information is through accessing recorded telephone messages. In 2016, we will be implementing an Interactive Voice Response (IVR) system to address this preference.

62% of Halton Hills Hydro customers prefer a pro-active replacement strategy over run-to-failure options. When asked about increased rates to pay for capital expenditures, 71% of customers were willing to pay more for replacing aging equipment to improve safety and reliability. This plan addresses a number of system renewal projects focused on replacing aging equipment including an accelerated pole replacement program to remove aging poles from our distribution system.

Receptivity for paying more increases when there is a direct benefit to the customer. Looking at operational expenditures, 53% of respondents said they would pay more for tree-trimming. They were less willing to pay for other operational items. Tree trimming remains a focus of the utility for the next five years.

3.2.5 Method and criteria to prioritize REG investments, including any distributor owned renewable generation projects (5.4.2 e)

Halton Hills Hydro makes investments in renewable energy generation that are specific to renewable projects for which we receive applications. Since program inception, the distribution system has had sufficient capacity to enable connection of microFIT and FIT generators without the need to make significant investments in the distribution system beyond connection assets (ex. meter, instrument transformers). Capital expenditures identified in this DS Plan are not the result of constraints that would limit renewable generation connections.

If Halton Hills Hydro were to receive an application for renewable generation that required upgrades or an expansion of the distribution system, Halton Hills Hydro would work with the applicant, identify the necessary upgrades and/ or expansions, develop a cost estimate for the work, and apply the methodologies for cost appropriation identified in the OEB Distribution System Code (ie: applicant responsible for $90,000/ megawatt).

3.3 System Capability Assessment for Renewable Energy Generation (5.4.3)

Halton Hills Hydro has completed a Renewable Energy Generation Investment Plan to assess the state of the utilities' existing distribution, study the current renewable-connected generation and near-term growth forecast and defines the strategy to accommodate predicted renewable generation growth. This plan is attached as Appendix G.

3.3.1 Applications over 10KW (5.4.3 a)

As of February 2015, Halton Hills Hydro has one 200 kW application currently in progress for connection in late May of 2015. There are no other applications over 10 kW as of that date.

3.3.2 Number and capacity in MW of connections anticipated over forecast period (5.4.3 b)

Since program inception in 2009, Halton Hills Hydro has made an average 18 microFIT connections per year totaling an average of 0.149MW of microFIT connected per year. There are currently 6 pending small FIT applications totaling 2.313 MW. Based on the volume of past connections and applications, we expect to continue connecting 10-15 projects annually for a total of 0.1MW to 0.15MW annually.

3.3.3 Capacity in MW of distribution system to connect renewable energy (5.4.3 c)

As of December, 2014, Halton Hills Hydro has connected 106 microFIT and six FIT projects for a total of 2.589MW of renewable generation. Table 24 below indicates the total microFIT and FIT capacity allocations and connections by municipal substation feeder.

Cumulative generation connections per feeder are limited on an individual feeder basis as follows:

- Feeders operating at 8.32 kV: 1.5MW
- Feeders operating at 4.16 kV: 1.4MW

Substation Designator	Feeder	Feeder Capacity Limit (MW)	Total Feeder Capacity Allocated & Connected (MW)	Remaining Available Feeder Capacity (MW)
19	1	1.440	0.450	0.990
	2	1.440	0.014	1.426
	3	1.440	0	1.440
23	1	0.850	0.119	0.731
	2	0.850	0.027	0.8234
	3	0.850	0.020	830.12
1	1	0.850	0.020	0.8301
	2	0.850	0	0.850
	3	0.850	0.007	0.8428
7	1	0.720	0.036	0.68433

	2	0.720	0.010	0.710
	3	0.720	0	0.720
13	1	1.440	0.010	1.430
	2	1.440	0.004	1.4357
	3	1.440	0.010	1.430
11	1	1.500	0.059	1.44112
	2	1.500	0.057	1.44329
	3	1.500	0.055	1.44524
17	1	1.440	0.027	1.41292
	2	1.440	0.006	1.434
	3	1.440	0.025	1.41475
21	1	0.850	0.020	0.830
	2	0.850	0.010	0.840
	3	0.850	0	0.850
15	1	1.440	0.502	0.93839
	2	1.440	0.058	1.3819
	3	1.440	0.006	1.4344
5	1	0.850	0.169	0.681137
	2	0.850	0.085	0.76487
	3	0.850	0.006	0.844
9	1	0.720	0.009	0.71054
	2	0.720	0.016	0.70398
	3	0.720	0.027	0.693
3	1	0.720	0.017	0.7028
	2	0.720	0	0.720
	3	0.720	0.004	0.7158

Table 24 Allocated/ Connected Capacity & Remaining Capacity on 4.16kV and 8.32kV Feeders

Halton Hills Hydro also has renewable energy generation projects connected directly to our 27.6kV and 44kV feeders. The connected and allocated capacity, as well as potential capacity, based on recent IESO Distribution Assessment Tests, is shown in Table 25 below. Because our 44kV and 16/ 27.6kV feeders originate at Hydro One owned transformer stations, Halton Hills Hydro has not included available or remaining capacity for these feeders as they are owned by Hydro One. Rather Halton Hills Hydro will utilize on-line resources provided by Hydro One to assess feeder capacity for new renewable energy generation.

Transformer Station	Feeder, Voltage	Allocated/ Connected Capacity (MW)	Potential Future REG >10kW (MW)
Pleasant TS DESN1	42M23, 44kV	0	0.250
	42M25, 44kV	0.010	0
	42M28, 44kV	0.955	2.063
Halton TS	41M21, 27.6kV	0.143	0
	41M29, 27.6kV	0.020	0
	41M30, 27.6kV	0.029	0

Table 25 Allocated/ Connected Capacity on 27.6kV and 44kV Feeders

3.3.4 Constraints related to connection, either with distribution system or upstream system (5.4.3 d)

Halton Hills Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects anticipated from 2016 to 2020. There are no large projects anticipated in the service territory. Should a large connection or a concentrated number of connections in a specific area occur, Halton Hills Hydro will assess any potential system limitations and work with the applicants to enable renewable energy connections provided such connections would not adversely affect the distribution system.

3.3.5 Constraints for an embedded distributor that may result from these connections (5.4.3 e)

At this time, Halton Hills Hydro has one embedded distributor – Hydro One Networks Inc. (Erin area) who is supplied from our 8.32kV distribution system. Presently there are no known constraints for this embedded distributor with respect to Halton Hills Hydro's distribution system supply to that embedded distributor that would limit the potential for connecting renewable generation below the limitations for an 8.32kV feeder as stated above.

In recent years Halton Hills Hydro has planned and constructed distribution system reinforcement projects which included expansion of our 27.6kV system and adding a new feeder to a substation. These projects were the result of the utilities own plans however they have the added benefit of providing potential capacity for future renewable energy generation connections. Over the next five (5) years, inclusive of the Distribution System Plan period, Halton Hills Hydro is planning projects that will serve to provide our customers with continued reliable electrical supply. These projects may also increase the available capacity for renewable energy generation.

Based on a calculated remaining maximum capacity and the projected generation projects Halton Hills Hydro has the capacity in place to accept future renewable generation projects. As such, there are no specific investments planned to accommodate renewable energy connections.

3.4 Capital Expenditure Summary (5.4.4)

The table below provides a summary snapshot of Halton Hills Hydro's expenditures over a 10 year period. This is the first 5 year Distribution System Plan filed with the Board and as such, comparisons between Planned and Actual amounts are not provided for historical years. This is consistent with the Notes to Table provided in *Chapter 5 Consolidated Distribution System Plan Filing Requirements.*

	Historical Period Actuals (Previous Plan n/a)															Forecast Period (Planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Plan	Actual $	Var	Plan	Actual $	Var	Plan	Actual $	Var	Plan	Actual $	Var	Plan	Budget $	Var	$	$	$	$	$
System Access	N/A	$1,182,087	-	N/A	5,251,191	-	N/A	1,867,987	-	N/A	2,680,732	-	N/A	1,578,189	-	1,339,885	290,760	1,589,978	256,040	256,410
System Renewal	N/A	$2,316,186	-	N/A	2,560,260	-	N/A	1,584,398	-	N/A	2,362,906	-	N/A	1,870,124	-	3,790,671	4,226,861	2,818,292	4,220,233	5,464,607
System Service	N/A	$757,210	-	N/A	1,192,256	-	N/A	1,777,792	-	N/A	1,975,057	-	N/A	3,485,366	-	2,302,791	1,854,882	3,535,241	4,537,366	1,856,986
General Plant	N/A	$865,557	-	N/A	1,210,052	-	N/A	420,040	-	N/A	1,272,141	-	N/A	784,136	-	777,613	479,416	421,000	425,000	374,000
Total	-	$5,121,039	-	-	10,213,760	-	-	5,650,217	-	-	8,290,836	-	-	7,717,815	-	**8,210,960**	**6,851,919**	**8,364,511**	**9,468,639**	**7,952,003**
System O&M		$1,215,158	-		2,703,576	-		1,543,011	-		1,406,841	-		1,850,667	-	1,779,072				

Table 26 Capital Expenditure Summary

3.4.1 Historical Period – Yearly Variation on Capital Expenditures

3.4.1.1 Variation in Capital Expenditures between 2011-2012

Explanation

System Access

2011: $1,182,087 2012: $5,251,191 Variance: $4,069,104

The level of expenditure in 2012 is significantly higher reflective of the disposition of the $3,660,492 smart metering capital cost.

In 2012 planned system access work began construction in which portions of our pole line along Steeles Avenue were relocated to accommodate regional road improvement plans between Trafalgar Road and Winston Churchill Blvd. HHHI also continued another portion of Steeles Avenue relocations, carried over from 2011 into 2012, between James Snow Parkway and 5th Line South. The level of expenditures in 2012 as compared to 2011 reflects the increased amount of system access work undertook in 2012.

System Renewal

2011: $2,316,186 2012: $2,560,260 Variance: $244,075

System renewal expenditures in 2011 and 2012 are consistent over the 2 year period and reflect HHHI's commitment to ensuring aged assets are rehabilitated or replaced prior to failure thus lessening negative impacts to customer resulting from failed equipment. Significant expenditures in this category relate to replacement of aged poles and underground infrastructure replacements (PoleTrans transformers and primary cable).

System Service

2011: $757,210 2012: $1,192,256 Variance: $435,046

In 2012 system service expenditures reflected HHHI ongoing focus on ensuring its distribution system is robust and flexible. System access projects in 2012 reflected HHHI's commitment to providing distribution excellence by procuring and beginning to install automated switches at key locations in our 44kV sub-transmission system. Expenditures in the category also included upgrading key feeder lines on our distribution system to ensure a continued support of current load and accommodate new load from in-fill development.Explanation

General Plant

2011: $865,557 2012: $1,210,052 Variance: $344,496

2012 had an increase in General Plant spending as a new bucket truck was purchased. In 2012, $200,278 of computer hardware and software capital cost was transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012. Other items added in 2012 that is affecting the variance are additions to Building, Furniture and Fixtures for $356,930, GIS system implementation for $57,583.

3.4.1.2 Variation in Capital Expenditures between 2012-2013

System Access

2012: $5,251,191 2013: $1,867,987 Variance: ($3,383,204)

The levels of expenditure in 2013 as compared to 2012 reflect an increased need to address municipally driven work along Steeles Avenue as the Region of Halton continued its road widening projects. The decrease is reflective of the 2012 disposition of smart metering expense.

System Renewal

2012: $2,560,260 2013: $1,584,398 Variance: ($975,862)

Expenditures for system renewal projects were greater in 2012 as the level of investment reflects the larger scope of work undertaken to replace aged and obsolete PoleTrans transformers. In 2012 HHHI PoleTrans expenditures in Acton totaled $1,040,177 as part of our 3 year PoleTrans phase out plan for Kingham Road. In 2013 HHHI completed the Kingham Road project began a smaller scoped PoleTrans replacement project on Bower Street and John Street in Acton to remedy safety issues. This smaller project totaled $345,071.

System Service

2012: $1,192,256 2013: $1,777,792 Variance: $585,536

The increased level of expenditures relating to system service projects in 2013 reflect HHHI's commitment to ensuring the distribution system is robust and accommodating for growth. In 2013 HHHI undertook two significant pole line projects addressing capacity on the distribution system. The projects addressed potential constraints at HHH's municipal substation MS19 by bringing a third feeder, 19-F3, out of the substation as well as increased reliability by extending our 27.6kV distribution system along Trafalgar Road from 15 Sdrd to 10 Sdrd working towards closing a loop.

General Plant

2012: $1,210,052 2013: $420,040 Variance: $(790,012)

2012 had an increase in General Plant spending as a new bucket truck was purchased. In 2012, $200,278 of computer hardware and software capital cost was transferred from the Deferral and Variance Account 1555 as result of HHHI smart meter disposition in 2012. Other items added in 2012 that is affecting the variance are additions to Building, Furniture and Fixtures for $356,930, GIS system implementation for $57,583.

3.4.1.3 Variation in Capital Expenditures between 2013-2014

System Access

2013: $1,867,987 2014: $2,680,732 Variance: $812,746

In 2014 the level of expenditures relating to system access projects was greater than 2013 mainly due to municipally driven projects along Steeles Avenue and at the intersection of 10 Side Road and 10th Line. In 2014 HHHI continued relocating plant along Steeles Avenue, as part of one Region contract and undertook a second Region initiated relocation project along Steeles Avenue.

System Renewal

2013: $1,584,398 2014: $2,362,906 Variance: $778,508

The increased level of expenditures in 2014 reflects HHHI's commitment to ensuring our aged assets that have reached their end of useful life are replaced before they fail. In 2014 HHHI undertook normal levels of individual pole replacements and also began renewing plant along Delrex Blvd and Sargent Road in Georgetown. In 2014 there was also an increase in Operations driven pole replacements (poles identified by line staff as needing replacement). HHHI undertook a significantly larger scope of Poletrans replacements in 2014 in the Lakeview Subdivision in Acton as compared to similar work on Bower Street in 2013.

System Service

2013: $1,777,792 2014: $1,975,057 Variance: $197,265

The increased level of expenditures in 2014 relating to system service projects reflects HHHI's continued conversion of our 8.32kV distribution system to 27.6kV as we aim to increase reliability in the southern regions of our service territory as well the purchase and installation of six (6) 46kV automated switches.

General Plant

2013: $420,040 2014: $1,272,141 Variance: $852,101

In 2014, HHHI implemented a new Enterprise Reporting Platform (ERP) financial software package to replace the legacy system that had been in place since 1997. This new system includes purchasing, inventory, payroll and financial systems and a robust estimating and job costing package.

3.4.1.4 Variation in Capital Expenditures between 2014-2015

Note: 2015 numbers are budgeted numbers, not actuals.

System Access

2014: $2,680,732 2015: $1,578,189 Variance: ($1,102,543)

In 2014 the level of expenditures relating to system access projects was greater than 2015 mainly due to municipally driven projects along Steeles Avenue and at the intersection of 10 Side Road and 10th Line. In 2014 HHHI continued relocating plant along Steeles Avenue, as part of one Region contract and undertook a second Region initiated relocation project along Steeles Avenue. Part of this project is continuing in 2015 but the majority of work was done in 2014.

System Renewal

2014: $2,362,906 2015: $1,870,124 Variance: ($492,782)

In 2015 the overall estimated level of expenditures relating to system renewal projects are less than 2014. This reflects that in 2014 HHHI undertook a significant amount of system renewal work relating to replacing old poles and removing aged obsolete PoleTrans transformers from service.

System Service

2014: $1,975,057 2015: $3,485,366 Variance: $1,510,308

In 2015 the estimated level of expenditures for system service projects is greater than the actual 2014 expenditures. The significant difference is the land purchase and engineering design for the new Transformer Station.

General Plant

2014: $1,272,141 2015: $784,136 Variance: ($488,005)

General Plant spending in 2015 is reduced as the new software system was purchased in 2014.

3.4.2 Forecast period – Yearly Variation on Capital Expenditures

3.4.2.1 Variation in Capital Expenditures between 2015-2016 (Forecast)

Note: 2015 numbers are budgeted numbers, not actuals.

System Access

2015: $1,578,189 2016: $1,339,885 Variance: ($238,304)

System Access spending is relatively consistent between the two years.

System Renewal

2015: $1,870,124 2016: $3,790,671 Variance: $1,920,547

2016 spending is increased due increased vintage replacement projects and pole replacement strategies.

System Service

2015: $3,485,366 2016: $2,302,791 Variance: ($1,182,575)

System Service spending in 2015 is significantly higher than most years due to the land purchase for the new Transformer Station.

General Plant

2015: $785,136 2016: $777,613 Variance: ($6,523)

Spending in this category is relatively consistent between the two years.

3.4.2.2 Variation in Capital Expenditures between 2016-2017 (Forecast)

System Access

2016: $1,339,885 2017: $290,760 Variance: ($1,049,125)

The main driver in System Access spending in 2016 is municipally directed road widening projects. Specifically, two significant projects: the intersection widening project at Trafalgar Road and 10 Side Road and the road widening project along 9th Line between Steeles Ave and 10 Side Road. The combined budget for these two projects is $1,668,844. These projects involve relocating our utility poles, wires, anchors, and related equipment. There are currently no significant road widening projects planned for

2017; however there is a large project planned for 2018. The primary risk to completion to these projects is that work may be delayed until the Region of Halton can acquire the necessary land and easements. Halton Hills Hydro generally will not commence construction until we receive confirmation that land and easements are acquired or we have received permission to enter and construct our work. As a result of these potential delays, budgeting and timing for these projects can be difficult to predict.

System Renewal

2016: $3,790,671 2017: $4,226,861 Variance: $436,190

The main driver in System Renewal spending in 2017 is an increase in vintage system replacement projects and substation improvements. Switchgear replacement projects are scheduled every two years, beginning in 2017. 2017 also includes a significant PoleTrans transformer replacement project in Acton. The design work for the project is scheduled for 2016 with construction in 2017.

The Silver Creek MS transformer is scheduled for replacement in 2017. The next major substation projects are scheduled for 2019.

System Service

2016: $2,302,791 2017: $1,854,882 Variance: ($447,909)

The main difference in System Service spending between the two years is the installation of automated switches on the 46kV system. Two switches are planned for installation in each of 2016, 2018 and 2019, with none in 2017 or 2020.

General Plant

2016: $777,613 2017: $479,416 Variance: ($298,197)

Three projects are the key drivers for the increased spending in General Plant in 2016. The roof on the garage portion of the Halton Hills Hydro office needs to be resurfaced in 2016. As well, the parking lot requires complete resurfacing and repaving that year. The other main project in 2016 is the implementation of an Interactive Voice Response (IVR) system. This system addresses customer preferences for improved communication and self-service options as identified in our customer surveys and focus groups.

3.4.2.3 Variation in Capital Expenditures between 2017-2020 (Trending)

System Access

System Access projects are expected to remain fairly consistent with the exception of 2018 when a large Region of Halton driven road widening project on Winston Churchill Blvd. is expected to proceed.

System Renewal

System Renewal projects are planned fairly evenly throughout the duration of this plan. There is a decrease in System Renewal spending planned in 2018 to accommodate the increase in System Access spending. Two larger feeder renewal projects are scheduled for 2020 to upgrade and harden parts of the distribution system in Acton and Georgetown. The intent of these projects is to renew portions of the distribution system that are reaching the end of useful life and no longer meet current standards for construction.

System Service

2018 and 2019 will see the completion of a number of voltage conversion projects as the construction of a new municipal substation. Voltage Conversion projects planned over the next several years are intended continue to expand the 27.6kV distribution system.

General Plant

General Plant expenditures are fairly consistent for the duration of this plan and are largely driven by fleet replacements.

3.5 Justifying Capital Expenditures (5.4.5)

- *Justification for how the plan delivers value to customers including controlling costs through optimization, prioritization and pacing*

Halton Hills Hydro capital plans over the next 5 years include utility driven projects (system renewal and system service) as well as customer driven project (system access). System Access projects are those the utility has obligations to act on and in doing so some system renewal or system service projects may be rescheduled to accommodate regulatory obligations. This becomes more evident where the municipality has undertaken an environmental assessment and cannot provide good information from which to budget. The utility is obligated by the Public Service Works on Highways Act, R.S.O. 1990, Chapter 49 to take up, remove or change our infrastructure however when the municipality cannot provide specific details or timeframes, utility driven projects can be put at risk. Halton Hills Hydro will mitigate such risk by reassessing priority and evaluating financial impacts of such changes to determine if all planned projects can commence or if some may need to be deferred.

3.5.1 Overall Plan (5.4.5.1)

3.5.1.1 Comparative expenditures by category over historical period

The proposed five year capital expenditure program for 2016-2020 is summarized in Table 27 below. This plan represents an average gross annual expenditure of $9.1 million. After capital contributions, the average annual expenditure is $8.1 million.

	Year					
OEB Category	2016	2017	2018	2019	2020	Total
System Access	$2,472,588	$866,314	$3,330,938	$967,143	$1,038,920	$8,695,904
System Renewal	$3,790,671	$4,226,861	$2,818,292	$4,220,233	$5,464,607	$20,520,664
System Service	$2,302,791	$1,854,882	$3,535,241	$4,567,366	$1,856,956	$14,117,266
General Plant	$777,613	$479,416	$421,000	$425,000	$374,000	$2,477,029
Net Totals:	**$9,343,663**	**$7,447,472**	**$10,105,471**	**$10,179,742**	**$8,734,513**	**$45,810,862**
Contributed Capital	$1,132,703	$595,554	$1,740,960	$711,103	$782,510	$4,962,830
Annual Totals:	**$8,210,960**	**$6,851,919**	**$8,364,511**	**$9,468,640**	**$7,952,003**	**$40,848,033**

Table 27 Proposed Capital Expenditure

	Year					
OEB Category	2011	2012	2013	2014	2015	Total
System Access	$ 1,609,792.00	$ 5,290,344.00	$ 2,775,610.00	$ 3,875,798.00	$ 3,026,326.00	$ 16,577,870.00
System Renewal	$ 2,316,186.00	$ 2,560,260.00	$ 1,584,148.00	$ 2,362,906.00	$ 1,870,124.00	$ 10,693,624.00
System Service	$ 757,210.00	$ 1,192,256.00	$ 1,777,792.00	$ 1,975,057.00	$ 3,485,366.00	$ 9,187,681.00
General Plant	$ 865,557.00	$ 1,210,052.00	$ 420,290.00	$ 1,272,141.00	$ 784,136.00	$ 4,552,176.00
Net Totals:	**$ 5,548,745.00**	**$ 10,252,912.00**	**$ 6,557,840.00**	**$ 9,485,902.00**	**$ 9,165,952.00**	**$ 41,011,351.00**
Contributed Capital	**$ 427,705.00**	**$ 39,153.00**	**$ 907,623.00**	**$ 1,195,066.00**	**$ 1,448,137.00**	**$ 4,017,684.00**
Annual Totals:	**$ 5,121,040.00**	**$ 10,213,759.00**	**$ 5,650,217.00**	**$ 8,290,836.00**	**$ 7,717,815.00**	**$ 36,993,667.00**

Table 28 Historical Capital Expenditure

3.5.1.2 Forecast impact on O&M costs including direction and timing of expected impacts

The impact of capital investments on O&M will vary from project to project. In most cases, pro-active O&M expenses such as pole testing and tree trimming will not be impacted by capital investment. Projects focused on replacing and upgrading vintage assets such as our pole replacement program which targets poles approaching end of life will have a positive impact on reactive O&M costs as they will contribute to improved system reliability.

Some specific projects, such as our PoleTrans Replacement projects address safety concerns for workers performing maintenance on this vintage equipment. As the PoleTrans transformers are no longer manufactured, spare parts are difficult and expensive to acquire. Upgrading to modern equipment will allow for improved maintenance and improved safety for our crews.

The main goals of a number of our system renewal projects, including voltage conversion projects, are to improve system reliability, which will again have a positive impact on reactive O&M costs.

Beyond this high level discussion, Halton Hills Hydro is unable to provide a specific or detailed forecast of the impact these capital investment plans will have on our O&M costs.

3.5.1.3 Drivers of investment by category – referencing info provided in asset management and capital plans, historical trends and expected evolution of each driver over forecast period

The key drivers for all investments in this plan are:

- System Access
- System Renewal
- System Services
- General Plant

Proposed capital expenditures by category are summarized below:

System Access:

Project Category	2016	2017	2018	2019	2020
Make Ready Upgrades	$17,424	$17,772	$18,128	$18,490	$18,860
microFIT/ FIT	$43,732	$44,609	$45,501	$46,411	$47,340
Subdivisions	$207,000	$244,260	$288,227	$340,108	$401,327
Technical Service Layouts	$376,036	$384,684	$393,532	$402,584	$411,843
Municipal Road Widening	$1,668,844	$0	$2,426,000	$0	$0
Metering	$159,550	$194,988	$159,550	$159,550	$159,550
Subtotals	$2,472,588	$886,314	$3,330,938	$967,143	$1,038,920
Capital Contributions	$1,132,703	$595,554	$1,740,960	$711,103	$782,510
Total System Access	**$1,339,885**	**$290,760**	**$1,589,978**	**$256,040**	**$256,410**

Table 29 Planned System Access Investments

These projects include customer connections, new development, renewable generation connections, and can also include municipal relocation projects where the utility is required to relocate infrastructure to accommodate road improvement projects.

System Renewal:

Project Category	2016	2017	2018	2019	2020
Vintage System Replacements	$963,062	$1,250,781	$726,867	$900,086	$900,698
Feeder Renewal Projects	$0	$22,728	$0	$506,452	$1,349,951
Substation Improvements	$736,184	$953,352	$0	$813,695	$1,122,532
Metering Retail/Interval PMU replacements	$91,425	$0	$91,425	$0	$91,425
Total System Renewal	**$3,790,671**	**$4,226,861**	**$2,818,292**	**$4,220,233**	**$5,464,607**

Table 30 Planned System Renewal Investments

System renewal projects are investments a distributor makes involving 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. These projects are distributor driven. Our goal with system renewal projects is to ensure the assets used in the deliverance of power as well as the supporting infrastructure are in good condition, are safe to operate, and will continue providing reliability to our customers. This category includes plans to replace defective, obsolete, and end-of-useful life assets.

System Service:

Project Category	2016	2017	2018	2019	2020
SCADA projects	$135,562	$86,579	$0	$0	$0
Automated Switches	$301,851	$150,406	$157,568	$164,730	$171,892
Feeder Upgrade & Reinforcement	$375,239	$497,853	$497,853	$0	$0
Voltage Conversion Projects	$1,334,510	$847,518	$1,594,351	$3,268,153	$1,685,094
Municipal Substation Upgrades	$155,629	$272,525	$1,111,000	$936,224	$0
Total System Service	**$2,302,791**	**$1,854,882**	**$3,535,241**	**$4,567,366**	**$1,856,986**

Table 31 Planned System Service Investments

System service projects are investments a distributor makes involving 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. These projects are distributor driven; they address system constraints, and promote operational effectiveness. Our goal with system service projects is to ensure the distribution system is free of constraints that may impact system functionality and increases the utilities ability to operate the distribution system. The identified projects demonstrate system planning and the effective execution of the projects will provide system reliability and prepare for long term growth.

General Plant:

Project Category	2016	2017	2018	2019	2020
Vehicles & Tools	$177,000	$322,000	$259,000	$298,000	$312,000
IT Infrastructure	$77,800	$38,840	$100,000	$65,000	$0
SCADA Outage Mgmt System Interfaces	$67,813	$0	$0	$0	$0
Interactive Voice Response (IVR)	$100,000	$0	$0	$0	$0
Building Upgrades	$355,000	$118,576	$62,000	$62,000	$62,000
Total General Plant	**$777,613**	**$479,416**	**$421,000**	**$425,000**	**$374,000**

Table 32 Planned General Plant Investments

General Plant projects are investments that support the ongoing business operations and efficiency of the utility. These projects are distributor driven and include fleet management as well as IT infrastructure, tools, equipment and general building and facility maintenance and improvements.

3.5.1.4 Information related to System Capability Assessment

Presently Halton Hills Hydro has capacity to manage known developments presently under construction. HHHI is able to assess demand for new services and developments using in-house software to determine impacts on the distribution system and what changes may be needed to accommodate the development. Specific capacity constraints in certain areas of Halton Hills Hydro's service territory are addressed throughout this plan.

Halton Hills Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects anticipated from 2016 to 2020. Based on a calculated remaining maximum capacity and the projected generation projects Halton Hills Hydro has the capacity in place to accept future renewable generation projects. As such, there are no specific investments planned to accommodate renewable energy connections.

3.5.2 Material Investments (5.4.5.2)

- *Focus on projects that meet materiality threshold of $50K but include others that may be distinct for any reason (such as marked divergence from previous trend). Level of detail proportional to materiality. The info below must be included for EACH project that meets materiality requirements.*

This section of the Distribution System Plan provides detail on material investments included in the capital expenditure plan. Information is provided in detail for the test year, 2016, and at a summary level for projects in the forecast years.

Projects are categorized into one of four investment categories: System Access, System Renewal, System Service and General Plant.

Detail is provided below for all material projects by category for the test year, 2016. A summary is provided for projects below the materiality threshold of $50,000.00. A summary of projects planned for the forecast period also follows.

Based on gross expenditures, not including capital contributions, capital expenditure in 2016 is distributed as follows:

Investment Category	Percent of Budget
System Access	26%
System Renewal	41%
System Service	25%
General Plant	8%

Figure 62 2016 Capital Project Budget Allocation

Detailed project sheets for all 2016 Capital Projects listed in the sections below are provided in Appendix J.

3.5.2.1 System Access

System access projects are investments a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system. These projects include customer connections, new development, renewable generation connections, and can also include municipal relocation projects where the utility is required to relocate infrastructure to accommodate road improvement projects. System Access projects are customer driven. The utility will work closely with customers to coordinate efforts and ensure we are in a position to connect their service on time.

3.5.2.1.1 Technical Service Layouts

This project involves the connection of any new or upgraded residential, general, and temporary service to Halton Hills Hydro's distribution system. It represents the cost and risk involved with customer services and the assets associated with such services. Halton Hills Hydro is mandated by regulation to respond to customer requests for connection.

Halton Hills Hydro receives many applications each year for new services and service upgrades/ modifications. Each service application is an individual project and managed as such. Standard policies and procedures are applied uniformly to applications. Halton Hills Hydro assesses each application and determines the extent of work based on the customers servicing needs and electrical demand requirements.

These projects are customer driven and affected by customer timelines. Halton Hills Hydro works with our customers to mitigate potential timing issues by advising customers of expected timeframes for preparing a service layout package and estimate as well as timeframes for ordering and receiving transformers. A close working relationship is necessary to ensure customer driven target service dates are met.

3.5.2.1.2 Subdivisions

This project involves the design and connection of subdivisions to Halton Hills Hydro's distribution system. It represents the cost and risk involved with subdivisions and the assets associated with such services. Halton Hills Hydro is mandated by regulation to respond to customer requests for connection.

Subdivisions are customer driven, they design the street networks, house locations, and perform the civil work involved with installing hydro distribution infrastructure. Two (2) years following the connection of a subdivision, Halton Hills Hydro performs a final inspection and once all is acceptable assumes ownership of the distribution infrastructure up to the demarcation points specified in our conditions of service.

Projects are customer driven and affected by customer timelines. Halton Hills Hydro works with our customers to mitigate potential timing issues by advising customers of expected timeframes for preparing a design for the system expansion project and estimates for the utilities work as well as timeframes for performing the work. A close working relationship is necessary to ensure customer driven target service dates are met.

3.5.2.1.3 Municipal Road Widening Projects

Halton Hills Hydro has two municipal road widening projects planned for 2016.

The first project is an Intersection Widening project at Trafalgar Road and 10 Side Road. This project involves relocating our utility poles, wires, anchors, and related equipment at the intersection of Trafalgar Road and 10 Side Road to accommodate Region of Halton intersection improvement plans. Halton Hills Hydro will install new distribution infrastructure as laid out in our design and approved by the Region of Halton.

The second project is a road widening project along 9th Line between Steeles Ave and 10 Side Road. This project involves relocating our utility poles, wires, anchors, and related equipment along Steeles Avenue between Steeles Avenue and 10 Side Road to accommodate Region of Halton intersection improvement plans. Halton Hills Hydro will install new distribution infrastructure following a final design that is approved by the Region of Halton.

The primary risk to completion to these projects is if we begin construction prior to land and easement acquisition, part of the work may be delayed until Region of Halton can acquire the necessary land and easements. Halton Hills Hydro generally will not commence construction until we receive confirmation that land and easements are acquired or we have received permission to enter and construct our work. A secondary risk to completion is the Region of Halton requesting further changes once construction has commenced. To mitigate this second risk Halton Hills Hydro works closely with the Region to evaluate such requests to determine if they are necessary.

3.5.2.1.5 Metering

The Ontario Energy Board has mandated that AMI compatible interval meters be installed for all general service >50 kW customers who do not already have an interval meter in place. All new installations must have these meters installed and all existing locations must be retrofitted by 2020. Once complete, these customers will be billed based on hourly data and have access to view their energy data online.

Halton Hills Hydro’s smart meters were all installed in 2009 and 2010. Sample groups must be pulled and reverified in accordance with Measurements Canada seal expiry requirements. To cost effectively manage the volume of meters that will require sampling over the period covered by this Distribution System plan, the utility will begin group sampling in 2016 and continue throughout the period of this plan. Also included in this project are the costs of instrument transformers required for larger commercial and industrial service installations.

3.5.2.2 System Renewal

System renewal projects are investments a distributor makes involving 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. These projects are distributor driven. Our goal with system renewal projects is to ensure the assets used in the deliverance of power as well as the supporting infrastructure are in good condition, are safe to operate, and will continue providing reliability to our customers. This category includes plans to replace defective, obsolete, and end-of-useful life assets.

3.5.2.2.1 Pole Replacements

Pole replacements has been given a priority ranking of 5 as there is currently a backlog of poles greater than 50 years old in Halton Hills Hydro’s service territory. This project involves the replacement of utility poles that have been tested and have been found defective. It also involves replacing poles that have reached the end of their useful life as determined in Halton Hills Hydro Asset Management Plan. Projects will include mostly individual spot replacements of defective poles but may also include larger replacement project where risk ranking identifies areas of our distribution system containing a cluster of aged poles. As identified in our Asset Management Plan, Halton Hills Hydro has 1400 poles over 50 years old and another 1400 poles approaching 50 years old. The utility intends to replace 275-280 poles per year to address these aging pieces of infrastructure.

Halton Hills Hydro has maintained a formal pole testing and replacement program since 2004. Following a testing schedule approximately 1200 poles are tested annually and those found to be defective are replaced. Based on previous years data (2004 to 2014) 32 poles on average fail testing. In more recent years Halton Hills Hydro has begun the process of replacing significantly old poles that are well beyond their useful life. Such end of useful life replacements can appear as a cluster in our system and are replaced as part of a larger scale project rather than spot replacement. Overall asset management principles are well served when it is feasible to renew a larger part of the distribution rather than spot replacements. Having over 10 years in accumulated data, Halton Hills Hydro staff can determine rough costs to replace poles and can monitor estimates and actuals effectively.

3.5.2.2.2 Cross MS Switchgear Replacement

This project involves the replacement of a walk-in, metal-clad 4.16 kV switchgear that has reached end of life. Also supported is the reinforcement of the Georgetown 4.16 kV system by adding an additional feeder circuit breaker and main bus with higher ampacity to fully support the existing power transformer rating. This project has been given the highest priority ranking of 5 because it had been previously delayed, increasing risk of failure.

Asset renewal is the main driver for this project. The equipment has reached the end of its useful life and will require ongoing repairs and refurbishment in order to keep the equipment in a fit operational state. A secondary driver is 4.16 kV system reinforcement by supporting increased load capacity to ensure adequate supply for future growth and the support of load transfers during peak loading periods or planned maintenance outages on the system.

3.5.2.2.3 PoleTrans Replacements

This project involves the replacement of aged and obsolete PoleTrans transformers many of which were installed more than 30 years ago and are reaching the end of their useful life. PoleTrans are distribution transformers that are located at the base of street light poles and are contained in the pole. Access to the transformer is gained by panels on the exterior of the street light pole. This system renewal project is aimed at replacing aged distribution equipment that is no longer made and for which parts are hard to obtain. While PoleTrans transformers continue to operate on our 2.4/4.16Y kV distribution system this proactive approach will prevent undue hardship to customers were a PoleTrans to fail and were not repairable. In such cases customers may be faced with a significant outage until alternate power arrangement can be made. The design of PoleTrans transformers presents a problem for field staff as the design does not accommodate installation of temporary working grounds on the incoming or outgoing medium voltage power cables and still allow for the front panel to be closed and locked. Further the design of PoleTrans transformers provides very little clearance within the main compartment which that they are adequate for 2.4/4.16Y kV but not higher voltages. This work relates directly to our Asset Management Plan as it addresses the plan’s direction to replace PoleTrans units.

This project involves the replacement of infrastructure close to customer property and other utility equipment. The risk to completion is mitigated through customer consultations and coordination with all affected parties is necessary to ensure effective installation and completion of the project. By consulting with customers and other utilities, Halton Hills Hydro can set forth our project plans with realistic expectations for all impacted parties.

3.5.2.2.4 Vintage Underground Replacements/Refurbishments

This project involves the replacement of end of useful life primary cable. The primary cable in the John Street area of Georgetown was installed in the mid 1970's and is approaching its end of useful life (Asset Management Plan, SP14-03, Table 4-1). This cable is direct buried, of a lesser rating than what current practices require to be installed, and is one of the older underground parts of our Georgetown urban center. The project investment level represents the risk associated with such infrastructure failing. Replacement of aged assets will be coordinated in a two (2) phase approach over the course of 2016 and 2017.

This project involves the replacement of infrastructure close to customer property and other utility equipment. The risk to completion is mitigated through customer consultations and coordination with all affected parties is necessary to ensure effective installation and completion of the project. By consulting with customers and other utilities, Halton Hills Hydro can set forth their project plans with realistic expectations for all impacted parties.

3.5.2.3 System Service

System service projects are investments a distributor makes involving 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. These projects are distributor driven; they address system constraints, and promote operational effectiveness. Our goal with system service projects is to ensure the distribution system is free of constraints that may impact system functionality and increases the utilities ability to operate the distribution system. The identified projects demonstrate system planning and the effective execution of the projects will provide system reliability and prepare for long term growth.

3.5.2.3.1 Ballinafad MS Reclosers

This project involves replacing legacy oil circuit reclosers with newer vacuum reclosers. Included is the upgrade to protection relay class controllers that bring the added benefit of advanced metering and automation. Future connection to the utility SCADA system will bring the added benefit of substation automation, improved system reliability and reduction in maintenance costs.

Reliability, efficiency and automation/smart grid are the main drivers for this project. Oil circuit reclosers require more frequent maintenance to keep them in operation and while they provide feeder protection from temporary and permanent faults, routine maintenance switching operations must be done manually on site. With the benefit of having a control room, efficiencies may be gained through the use of remotely operable reclosers with advanced control capability.

3.5.2.3.2 SCADA Remote Operated Switch Integration

This project involves integrating existing motor operated and SCADA Mate switches with the utility SCADA system by installing radio communication technology.

Reliability is the main driver for this project. Interruptions on the 44kV and 27.6 kV systems affect many customers and large amounts of load. Motor operated switches have been installed to provide the ability to quickly sectionalize faulted sections and restore power back to unaffected sections. The objective of this project is for control room operators to reduce some restoration times and assist field crews with switching, thereby speeding the restoration process.

The continued investment in distribution automation will improve system reliability by reducing outage times due to remote operator intervention, and increase cost efficiencies by reducing on site operator visits during switching. Benefits to customers would be the utility ability to better monitor the feeders during peak loading conditions and ensure optimum power quality is delivered.

3.5.2.3.3 SCADA Wireless Faulted Circuit Indicators

This project involves the purchase of new wireless faulted circuit indicators for use on the 44 kV sub-transmission systems. This will give control room operators greater ability to find faulted portions of the system.

3.5.2.3.4 Voltage Conversion Projects

Halton Hills Hydro has a number of voltage conversion projects planned over the next several years to continue to expand the 27.6kV distribution system. The two projects planned for 2016 extend the 27.6kV system along 5 Side Road and Trafalgar Rd.

The first project is along 5 Side Road between Trafalgar Rd and 8th Line. It continues Halton Hills Hydro's planned expansion of our 27.6kV distribution system into areas of our service territory where 8.32kV is the current distribution voltage. By expanding our 27.6kV distribution system we will also be phasing out portions of our 8.32kV distribution system in the southern regions of our service territory that often single phase radial supplies. This project will enable Halton Hills Hydro to build a feeder loop between our 41M21 and 41M29 feeders along 5 Side Road between Trafalgar Road and 8th Line. It will also serve to support additional load growth anticipated by the Town of Halton Hills Vision Georgetown plan (20,000 people and 1700 jobs by 2031) where development is expected to start in the early 2020's. This project will also provide options for directing power flow to current load and subdivisions under development in Georgetown by providing additional switching capabilities which will enable Halton Hills Hydro to switch load and maintain good service quality and reduce restoration time.

This project is comparative to past 27.6kV expansion projects along 5 Side Road between 5th Line and Trafalgar Road. The project takes place in our rural service territory where much of the land is farmed and there exists significant tree populations. In past experience we have communicated with our customers to advise them of our planned work and any impacts it may have near their property. We also have coordinated tree trimming, removals, and replacements where customer trees have been impacted. We learn from past experiences and incorporate such experiences into our future designs so that we can better address customer concern and the utilities' needs.

The second project is on Trafalgar Rd. from 15 Side Rd to Maple Ave. This project continues Halton Hills Hydro's planned expansion of our 27.6kV distribution system to support anticipated load growth, in this case north of Town of Halton Hills office on Halton Hills Drive. This project will see our 27.6kV distribution system brought north along Trafalgar Road between 15 Side Road and 17 Side Road/ Maple Avenue and will require poles and supporting apparatus to be replaced and new infrastructure installed that will support the existing 44kV and 8.32kV circuits and additionally permit a place for a 27.6kV circuit. This project will also ensure that Halton Hills Hydro remains compliant with the Distribution System Code and can provide an Offer to Connect.

This project is comparative to past 27.6kV expansion projects along Trafalgar Road between 10 Side Road and 15 Side Road. That project took place in our rural service territory where much of the land is farmed. In past experience we have communicated with our customers to advise them of our planned work and any impacts it may have near their property. We also have coordinated tree trimming, removals, and replacements where customer trees have been impacted. We learn from past experiences and incorporate such experiences into our future designs so that we can better address customer concern and the utility’s needs. This project will be completed within the urban limits where work will be close to residential properties.

The main two (2) risks to completion of these two projects are that of customer awareness and material ordering. In respect of customer awareness, Halton Hills Hydro communicates with our customers about planned work to inform our customers of the work that will be taking place in their vicinity. Halton Hills Hydro works closely with customers to ensure their concerns are addressed as the project progresses. Secondly but of no less importance is material ordering. Halton Hills Hydro plans its projects to ensure enough lead time to receive materials before the job is scheduled to begin.

3.5.2.3.5 Feeder Upgrade and Reinforcement

There are two projects in this category planned for 2016.

Halton Hills Hydro will reinforce part of its 2.4/4.16kV distribution system along Delrex Blvd. between Rexway Drive and Maple Avenue. This project will include replacing utility poles, transformers, wire, and guying. The intent to continue feeder upgrades and reinforcement projects that began in 2014 to strength our distribution system in Georgetown and support existing and future load growth.

This project is comparative to past system reinforcement projects along Sargent Road and on Delrex Blvd in 2014. The project takes place in our urban Georgetown service territory where most services are residential but do include some small commercial. In past experience we have communicated with our customers to advise them of our planned work and any impacts it may have near their property. We also have coordinated tree trimming, removals, and replacements where customer trees have been impacted. We learn from past experiences and incorporate such experiences into our future designs so that we can better address customer concern and the utility’s needs. These areas of the distribution system contain assets that have been in-service well beyond their useful life and replacing the infrastructure should not leave stranded assets.

The main two (2) risks to completion are that of customer awareness and material ordering. In respect of customer awareness, Halton Hills Hydro communicates with our customers about planned work that will be taking place in their vicinity. Halton Hills Hydro works closely with customers to ensure their concerns are addressed as the project progresses. Secondly but of no less importance is material ordering. Halton Hills Hydro plans its projects to ensure enough lead time to receive materials before the job is scheduled to begin.

Halton Hills Hydro will be completing a project to extend the 8.32 kV 5F3 feeder along 32 Sideroad from 5th Ln to 4th Ln to connect with the 5F1 feeder to better utilize the existing 5F3 feeder capacity and relieve the 5F1 from high loading.

This project involves the installation of infrastructure close to wooded areas and across a transmission corridor. The risk to completion is mitigated through customer and transmitter consultations and coordination with all affected parties is necessary to ensure effective installation and completion of the project. By consulting with customers and other utilities, Halton Hills Hydro can set forth our project plans and set realistic expectations for all impacted parties.

The main driver is reinforcement of the 8.32 kV system. Transfer of 5F1 load to the 5F3 will better balance the feeders out of Silver Creek MS, reduce line losses and provide better load transfer capability during maintenance outages and unplanned outages, contributing to better reliability.

3.5.2.3.6 Automated Switches

Halton Hills Hydro continues to install automated switches at key locations throughout the distribution system to develop the utility’s smart grid. Two ongoing projects focus on installing switches on the 44 kV system and the 27.6 kV system.

The first project focuses on 46 kV switches. In 2016, Halton Hills Hydro will purchase and install two automated switches that will be installed at key locations on our 44kV distribution system to enhance the utility's ability to systematically perform switching operations during normal and emergency conditions.

The second project will be to install two automated switches at key locations on the 27.6 kV distribution system.

Halton Hills Hydro has installed automated switches on our 44kV distribution system since 2012. In the past switches were installed at normally open and normally closed switch points. Coordination with staff installing the switches and the control room are of vital importance to ensure switches are installed and commissioned to avoid impacting our 44kV distribution system.

3.5.2.4 General Plant

General Plant projects are investments that support the ongoing business operations and efficiency of the utility. These projects are distributor driven and include fleet management as well as IT infrastructure, tools, equipment and general building and facility maintenance and improvements.

3.5.2.4.1 Vehicles & Tools

Halton Hills Hydro maintains a long term vehicle maintenance strategy where smaller vehicles are replaced every 10 years and large trucks are replaced every 12 years. Other equipment such as trailers and generators are evaluated every 5 years once they reach 20 years of age and are only replaced when necessary. This long term strategy ensures a relatively even annual budget for vehicles.

The 2016 trucking project involves $110,000 to purchase chassis in Q3 for new digger derrick in 2016, boom and body to be purchased in 2017. Costs spread over 2 years to balance spending over a ten year period for fleet purchasing. Also $35,000 is budgeted in Q2 for a new Engineering/Metering vehicle as we currently have 7 employees sharing 3 vehicles in our Engineering & Metering departments.

Historically chassis prices can range between $85,000 to $110,000 depending on the size of vehicle to be manufactured. We will be replacing our dual axle (large) digger derrick in 2017 so our chassis will need to be able to accommodate this heavy vehicle. We must also take into consideration the exchange rate on the US dollar as the chassis' are manufactured in the United States. Small vehicle fleet purchases range between $25,000 and $50,000. We will be considering electric & hybrid vehicles for our Engineering/Metering department. We also purchase AWD or 4x4 vehicles for safety reasons due to the environment and road conditions that these vehicles are subjected to. ie subdivisions under construction, unassumed roads, winter driving conditions etc.

Provided we follow our 20 year fleet replacement plan we have a reasonably balanced dollar value budgeted for each year to avoid hills and valleys in spending while maintaining a 10 year replacement for small fleet vehicles and a 12 year replacement for large fleet vehicle formula. If a budgeted purchase is deferred for any reason, the costs associated with the deferred purchase are added to the following year’s non construction capital budget as these costs do not go away. Maintaining post end of life fleet vehicles directly affects our OM&A budget as well as creating downtime for the employees that rely on our fleet vehicles to perform their duties safely and efficiently.

Each year, $32,000 is budgeted for new tools for engineering and operations staff to utilize in the field. Upgraded tools are chosen to replace tools where necessary and to improve ergonomics and safety for staff.

3.5.2.4.2 IT Infrastructure

This project is to replace our existing IBM System i 520 (Power5+) Server which was installed in 2008. In 2016 Halton Hills Hydro will purchase and install an IBM Power System S814 (Power8). The new Enterprise POWER8 Server will provide increased system performance, dynamic resource sharing, reduced footprint, and improved energy efficiency. Halton Hills Hydro installed our current System i5 520 in June 2008 for roughly $75,000.

By not completing this project Halton Hills Hydro may run the risk of increased hardware failures, slower system performance, and an increase of downtime (current objective of 99.0%) by maintaining the existing 8 year old server. The existing IBM System I was withdrawn from the market late in 2008.

3.5.2.4.3 SCADA Outage management System Interfaces

This project involves the purchase of new software interface licenses for the SCADA system and contract services for implementation of a SCADA based outage management system. In order to give the control room operators greater ability to find faulted portions of the system, greater information needs to be brought into the real time SCADA database from customer information systems, Advanced Metering Infrastructure, among others.

3.5.2.4.4 Interactive Voice Response Phone System (IVR)

Currently, Halton Hills Hydro has live Customer Care Representatives to answer inquiries during normal business hours (Monday to Friday 8:30am to 4:30pm, excluding holidays). If customers are unable to call the office during office hours, they only have internet based options to communicate with the utility by utilizing Halton Hills Hydro's webpage or social media. The IVR system will be available 24 hours a day, 7 days a week, including holidays. The IVR will be directly connected to the Customer Information System (CIS) and will allow customers to access information about their accounts and power outages in real-time. The IVR will allow better accessibility to customers without internet or those who prefer to use the phone.

3.5.2.4.5 Building Maintenance

In 2016, Halton Hills Hydro plans to resurface the garage roof. This was last done in 1990. The utility also plans to repave the entire parking lot. This project will include complete resurfacing including removal of existing asphalt; full-depth reclamation and sub-base preparation including grading of base with proper pitch for effective drainage, new gravel base, compact and resurface over new compacted gravel surface. The parking lot has suffered from extensive frost heaving over the years and is now severely cracked and heaved in several areas. This project will ensure staff and customer safety while attending the facility.